AES Indiana

2022 Integrated Resource Plan

(IRP)

Volume I

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2022 Integrated Resource Plan (IRP)

Letter from AES Indiana's President and CEO

Accelerating the Future of Energy in Indianapolis

For more than a decade, AES Indiana has been a leader in our state's energy transition. As the energy landscape changes, we understand our responsibility to our customers and to the business community to facilitate an inclusive transition that grows our economy and strengthens our communities. New technology presents us with a tremendous opportunity to reduce our environmental impact and power greener customer choices by making smart and balanced investments in our generation portfolio.

Our 2022 plan is our boldest move towards sustainability in the company's history. We plan to further transform our city's energy infrastructure by more than quadrupling our renewable energy capacity – and saving our customers hundreds of millions of dollars in the coming years. We will also convert Petersburg Units 3 and 4 in 2025 to operate using natural gas, which will maintain reliability by offering a one-for-one replacement of dispatchable capacity of the Petersburg units.

Under this plan, we will further reduce our carbon dioxide emissions per hour of electricity generated by two-thirds in this decade. By 2042, we expect to source more than 85% of our energy from wind, solar and other renewable technologies. As we progress in our plan, each investment decision in our generation fleet is subject to regulatory and other approvals.

Our plan is designed to meet our customers' needs of affordability, reliability, and sustainability both now and into the future.

Accelerating the Future of Energy, Together

I would like to thank all our customers, partners, suppliers, and stakeholders who engaged in our 2022 IRP process. Energy is foundational to our high quality of life, economic growth, and community development in central Indiana. We aspire to create the energy services of the future that will benefit all our customers and strengthen our communities. This IRP is a very important step on this journey.

Kristina Lund
President and CEO, AES US Utilities

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Acronyms and Defined Terms

#

2H	Second Half

A

AC	Alternating Current
ACE	Affordable Clean Energy Rule
ACI	Activated Carbon Injection
ACLM	Air Conditioning Load Management
AD/CVD	Anti-Dumping Countervailing Duties
AEO	Energy Information Administration’s Annual Energy Outlook
AEP	Indiana Michigan Power Company
Aero CT	Aeroderivative Combustion Turbine
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
Anchor Power	Anchor Power Solutions LLC’s
ANSI	American National Standards Institute
ATB	Annual Technology Baseline

B

BAU	Business-as-Usual
BESS	Battery Energy Storage System
BIP	Balanced Indigenous Population
BNEF	Bloomberg New Energy Finance’s
Brightline	Brightline Group
Btu	British Thermal Units
BTA	Best Technology Available

C

C&I	Commercial and Industrial
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CAC	Citizens Action Coalition
CAIR	Clean Air Interstate Rule
CASPR	Cross State Air Pollution Rule
CBECS	Energy Information Administration's Commercial Buildings Energy Consumption Survey
CCGT	Closed Cycle Gas Turbine
CCP	Coal Combustion Products
CCR	Coal Combustion Residuals
CCT	Clean Coal Technology
CDD	Cooling Degree Days
CEPP	Clean Energy Performance Program
CO2	Carbon Dioxide
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbines
CWA	Clean Water Act
CWIS	Cooling Water Intake Structures

D

DC	Direct Current
DCFC	Direct Current Fast Charging
DEI	Duke Energy Indiana, LLC
DER	Distributed Energy Resource
DG	Distributed generation

DLC	Direct Load Control
DOE	U.S. Department of Energy
DOJ	U.S. Department of Justice
DR	Demand Response
DSM	Demand Side Management

E

Eagle Valley	Eagle Valley Generating Station
EE	Energy Efficiency
Eff. Prod	Efficiency Products
EGU	Electric Generating Unit
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitations Guidelines
EnCompass	EnCompass Power Planning Software
EPA	United States Environmental Protection Agency's
ERAG	Eastern Interconnection Reliability Assessment Group
ESCR	Effective Short Circuit Ratio
ESP	Electrostatic Precipitator
ESR	Electric Storage Resources
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment

F

FAC	Facility Ratings
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
FGD	Flue Gas Desulfurization
FHA	U.S. Department of Transportation's Federal Highway Administration
FIP	Federal Implementation Plan

FLISR	Fault Location, Isolation, and Service Restoration
Frame CT	Simple Cycle Combustion Turbine
FTE	Full-Time Employees

G

GDP	Gross Domestic Product
GDS	GDS Associates, Inc.
Georgetown	Georgetown Generating Plant
GFM	Grid-Forming Inverters
GHG	Greenhouse Gases
GT1	Harding Street Diesel Unit 1
GT2	Harding Street diesel Unit 2
GVTC	Generation Verification Test Capability

H

HAP	Hazardous Air Pollutant
Hardy Hills	Hardy Hills Solar (IURC Cause No. 45493)
HDD	Heating Degree Days
HE	Hoosier Energy Rural Electric Cooperative, Inc.
HER	Home Energy Report
HL	High Load Factor Rate
Horizons Energy	Horizons Energy, LLC
HRSG	Heat Recovery Steam Generator
HS or Harding Street	Harding Street Generating Station
HVAC	Heating, Ventilation, and Air Conditioning

I

IAC	Indiana Administrative Code
IBR	Inverter Based Resources
ICAP	Installed Capacity
ICE	International Exchange, Inc.

IDEM	Indiana Department of Environmental Management
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IIJA	Infrastructure Investment and Jobs Act
ILR	Inverter Loading Ratio
Indiana BMV	Indiana Bureau of Motor Vehicles
IQW	Income Qualified Weatherization
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ITC	Investment Tax Credits
IURC	Indiana Utility Regulatory Commission

K

kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt Hour

L

LBNL	Lawrence Berkeley National Labs
LCOE	Levelized Cost of Energy
LED	Light-Emitting Diode
LIDAR	Light Detection and Ranging
Li-ion	Lithium-ion
LMR	Load Modifying Resources
LNB	Low NOx Burner
LOLE	Loss of Load Expectation
LQG	Large Quantity Generator

M

MAP	Maximum Achievable Potential

MAPE	Mean Absolute Percent Error
MATS	Mercury and Air Toxic Standard
MECS	Energy Information Administration's Manufacturing Energy Consumption Survey
MF	Multifamily
MISO	Midcontinent Independent System Operator
MMBtu	Millions of British Thermal Units
mmgal	Millions of Gallons
mmtons	Millions of Tons
MOD	Modeling Data Analysis
MPP	Multi-Pollutant Plan
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Plan
MVA	Megavolt-Amperes
MVAR	Megavolt Amperes Reactive
MW	Megawatts
MWh	Megawatt-hour

N

NAAQS	National Ambient Air Quality Standard
NAICS	North American Industry Classification System
NDA	Nondisclosure Agreement
NERC	North American Reliability Corporation
NG	Natural Gas
NN	Neural Net
NOx	Nitrogen Oxides
NPDES	National Pollution Discharge Elimination System
NREL	National Renewable Energy Labs

O

O&M	Operation and Maintenance

OFA	Overfire Air

P

P5	Fifth Percentile
P95	95th Percentile
PC	NERC Registered Planning Coordinator
PEC	Petersburg Energy Center (IURC Cause No. 45591)
Petersburg Conversion	Petersburg Generating Station Conversion from Coal to Natural Gas Steam Turbines
Petersburg	Petersburg Generating Station
PJM	PJM Interconnection, L.L.C.
PPA	Power Purchase Agreements
ppb	Parts per Billion
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credits
PV	Photovoltaic
PVRR	Present Value of Revenue Requirements

Q

Quanta	Quanta Technology, LLC

R

RAP	Realistic Achievable Potential
Rate EVP	Electric Vehicle Charging on Public Premises
Rate EVX	Time of Use Service for Electric Vehicle Charging on Customer Premises
Rate REP	Rate Renewable Energy Production
RC	Residential General Service with Electric Water Heating
RCRA	Resource Conservation and Recovery Act
RCRA	Resource Conservation and Recovery Act

Recip. Engines	Reciprocating Engines
REX	Rockies Express pipeline
RF	Reliability First
RFI	Request for Information
RFP	Request for Proposals
RH	Residential General Service with Electric Heat
RIIA	Renewable Integration Impact Assessment
RPS	Renewable Portfolio Standard
RS	Residential General Service
RTE	Round Trip Efficiency
Rx	Prescriptive

S

SAC	Seasonal Accredited Capacity
SAE	Statistically Adjusted End-Use
SAM	National Renewable Energy Labs' System Advisor Model
SCR	Selective Catalytic Reduction
SEM	Strategic Energy Management
SH	Small C&I Secondary Service – Electric Space Conditioning
SI	Sorbent Injection
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SQG	Small Quantity Generator
SS	Small C&I Secondary Service – Small
ST	Steam Turbines

T

T&D	Transmission and Distribution
Task Force	Indiana's 21st Century Energy Policy Development Task Force
TBEL	Technology-Based Effluent Limits

TDSIC	Transmission, Distribution, and Storage System Improvement Charge
TDSIC Plan	AES Indiana's Seven-Year TDSIC Plan
TGT	Texas Gas Transmission
TO	Transmission Owner
TOU	Time of Use
TP	Transmission Planner
TPL	NERC Transmission System Planning Performance Requirements
TRC	Total Resource Cost

U

UCAP	Unforced Capacity Credit
UCT	Utility Cost Test
UFLPA	Uyghur Forced Labor Prevention Act

V

VAR	Volt-Amps Reactive
VER	Variable Energy Resource
VSQG	Very Small Quantity Generator

W

WIIN	Water Infrastructure Improvements for the Nation Act
WQBEL	Water Quality Based Effluent Limits
WTP	Willingness to Participate

X

XCool	Itron's Estimates of Cooling Requirements
XEFORd	Three-Year Rolling Average Availability Rating
XHeat	Itron's Estimates of Heating Requirements
XOther	Itron's Estimates of Other Uses

Executive Summary

AES Indiana's 2022 Integrated Resource Plan ("IRP") was developed in an environment with unprecedented market changes that created challenges for long-range planning. Specifically, the approval of Midcontinent Independent System Operator's ("MISO") seasonal resource adequacy construct, the passage of the Inflation Reduction Act, volatile commodity prices for power and fuels, inflated costs for replacements resources, and scarcity within the nitrogen oxides ("NOx") allowance market have all influenced AES Indiana's strategy and process for this IRP.

Through a transparent planning and stakeholder engagement process that addressed the noted challenges and a comprehensive evaluation of 17 Scorecard Evaluation metrics, AES Indiana selected a Preferred Resource Portfolio and Short Term Action Plan that provides affordable, reliable, and sustainable energy for its customers.

AES Indiana's Preferred Resource Portfolio and Short Term Action Plan will:

Add Renewables

Add up to 1,300 MW of wind, solar, and storage resources by 2027

AES Indiana's EnCompass Capacity Expansion Model ("EnCompass Model") indicates that an additional 500 to 1,065 MW of wind and solar resources by 2027 to cost effectively source energy for its customers. AES Indiana has already issued a Request for Proposals ("RFP") for generation and expects to issue more RFPs in the future. With the Inflation Reduction Act tax incentives, wind, solar, and battery energy storage resources are among the most cost effective energy sources, particularly renewable and energy storage projects located in "Energy Communities," as the term is used in the Inflation Reduction Act, such as Pike County, Indiana.

Additionally, AES Indiana has a 240-megawatt ("MW") winter capacity need starting in 2025 due to MISO's new seasonal resource adequacy construct. Modeling results indicate that, after including the Investment Tax Credit benefits for standalone storage that were included in the Inflation Reduction Act, battery energy storage is the most cost effective capacity resource to fill this need.

Convert

Convert Petersburg Generating Station ("Petersburg") Units 3 and 4 (1,052 MW) to natural gas in 2025 via existing pipeline on site

Based on extensive modeling, AES Indiana has determined that the conversion of the Company's remaining coal units from coal to natural gas provides customers with a strategy that can reliably meet capacity obligations in MISO's seasonal resource adequacy construct. AES Indiana will convert Petersburg Units 3 and 4 in 2025 to operate using natural gas. The conversion involves modifications to AES Indiana's existing infrastructure and will utilize gas delivered via a pipeline that is already on AES Indiana's property. The conversion maintains reliability for AES Indiana's customers while reducing cost and carbon emissions from generation.

Monitor

Monitor emerging technologies for inclusion in future planning

Beyond the three- to five-year Short Term Action Plan, which includes the items mentioned above, AES Indiana will continue to monitor new and emerging technologies that could serve as viable clean energy options for future IRP planning. More specifically, the Company is closely following progress made in new technologies, such as longer duration storage coupled with solar, clean hydrogen, and small modular reactors that could serve as reliable capacity in future years. If these technologies are deemed cost effective and viable, the Company will include them as replacement options in future Integrated Resource Plans.

The Preferred Resource Portfolio and Short Tern Action Plan will provide AES Indiana customers:

Affordability

- → Saves AES Indiana customers more than $240 million over the 20-year planning horizon.
- → Provides the least cost to customers over the 20-year planning horizon through the economic conversion of the remaining Petersburg units from coal to natural gas.
- → Demonstrates lowest annual Present Value Revenue Requirement ("PVRR") relative to other portfolios over the 20-year planning horizon.

Sustainability

- → Provides 68% reduction in carbon intensity in 2030 compared to 2018 levels.
- → Delivers the quickest exit from coal-fired generation (in 2025) which provides the lowest 20-year AES Indiana generation portfolio emissions for sulfur dioxide ("SO2"), NOx, water use and coal combustion products, and the second lowest emissions for carbon dioxide ("CO2").

Reliability

- → Highest composite reliability score using Quanta Technology, LLC's ("Quanta") Reliability Analysis.
- → Offers one-for-one replacement dispatchable capacity (measured in unforced capacity) for Petersburg that economically and effectively delivers in meeting MISO's seasonal resource adequacy construct.
- → Provides firm unforced capacity when needed, which will allow AES Indiana to responsibly and gradually transition to renewable energy resources over the planning horizon.
- → Demonstrates the highest composite reliability score while still delivering significant renewable generation investment.

Optionality

→ AES Indiana's Short Term Action Plan meets customers' objectives, while preserving optionality for the future. AES Indiana will monitor existing trends and be able to incorporate emerging, economically viable technologies into future IRPs.

2022 IRP Framework

AES Indiana utilized a Portfolio Matrix scenario framework that evaluated five predefined strategies and one optimization (allowed the planning model to economically select a portfolio without a strategy predefined).

The five predefined strategies included are:

1. Operating the remaining Petersburg coal Units 3 and 4 on coal through the remainder of their useful lives.
2. Converting Petersburg Units 3 and 4 to natural gas in 2025.
3. Retiring Petersburg Unit 3 in 2026 and leaving Petersburg Unit 4 on coal through the remainder of its useful life.
4. Retiring both Petersburg Units 3 and 4 in 2026 and 2028.
5. Retiring both Petersburg Units 3 and 4 in 2026 and 2028 and replacing them with wind solar and storage.

These five strategies and the sixth optimization were optimized across four different scenarios that included a range of environmental policy assumptions:

1. **No Environmental Action** – included relaxed environmental regulation and no subsidies for renewables.
2. **Current Trends/Reference Case** – included the most likely future environmental regulations including renewable subsidies contained in the Inflation Reduction Act.
3. **Aggressive Environmental** – included a carbon tax starting in 2028 at $19.47 per ton.
4. **Decarbonized Economy** – included a Renewable Portfolio Standard that requires utilities to transition supplying most of the energy from clean energy sources by 2042.

Results from the scenario analysis demonstrated that converting Petersburg to operate using natural gas in 2025 is the most affordable strategy for customers – particularly in the Current Trends/Reference Case scenario, which provides the most likely representation of the future.

Scorecard Evaluation & Results Summary

AES Indiana conducted a robust Scorecard Evaluation of the Current Trends/Reference Case strategies (Candidate Portfolios) to select the Preferred Resource Portfolio and Short Term Action Plan. In the Scorecard Evaluation, the Company evaluated the Candidate Portfolios using five categories that address critical utility planning considerations. These include the Five Pillars of Electric Service as defined by the 21st Century Energy Policy Development Task Force of **Affordability, Sustainability, Reliability, Resiliency and Stability**. Additionally, the Company included metric categories for **Risks & Opportunities and Social and Economic Impacts**.

Each category included metrics that appropriately quantify and measure the Candidate Portfolios' performance. Figure 0-1 provides the Scorecard Evaluation and results used for evaluation and decision making.

Figure 0-1: Scorecard Evaluation Results Summary

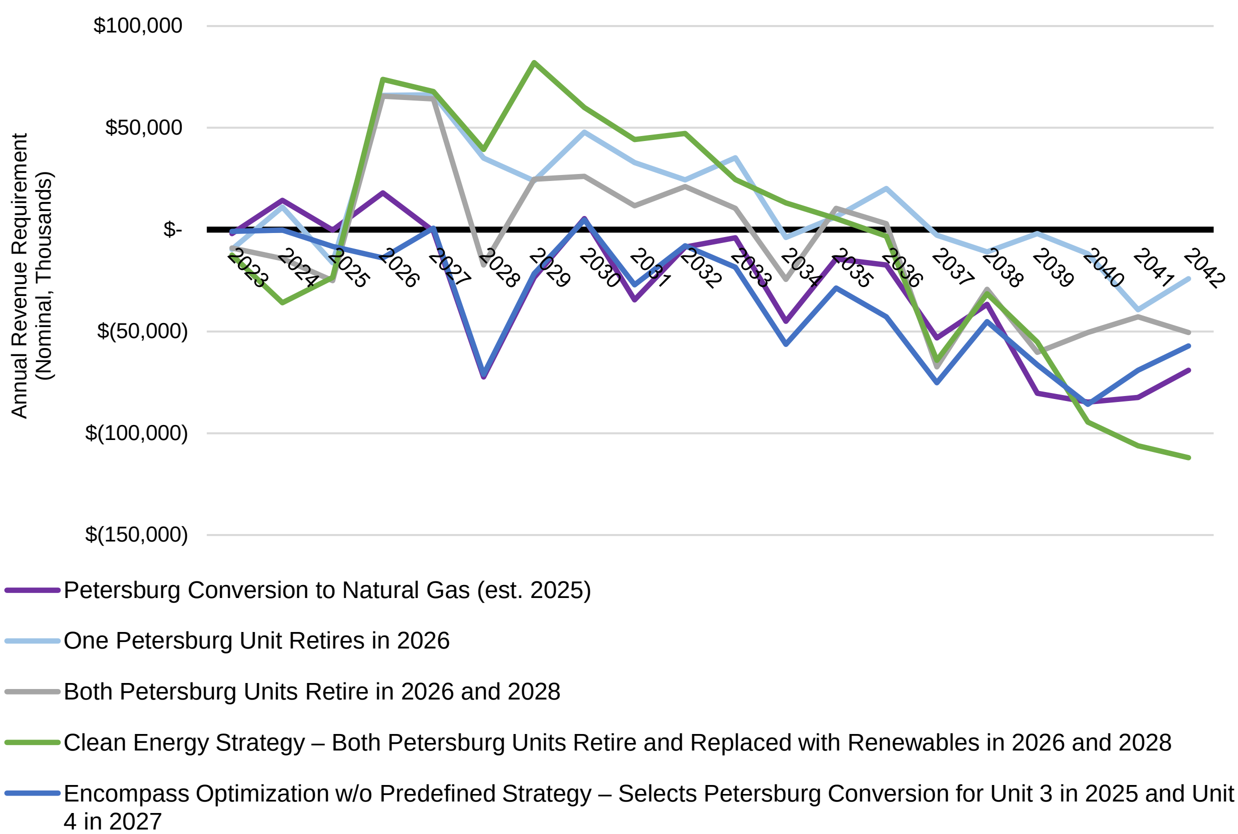
	Affordability	Environmental Sustainability						Reliability, Stability & Resiliency	Risk & Opportunity							Economic Impact	
	20-yr PVRR	*CO_2 Emissions*	*SO_2 Emissions*	*NO_x Emissions*	*Water Use*	*Coal Combustion Products (CCP)*	*Clean Energy Progress*	*Reliability Score*	*Environmental Policy Opportunity*	*Environmental Policy Risk*	*General Cost Opportunity **Stochastic Analysis***	*General Cost Risk **Stochastic Analysis***	*Market Exposure*	*Renewable Capital Cost Opportunity (Low Cost)*	*Renewable Capital Cost Risk (High Cost)*	*Generation Employees (+/-)*	*Property Taxes*
	Present Value of Revenue Requirements ($000,000)	Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)	% Renewable Energy in 2032	Composite score from Reliability Analysis	Lowest PVRR across policy scenarios ($000,000)	Highest PVRR across policy scenarios ($000,000)	P5 [Mean - P5]	P95 [P95 – Mean]	20-year avg sales + purchases (GWh)	Portfolio PVRR w/ low renewable cost ($000,000)	Portfolio PVRR w/ high renewable cost ($000,000)	Total change in FTEs associated with generation 2023 - 2042	Total amount of property tax paid from AES IN assets ($000,000)
1	$ 9,572	101.9	64,991	45,605	36.7	6,611	45%	7.95	$ 8,860	$ 11,259	$ 9,271	$ 9,840	5,291	$ 9,080	$ 10,157	222	$ 154
2	$ 9,330	72.5	13,513	22,146	7.9	1,417	55%	7.95	$ 8,564	$ 11,329	$ 9,030	$ 9,746	5,222	$ 8,763	$ 9,999	99	$ 193
3	$ 9,773	88.1	45,544	42,042	26.7	4,813	52%	7.86	$ 9,288	$ 11,462	$ 9,608	$ 10,237	5,737	$ 9,244	$ 10,406	195	$ 204
4	$ 9,618	79.5	25,649	24,932	15.0	2,700	48%	7.90	$ 9,135	$ 11,392	$ 9,295	$ 9,903	5,512	$ 9,104	$ 10,249	74	$ 242
5	$ 9,711	69.8	25,383	24,881	14.8	2,676	64%	7.57	$ 9,590	$ 11,275	$ 9,447	$ 10,039	6,088	$ 9,017	$ 10,442	55	$ 256
6	$ 9,262	76.1	18,622	25,645	10.9	1,970	54%	7.95	$ 8,517	$ 11,226	$ 8,952	$ 9,629	5,136	$ 8,730	$ 9,909	88	$ 185

Strategies

1. No Early Retirement
2. Pete Conversion to Natural Gas (est. 2025)
3. One Pete Unit Retires in 2026
4. Both Pete Units Retire in 2026 and 2028
5. Clean Energy Strategy – Both Pete Units Retire and replaced with Renewables in 2026 and 2028
6. Encompass Optimization without Predefined Strategy

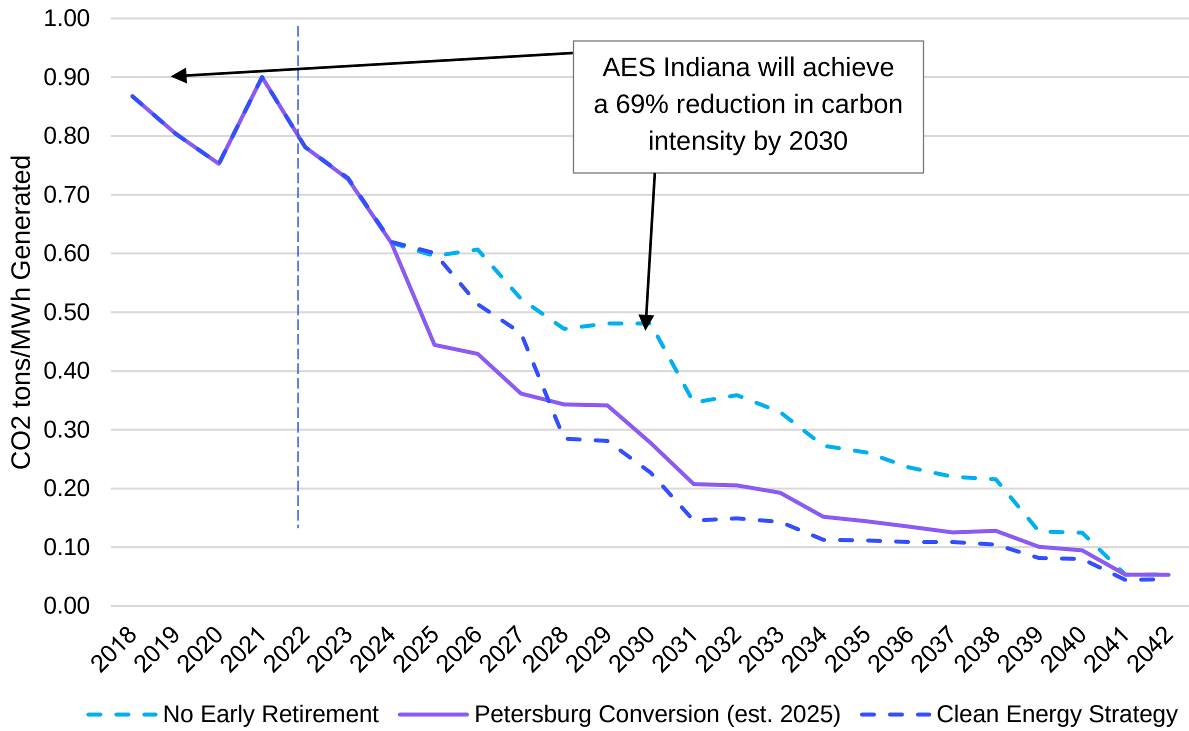
The Scorecard Evaluation demonstrated that the Petersburg Conversion provides the most affordable strategy for AES Indiana customers by exhibiting the lowest 20-year PVRR and lowest annual revenue requirement volatility over the 20-year planning period. Figure 0-2 below compares the annual revenue requirement impact from the different strategies to operating Petersburg as a coal resource. The graph demonstrates that the conversion of Petersburg Units 3 and 4 provides the lowest annual revenue requirement impact to customers over the planning period. Figure 0-2 identifies the annual PVRR of each Candidate Portfolio Compared to the No Early Retirement strategy.

Figure 0-2: Candidate Portfolios Annual PVRR Compared to the No Early Retirement Strategy



Additionally, the Scorecard Evaluation demonstrated that the Petersburg conversion provides the lowest SO2, NOX, water use and coal production product emissions and the second lowest CO2 emissions over the 20-year planning period making it the best performing strategy in the Sustainability category. Figure 0-3 below shows that the Petersburg conversion will provide a 69% reduction in CO2 emission by 2030 compared to 2018 levels.

Figure 0-3: Candidate Portfolio Annual Present Value Revenue Requirement Compared to the No Early Retirement Scenario



To measure Reliability in the Scorecard Evaluation, AES Indiana consulted with Quanta Technology to perform a Reliability Analysis of the Candidate Portfolios. Quanta evaluated nine different reliability categories including Energy Adequacy, Operational Flexibility and Frequency Support, Short Circuit Strength Requirement, Power Quality (Flicker), Blackstart, Dynamic VAR Support, Dispatchability and Automatic Generation Control, Predictability and Firmness of Supply, and Geographic Location Relative to Load (resilience). Quanta created a Composite reliability score from these nine categories to evaluate the Candidate Portfolios. Their analysis demonstrated that the Petersburg conversion performed the best among the Candidate Portfolios by maintaining Petersburg as a dispatchable resource.

The Scorecard Evaluation also evaluated the Candidate Portfolios for the Risk and Opportunity associated with changing environmental policies, volatile commodities, market interaction & exposure, and fluctuating renewable resource costs. This evaluation included a stochastic analysis that ran 100 simulations of power prices, gas prices, coal prices, load, and renewable generation. The Petersburg conversion performed the best overall across the Risk and Opportunity Metrics that were considered.

Finally, the Scorecard Evaluation considered the social and economic impact from the Candidate Portfolios. It was determined that the Petersburg Conversion will continues to contribute economically to the Petersburg community by leveraging existing infrastructure and maintaining operation of the Petersburg Generating Station as a gas resource and hub for renewable resources.

Section 1: Introduction

AES Indiana generates, transmits, distributes, and sells electricity to approximately 517,000 retail customers in Indianapolis and neighboring areas up to 40 miles from Indianapolis. AES Indiana's service area covers about 528 square miles. AES Indiana is subject to the regulatory authority of the Indiana Utility Regulatory Commission ("IURC") and the Federal Energy Regulatory Commission ("FERC"). AES Indiana fully participates in the electricity markets managed by the MISO. AES Indiana is a transmission company member of Reliability First ("RF"). RF is one of eight Regional Reliability Councils under the North American Reliability Corporation ("NERC"), which has been designated as the Electric Reliability Organization under the Energy Policy Act of 2005.

Every three years, AES Indiana submits an IRP to the IURC in accordance with the provisions in the Indiana Administrative Code ("IAC") (IAC 170 4-7) to describe expected electrical load requirements, potential risks, possible future scenarios, and defines a preferred resource portfolio to meet those requirements over a forward-looking 20-year study period based upon analysis of all factors. This process includes extensive collaboration with stakeholders known as a "Public Advisory" process.

The IRP is viewed as a guide for future resource decisions made at a snapshot in time. Resource decisions, particularly those beyond the five-year horizon, are subject to change based on future analyses and regulatory filings. Any new resource additions, including supply-side and demand-side resources, may require regulatory approval.

1.1 IRP Objective

170 IAC 4-7-4(24)

The objective of AES Indiana's IRP is to identify a preferred resource portfolio that provides safe, reliable, sustainable, and reasonable least cost energy service to AES Indiana customers giving due consideration to potential risks and stakeholder input. The study period for this IRP is 2023-2042.

AES Indiana engaged in a bottom-up review of every modeling assumption and modeling practice from its 2019 IRP in preparation for its 2022 IRP. Through five Public Advisory Meetings and five Technical Meetings, AES Indiana has developed its IRP assumptions and modeling framework in an open, transparent, and fact-based manner that considered a wide range of factors facing AES Indiana's generation fleet over the next 20 years. As will be demonstrated in this report, AES Indiana's Preferred Resource Portfolio and three-year Short Term Action Plan were selected through a rigorous Scorecard Evaluation that assessed affordability, environmental sustainability, system reliability, resilience & stability, economic impacts and included a comprehensive risk analysis.

1.2 Guiding Principles

The guiding principles AES Indiana used in its 2022 IRP decision analysis process are as follows.

1. AES Indiana will comply with IURC Orders, IAC requirements, NERC reliability standards, and FERC-approved MISO tariffs.
2. Cost sensitivity estimates for supply-side replacement resources were based on responses from AES Indiana's 2022 All-Source RFP and further supported by a thorough analysis of cost estimates from multiple secondary sources. Demand-side cost estimates were based on a detailed Market Potential Study ("MPS") report built up from the measure level and AES Indiana Demand Side Management ("DSM") implementation experience.
3. The modeling was conducted using a reasonable least cost economic basis and is, therefore, indifferent to the resource mix comprising portfolio plans.
4. DSM was modeled as a selectable replacement resource in the EnCompass Model in a manner consistent with IURC rules.
5. AES Indiana plans to continue to offer cost effective DSM programs that are inclusive for customers in all rate classes, appropriate for AES Indiana's market and customer base, modify customer behavior, and provide continuity from year to year.

AES Indiana assumed the following parameters remain constant in the IRP study period of 2023-2042. Should these change in the future, results of analyses subsequent to the 2022 IRP may vary.

→ Regulatory framework remains – This IRP assumes AES Indiana's current regulatory framework based on the IURC and FERC scopes of jurisdiction will not change during the IRP study period.

→ MISO capacity construct – In November 2021, MISO petitioned FERC to implement a seasonal resource adequacy construct and revise its resource accreditation methodology starting in the 2023/2024 planning year. On August 31, 2022, FERC approved MISO's filing consistent with MISO's request. AES Indiana has included the construct and construct timing as a basis for the planning requirements in this IRP.

→ MISO interaction – AES Indiana will continue to engage in the MISO stakeholder process to influence tariff and business practice changes to benefit AES Indiana's customers.

→ Distributed generation ("DG") – DG is synchronized with the distribution grid as a best safety practice and designed to align with system requirements to support no production curtailment such as might occur with wind resources connected to a transmission system.

AES Indiana recognizes the following items may initiate future changes in its Preferred Resource Portfolio.

→ Technology costs and improvements – All resource technologies will likely improve in performance during the IRP study period. The model assumed all resource technologies will perform at their current levels and projected cost forecasts based on industry data and knowledge.

→ Future elections – Policy changes may follow national, state, and local election results in the next few years.

→ Commodity & Emission Allowance Prices – In 2022, commodity prices rose to levels not seen in over 10 years due to the energy crisis in Europe. Additionally, potential changes in the United States Environmental Protection Agency's ("EPA") Cross State Air Pollution Rule ("CASPR") caused by NOx" prices to rise to unprecedented highs. AES Indiana captured these changes in the modeling assumptions. However, the Company recognizes the volatility of these markets and will closely monitor for future changes that may affect the strategic decisions related to the Preferred Resource Portfolio.

→ Stakeholder sustainability interests – As discussed in multiple stakeholder forums within AES Indiana's IRP public advisory process, regulatory proceedings, customer meetings, and investor interactions in the normal course of business, AES Indiana recognizes the potential for continued pressure to change its resource mix in response to advocates' interests in cleaner sources of energy as they align with the IRP objectives to provide safe, reliable, sustainable, and reasonable least cost energy service to AES Indiana customers.

→ Environmental regulations – While no federal carbon tax exists, public pressure, proposed legislation, and corporate support for carbon pricing has led AES Indiana to include a carbon tax as a proxy for future carbon legislation. The carbon tax level and formation of prices could vary significantly. Any future IRPs will incorporate changes in the state and federal environmental landscape.

→ Tax subsidies for renewable resources – In 2022, Congress passed the Inflation Reduction Act ("IRA") into law which provides a 10-year extension for the Production Tax Credits ("PTC") and Investment Tax Credits ("ITC") for wind, solar and storage resources at their full incentive levels. Accordingly, AES Indiana included these subsidies in its Current Trends/Reference Case scenario. The Company will continue to monitor changes with these tax credits and adjust future planning and IRPs as needed.

AES Indiana will monitor these developments and incorporate changes in subsequent IRP analyses.

1.3 2022 IRP Improvements

AES Indiana has incorporated several changes in its IRP process for its 2022 IRP based on IURC and stakeholder feedback to its 2019 IRP, including the following:

1. AES Indiana transitioned to Anchor Power Solutions LLC's ("Anchor Power") EnCompass Power Planning Software ("EnCompass") for portfolio Capacity Expansion and Production Cost Modeling, which provided the following benefits:
    a. Clear and straightforward deterministic capacity expansion modeling approach;
    b. Stakeholders have greater transparency and accessibility of the model database;
    c. Faster modeling runtimes; and
    d. Proven approach to modeling DSM as a resource.
2. AES Indiana included a traditional scenario analysis with capacity expansion modeled for five strategies (as well as an analysis that allowed the EnCompass Model to optimize on its own; "Encompass Optimization") under four different scenarios – No Environmental, Current Trends (Reference Case), Aggressive Environmental, and Decarbonized Economy.
3. AES Indiana engaged in extensive collaboration with stakeholders on DSM, which resulted in improvement and agreement on the DSM bundling methodology.
4. AES Indiana utilized the Lawrence Berkeley National Labs ("LBNL") and National Renewable Energy Labs ("NREL") end-use load shapes database to inform the hourly profiles for DSM measures.
5. AES Indiana expanded its IRP Scorecard Evaluation metrics for portfolio evaluation, including the addition of the portfolio Reliability Analysis and reliability scoring criteria performed by Quanta.

Figure 1-1 below provides an overview of the improvements AES Indiana made to its 2022 IRP based on stakeholder feedback and feedback provided in the IURC's Director's Report for AES Indiana's 2019 IRP.

Figure 1-1: Overview of 2022 IRP Improvements

Topic	Comments Summary (not exhaustive)	2022 IRP Improvements
Resource Optimization & Risk	→ General lack of clarity around the model and methodology. → PowerSimm's stochastic capacity expansion methodology caused confusion and lacked explanation. → "Future IRPs would benefit from industry experts' judgements to evaluate whether there is a rationale for hardwiring certain resource decisions." (p. 26, Director's Report for AES Indiana's 2019 IRP).	→ AES Indiana has provided better explanation of the model and methodology used at stakeholder meetings and in the report. → AES Indiana transitioned to deterministic capacity expansion using EnCompass, which should provide a more straightforward methodology. → An outside third-party consultant provided industry expert guidance regarding resource options and modeling approaches.
DSM Modeling	→ DSM bundles span the entire planning period, which is too long. → Combining unrelated measures across residential and C&I measures makes a questionable load shape. → It is important that hourly impact of DSM measures are given particular attention.	→ Encompass allowed for optimization using shorter duration bundles; AES Indiana will collaborate with stakeholders to determine more appropriate bundle durations. → AES Indiana collaborated with its consultants and stakeholders to consider alternative approaches for measure bundling. → AES Indiana worked with LBNL and NREL to capture the hourly shapes associated with DSM measures for inclusion in the portfolio modeling.
Load Forecasting	→ IRP excluded detailed Itron report in the appendix. → IRP excluded analysis on the appropriateness of base temperature for weather normalization. → IRP excluded discussion of street lighting usage and how it is modeled in the load forecast. → IRP excluded discussion of risk and uncertainty associated with the load forecasting scenarios.	→ AES Indiana contracted Itron to perform the load forecast and provide a detailed report that describes the methodology including all items noted to by the Director.

1.4 Stakeholder Engagement

170 IAC 4-7-4(30)

The 2022 meeting series included discussions of the IRP process, modeling assumptions, data inputs, the MPS and modeling DSM, strategy and scenario development, risk analysis, Reliability Analysis, modeling results, and Scorecard Evaluation to compare portfolios. AES Indiana incorporated stakeholder suggestions throughout the process, such as including a stakeholder suggested “Clean Energy Strategy” in the Portfolio Matrix. In addition to providing a fully collaborative DSM MPS process with biweekly stakeholder meetings, AES Indiana provided data releases of detailed resource planning and DSM modeling assumptions early and throughout the IRP process. Stakeholders with nondisclosure agreements received the complete Encompass database which allowed those with the Encompass software to recreate and run the IRP portfolios on their own.

Figure 1-2 provides a comprehensive list and dates of data shares AES Indiana completed with stakeholders during the 2022 IRP Process:

Figure 1-2: IRP Data Shares

Data Share	Date	Items Shared
Data Share #1	1/21/2022	→ Electric Vehicle and Distributed Generation Forecasts
Data Share #2	1/31/2022	→ Base Load Forecast
Data Share #3	4/22/2022	→ Electric Vehicle and Distributed Generation Forecast Revisions → High and Low Load forecasts → Residential MPS Energy Efficiency Model → C&I MPS Energy Efficiency Model → Replacement Resource Costs (Initial – 4/22/2022)
Data Share #4	5/17/2022	→ MPS Demand Response Model → DSM Bundle Mapping → DSM Bundle Cost Summary → DSM Coincident Peak Impacts
Data Share #5	7/5/2022	→ Commodity Curve Summaries by Scenario → MISO Planning Assumptions – Planning Reserve Margin Requirement
Data Share #6	7/15/2022	→ Supply-side Replacement Resource Costs
Data Share #7	8/19/2022	→ Industrial Decarbonization/Electrification Forecast → Low, Base and High Replacement Resource Cost Methodology
Data Share #8	8/22/2022	→ Draft Market Potential Study Report
Data Share #9	9/15/2022	→ Natural Gas Basis Assumptions
Data Share #10	9/20/2022	→ IRP Scenario Loader – Encompass Database Files → Summary of Present Value Revenue Requirement Calculations
Data Share #11	9/27/2022	→ Capacity expansion modeling results → Additional detail on Petersburg Conversion Costs
Data Share #12	11/3/2022	→ IRP Stochastic Loader – Encompass Stochastic Files → Stochastic Analysis Results

AES Indiana was engaged in discussions with individual stakeholders and its technical stakeholders throughout the process. Specifically, AES Indiana met with technical stakeholders who executed a Nondisclosure Agreement ("NDA") prior to each Public Advisory Meeting. In these IRP Technical Meetings, AES Indiana provided presentations, data files, and discussed modeling status and results. AES Indiana approached stakeholders early and often for ample discussion and time for feedback. In fact, AES Indiana delayed its filing of its IRP Report to provide customers additional time to review and provide feedback to its IRP process.

Discussions proved to be quite productive and facilitated dialogue among stakeholders prior to the IRP filing. Public Advisory Meeting materials are provided as Attachment 1-2.

1.5 Contemporary Issues

170 IAC 4-7-4(17)

AES Indiana participates in the IURC's IRP Contemporary Issues Technical Conference held each year. In 2021, the IURC, in collaboration with LBNL, hosted a series of three virtual conferences that focused on modeling DSM in an IRP. AES Indiana Manager of Resource Planning, Erik Miller, presented on including Energy Efficiency ("EE") in a load forecast in Workshop #1 and facilitated discussion on bundling and modeling DSM as a resource in Workshop #3. Additionally, Quanta presented at the IURC's IRP Contemporary Issues Technical Conference held on September 22, 2022 that focused on reliability planning, and AES Indiana contracted with Quanta to perform a Reliability Analysis for its 2022 IRP. The Company enjoys engaging both as a participant and as a presenter in this Conference as it always covers current and relevant topics to Indiana utilities and stakeholders.

Section 2: Reliability – Resource Adequacy and Energy Adequacy

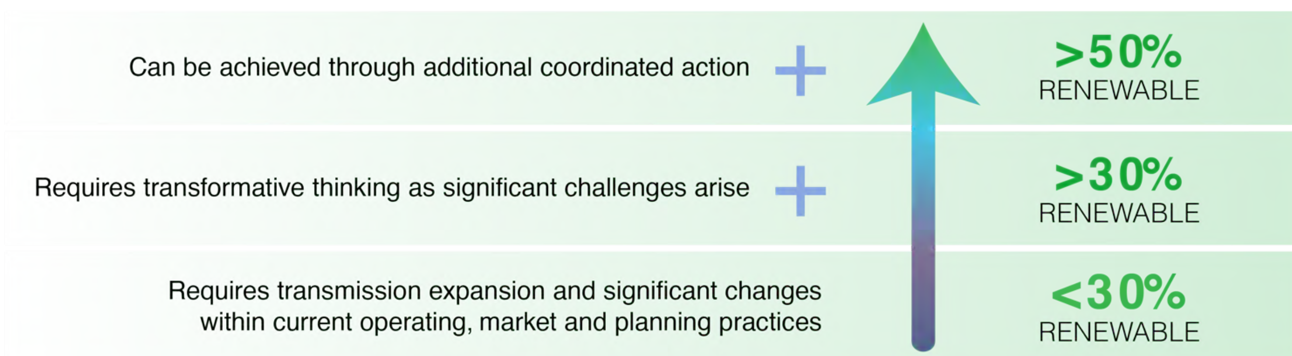
170 IAC 4-7-6(b)(3)(B) and 170 IAC 4-7-6(b)(4)(E)

As utilities retire and replace baseload generation with intermittent renewable generation, it has become increasingly critical to evaluate and ensure that customers will receive energy during peak periods or system emergencies. AES Indiana looked to MISO and work performed by other utilities for guidance on measuring and evaluating the reliability attributes of the IRP portfolios.

2.1 MISO's Renewable Integration Impact Assessment ("RIIA") Study

In February 2021, MISO completed their RIIA study, which is an analysis to understand the bulk system needs and risks as intermittent renewable resources increasingly replace baseload resources. In brief, the study found an increasing risk and need for coordinated action among stakeholders as renewables grow to 30% and 50% of the MISO system portfolio. Managing the system above 30% renewable integration will require transformational change in MISO's planning, markets, and operations. Figure 2-1 below provides a high-level summary of MISO's findings.

Figure 2-1: Grid Inflection Points for Increasing Renewable Energy Penetration



The RIIA study suggests three key areas of focus for MISO and its stakeholders in planning for increasing renewable penetration levels. They include resource adequacy, energy adequacy, and operating reliability. As noted in Figure 2-2 below, AES Indiana considered resource adequacy and energy adequacy within the context of this IRP analysis. AES Indiana's Transmission and Distribution engineers coordinate with MISO regularly to ensure Operating Reliability.

Figure 2-2: Focus Areas for Maintaining Reliability with Increasing Renewable Energy Penetration

Topic	Definition	Planning Responsibility
Resource Adequacy	Having sufficient resources to reliably serve peak demand in all four seasons	This IRP addresses this through the resource adequacy seasonal construct, planning reserve margin, and capacity accreditation for replacement resources
Energy Adequacy	Ability to provide energy in all operating hours continuously throughout the year	This IRP addresses this through the hourly Production Cost Analysis and Quanta Technology's Reliability Analysis
Operating Reliability	Ability to withstand unanticipated component losses or disturbances	This IRP addresses this through ongoing joint coordination between AES Indiana and MISO

In this IRP, AES Indiana coordinated with MISO to model current changes in resource adequacy including transitioning to a resource adequacy seasonal construct that was approved by FERC on August 31, 2022. To address energy adequacy, the Company expanded the IRP analysis to evaluate each portfolio's ability to sufficiently provide energy and system stability in all operating hours over the planning horizon. These topics are discussed in more detail below.

2.2 Resource Adequacy

Resource adequacy is the ability of generation resources to reliably serve electric demand during peak or reasonably foreseen electric conditions. A utility achieves resource adequacy by possessing sufficient supply-side and demand-side resources to satisfy forecasted future loads. The IRP process focuses on developing potential resource portfolios needed to meet two different types of customer needs: energy use and peak demand. Energy use is measured in megawatt-hour ("MWh") to reflect the accumulation of electricity used over time. Peak demand is the measure of the highest hour of usage for a defined time period and is measured in megawatts. The resource adequacy analysis serves as the foundation of the IRP process to create resource portfolios that meet the quarterly forecasted peak demand throughout the 20-year study period. Energy contributions of each resource are dependent upon the economic dispatch model results and renewable generation profiles in individual scenarios. Each scenario includes a set of input assumptions that are based upon varying potential futures and related risks, such as commodity prices, environmental policy changes and increased or decreased load growth. The scenarios are described in Section 8.4 of this IRP.

For the purpose of IRP planning and consistent with MISO guidance, AES Indiana captures resource adequacy assumptions using two criteria: seasonal planning reserve margin requirements and resource capacity credit.

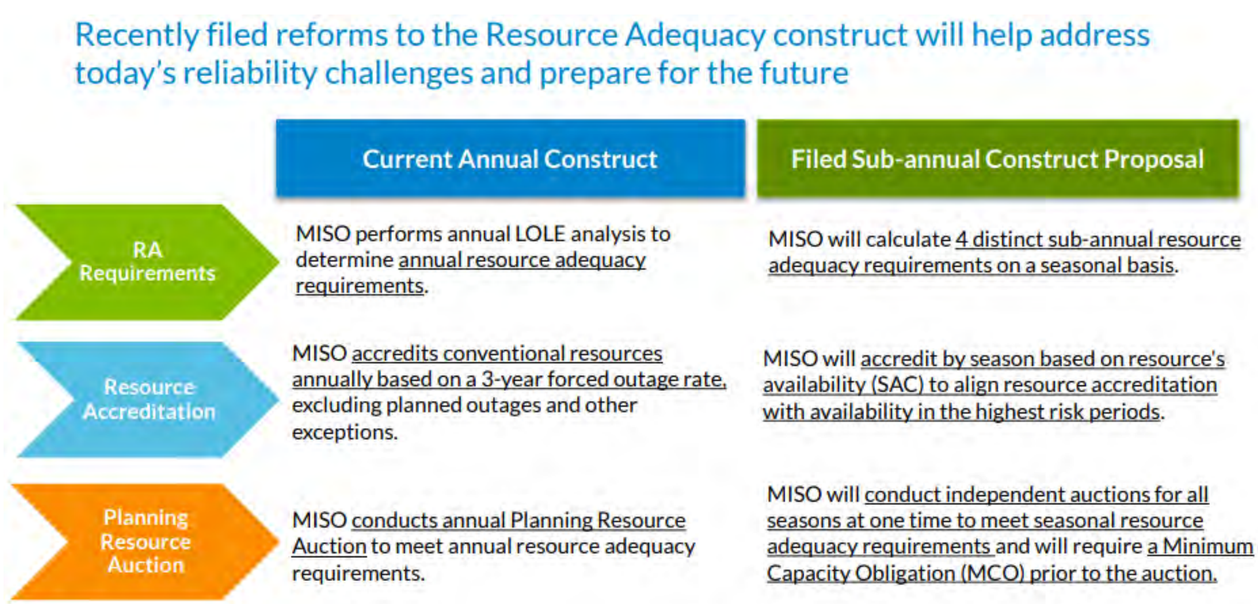
2.2.1 Seasonal Planning Reserve Margin Requirements

AES Indiana participates in MISO's resource adequacy (or capacity) construct as outlined in Module E-1 of MISO's FERC approved tariff. AES Indiana, not MISO, is responsible for resource adequacy and developing long-term resource plans pursuant to 170 IAC 4-7.

To calculate a utility's capacity requirement for MISO's capacity construct, MISO establishes a Planning Reserve Margin ("PRM") based on its Loss of Load Expectation ("LOLE") Study. This value is modeled to represent the needed margin above the utility's forecasted peak load for a reliability standard of one day of load loss every 10 years. For Planning Year 2022-2023, the UCAP PRM was 8.7% as calculated in the LOLE Study.[1] This means that if all utilities in the MISO footprint carried an average of 8.7% reserves, the expectation would be that every 10 years there would be no more than 24 hours of loss of load events within the footprint resulting from peak load exceeding resources available at peak. The PRM is meant to account for forecast error and uncertainty. When the PRM is applied to the forecasted demand at time of MISO Peak, the result is the Planning Reserve Margin Requirement ("PRMR").

MISO's RIIA Study identified several developing risks to the grid maintaining reliable operation, including the growing penetration of renewables and high-risk hours occurring outside of the typical summer period in their annual capacity construct. In response to these risks, MISO submitted tariff revisions to FERC on November 30, 2021 to establish a seasonal capacity construct. Figure 2-3 provides a comparison of some of the key reforms in their filing to move from an annual to a seasonal capacity construct.

Figure 2-3: Comparing MISO's Annual and Seasonal Capacity Construct



[1] MISO's Planning Year 2022-2023 Loss of Load Expectation Study Report https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

The seasonal resource adequacy construct was approved by FERC on August 31, 2022. As such, AES Indiana included this design in the IRP planning analysis starting in the 2023/2024 planning year as proposed by MISO. Under MISO's seasonal resource adequacy construct, Summer is defined as June through August, fall is defined as September through November, winter is defined as December through February, and spring is defined as March through May. This means a different PRM was applied to each season rather than a single number for the entire year. Figure 2-4 displays MISO's estimate of the seasonal PRM values based on MISO's 2022/2023 planning year LOLE analysis modeling assumptions. These PRM values were provided and presented by MISO at AES Indiana's Public Advisory Meeting #3 held on June 27, 2022. MISO updated these values for the 2023/2024 planning year on November 1, 2022. The updates occurred late in the IRP process and were not practical to incorporate given the timing of the IRP and publishing of the report. AES Indiana does not anticipate that the inclusion of the updated PRMs would change the decisions being made in this IRP. The peak load during the spring typically occurs in May, characteristics of which are aligned with summer months. Similarly, the peak load during the fall typically occurs in September, characteristics of which are also aligned with summer months. Throughout most of the IRP analysis, spring, summer, and fall seasons could be treated similarly, which is in contrast to winter. This IRP was conducted to ensure capacity and energy adequacy across all four seasons.

Figure 2-4: Planning Reserve Margin by Season

PRM (%) Summer	7.51%
PRM (%) Fall	11.82%
PRM (%) Winter	21.35%
PRM (%) Spring	26.27%

2.2.2 Resource Capacity Credit

In order to meet the PRMR, resources are assigned UCAP values, which reflect resources' expected availability during peak load. If all resources collectively meet the PRMR, the Resource Adequacy Metric is achieved. Alternatively, a short position can be resolved by purchasing capacity in the MISO Planning Resource Auction ("PRA").

Thermal resources receive UCAP values based on an annual Generation Verification Test Capability ("GVTC") rating that is discounted for a three-year rolling average availability rating ("XEFORd"). MISO received approval from FERC to establish Seasonal Accredited Capacity ("SAC"), which would give thermal resources varying UCAP value by four seasons rather than a fixed UCAP value for the entire year. AES Indiana chose not to include this detail in its 2022 IRP because there is limited data to indicate what the long-term forecasts will look like and SAC will have a smaller impact on thermal resources' UCAP than other resources' seasonal accreditation (e.g., non-dispatchable resources). AES Indiana expects more detail to be available towards the end of 2022, which can be incorporated in future planning.

Wind capacity credit is calculated using Effective Load Carrying Capability ("ELCC"), which accounts for the probabilistic shortfalls of wind generation coinciding with peak load in the MISO footprint. Due to the mismatch of low wind production during high load periods, wind is given a much lower capacity credit than thermal generation. MISO's latest study for Indiana (Zone 6) indicates an ELCC of 8.9%.[2] Given the seasonal capacity construct, 8.9% was applied to the spring, summer, and fall. MISO has performed preliminary analysis that suggests wind generation will better align with winter peak hours than it does during summer peak hours, so wind was given an ELCC value of 20% for the winter.[3]

Similarly, production from solar units at time of peak load have proven to be less than traditional thermal unit production. MISO currently provides solar resources capacity credit of 50% of its nameplate capacity for each solar resource's first year of operation, and future years' capacity credit is based off historical performance. MISO is currently evaluating other methods for determining the capacity value for solar resources within its Resource Adequacy Subcommittee as more solar is added to the grid. Refer to the Section 6.2.2 for more detail regarding the treatment of solar capacity credit in AES Indiana's 2022 IRP.

Load Modifying Resources ("LMR") are demand response programs that are able to respond to emergency conditions for at least four hours. As MISO migrates to a seasonal capacity construct, certain technologies, such as Air Conditioning Load Management ("ACLM") can only provide capacity when temperatures are warm enough for this action to be effective. Therefore, ACLM only receives capacity credit for spring, summer, and fall, while other LMRs receive credit year round.

AES Indiana plans for a combination of these resource types to meet its PRMR going forward. Please see Section 6.2 for the Capacity Credit and ELCC planning assumptions used in this IRP for the replacement generation resources.

2.3 Energy Adequacy

In past IRPs, AES Indiana used the resource adequacy components – annual capacity construct, planning reserve margin, and resource accreditation – as the primary reliability planning assumptions. With increasing focus on reliability as utilities transition to renewable resources, and with guidance from MISO, AES Indiana has expanded the IRP analysis to also consider energy adequacy.

[2] MISO's Planning Year 2022-2023 Wind and Solar Capacity Credit Report, January 2022, https://cdn.misoenergy.org/2022%20Wind%20and%20Solar%20Capacity%20Credit%20Report618340.pdf.

[3] MISO's RAN Renewable Impact Analysis, September 2021, https://cdn.misoenergy.org/20210908%20RA%20Construct%20Tariff%20Review%20Workshop%20Item%2002%20Renewable%20Impact%20Analysis587681.pdf.

Energy adequacy is defined by MISO as "the ability to operate the system continuously and deliver sufficient energy every hour of the year."[4] From a utility generation portfolio perspective, this means understanding how well a utility's potential fleet of resources can deliver power to critical loads during system emergencies as well as evaluating the quality and stability of customers' electric service through other analysis, like frequency and VAR support.

In this IRP, AES Indiana considers energy adequacy in two ways:

1. Economic energy adequacy can be thought of as the volume of market interaction by way of energy sales and purchases required by a generation portfolio. Generally, the more market exposure in terms of sales and purchases a portfolio has, the more cost risk the portfolio poses to customers. AES Indiana measured the economic energy adequacy of the candidate portfolios as part of the Scorecard Evaluation. This was measured in terms of the absolute value of the total sales and purchases for each portfolio over the planning period. More detail on this analysis can be found in Section 6.2.
2. AES Indiana has contracted Quanta Technologies to perform a Reliability Analysis for each of the candidate portfolios. The analysis evaluates the ability of each portfolio to provide energy and system stability in every hour over the planning period. For more detail on the Reliability Analysis performed by Quanta, please see Section 8.3.

2.4 Fuel Procurement

170 IAC 4-7-4(20)

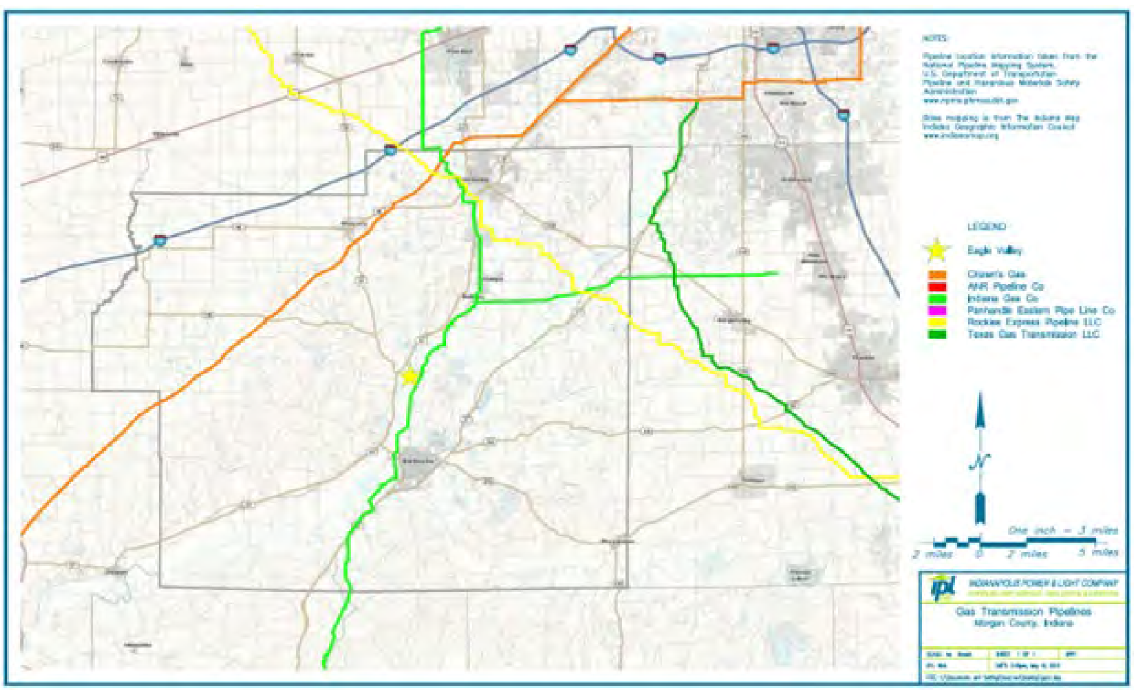
AES Indiana procures and manages a reliable supply of fuel for its generating units at the lowest cost reasonably possible, consistent with maintaining low busbar cost and compliance with all environmental requirements and guidelines. Busbar costs reflect those costs needed to produce a kilowatt of energy at the production facility. They do not include transmission or substation expenses. AES Indiana seeks competitive prices for coal using competitive bidding for both long-term contracts and spot purchases. Long-term contracts provide price and supply certainty for AES Indiana customers. Spot purchases are made for three reasons: (1) to meet needs of short-term position due to stronger than forecasted burns; (2) to test quality of coal and reliability of the producer; or (3) to take advantage of occasional low market price coal. AES Indiana considers all material factors, including, but not limited to: (a) availability of supply from qualified suppliers, (b) current inventory levels, (c) diversity of suppliers and transportation options, (d) forecast of fuel usage, (e) market conditions and other factors affecting price and availability, and (f) existing and anticipated environmental standards. AES Indiana uses a combination of multi-year contracts with staggered expiration dates to limit the extent of AES Indiana's coal position open to the market in any given year to help manage market variability from year-to-year. Many of these multi-year contracts contain some level of volumetric variability as an additional tool to address market variability.

[4] MISO's Renewable integration Impact Assessment, Executive Summary, February 2021, pg. 6

AES Indiana prepares long-term projections of fuel purchased, annual inventory levels, quality, and delivered cost for each plant. For the coal-fired units, AES Indiana maintains coal inventory at levels sufficient to ensure service reliability, to provide flexibility in responding to known and anticipated changes in conditions, and to avoid operational risks due to low inventories. Inventory target ranges are established based upon forecasted usage, deliverability, and quality of the required fuel to each unit, the position of the unit in the dispatch order, risk of market supply-demand imbalance, and the ability to conduct quick market transactions. The general level of inventory throughout the year is adjusted to meet anticipated conditions (i.e., summer/winter peak load, transportation outages, unit outages, fuel unloading system outages, etc.).

Natural gas ("NG") is currently purchased on a daily basis as required based on availability and pricing from several suppliers for its NG-fired peaking units at Harding Street Generating Station ("Harding Street" or "HS") and Georgetown Generating Plant ("Georgetown"). The Eagle Valley CCGT dispatches as a baseload unit so AES Indiana uses a combination of baseload hedges that may include fixed price, index, and daily purchases to supply natural gas to the station. AES Indiana maintains firm pipeline transportation contracts, which provide access to Texas Gas Transmission ("TGT") supply zones to supply the Eagle Valley Generating Station ("Eagle Valley") Closed Cycle Gas Turbine ("CCGT") and Harding Street. The TGT contracts allow AES Indiana scheduling flexibility to draw or hold limited quantity of natural gas which is used for unexpected unit starts & stops to mitigate fuel availability risks. The lateral gas line that serves the Eagle Valley CCGT also has a connection to the Rockies Express pipeline ("REX"). Having a connection with two major supply pipelines allows AES Indiana the ability to balance these two sources for pricing advantages as well as supply certainty. Figure 2-5 is a map of gas transmission around the AES Indiana's Eagle Valley CCGT.

Figure 2-5: Gas Transmission Map Near Eagle Valley CCGT



Georgetown and Harding Street units are used for peaking needs and AES Indiana has determined that firm transportation has value to provide reliability to those units, especially during the winter period. AES Indiana has procured on-system storage from Citizens Gas that can facilitate the swings that naturally occur from peaking units and provide a source of firm supply. To ensure firm delivery to Citizens Energy Group, AES Indiana has procured firm transportation from Panhandle Eastern Pipeline and REX Pipeline. AES Indiana contracts with Citizens Energy Group for firm redelivery and balancing services to the generating units located at the Harding Street and Georgetown plants, and with Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (“CenterPoint”) for firm redelivery to the Eagle Valley CCGT.

As described in Section 6.2, AES Indiana considered the conversion of Petersburg Units 3 and 4 to operate using natural gas as a replacement resource option in many of the strategies in its 2022 IRP analysis. This option caused AES Indiana to evaluate natural gas procurement strategy to fuel the converted Petersburg units. There is a natural gas interstate pipeline that runs through AES Indiana’s Petersburg property. In discussions with the owners of this pipeline, it was determined that the pressure was sufficient to meet the needs of the converted Petersburg plant, and with some modifications to the mainline of the pipe, there would be sufficient capacity to provide firm transportation to the converted Petersburg plant to meet all its natural gas supply needs. The cost associated with building the lateral, meter station, and meter tap were included in the scope of the project cost for the conversion of Petersburg Units 3 and 4 and the pipeline capacity costs were weighed against other options to determine the best course of action. Once the pipeline was determined, AES Indiana utilized forward gas curves for its market to forecast fuel cost for the plant. The readily available supply of natural gas and the location of a pipeline on the property were significant factors relating to the cost of the project overall.

Section 3: Transmission Planning

170 IAC 4-7-6(a)(5)*,* 170 IAC 4-7-6(b)(3)(B)*,* 170 IAC 4-7-6(b)(4)(A)-(B), and 170 IAC 4-7-6(b)(4)(D)-(E)

3.1 Transmission System Overview

AES Indiana provides electric power to the city of Indianapolis and portions of the surrounding counties as a member of MISO. The AES Indiana transmission system consists of approximately 458 circuit miles of lines at 345 kilovolts ("kV"), 408 circuit miles of line at 138 kV, and associated substations. The AES Indiana transmission system includes 345 kV and 138 kV voltage levels. The 345 kV system consists of a 345 kV loop around the city of Indianapolis and 345 kV transmission lines connecting the AES Indiana service territory to the Petersburg Generating Station in southwest Indiana. At Petersburg, AES Indiana has 345 kV interconnections with Indiana Michigan Power Company ("AEP")[5] and Duke Energy Indiana, LLC ("DEI"), and 138 kV interconnections with DEI, Hoosier Energy Rural Electric Cooperative, Inc. ("HE"), and CenterPoint within the MISO footprint. In the Indianapolis area, AES Indiana has 345 kV interconnections with AEP and DEI and 138 kV interconnections with DEI and HE. Autotransformers connect the 345 kV network to the underlying AES Indiana 138 kV network transmission system, which principally serves AES Indiana load.

AES Indiana's electric transmission facilities are designed to provide safe, reliable, and reasonable least cost service to AES Indiana customers. As part of this transmission system assessment process, AES Indiana participates in and reviews the findings of assessments of transmission system performance by regional entities, including MISO and RF as it applies to the AES Indiana transmission system. In addition to the summer peak demand period, which is the most critical for AES Indiana, assessments are performed for a range of demand levels, including winter seasonal and other off-peak periods. For each of these conditions, sensitivity cases may be included in the assessment.

3.2 Transmission Planning Process

170 IAC 4-7-4(24) and 170 IAC 4-7-4(27)

As a NERC registered Transmission Planner ("TP"), AES Indiana performs an annual transmission reliability assessment to ensure that the NERC performance requirements are met. Additionally, AES Indiana participates in assessments of transmission system performance performed by MISO and RF.

As a member of MISO, AES Indiana actively participates in the MISO Transmission Expansion Plan ("MTEP") process with MISO functioning as the NERC Registered Planning Coordinator ("PC"). MISO annually performs MTEP studies to facilitate a reliable and economic transmission

[5] AEP ties to the PJM footprint.

planning process.[6] The AES Indiana assessment and MTEP study process includes identification of transmission issues and potential solutions to those issues. AES Indiana studies its local system and submits any local upgrades to MISO. The local upgrade projects are then submitted to MISO for planning review ensuring no harm is done to the larger regional transmission system. MISO through either the MTEP or other study processes may propose additional transmission system projects or other upgrades that are not reliability based but are economically based to relieve congestion. For potential economic projects, MISO assesses costs and benefits to ensure that costs allocated are commensurate with benefits received. Factors in the cost/benefits analysis include: the value of congestion, fuel savings, reductions in operating reserve needs, system planning reserve margins, and transmission line losses of a proposed transmission project or portfolio. Through the MTEP, MISO ensures that transmission is developed system-wide through one uniform planning process that coordinates system needs to minimize costs. Generator interconnection requests (additions or material modifications) to the AES Indiana system would be coordinated and studied through the MISO Generation Interconnection Process. Generator retirements would be studied through the MISO Attachment Y process. AES Indiana actively participates in these MISO processes to ensure that the transmission system meets the performance requirements.

AES Indiana's FERC Form 715 was submitted by MISO to FERC. The FERC Form 715 was based on MTEP 21 studies, which contain the most recent power flow study available to AES Indiana including interconnections. In MTEP 21, MISO conducted studies using models for 2023 Spring Light Load, 2023 Summer Peak, 2026 Spring Light Load, 2026 Summer Shoulder, 2026 Summer Peak, and 2031 Summer Peak. MTEP 22 studies are being finalized.

Finally, AES Indiana and MISO utilize the latest internal customer load forecast, in conjunction with current and future system configurations, generator dispatches, and system transactions (as necessary), as a basis for the aforementioned system planning and reliability studies.

AES Indiana has submitted the projects below to MISO to be included in the MISO MTEP.

→ Replace Sunnyside 345kV and 138kV Breakers

→ Replace Southwest 138kV Breakers

→ Replace West 138kV Breakers

→ Replace Southeast 138kV Breakers

RF also performs seasonal, near-term, and long-term assessments of transmission system performance conditions based on information from each transmission planner, including both MISO and AES Indiana. The transmission system seasonal assessment summarizes the projected performance of the bulk transmission system within RFs footprint for the upcoming summer peak season and is based upon the studies conducted by RF staff, MISO, PJM

[6] The MISO MTEP analysis may be found on the MISO website at URL: https://www.misoenergy.org/planning/planning/mtep21/.

Interconnection, L.L.C. ("PJM"), and the Eastern Interconnection Reliability Assessment Group ("ERAG"). As an entity within the reliability region of RF, AES Indiana actively participates and reviews the studies.

3.3 Transmission Planning Criteria

170 IAC 4-7-4(27)

AES Indiana transmission system is planned to meet the performance requirements based on system-specific transmission planning criteria, NERC reliability standards, distribution planning requirements, and other considerations, including, but not limited to, load growth, equipment retirement, decrease in the likelihood of major system events and disturbances, equipment failure, or expectation of imminent equipment failure.

Changes or enhancements to transmission facilities are considered when the transmission planning criteria are not expected to be met and when the issue cannot feasibly be alleviated by sound operating practices. Any recommendations to either modify transmission facilities or adopt certain operating practices must adhere to good engineering practice.

A summary of AES Indiana transmission planning criteria follows.[7] AES Indiana transmission planning criteria are periodically reviewed and revised.

- → Limit transmission facility voltages under normal operating conditions to within 5% of nominal voltage, under single contingency outages to 5% below nominal voltage, and under multiple contingency outages to 10% below nominal voltage. In addition to the above limits, generator plant voltages may also be limited by associated auxiliary system limitations that result in narrower voltage limits.
- → Limit thermal loading of transmission facilities under normal operating conditions to within normal limits and under contingency conditions to within emergency limits. New and upgraded transmission facilities can be proposed at 95% of the facility normal rating.
- → Maintain stability limits including critical switching times to within acceptable limits for generators, conductors, terminal equipment, loads, and protection equipment for all credible contingencies, including three-phase faults, phase-to-ground faults, and the effect of slow fault clearing associated with undesired relay operation or failure of a circuit breaker to open.
- → Install and maintain facilities such that three-phase, phase-to-phase, and phase-to-ground fault currents are within equipment withstand and interruption rating limits established by the equipment manufacturer.
- → Install and maintain protective relay, control, metering, insulation, and lightning protection equipment to provide for safe, coordinated, reliable, and efficient operation of transmission facilities.

[7] The AES Indiana Transmission Planning Criteria can be found on the MISO website at https://cdn.misoenergy.org/IPL%20TO%20Planning%20Criteria108233.pdf.

- → Install and maintain transmission facilities as per all applicable IURC rules and regulations, American National Standards Institute ("ANSI")/Institute of Electrical and Electronics Engineers ("IEEE") standards, National Electrical Safety Code, AES Indiana electric service and meter guidelines, and all other applicable local, state, and federal laws and codes. Guidelines of the National Electric Code may also be incorporated.
- → The analysis of any project or transaction involving transmission facilities consists of an analysis of alternatives and may include, but is not limited to, the following:
  - Initial facility costs and other lifetime costs such as maintenance costs, replacement cost, aesthetics, and reliability.
  - Consideration of transmission losses.
  - Assessment of transmission right-of-way requirements, safety issues, and other potential liabilities.
  - Engineering economic analysis, cost benefit, and risk analysis.
- → Plan transmission facilities such that generating capacity is not unduly limited or restricted.
- → Plan, build, and operate transmission facilities to permit the import of power during generation and transmission outage and contingency conditions. Provide adequate import capability to the AES Indiana 138 kV system in central Indiana assuming the outage of the largest base load unit connected to the AES Indiana 138 kV system.
- → Maintain adequate power transfer limits within the criteria specified herein.
- → Provide adequate dynamic reactive capacity to support transmission voltages under contingency outage or other abnormal operating conditions.
- → Minimize and/or coordinate reactive power measured in Megavolt Amperes Reactive ("MVAR") exchange between AES Indiana and interconnected systems.
- → Generator reactive power output shall be capable of, but not limited to, 95% lag (injecting MVAR) and 95% lead (absorbing MVAR) at the point of interconnection to the transmission system.
- → Design transmission substation switching and protection facilities such that the operation of substation switching facilities involved with the outage or restoration of a transmission line emanating from the substation does not also require the switched outage of a second transmission line terminated at the substation. This design criterion does not include breaker failure contingencies.
- → Design 345 kV transmission substation facilities connecting to generating stations such that maintenance and outage of facilities associated with the generation do not cause an outage of any other transmission facilities connected to the substation. Substation configurations needed to accomplish this objective and meet safety procedures are a breaker and a half scheme, ring bus, or equivalent.

- → Avoid excessive loss of distribution transformer capacity resulting from a double contingency transmission facility outage.
- → Coordinate planning studies and analyses with customers to provide reliable service as well as adequate voltage and delivery service capacity for known load additions.
- → Consider long-term future system benefits and risks in transmission facility planning studies.
- → Maintain the ability to produce a restoration plan as required by NERC standards in which the use of Blackstart Resources are required to restore the shutdown area of the Bulk Electric System to service.

AES Indiana transmission facilities are also planned and coordinated with the following reliability criteria: the reliability standards of NERC including the Transmission System Planning Performance Requirements ("TPL") standards, Modeling Data Analysis ("MOD") standards, and Facility Ratings ("FAC") standards.[8]

The NERC TPL-001-4 Planning Events (Contingencies) that the transmission system is assessed to meet the performance requirements include:

- → System performance under normal (no contingency) conditions (Category P0).
- → System performance of the Bulk Electric System for the loss of the one of the following elements: Generator, transmission circuit, transformer, shunt, or single pole of a direct current ("DC") line (Category P1).
- → System performance of the Bulk Electric System for the loss of the one of the following elements: Opening of a line section w/o a fault, bus section fault, or internal breaker fault (Category P2).
- → System performance of the Bulk Electric System for loss of multiple elements: Generator and a generator, transmission circuit, transformer, shut, or single pole of a DC line (Category P3).
- → System performance following the loss of multiple Bulk Electric System elements caused by a stuck breaker attempting to clear a fault on a generator, transmission circuit, transformer, shunt, or bus section (Category P4).
- → System performance following the loss of multiple Bulk Electric System elements due to a delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed for one of the following: generator, transmission circuit, transformer, shunt, or bus section (Category P5).
- → System performance of the Bulk Electric System for loss of multiple elements: Transmission circuit, transformer, shunt, or single pole of a DC line (Category P6).

[8] The NERC reliability standards may be found on the NERC website at http://www.nerc.com.

- System performance of the Bulk Electric System for loss of multiple elements for circuits on common structure or loss of a bipolar DC line (Category P7).

3.4 Transmission System Performance Assessment

Individually and combined, the transmission performance assessments performed by AES Indiana, MISO, and RF demonstrate that AES Indiana meets the system performance requirements of NERC summarized above. From these transmission performance assessments, the AES Indiana transmission system is expected to perform reliably and with continuity over the long term to meet the needs of its customers and the demands placed upon it.

The following is a summary of AES Indiana's transmission system performance.

- AES Indiana transmission performance analysis using dynamic simulations for stability as evaluated under the NERC TPL reliability standards shows no evidence of system or generator instability.
- AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows a few localized thermal violations appearing on AES Indiana lines and transformers resulting primarily from multiple element outages of internal AES Indiana transmission facilities. These overloads will be mitigated via operational procedures.
- AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows transmission voltages in the expected range on AES Indiana facilities.
- AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows expected loss of demand that is planned, controlled, small, and localized.
- AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of curtailed firm transfers.
- AES Indiana transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of area-wide cascading or voltage collapse.
- Applicable operating and mitigation procedures, in conjunction with planned major transmission facility additions and modifications, result in transmission system performance which meets the requirements of the NERC TPL reliability standards.

3.5 Coordinating Transmission and Resource Planning

During the evaluation of future resource portfolios, it is important that transmission system limitations are evaluated to ensure reliability. One process used to evaluate the transmission system is a power transfer study to determine the import capability into the AES Indiana load pocket. The AES Indiana load pocket is the Indianapolis area load that is supplied by the highly networked AES Indiana 138 kV transmission system that is supplied by external and internal generation. External generation is primarily supplied by seven 345 kV transmission lines connected to a 345 kV loop around load pocket. The 345 kV transmission loop design is analogous to Interstate 465 around Indianapolis. The 345 kV loop connects to the 138 kV system through 345-138 kV autotransformers. The 345-138 kV autotransformers can be analogously thought of as off-ramps on the interstate. Internal generation is interconnected directly to the 138 kV transmission system and is currently located at the three AES Indiana generation plants: Harding Street, Eagle Valley, and Georgetown. A transfer study determines transmission system limitations for the applicable reliability criteria. If the transfer capability is insufficient for a future resource plan, additional transmission upgrades would be needed to meet the reliability criteria. Additionally, the current internal generation provides other ancillary services like reactive power and voltage control, short circuit strength, frequency response and Blackstart capability. Specific analyses will determine the need for any additional upgrades or modifications to the transmission system, which may be needed to provide these services.

The import capability into the AES Indiana 138 kV system for different NERC contingency categories include a single element failure or breaker failure ranges from 2,233 to 2,934 MW. The limit based on a double-element failure ranges from 1,415 to 2,005 MW. Figure 3-1 depicts detailed information about these contingencies.

Figure 3-1: Import Capability Summary

NERC Category	Limiting Element	Import Capability (MW)	Contingency Description
Single Element (P1)			
2022	Guion North XFMR	2233	Guion South 345-138 kV XFMR
2025	Stout Auto XFMR	2934	Rockville to Thompson 345 kV line
Breaker Failure			
2022	Guion North XFMR	2233	345 kV Breaker at Guion
2025	Future Guion XFMR	2556	Guion N & S 345-138 kV XFMR
Double Element (P6)			
2022	Guion North XFMR	1415	Guion South 345-138 kV XFMR & Whitestown to Hortonville 345 kV line
2025	Hanna East XFMR	2005	Hanna to Stout & Hanna to Sunnyside 345 kV lines
** Import capability can vary based on many factors*			

In addition to coordinating import capabilities, top-down and bottom-up load forecasting is coordinated between the Resource Planning and Transmission Planning. Resource Planning provides the top-down or total system load and the Transmission Planning team works to break the top-down load in to loads at specific substations in the transmission models.

Section 4: Distribution System Planning

4.1 Distribution System Overview

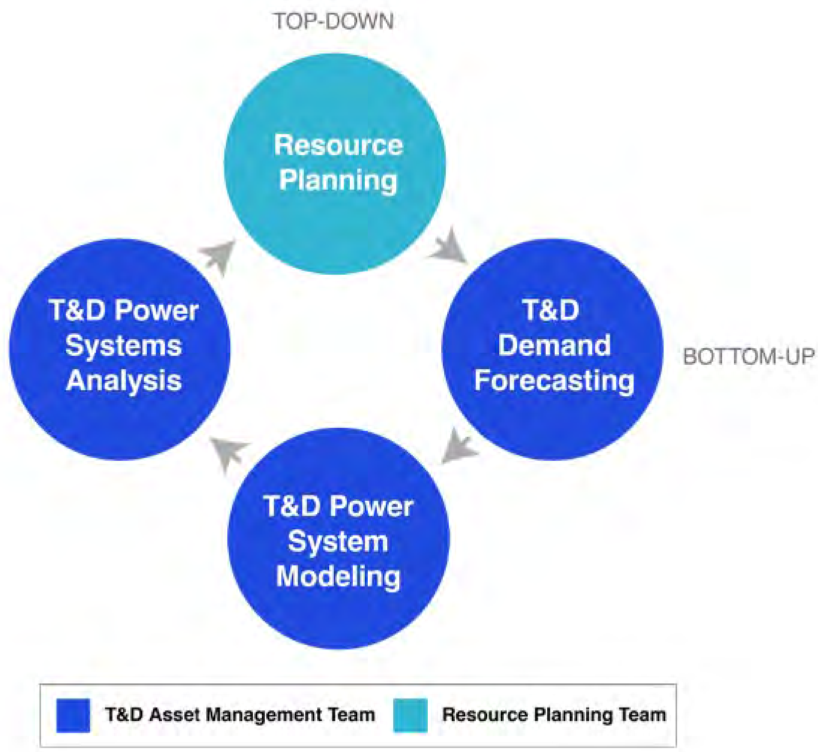
The distribution system consists of 5,115 circuit miles of underground primary and secondary cables and 6,119 circuit miles of overhead primary and secondary wire as well as 136 substations. AES Indiana uses a Secondary Network System to serve the City of Indianapolis Central Business District, sometimes also referred to as the “Mile Square.” A unique feature of the Secondary Network System is that the loss of a single component, such as a primary feeder or a network transformer, typically will not result in any customer losing power.

4.2 Distribution System Planning Overview

170 IAC 4-7-4(18)

AES Indiana has moved to combine the traditional Transmission and Distribution (“T&D”) planning roles under one department that works closely with Distribution Operations, Engineering, and Field Services teams to develop holistic solutions. Processes are mapped (as illustrated in Figure 4-1) such that Resource Planning and T&D forecasting work off same assumptions for top-down and bottom-up load forecasting. The forecasted generation resources and demands act as inputs to T&D power system modeling and analysis processes with common assumptions. As a result, AES Indiana T&D Planning is building the foundation with an aligned organization, smart grid devices, demand forecasting, and network modeling that will enable AES Indiana to effectively plan for multiple scenarios and test non-traditional solutions. Non-traditional solutions could be targeted distributed energy resource (“DER”) installations, grid inverter orchestration, or strategic battery placements that could serve multiple purposes for distribution reliability and serve as part of overall capacity plan. AES Indiana is building the core platforms to study these scenarios to ensure implementations can be completed in a safe and reliable manner. As use cases are studied and developed using the foundational tools, AES Indiana is working to implement potential pilot programs that may be brought forward to test capacity alternatives and non-wires alternative concepts.

Figure 4-1: Integrated T&D Planning Process



With increasing penetrations of DERs (photovoltaic systems), EVs and charging stations, demand responses and smart appliances, and energy storage systems, AES Indiana is transitioning to a new distribution system planning process with ongoing adoptions of advanced tools, which can help AES Indiana proactively manage, forecast, model, and analyze system needs. Such process is described in Figure 4-2.

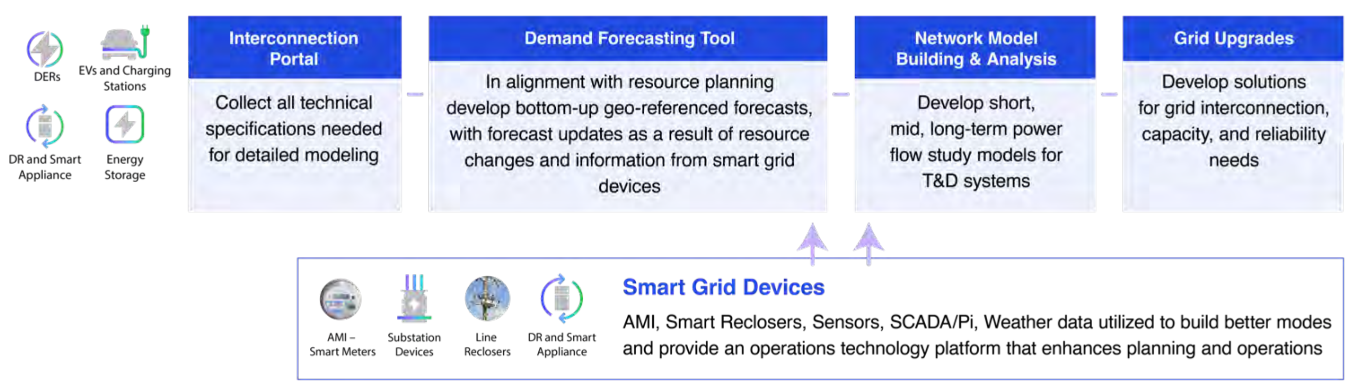
First, a more efficient and user-friendly interconnection portal is needed to manage customer applications and information, perform screening engineering analysis, and prepare input data for the forecasting process. Once such portal is implemented to replace the current manual process and paper-based application forms, AES Indiana will transition to a more efficient and intelligent interconnection process.

The forecasting process takes the DER data from the interconnection portal as input along with the prior year's load data and corporate demand forecast. LoadSEER, an integrated spatial load/DER/ electric vehicle ("EV") forecasting tool developed by Integral Analytics, Inc., is used to create circuit- and transformer-level demand forecasts.

The modeling and analysis process involves building/modifying the CYME model and performing detailed CYME load flow and contingency analyses to ensure AES Indiana's distribution circuits with adequate capacity and reliability (back-tie capabilities). Planning criteria have been established that provide the basis for determining the adequacy of the electric distribution system. In situations where the criteria are not met, grid needs are identified. In addition to the traditional distribution system studies, DER hosting capacity analysis will be performed regularly to improve internal and external awareness of capacity rooms for increasing DER interconnections. In case a DER/energy storage with a large size (e.g., 500 kilowatts ("kW") and above) is proposed to connect to a distribution circuit, a DER impact study can be performed using CYME to ensure no steady-state and transient criteria is violated.

In the process of grid upgrades, requirements to meet the grid needs are determined, and traditional solutions and non-wires alternatives are developed. These solutions are evaluated against short-term and long-term needs/benefits, estimated costs, and physical installation constraints to identify a most effective and economical solution with AES Indiana's Engineering and Construction teams. It is worth noting that during the calendar year, it is expected that new service requests or projects will arise that will require modifications to the circuit- and or transformer-level forecasts. AES Indiana will, therefore, continually evaluate grid needs throughout the year and make decisions on when to address any grid deficiencies identified outside of the forecast and analysis processes.

Figure 4-2: Distribution Planning Process



4.3 AES Indiana's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan

170 IAC 4-7-4(16)

On March 4, 2020, AES Indiana received IURC approval for its seven-year TDSIC Plan ("TDSIC Plan"). AES Indiana's $1.2 billion TDSIC Plan includes 13 Project Types with defined projects that replace, rebuild, upgrade, redesign, and modernize a wide range of AES Indiana's aging transmission and distribution assets in two thematic areas: Age and Condition, and Deliverability. The 13 Project Types are listed in Figure 4-3 below.

The Age and Condition category (83% of the TDSIC Plan) addresses the many risks posed by aging assets. This category includes the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and rebuilding portions of the Indianapolis central business district. The Deliverability category (17% of the TDSIC Plan) deploys new technologies for advanced distribution management, adds new substation equipment to meet growth-driven capacity requirements, and creates system and operating efficiencies through automation, control functions, and other advanced infrastructure.

Both categories support AES Indiana's ability to maintain and operate the grid in a safe, reliable, and efficient manner. Many of the improvements are focused on giving AES Indiana's operators and engineers more information and control over the grid for purposes of delivering a better, more efficient energy experience. Other projects target improvement in overall levels of reliability and integrity.

As part of AES Indiana's TDSIC Plan, certain projects will have impacts on the AES Indiana distribution system. Some of these projects include the 4 kV Conversion project, the Advanced Metering Infrastructure ("AMI") project, and the Distribution Automation project. These projects contribute to a hardened and resilient grid that better withstands weather impacts and is easier to restore when outages inevitably occur.

Figure 4-3: TDSIC Project Types

Project Type
Age & Condition Projects
Circuit Rebuilds
Substation Assets Replacement
XLPE Cable Replacement
4kV Conversion
Tap Reliability Improvement Projects
Meter Replacement (AMI)
CBD Secondary Network Upgrades
Static Wire Performance Improvement
Remote End – Breaker Relay/Upgrades
Pole Replacements
Steel Tower Life Extension
Deliverability Projects
Distribution Automation
Substation Design Upgrades

4.3.1 4 kV Conversion

The 4 kV to 13.2 kV conversion plan consists of the replacement of critical transformers and the conversion of radial circuits where 13.2 kV sources are available to avoid overloads on critical substations. This plan is formulated to avoid the failure of adjacent substations that may lead to a cascading outage event. Any equipment with remaining life that is removed due to conversion is used to provide adequate capacity to the remaining 4 kV loads, to provide spare units to cover unforeseen transformer or switchgear failures, or to permit the retirement of equipment that has outlived its useful life and cannot provide reliable service. As of March 31, 2022, AES Indiana has completed 43% of the 4 kV Conversion project.

4.3.2 Advanced Metering Infrastructure

AES Indiana will replace approximately 282,000 residential and small commercial single and three phase electric meters over a four-year period through 2023.

The AMI project included in the TDSIC Plan improves safety with the ability to connect, disconnect, and reconnect customers more efficiently through automated technology.

In summary, AES Indiana’s AMI project mitigates the risk of a reasonably expected increase in urgent meter replacements due to failed or failing AMR meters. The AMI project enables the delivery of operational and engineering benefits as well as customer care benefits made possible through an advanced metering network. As of March 31, 2022, AES Indiana has completed 64% of the AMI project.

4.3.3 Distribution Automation

Distribution Automation has enhanced outage restoration with the additional reclosers and advanced relays allowing sections of circuits to be isolated if there is a fault on the system resulting in fewer customers experiencing a service interruption. In addition, quicker service restoration results when operators may remotely back-feed sections of circuits. Circuits are now operated more efficiently with interactive information received from devices with two-way communication equipment. AES Indiana has remote operation capabilities with feeder relays, reclosers, and capacitors.

As part of the TDSIC Plan, the Distribution Automation project adds distribution infrastructure and replaces older control systems with modern control systems that will increase automation, improve distribution system operation, and enhance safety and reliability. This project also facilitates outage management and service restoration, enables voltage control and associated energy conservation, and improves interconnection with distributed energy resources and new loads. AES Indiana plans to install approximately 1,200 new distribution line reclosers and a new central control system to further increase system automation.

An Advanced Distribution Management System improves reliability with Fault Location, Isolation, and Service Restoration (“FLISR”) functionality. The FLISR functionality is expected to eliminate a significant number of customer interruptions per year. FLISR is also expected to reduce the duration of a significant number of interruptions per year to less than 5 minutes.

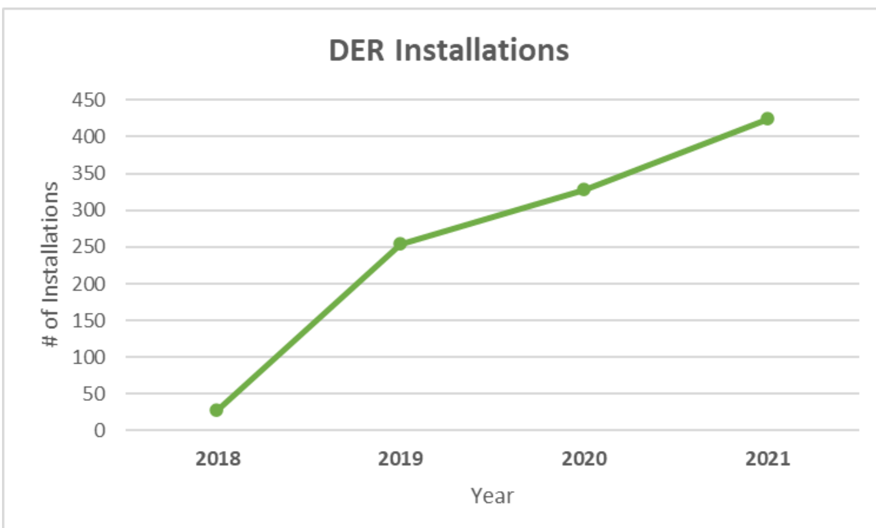
The Distribution Automation project offers a variety of benefits to the distribution system and AES Indiana's customers. This project improves reliability, enhances safety, and provides voltage management and associated energy conservation as well as modern infrastructure facilitates economic development. The Distribution Automation project also prepares the distribution system for the ongoing development of distributed energy resources and loads. As of March 31, 2022, AES Indiana has completed 30% of the Distribution Automation project.

4.4 Distributed Generation

170 IAC 4-7-4(18)

Figure 4-4 shows the trend of DER interconnections to AES Indiana systems since 2012. Note that the number of DER installations from Jan. 1, 2022, to November 16, 2022, is 454. Until July 14, 2022, AES Indiana has 466 Level 1 DERs with a total nameplate capacity of 2,429 kW, 84 Level 2 DERs with a total nameplate capacity of 9,342 kW and 15 Level 3 DERs with a total nameplate capacity of 40,195 kW.

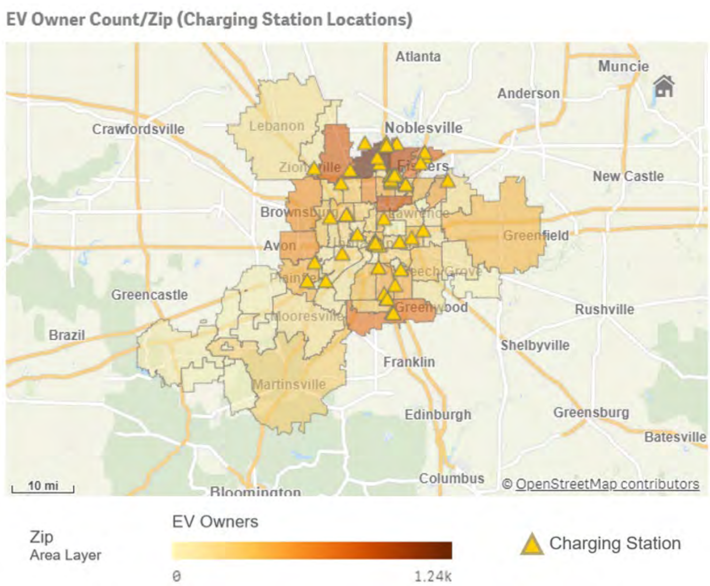
Figure 4-4: DER Interconnection Trend



4.5 Electric Vehicles

Since AES Indiana's 2016 IRP, AES Indiana has worked to develop a process that utilizes internal and external data to map and locate EV charging throughout its service territory. See Figure 4-5 below, which uses data from the Indiana Bureau of Motor Vehicles ("Indiana BMV") shows penetration of EV ownership by zip code. A higher penetration of EV ownership as shown in Figure 4-5 represents a proxy for associated on-premise charging in absolute terms. In other words, the heat map does not reflect the level of demand or energy associated with electric vehicle charging but defines geographic areas where EV adoption is highest. As indicated above, the existing EV adoption data will be an input to AES Indiana's LoadSEER forecasting tool for EV demand forecast, which will be analyzed using CYME to identify the grid needs and solutions.

Figure 4-5: Heat Map of EV Adoption by Zip Codes



4.6 Future Smart Grid Expectations

170 IAC 4-7-4(16) and 170 IAC 4-7-4(18)

AES Indiana recognizes that as more DERs are added to its system, their role will increase in future transmission, distribution, and resource planning efforts. These planning efforts inform each other to ensure alignment in the consideration of DERs across the system. AES Indiana is working to build the foundational interconnection, forecasting, modeling, and analysis platforms to implement a smart grid with reliable solutions to the challenges presented by an evolving grid. In the future, as AES Indiana stands up its foundational forecasting, modeling, and analysis platforms, AES Indiana may bring pilot programs forward to test new ways of integrating distribution level resources into the resource plan through strategic DER and smart grid device placement plans using optimal device placement and advanced forecasting tools.

Section 5: Load Research, Load Forecast, and Forecasting Methodology

170 IAC 4-7-4(11)

AES Indiana forecasts its load to be relatively flat with an average annual growth of 0.5% over the IRP planning horizon before consideration of any DSM impacts.[9] EIA projected efficiency trends will continue to show improvements in efficiency, which is a key contributor to the load trend.

5.1 Load Research

170 IAC 4-7-4(13) and 170 IAC 4-7-4(16)

AES Indiana conducts load research based on historical customer load shape data by segment. This information is used in cost of service studies and rate design efforts. The granular data aligns with load forecasting data, but it is not a direct input to the forecast at this time. See Attachment 5-1 for the Hourly Load Shapes by Rate and Customer Class from the July 2016 to June 2017 Test Year in AES Indiana's Rate Case (Cause No. 45029). Historically, AES Indiana has used a statistical sample of interval meters installed throughout the service territory to collect load research data. This data collection and sampling methodology is discussed in Section 5.1.1 and Section 5.1.2 below. With the high prevalence of AMI meters now installed at AES Indiana services, the Company anticipates using AMI more fully for load research and load forecasting to update the statistical sample and as an improvement in future rate cases and IRPs.

Load shape data is maintained by AES Indiana at the rate class/customer class level. The sample for the small Commercial and Industrial ("C&I") Class (i.e., Rate SS and Rate SH) is stratified using North American Industry Classification System ("NAICS") codes into manufacturing low and high use and non-manufacturing low and high use strata. All load research is developed by AES Indiana.

5.1.1 Energy Only (Non-Demand) Metered Customers

AES Indiana currently maintains a load research sample of 542 load profile meters. The distribution of these meters by rate and class are shown in the following table, Figure 5-1.

Figure 5-1: Load Research Meters by Rate Class – Energy Only

Residential		Small C&I	
Rate RS	126	Rate SS	95
Rate RC	102	Rate SH	68
Rate RH	151		
Total Residential	**379**	**Total Small C&I**	**163**

[9] AES Indiana-sponsored DSM has been removed from the load forecast. All future DSM will be selected as part of the IRP modeling process.

Figure 5-2 shows the load research sample design which is designed based upon a 90% confidence interval plus or minus a 10% error margin. The stratification criteria are shown for the following rates:

→ Residential General Service ("RS")

→ Residential General Service with electric water heating ("RC")

→ Residential General Service with electric heat ("RH")

→ Small C&I Secondary Service – Small ("SS")

→ Small C&I Secondary Service – Electric Space Conditioning ("SS")

Figure 5-2: Load Research Design

Rate	Number of Strata	Criteria
RS	4	High/low winter and high/low summer
RC	4	High/low winter and high/low summer
RH	5	Small/large heat pump houses, small/large resistance houses and apartments
SS	4	Survey small/large by manufacturing; non-manufacturing; billing manufacturing/non-manufacturing
SH	4	Annual kilowatt hour ("kWh")

Furthermore, hourly 8,760 data is retained in Excel spreadsheets. Historical billing data by account for the demand billed customers is maintained on an on-going basis.

5.1.2 Large Commercial and Industrial Customers

In addition to the residential and small C&I meters outlined above, all large C&I meters have 15-minute profile metering. The 15-minute information provides load research and billing increment data for AES Indiana's demand metered customers.

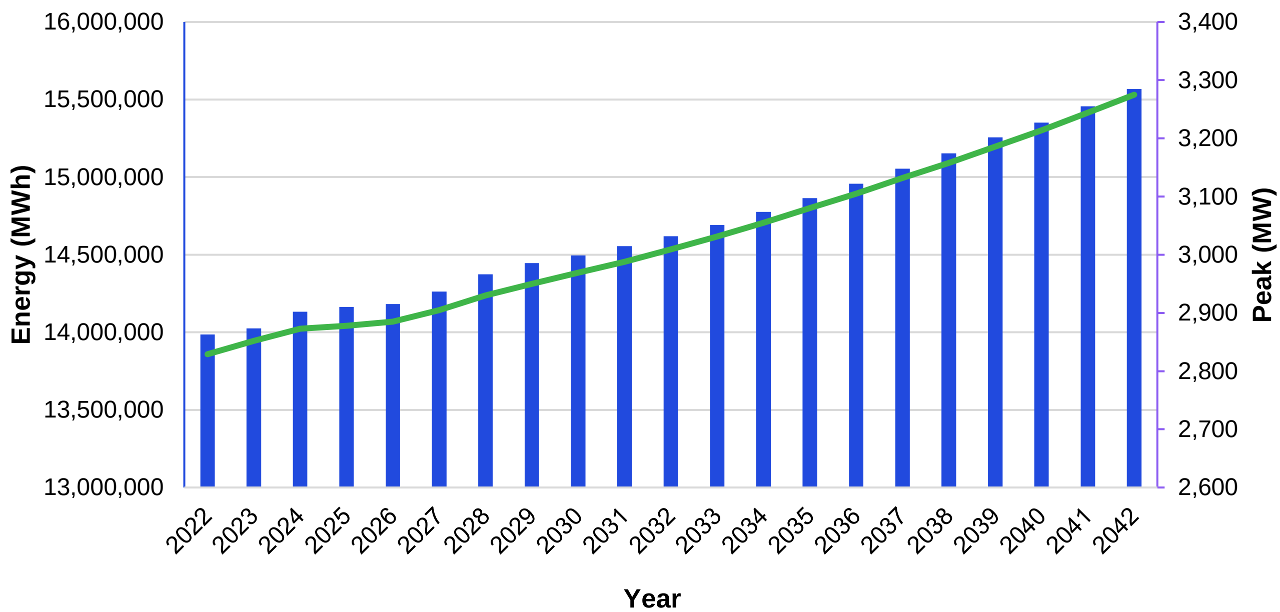
5.2 AES Indiana Load Forecast Overview

AES Indiana developed the 2022 IRP forecast using a bottom-up approach in which customer sector sales forecast for residential, commercial, and industrial sectors are translated into long-term baseline energy and system demand requirements, excluding future energy efficiency program impacts. In the IRP study period, EE savings[10] are treated as a supply side resource, thus the forecast treats all future energy efficiency as selectable and excludes it from the models. The baseline forecast is also adjusted for the expected impact of behind-the-meter solar and electric vehicle charging loads.

[10] EE discussed in this Report refers to utility sponsored EE.

Figure 5-3 below shows the forecasted annual energy demand (in MWh) and the associated peaks (in MW). This yields an average annual growth rate of 0.5% in energy and a 0.7% in peak demand.

Figure 5-3: Forecasted Annual Energy Demand and Associated Peaks[11]



AES Indiana anticipates stable customer growth in the residential sector with an average annual growth rate of 0.9% from 2022 through 2042. Customer growth, combined with modest growth in average use in the residential sector, results in an expected 1.0% annual load growth rate. Load growth in the commercial sector is expected to be modest, keeping load relatively flat with an average annual load growth rate of 0.4%. Industrial sector load is anticipated to be flat (0.0% average annual growth rate), showing no significant growth over the IRP forecast horizon. Please see pp. 17-18 of Itron's 2022 Load Forecast Report, which is attached to this Report as Attachment 5-2, for additional description of the Residential load forecasting methodology and resulting forecast.

5.3 Forecast Methodology

170 IAC 4-7-4(1), 170 IAC 4-7-4(3), 170 IAC 4-7-4(28), 170 IAC 4-7-5(a)(4), 170 IAC 4-7-5(a)(7), 170 IAC 4-7-5(a)(8), 170 IAC 4-7-5(c), and 170 IAC 4-7-6(a)(6)

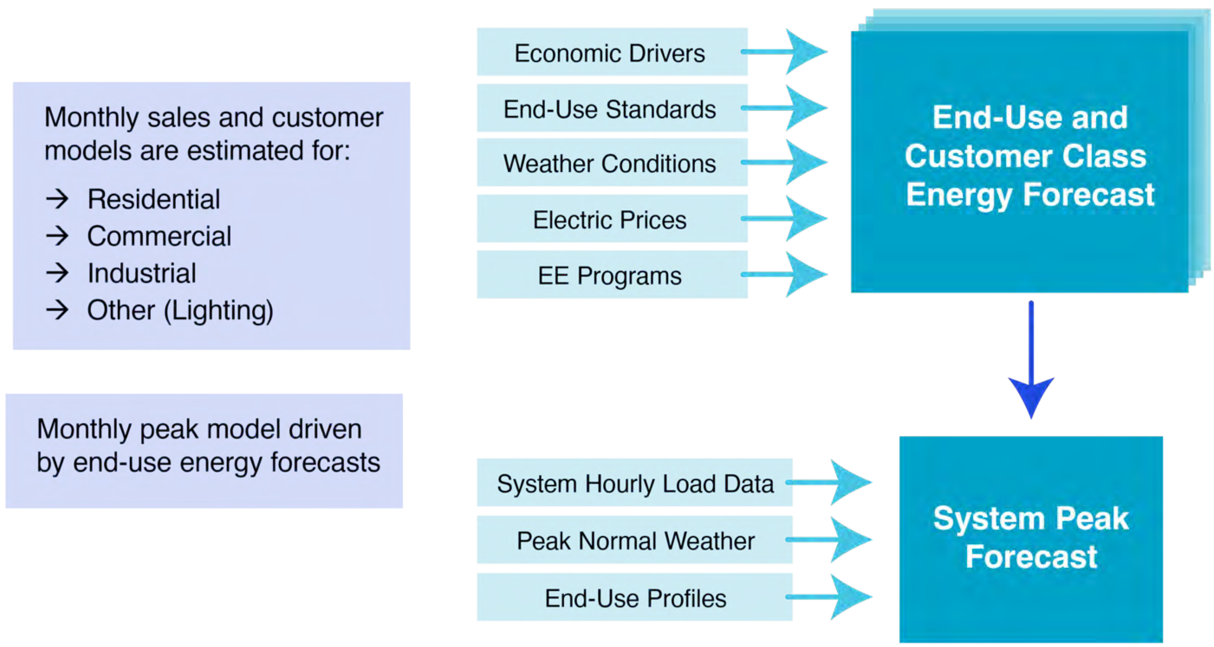
The load forecast in AES Indiana's 2022 IRP was developed by Itron using their Statistically Adjusted End-Use ("SAE") load forecasting methodology. Historically, Gross Domestic Product ("GDP") and other economic indicators exhibited strong correlation with electricity sales. As such, load forecasts were heavily reliant on GDP and economic forecasts. However, this linkage has been less pronounced since 2008. Sales have flattened due to efficiency improvements driven by

[11] Figure 5-3 does not include future DSM. Future DSM is modeled as selectable resources in the IRP model.

codes, standards, and utility-sponsored DSM while GDP has continued to grow. Itron's SAE methodology addresses this issue by incorporating end use saturations and efficiency trends using EIA data.

Figure 5-4 provides an overview of the workflow of Itron's SAE model that builds up to a system energy and peak forecast. The dependent variables are being predicted using estimates of cooling requirements ("XCool"), heating requirements ("XHeat"), and other uses ("XOther"). These three variables are constructed using the weather, economic, utility price, and end use inputs. Thus, all structural and equipment changes, predicted economic impacts, price elasticities, and weather assumptions are captured in the resulting forecast.

Figure 5-4: Itron's SAE Modeling Framework



AES Indiana forecasts monthly sales and customers for each rate code using the method described above. Each customer class is modeled slightly differently owing to the unique characteristic of the classes. In the residential customer class models are developed for average use and the number of customers, total sales are then the product of the two model outputs. Commercial sales are directly modeled using the SAE approach described above. Industrial sales are directly modeled using an econometric approach given the lack of saturation and efficiency data provided by the Energy Information Administration ("EIA") for the industrial sector. The rate code level forecasts are aggregated into a system-level forecast in which line losses are added based on historic loss factors. This system-level forecast along with the system hourly load history, peak-day weather, and end use intensity data drive the peak forecast. Please see Itron's 2022 Load Forecast Report, which is attached to this Report at Attachment 5-2, for more detail on the forecast methodology and results.

Figure 5-4 also illustrates the independent variable inputs that flow into the model. The independent variables with data source descriptions are as follows:

- *End-use appliance saturation and efficiency trends data* – Energy intensities are derived from the EIA's 2020 Annual Energy Outlook ("AEO") for the East North Central Census Division. The EIA End Use Data is available in Confidential Attachment 5-3a-g. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types. The EIA does not provide saturation and efficiency trends for the industrial sector.
- As part of the DSM Market Potential Study, AES Indiana conducted an in-depth end-use analysis of each customer sector in order to gain an accurate representation of the saturations and efficiencies of equipment in the service territory. Results from the analysis informed the EIA intensity base year assumptions used in the Itron models. Future intensities still rely on the EIA forecasts of equipment saturation and efficiencies. For more information regarding end use modeling techniques, see Attachment 5-2.
- *DER and Other Electrification MPS* – GDS conducted a DER and electrification MPS as part of a broader effort that included an energy efficiency and demand response potential study in support of AES Indiana's IRP and DSM planning. The study included an analysis of various DER options, including solar photovoltaics and combined heat and power, a study of transportation electrification, including both commercial sector and residential sector vehicles, and a building electrification analysis of the residential, commercial, and industrial sectors. For more information regarding GDS's DER and Electrification Report, see Attachment 5-4.
- *Economic data* – Economic inputs are Moody's Analytics projections from Q3 2021, see Confidential Attachment 5-5a. The high and low forecasts use a combination of different Moody's Q3 2021 economic scenarios and forecast model standard deviations, see Confidential Attachments 5-5b-c. The high and low load forecasting approach will be described later in this section.
- *Historical class sales and customers* – AES Indiana tracks historical sales and customer data for each discrete rate code, which serves is an input into the load forecasting models.
- *AES Indiana price forecast* – Historical prices are derived from billed sales and revenue data. Prices are calculated as a 12-month moving average of the average rate (revenues divided by sales including trackers); prices are expressed in nominal dollars.
- *Weather data* – Historical and normal monthly heating degree days ("HDD") and cooling degree days ("CDD") are derived from National Oceanic and Atmospheric Administration daily temperature data for the Indianapolis Airport. For residential classes, a temperature base of 60 degrees is used in calculating HDD and a temperature base of 65 degrees are used in calculating CDD. For commercial classes, a temperature base of 55 degrees is used in calculating HDD and a temperature base of 60 degrees are used in calculating

CDD. Adjusting the base temperature for calculating the HDDs and CDDs for the commercial sector in AES Indiana's 2022 IRP generally improved key forecast model statistics – R-squared and Mean Absolute Percent Error. The improvement in the statistics indicates that this base temperature adjustment better captures the heating and cooling breakpoints for the commercial sector. Generally, industrial classes are not considered weather sensitive and only receive a small if any weather adjustment. The base temperature selection is determined by evaluating the sales/weather relationship and determining the temperature at which heating and cooling loads begin.

Capturing Increasing Temperatures

Since 1960, average annual temperatures have been increasing by 0.05 degrees per year, or 0.5 degrees per decade. The average annual temperature in 2021 is six percent higher than in 1960. Temperatures on the coldest days are increasing at an even faster rate of 1.1 degrees per decade. These results are similar to those found in the Purdue University study for the Indiana Climate Change Impact Assessment.[12] For the baseline forecast AES Indiana has assumed that temperatures will continue to increase at the historical trend rates.

AES Indiana-sponsored DSM was included as an endogenous variable in the sales models. The residential and commercial models incorporate DSM to account for historical program savings. The DSM variables help explain historical usage trends. The DSM variables are based on annual verified DSM savings that are converted to a monthly series. It should be noted that in the residential model, DSM is expressed as savings per customer and included in the residential average use model. AES Indiana only included this variable in the sales model if it was considered significant (using p-value) and did not impair other model statistics (R-square). The inclusion of the DSM variable in the forecast model provides a term for the proportion of future DSM that is included as a reduction of the load forecast moving forward. For example, a coefficient of -0.8 would mean that 80% of the future DSM is being subtracted from the load forecast. This method captures the trend embedded in AES Indiana's load history and results in a forecast that is reduced for DSM. Because DSM is treated as a resource in the IRP model, AES Indiana needed to include a load forecast that is free of all future DSM. Modeling a future that assumes no future DSM provides a blank slate for the model to add DSM. To achieve this, AES Indiana grossed up the load forecast that had been reduced for future DSM as described above. AES Indiana made this adjustment in spreadsheets outside the model.

In addition to the base forecast, AES Indiana developed a high and low load forecast for use in certain IRP scenarios. The forecasts were developed using the growth rates Moody's "Alternative Scenario 1 – Upside – 10th Percentile" and "Alternative Scenario 3 – Downside – 90th Percentile." Each alternative scenario represents the case in which the economy has an estimated 10% chance of potentially preforming at a higher (or lower, in the downside case) level. See Confidential Attachments 5-5a-c for the Moody's data. The economic scenarios are constructed by applying the scenario economic growth rates to the baseline economic variables starting in the first month of the forecast period (2022). Scenarios are further adjusted to ensure the growth rates

[12] https://ag.purdue.edu/indianaclimate/indiana-climate-report/.

are less than or equal to the baseline growth rates in the lower case and greater than or equal to the baseline growth rates in the high case. Please see Attachments 5-6 for AES Indiana's 10-year energy and peak forecast and Attachments 5-7a-b for AES Indiana's 20-year base, high, and low forecast. The different economic scenarios are used to explore the model's sensitivity to the economic inputs as well as capture risk and uncertainty associated with different economic environments. However, the economic inputs produced only modest changes in the results across most scenarios. Through the modeling results, AES Indiana found the uncertainty in the future state of the EV and DG markets was the greatest source of risk in the models. The adoption of EV and DG is still in its early stages with tremendous potential to impact load growth in the coming years. To capture this risk, AES Indiana developed multiple scenarios including a "very high" EV forecast, which was paired with a high DG forecast that was included in the Decarb Economy scenario. The load scenarios are as follows:

→ Low – low economics, low EV and DG.

→ Base – base economics, base EV and DG.

→ High – high economics, high EV and DG.

→ Very High – high economics, very high EV and high DG.

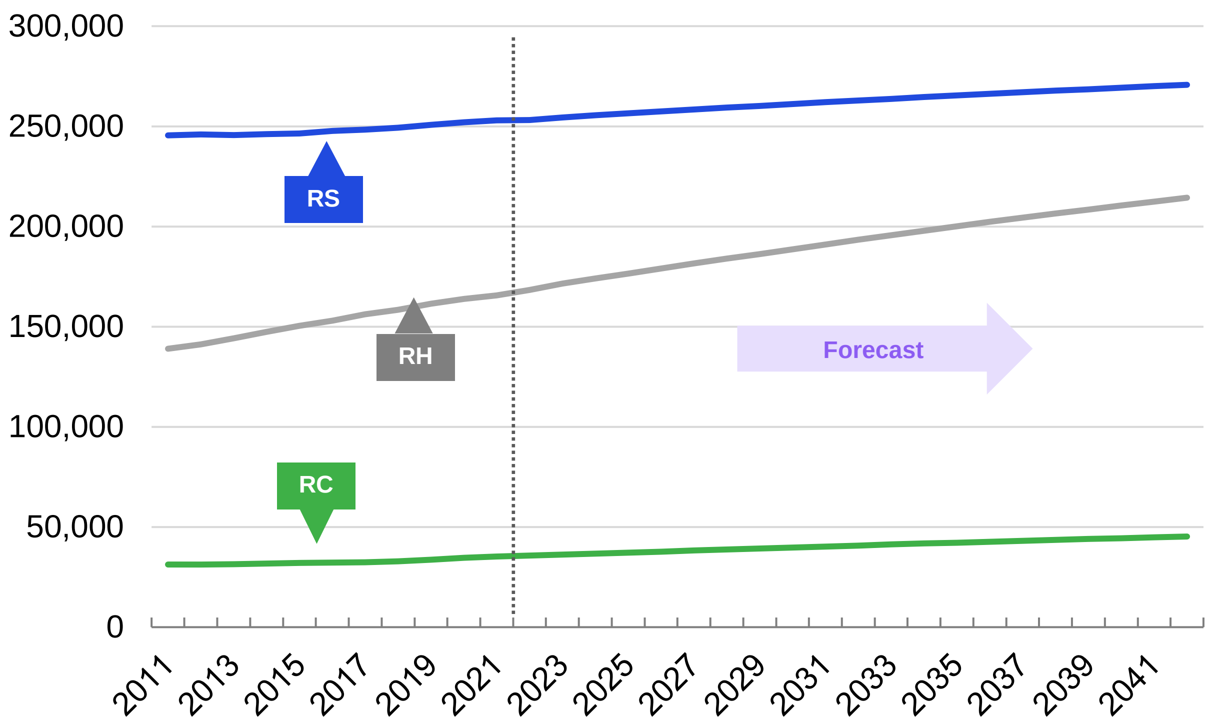
Additionally, AES Indiana included load as a stochastic parameter to capture the volatility that could be attributed to weather in the various scenarios.

5.3.1 Residential Sector

The residential sector is comprised of three primary customer types: those with natural gas heat, electric heat, and natural gas heat with electric water heat. On a percent of customer basis, the residential customer types are disaggregated as follows: 56% natural gas heat, 37% electric heat, and 8% natural gas heat with electric water heat. While on a percentage of sales basis, the residential customer types are disaggregated as follows: 46% natural gas heat, 45% electric heat, and 8% natural gas heat with electric water heat. The residential sector makes up 40% of AES Indiana's total sales.

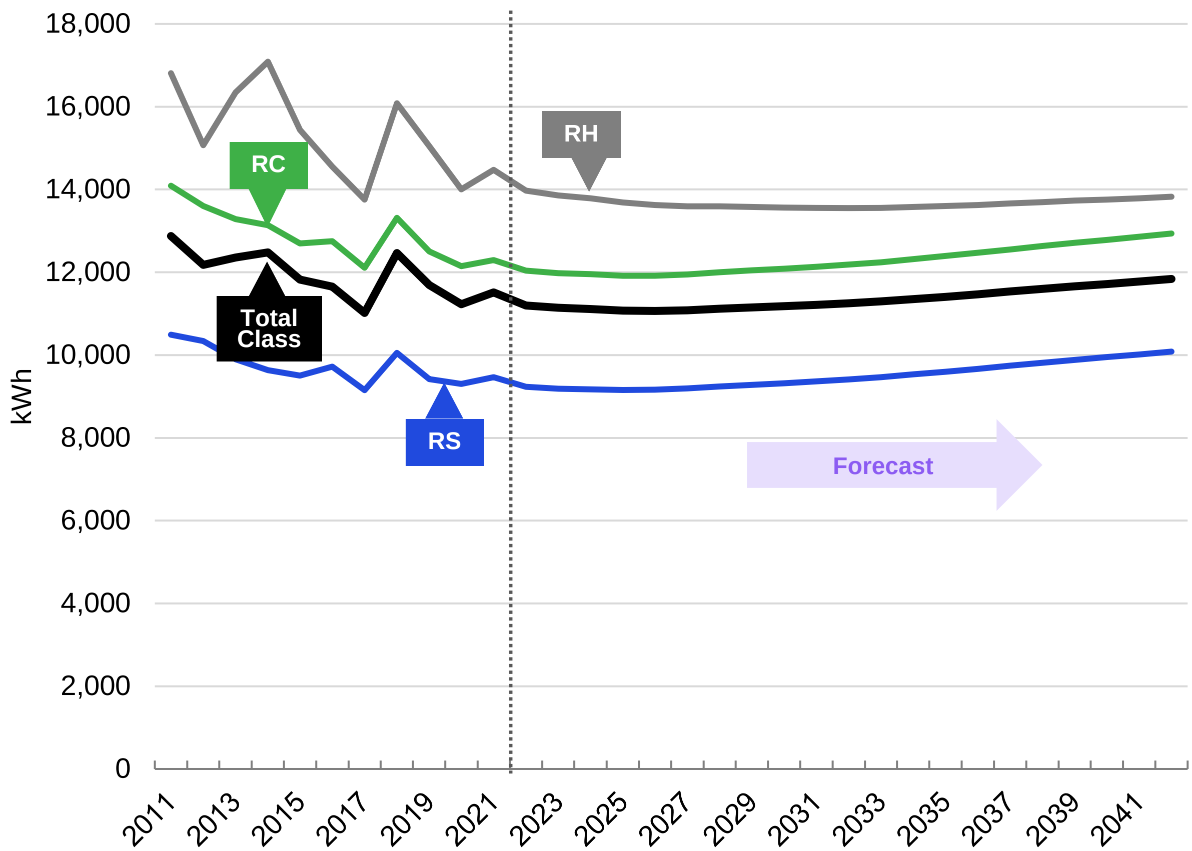
The customer forecast is based on population forecast for Marion County. The correlation between Marion County population and number of AES Indiana residential customers is over ninety percent. While all residential customers classes are forecasted to increase, the RH and RC classes are increasing at a significantly faster rate than the RS class. RH and RC customers are forecasted to increase 1.2% annual over the forecast period, RS customers are forecasted to increase 0.3% annually. Figure 5-5 shows the residential customers forecast.

Figure 5-5: Residential Customer Counts



Residential average use has been declining since 2011. However, average use flattens out and even begins to increase over the forecast period. This forecasted increase is caused largely by two factors; economic growth countering improving end-use efficiency and future DSM program savings being excluded in the forecast period. Total rate class average use increases partly due to the increasing share of customers with electric heat. Figure 5-6 below shows the historical and forecasted average use, excluding future DSM.

Figure 5-6: Residential Average Use[13]



[13] Figure 5-6 does not include future DSM. Future DSM is modeled as selectable resources in the IRP model.

The residential sales forecast is generated as the product of the average use and customer forecasts. Total residential sales are calculated by totaling the rate level forecasts. Figure 5-7 below shows the forecasted residential customer, sales, and average use before future DSM, distributed generation, and electric vehicle adjustments.

Figure 5-7: Forecasted Residential Customer Sales and Average Use[14]

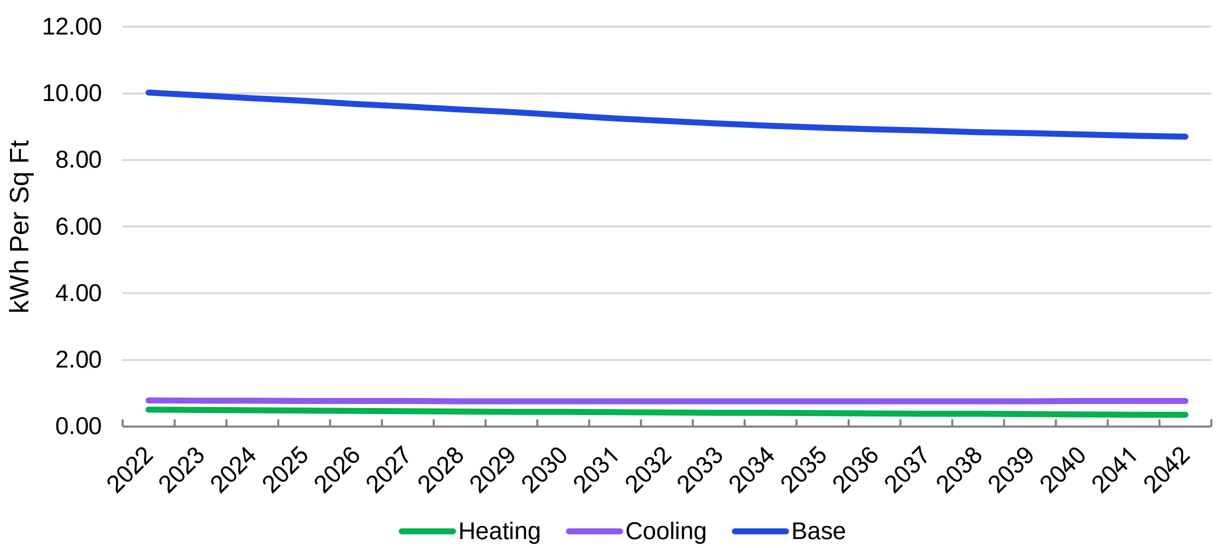
Year	Sales (MWh)	Change	Customers	Change	Average Use (kWh)	Change
2022	5,120,205		415,728		12,316	
2023	5,148,145	0.5%	418,276	0.6%	12,308	-0.1%
2024	5,183,132	0.7%	421,275	0.7%	12,303	0.0%
2025	5,208,018	0.5%	425,237	0.9%	12,247	-0.5%
2026	5,246,104	0.7%	429,000	0.9%	12,229	-0.2%
2027	5,299,299	1.0%	432,885	0.9%	12,242	0.1%
2028	5,360,175	1.1%	437,014	1.0%	12,265	0.2%
2029	5,416,700	1.1%	440,588	0.8%	12,294	0.2%
2030	5,472,660	1.0%	445,760	1.2%	12,277	-0.1%
2031	5,532,095	1.1%	450,367	1.0%	12,284	0.1%
2032	5,592,595	1.1%	453,800	0.8%	12,324	0.3%
2033	5,654,854	1.1%	457,267	0.8%	12,367	0.3%
2034	5,723,758	1.2%	462,142	1.1%	12,385	0.2%
2035	5,792,730	1.2%	466,305	0.9%	12,423	0.3%
2036	5,862,577	1.2%	470,260	0.8%	12,467	0.4%
2037	5,934,492	1.2%	474,157	0.8%	12,516	0.4%
2038	6,006,119	1.2%	478,188	0.9%	12,560	0.4%
2039	6,076,064	1.2%	481,976	0.8%	12,607	0.4%
2040	6,142,240	1.1%	485,759	0.8%	12,645	0.3%
2041	6,210,088	1.1%	489,543	0.8%	12,685	0.3%
2042	6,279,732	1.1%	493,330	0.8%	12,729	0.3%
2022-42		**1.0%**		**0.9%**		**0.2%**

[14] The forecasted sales and average use values do not include future DSM, distributed generation, or electric vehicle adjustments.

5.3.2 Commercial Sector

Commercial sales are also estimated using an SAE model structure, the difference is that the commercial sector sales forecast is based on total sales model rather than an average use and customer model. The constructed model variables include HDD, CDD, billing days, commercial economic activity variable, price, end-use intensity trends, and historical DSM savings. All but miscellaneous end-use intensities are trending down as the end-use efficiency continues to improve, as can be seen in Figure 5-8. Figure 5-8 shows the commercial end-use intensities that are forecasted through the IRP forecasting horizon from 2022 to 2042. To be consistent with rate class sales that are in MWh, the intensity estimates are then scaled to MWh.

Figure 5-8: Aggregated Commercial End-Use Intensity



Commercial sales, like residential sales, have been trending down. Since 2011, annual commercial sales have declined on average 0.9% per year. The COVID-19 pandemic had a significant impact on commercial electric sales, with sales declining over 7% in 2020. Sales continue to recover in 2021 but have not fully returned to pre-COVID levels. Excluding 2020 and 2021, commercial sales have declined on average 0.4% annually from 2011-2019. Aside from negative shock from COVID, the primary factors driving commercial sales are expected economic activity, declining end-use intensities, electric prices, and historical DSM program savings. Over the next twenty years, employment, and output averages 0.6% and 2.1% annual growth, and total end-use intensity declines 0.7% per year. The combination of these factors results in 0.4% annual commercial sales growth through 2042 before DSM savings adjustments. Figure 5-9 shows the commercial sales forecast, sales forecast excludes the impact of future DSM program activity.

Figure 5-9: Commercial Sales Forecast

Year	Commercial (MWh)	Change
2022	5,099,965	
2023	5,175,810	1.5%
2024	5,242,675	1.3%
2025	5,256,152	0.3%
2026	5,263,430	0.1%
2027	5,283,036	0.4%
2028	5,313,462	0.6%
2029	5,327,254	0.3%
2030	5,326,090	0.0%
2031	5,327,322	0.0%
2032	5,334,535	0.1%
2033	5,344,582	0.2%
2034	5,358,687	0.3%
2035	5,374,903	0.3%
2036	5,393,600	0.3%
2037	5,413,422	0.4%
2038	5,434,746	0.4%
2039	5,459,080	0.4%
2040	5,481,652	0.4%
2041	5,509,752	0.5%
2042	5,539,743	0.5%
2022-42		**0.4%**

5.3.3 Industrial Sector

The industrial billed sales forecast is based on manufacturing, employment, and industrial output. The model does not include end-use intensity estimates due to the lack of data for developing industrial intensity estimates. As such, the industrial sector is forecasted using a more traditional econometric modeling approach – please see p. 16 of Itron's 2022 Load Forecast report in Attachment 5-2 for more regarding the Industrial load forecasting methodology. The industrial economic variable is weighted between manufacturing employment and manufacturing output with a stronger weight on output. The economic weighting is derived by evaluating the model in-sample and out-sample statistics.

Several of the high load factor rate ("HL") schedules have relatively few customers (e.g., HL2 and HL3). HL2 currently has 5 customers and HL3 has 3 customers. Other than seasonal cooling load variation HL2 and HL3 sales have been flat. HL2 did see a significant drop in sales with the onset of COVID-19 but much of that had recovered by the end of 2021. HL2 and HL3 sales have been held constant through the forecast period. Attachment 5-8 provides AES Indiana's energy forecast drivers and input data, and Attachment 5-9 provides AES Indiana's peak forecast drivers and input data. Figure 5-10 shows the industrial sales forecast, sales forecast excludes the impact of future DSM program activity. In order to capture load that will be coming on the AES Indiana system that is not represented in the historical data the load forecasting team meets with the AES Indiana Strategic Accounts team to access new customer load. A hypothetical example of a new customer load may be that an existing customer is adding a new 10 MW facility on January 1, 2023. Using the customer input on the type of facility, AES Indiana estimates a load factor for the addition (for example – 80%) to calculate annual MWh consumption (in this hypothetical case 10*0.8*8760 = 70,080 MWh annually). AES Indiana then divided this estimate by 12 months and added it to the load forecast starting January 1, 2023. This load remains on the system unless the customer indicates that it is only temporary or shutting down.

Figure 5-10: Industrial Sales Forecast

Year	Industrial (MWh)	Change
2022	2,933,049	
2023	2,940,658	0.3%
2024	2,942,141	0.1%
2025	2,931,960	-0.3%
2026	2,905,114	-0.9%
2027	2,907,949	0.1%
2028	2,921,722	0.5%
2029	2,920,310	0.0%
2030	2,912,630	-0.3%
2031	2,908,714	-0.1%
2032	2,901,176	-0.3%
2033	2,896,113	-0.2%
2034	2,893,268	-0.1%
2035	2,891,749	-0.1%
2036	2,891,692	0.0%
2037	2,891,729	0.0%
2038	2,892,841	0.0%
2039	2,895,513	0.1%
2040	2,897,307	0.1%
2041	2,901,085	0.1%
2042	2,905,324	0.1%
2022-42		**0.0%**

Streetlighting

The Commission's December 13, 2017 Order in Cause No. 44981 approved a Public Lighting Agreement between AES Indiana and the City of Indianapolis, which provided a three-year Light-Emitting Diode ("LED") conversion project and the installation of additional LED street lighting in the city. The conversion work commenced following the awarding of contracts in the spring of

2018 and concluded in November 2021. Though the life of the program, the number of LED conversion are 26,434 and the number of additional LED streetlights installed is 2,120. The forecast model for street lighting is a trended time series model, since the conversion and additions were included in the model's input data this will be reflected in the forecasted load moving forward.

5.4 Electric Vehicles and Distributed Solar

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Transportation electrification is consistently identified as a significant means by which to reduce environmental impacts and improve transportation efficiency. The market for EVs is expected to grow rapidly. This increased EV adoption has the potential to result in significant measurable future grid impacts, which if managed, could improve long-term energy affordability and core system reliability. As the only entity in a position to manage this growth in a system wide manner, it is important that AES Indiana continues to monitor EV adoption in its service territory and offer cost effective customer programs in the future that deliver net benefits to AES Indiana's customers and communities.

5.4.1 Electric Vehicle Forecast

Electric transportation is viable today and adoption is accelerating as prices decline and adoption barriers diminish. Most vehicle manufacturers have set aggressive targets for EV sales, fuel prices have been at historic highs, and there is significant state[15] and federal[16] public policy support to build out EV charging infrastructure – all these factors contribute to growing demand for EVs.

As the electric distribution company serving central Indiana, AES Indiana sees a variety of benefits associated with supporting increased EV adoption and charging load modification. Increased EV adoption results in increased contributions to AES Indiana's fixed costs in the form of new retail rate revenue, which provides an opportunity for future downward pressure on rates for all customers served by AES Indiana. Additionally, AES Indiana believes it is important to actively influence this incoming load growth such that this new load is managed for the benefit of customers.

EVs increase the demand for electricity that regulated electric utilities like AES Indiana are required to supply to customers in their service territory. The growing adoption of EVs amongst all customer classes (residential, commercial, and industrial) poses supply and demand challenges that may require increased focus towards the assessment of the transportation sector and how it effects retail electric rates. Eventually, controlled EV charging ("Managed Charging") may also serve as a resource in grid management. AES Indiana expects that this trend of increased EV adoption will also be realized in its service territory over the next several years.

[15] E.g., HEA 1221, 2022 Indiana General Assembly.
[16] E.g., Infrastructure Investment and Jobs Act ("IIJA"), which established the National Electric Vehicle Infrastructure Program.

To better understand EV impacts and provide innovative solutions for customers, AES Indiana has undertaken significant efforts in this area. Beginning in 2011, AES Indiana received federal smart grid funding that was used to support the installation of public and private electric vehicle supply equipment (“EVSE”). To accompany the EVSE deployment, the Company proposed public and private electric vehicle rates that were designed to support adoption of electric vehicles. In its Order in IURC 30-Day Filing No. 2786, the Commission authorized AES Indiana to implement a Time of Use Service for Electric Vehicle Charging on Customer Premises (“Rate EVX”), which is an EV-specific, time of use (“TOU”) rate. Additionally, the Company deployed public charging infrastructure, which included a flat public charging rate under its Electric Vehicle Charging on Public Premises (“Rate EVP”) tariff offering, the rate of which is set at $2.50 per charging session. In 2018, AES Indiana retrofitted its public charging stations with more modern EVSE, which allowed customers payment flexibility and improved AES Indiana’s ability to remotely monitor charging occupancy. Both Rates EVX and EVP are still in effect today.

AES Indiana currently owns and operates level 2 EV charging infrastructure in Indianapolis and is expanding its investment as part of a statewide effort to install Direct Current Fast Charging (“DCFC”) at more than 60 locations along interstate highway corridors. AES Indiana is part of a consortium of Indiana utilities who were awarded $5.5M from the Volkswagen Diesel Emissions Environmental Mitigation Trust. These dollars will in part fund AES Indiana’s commitment to install, own and operate DCFC at eight locations along interstate highways in central Indiana, making it easier for residents and visitors to quickly and conveniently charge while on the go.

More recently, AES Indiana, has offered a residential Managed Charging program, and has seen early successes in customer adoption. Currently, slightly more than 100 residential customers have signed up to participate, and early test results indicate that peak coincident demand impacts average 0.5 kW per household. This flexible demand side resource will be important in the future to preserve system reliability as EV load increases.

AES Indiana is also committed to electrifying its own fleet of vehicles. The company has recently taken delivery of new electric light duty trucks, is installing charging infrastructure at AES Indiana facilities, and is committed to full light duty vehicle electrification by 2030.

5.4.2 Literature Review and Prototypical Electric Vehicle

Wide-scale adoption of EVs across the U.S. will necessitate a substantial amount of energy supply to meet the needs of consumers over time. As traditional internal combustion engine vehicles are offset by both battery electric vehicles and plug-in hybrid electric vehicles, electric service providers will need to account for the expanding EV market in their resource planning efforts.

As of December 2021, the U.S. Department of Transportation’s Federal Highway Administration (“FHA”) provides that there are over 275 million vehicles in the U.S. and roughly 6.1 million in Indiana. The U.S. Department of Energy (“DOE”), in accordance with NREL, estimates that just over one million EVs were registered in the U.S in 2021. The annual number of EV sales has been steadily increasing over time as well. In 2010, there were just over 15,000 EVs sold in the

U.S.; in 2015 that number grew to over 120,000; and in 2021, EV sales were over 600,000 units. As of the beginning of 2022, EPA fuel economy report notes over 65 different makes and models of EV passenger cars are available to consumers, with new makes and models reported to hit the market year after year.

Differentiating between residential and commercial vehicles is the first step to determining the impact of new EVs in AES Indiana's service territory. Residential vehicles can be typically defined as light- or medium-duty passenger vehicles or trucks used for daily commutes or recreational purposes. Commercial vehicles can be any type of vehicle used for business purposes (e.g., used for the transportation of goods or people; owned by a company or the public sector). This range of potential commercial vehicles can include light duty passenger cars, such as taxis and police cars, all the way to vans, large trucks, and transit/school buses. Determining the number of each vehicle type takes a bottom-up approach before the energy consumption values can be approximated for AES Indiana's service territory.

While EV passenger cars have a wide variety of options, the market for small delivery trucks and vans, large heavy-duty trucks (e.g., semi and tractor trailer trucks), limos, transit buses, and school buses is currently limited to a small number of makes and models, as of 2022. The adoption of these vehicles is still in its infancy. For example, car manufacturers like Tesla, Volvo, Daimler, and BYD are still in the process of developing an EV semi-truck, with production estimates as early as the fourth quarter of 2022. Additionally, regarding school buses, of the roughly 500,000 in the U.S. as of December 2021, less than 1% are electric. While identifying the initial vehicle counts of these vehicle types is useful, forecasting the adoption and associated energy usage of each has its limitations.

5.4.3 Forecasting Methodology

To assess the future impacts of EVs and DERs, AES Indiana leveraged the analysis completed by GDS Associates, Inc. ("GDS") as part of its MPS effort. The various methodologies to conduct the analysis are discussed below.

Commercial EV Forecasting Methodology

This analysis utilizes existing, publicly available, historical data and trends along with supplemental data specific to AES Indiana. First, to establish a forecasted value of commercial vehicles in AES Indiana's service territory, an AES Indiana provided baseline year of 2021 was used. Commercial vehicle types were determined, and primary data was collected for historical U.S. vehicle registrations from sources, such as the FHA and the DOE. Historical values were compared against national, state, and city population values year-over-year, and the number of registered vehicles in a specific state and county can be extrapolated for a single historical year. Commercial vehicle types were then grouped in segments based on vehicle characteristics.

Various industry sources have offered opinions and projections of the future of the U.S. EV market. For example, the EIA, the International Energy Agency ("IEA"), and NREL all publish annual studies on potential EV penetration and adoption and have unique sales forecasts for the U.S. The characterization of the current EV market and the best estimates of future trends are based on leveraging both national and local historical data to the extent possible. Local data, such as historical values of school and transit buses in Marion County, IN, was used when available.

Due to the 20-year length of the IRP study timeframe, and the current state of the EV market, this study uses four linear-trend scenarios of EV shares of total vehicle sales as described below:

- → Low – starting at 1.7% in 2020 rising to 9.1% in 2042.
- → Medium – starting at 1.7% in 2020 rising to 18.2% in 2042.
- → High – starting at 1.7% in 2020 rising to 36.0% in 2042.
- → Very High – starting at 1.7% in 2020 rising to 85% in 2042.

A linear regression analysis is utilized for each cohort to develop a projection of new commercial vehicle purchases and replacements for each cohort within the forecasted years in the planning period. The linear regression approach is used because of its simplicity and the uncertainty in the EV market. Regarding uncertainty, the linear regression approach avoids a large adoption spike that may appear when using other bass-diffusion-based forecast curves. From a resource planning perspective, a large, sudden spike in load resulting from EV adoption may require significant capacity additions. The problem is that there remains significant uncertainty as to exactly when in the future this spike will occur. The linear methodology smooths out EV adoption to avoid incorrectly forecasting when the adoption spike will occur. The forecast does not include any additional market interventions by AES Indiana, such as customer incentives of exceptional energy rate structures.

Residential EV Forecasting Methodology

GDS developed a residential EV forecast for AES Indiana, which includes low, base, and high scenarios for the number of residential EVs and the associated total energy consumption by the forecasted EVs. The forecasting linear-based model is based on many inputs and assumptions. The methodology and data inputs are discussed below.

The first key input in the residential EV model is the number of AES Indiana customers that make up potential EV owners. GDS utilized the most recently completed load forecast from AES Indiana to input the number of residential customers on the system. The number of residential customers is essentially the number of households served by AES Indiana; therefore, the number of residential customers can be multiplied by the number of vehicles per household to estimate the total number of vehicles within the AES Indiana service territory. The U.S. Census Bureau estimates there are 1.86 vehicles per household in the Indianapolis metropolitan area.

A second key assumption is the number of EVs currently in the AES Indiana service territory. GDS utilized Indiana BMV registration data and the 2021 residential consumer survey conducted for the 2021 MPS to determine the number of residential EVs served by AES Indiana. Based on the data discussed above, GDS estimates that in 2021 3,575 EVs were served by AES Indiana.

The final key assumption used in the EV model is the percentage of EVs that make up new vehicle sales. GDS started with publicly available data from the EIA and its Annual Energy Outlook (“AEO”) for 2021. The 2021 AEO projects that 11.7% of new vehicle sales will be EVs in the year

2050. GDS conducted broad and thorough EV industry research to understand the AEO projections and form a basis for the new vehicle sales percentage included in alternate scenarios. The AEO estimate of 11.7% is on the low end of the current industry projections based on GDS research, so the AEO trend was closely followed for the low scenario. GDS then developed a base case and a high case scenario using various industry sources/research. The various scenarios all produce a linear growth trend for EV sales as a percentage of new vehicle sales. A very high forecast was also included to capture potential load risk associated with aggressive EV adoption. This scenario was developed using auto manufacturers stated plans for EV production and sales. See Section 8.4.2 for discussion of how the EV forecast scenarios were included in the IRP scenarios.

Photovoltaic ("PV") Forecasting Methodology

Photovoltaic systems utilize solar panels, a packaged collection of photovoltaic cells, to convert sunlight into electricity. A system is constructed with multiple solar panels, DC to Alternating Current ("AC") inverter(s), a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted and face south-west, south, and/or, south-east.

The study analyzed the potential associated with roof-mounted systems installed on residential and non-residential sector buildings. For the non-residential sector, the analysis also estimated potential for ground mounted (or covered parking) systems for a few specific business types. The analysis included battery storage as an additional configuration with each solar PV system type; however, due to the uncertainty associated with battery dispatch schedules, potential battery generation is excluded from this analysis. As noted above, this study did not explore the market potential associated utility-scale solar PV installations.

The approach to estimating technical potential required calculating the total square footage of suitable rooftop area within the AES Indiana's territory and calculating solar PV system generation based on building and regional characteristics. Technical potential is computed using the following equation.

$$\boldsymbol{PV\ Technical\ Potential} = \boldsymbol{\Sigma}(\boldsymbol{Suitable\ Rooftop\ Square\ Footage}\ \times \boldsymbol{PV\ System\ Generation\ per\ Sq.Ft.})$$

The two key parameters in prior equation were estimated based on multiple data sources relevant to the AES Indiana territory. Methods for defining these parameters are discussed below.

GDS estimated total rooftop square footage using the forecast disaggregation analysis to characterize the residential and non-residential building stocks. The building stocks were characterized based on relevant parameters such as number of facilities, average number of floors, average premise consumption, and premise end-use intensity. GDS used these parameters to estimate the total rooftop square footage.

To estimate the fraction of the total roof area that is suitable for rooftop solar PV, the GDS Team relied on research completed by the NREL. NREL has developed estimates of the portion of total rooftops across the country that are suitable for solar PV based on analysis of Light Detection and Ranging ("LIDAR") data. NREL criteria for suitable roof area include:

- → **Contiguous rooftop area size**: Rooftops with fewer than 10 square meters of contiguous roof area excluded.
- → **Rooftop orientation (tilt and azimuth):** Northeast through northwest orientation and roof pitches greater than 60 degrees excluded.
- → **Shading:** Roof areas that had a minimum solar exposure of less than 80% relative to an unshaded roof were excluded.

Based on NREL's data, GDS was able to apply unique suitability factors to estimate the total square footage of suitable rooftop for residential and non-residential buildings across AES Indiana's territory.

The second key parameter – PV system generation – was estimated by developing standardized solar PV system configurations. These included system sizes for residential premises ranging from 3 to 20 kW (DC) and 10 to 2,000 kW (DC) for non-residential premises. Additionally, the GDS Team selected battery system sizes for each solar PV system size to dispatch energy for 2-4 hours.

GDS relied on NREL's PVWatts[17] (Version 6.1.4) and System Advisor Model ("SAM")[18] tools to estimate system generation for both residential and non-residential sited systems. These tools model PV power density based on site specific data from NREL's LIDAR-based NSRDB to estimate total solar irradiance in conjunction with PV system specifications. The PV system simulations were generated based on characteristics specific to Indianapolis, Indiana. GDS based assumptions for PV system azimuth on rooftop orientation data sourced from Google's Project Sunroof, which is also based on data specific for Indianapolis. The analysis assumptions are summarized in Figure 5-11.

[17] PVWatts estimates solar PV energy production and costs. Developed by NREL, http://pvwatts.nrel.gov/.
[18] SAM estimates hourly solar PV energy production and costs with more detailed inputs and outputs than PVwatts. Developed by NREL, http:// https://sam.nrel.gov/.

Figure 5-11: Key Assumptions in Solar PV Analysis

Parameter	Assumptions
Residential System Sizes (Nominal DC Capacity)	3 kW, 5 kW, 7.5 kW, 10 kW, 15 kW, 20 kW
Non-Residential System Sizes (Nominal DC Capacity)	10 kW, 15 kW, 20 kW, 25 kW, 50 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, 2,000 kW
System losses	14.1%
Tilt	By region
Azimuth:	By region
DC to AC size ratio	1.2
Inverter efficiency	96% (micro-inverter)
Battery Round-Trip Efficiency	85%

Based on the simulations and resulting capacity factors for residential and non-residential buildings for Indianapolis, GDS applied the state-specific capacity factor to the system size to estimate annual electricity generation. These system generation values were used to calculate total energy generation per square foot of rooftop and extrapolated based on the total suitable rooftop square footage to estimate overall all technical potential. As a final step, GDS removed from the technical potential for any generation occurring from existing systems. Data on existing systems was provided directly by AES Indiana.

To estimate economic potential for solar PV, GDS gathered pertinent data on system costs along with calculated generation benefits to use in the benefit-cost analysis, which GDS conducted at the system measure level. GDS assessed system component costs based on data included in NREL's Q1 2020 Benchmarking report as well as public data files from Tracking the Sun[19] and compared these national cost parameters to AES Indiana-specific values by using various market data provided by Energy Sage.[20] This analysis produced an estimated installation cost per watt installed, which GDS applied to each system size to estimate total installed cost. Additionally, GDS included Operation and Maintenance ("O&M") costs that scale with system size.[21] Finally, GDS assumed the impact of the ITC to follow the existing schedule at the time of this report which equates to a 10% tax credit for commercial systems by 2024 and a 0% tax credit for residential systems by 2024.

[19] Feldman, D, et. al., U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020. NREL, January 2021.
[20] https://www.energysage.com/solar-panels/in/; https://www.energysage.com/solar-panels/mi/ (accessed March 2021).
[21] Feldman, D, et. al., U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020. NREL, January 2021.

In addition to modeling solar PV system costs, the GDS Team estimated cost impacts for solar PV systems coupled with battery storage based on analysis from NREL's Q1 2020 Benchmarking report and Lazard's Levelized Cost of Storage Analysis.[22] The GDS Team estimated an average lithium-ion battery installation cost of $1,093 per kWh and $721 per kWh for the residential and non-residential sectors, respectively, inclusive of the ITC. Figure 5-12 provides the average solar PV installation cost by sector.

Figure 5-12: Average Solar PV Installation Cost

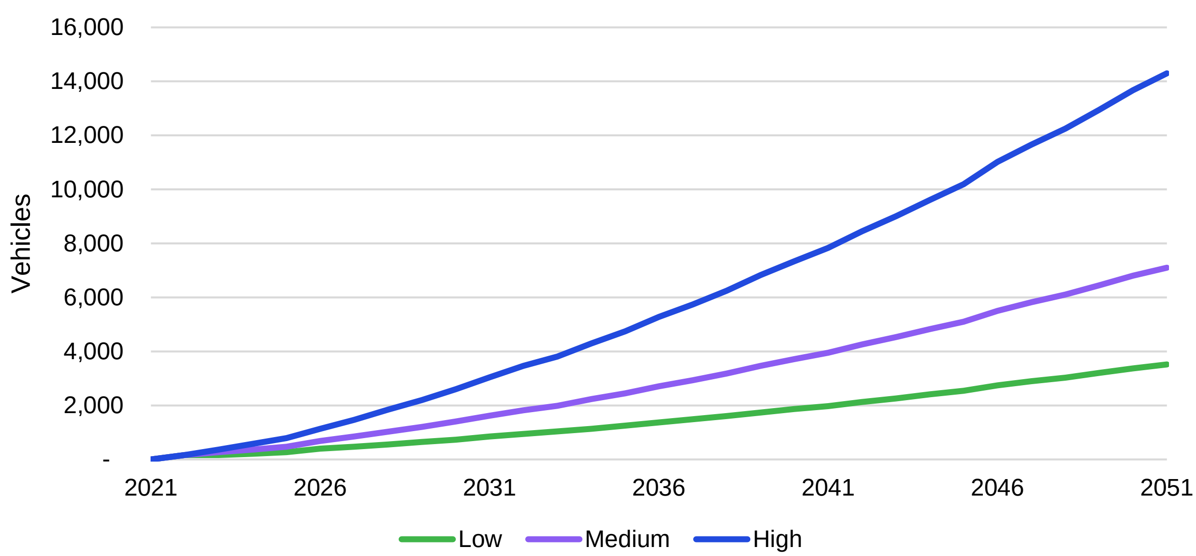
Sector	System Cost ($/Wdc)[23]
Residential	$3.05
Non-Residential (<100 kW)	$2.56
Non-Residential (>100 kW)	$2.20
Non-Residential - Tracking (<100 kW)	$3.95
Non-Residential - Tracking (>100 kW)	$3.39

5.4.4 Electric Vehicle and Distributed Solar Forecasting Results

This section provides the results of the commercial and residential electrification forecasts and the findings of the solar PV forecast analysis.

Figure 5-13 below shows the forecast for incremental new commercial electric vehicles for all three scenarios (low, medium, and high).

Figure 5-13: Incremental New Commercial Vehicles



[22] *Id.*

[23] Costs reflect impact of federal investment tax credit; battery systems not reflected in cost. System costs are measured in dollars per watt (dc).

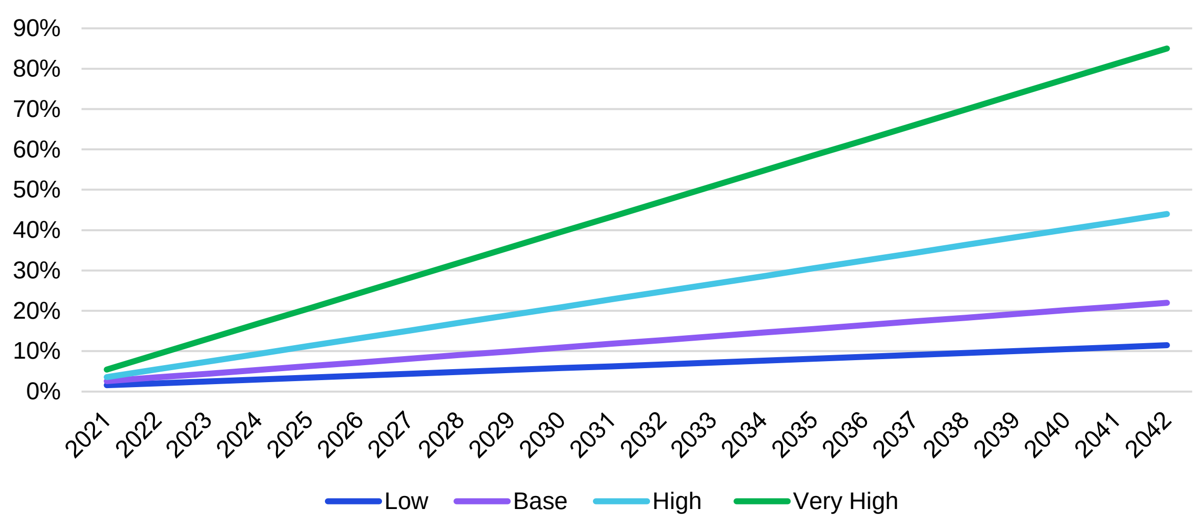
After the offset adoption of some of the larger vehicles is realized after 2024, the commercial EV's incremental energy usage takes a significant jump under all three scenarios. By 2030, under the "low scenario" the commercial EV sector will consume 7,700 MWh of energy supply. Under the high scenario, that energy supply increases to over 25,800 MWh. By 2041, incremental energy usage ranges from roughly 22k MWh to 88k MWh between the low and high scenarios. Under all scenarios, Class 7 (26,001 to 33,000 pounds) and 8 (greater than 33,000 pounds) vehicles account for nearly 50% of all energy needs every year. The adoption of these vehicles has the most potential to influence the energy usage values of the commercial EV market. Figure 5-14 shows the EV cumulative energy usage as percentage of total forecasted AES Indiana non-residential energy sales through 2041 in the low and high scenarios.

Figure 5-14: Cumulative Energy Usage – Non-Residential EV

Year	Non-Residential Sales Forecast (GWh)	Percentage of EV Energy Sales (Low Scenario)	Percentage of EV Energy Sales (High Scenario)
2022	8,025	0.01%	0.01%
2026	8,087	0.09%	0.18%
2031	8,080	0.51%	1.48%
2036	8,052	1.32%	4.47%
2041	8,080	2.57%	9.30%

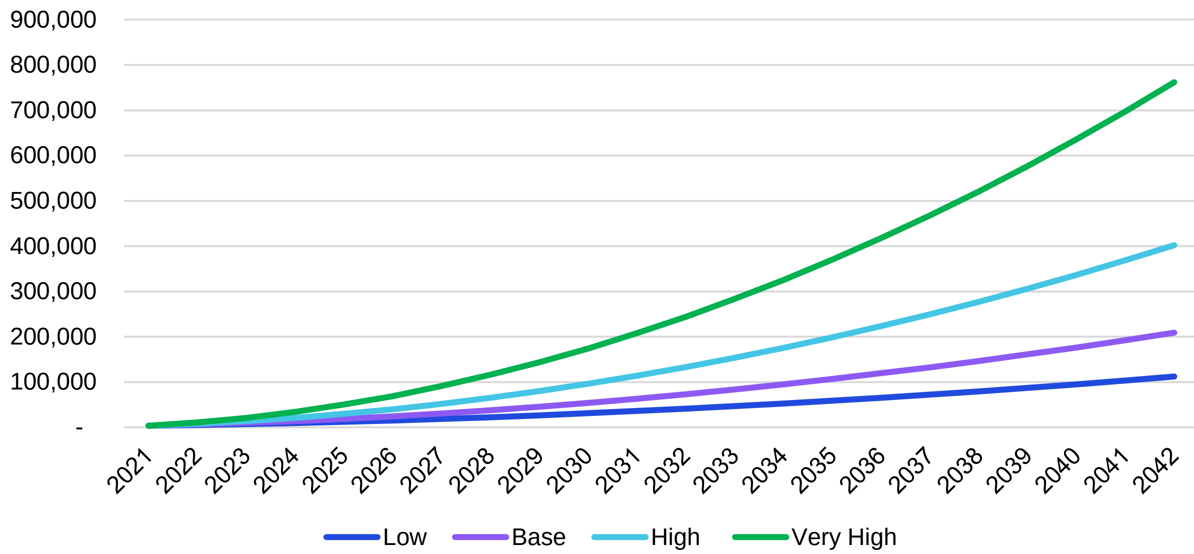
Figure 5-15 below shows the growth trend for EV sales as a percentage of new residential vehicle sales, with the low scenario closely following the AEO projections and the base and high scenarios representing more optimistic projections. While the very high scenario may appear overly optimistic compared to the low, base, and high scenarios, this forecast was estimated based on automakers stated goals for EV production.

Figure 5-15: Residential EV Sales as a Percentage of New Vehicle Sales



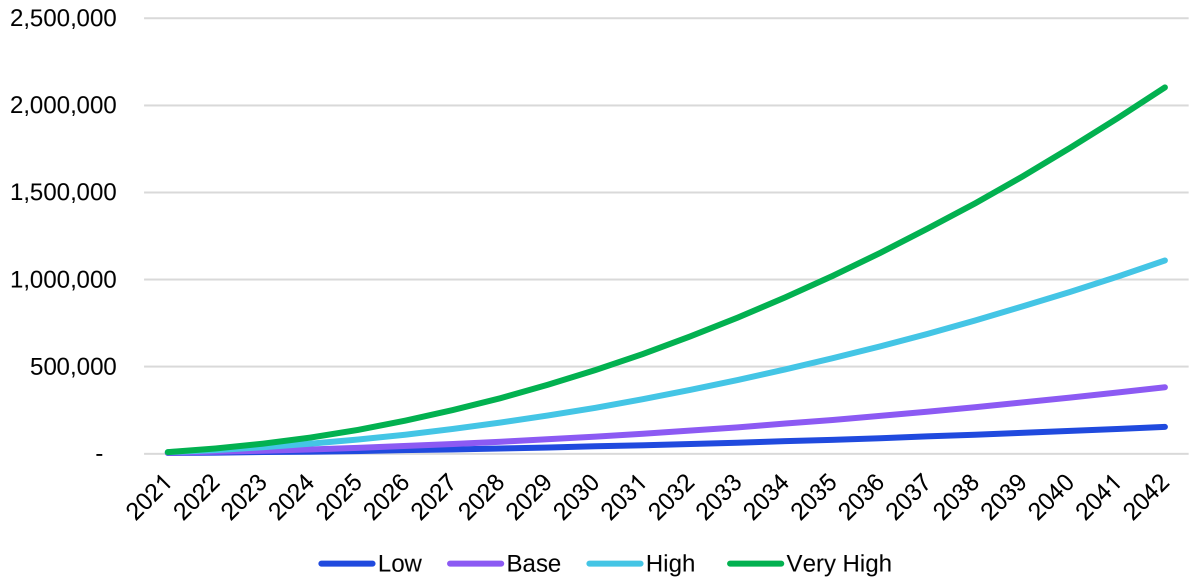
Given the initial number of EVs in Indianapolis and the projected percentage of new vehicle EV sales, the cumulative number of EVs served by AES Indiana can be projected annually. The projection of the total number of EVs accounts for the typical “lifespan” of a vehicle as well. Figure 5-16 below shows the projections for total number of electric vehicles.

Figure 5-16: Projected Total Number of Residential EVs in AES Indiana’s Service Territory



The total number of EVs and several other inputs, including average miles driven per year and kWh per mile efficiency, were used to calculate the total energy sales attributable to the projected number of EVs on the AES Indiana system. The expected average miles driven varies between scenarios, representing another layer of either optimistic or pessimistic assumptions regarding EV adoption and use. As seen below in Figure 5-17, the differences between the scenarios in expected MWh sales has increased due to the changing miles driven per year assumption.

Figure 5-17: Projected Sales (MWh) Attributable to EVs



It is notable that no solar PV technologies pass cost effectiveness screening under the Total Resource Cost ("TRC") for utility incentivization. However, while the TRC test for solar PV systems does not meet a 1.0 cost effectiveness threshold, AES Indiana customers install solar PV systems at their homes and businesses. Consequently, a baseline, Business-as-Usual ("BAU") forecast was developed for integration into the IRP modeling. The BAU forecasts are based upon the following assumptions:

- AES Indiana customer and rooftop characterization described earlier
- Number of existing systems
- Trend of existing system installation from 2015-2020
- Willingness to participate and market adoption data collected from AES Indiana customers
- Bass-diffusion curve and coefficients based upon the NREL dGen model[24] and EIA DG/PV interconnection and Census data

Based on the application of the BAU assumptions noted above, the GDS Team developed three adoption scenarios for BAU solar PV installations are described below for the residential sector:

- Low; up to 6% market adoption
- Medium; up to 15% market adoption
- High; up to 29% market adoption

The BAU forecasts for system and energy (MWh-DC) are shown in Figure 5-18 and Figure 5-19, respectfully.

[24] https://www.nrel.gov/analysis/dgen/

Figure 5-18: Residential Solar PV System Forecast (Business-As-Usual)

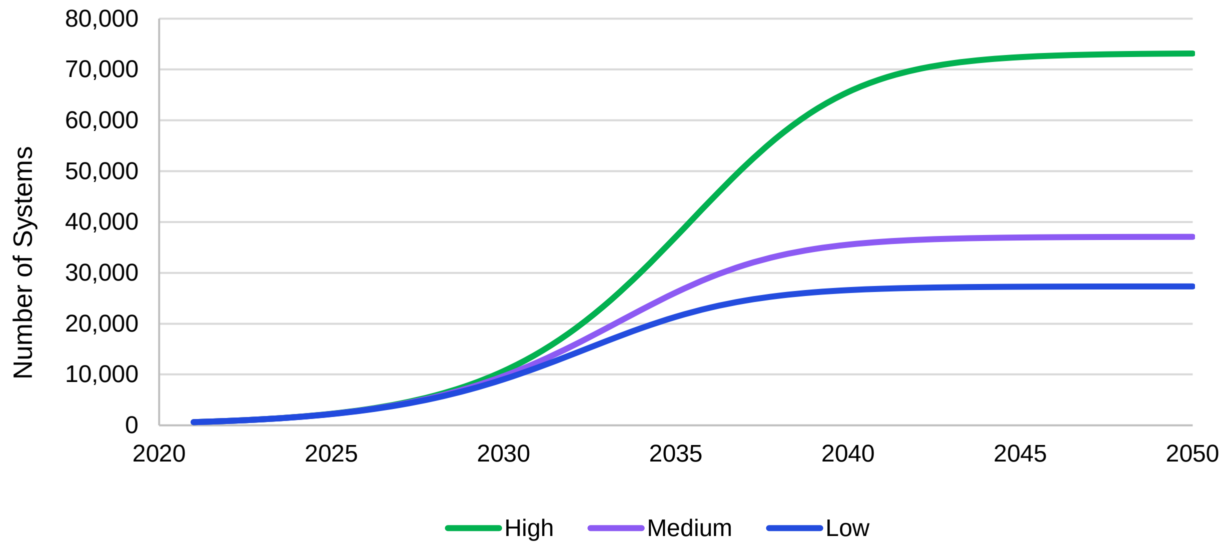
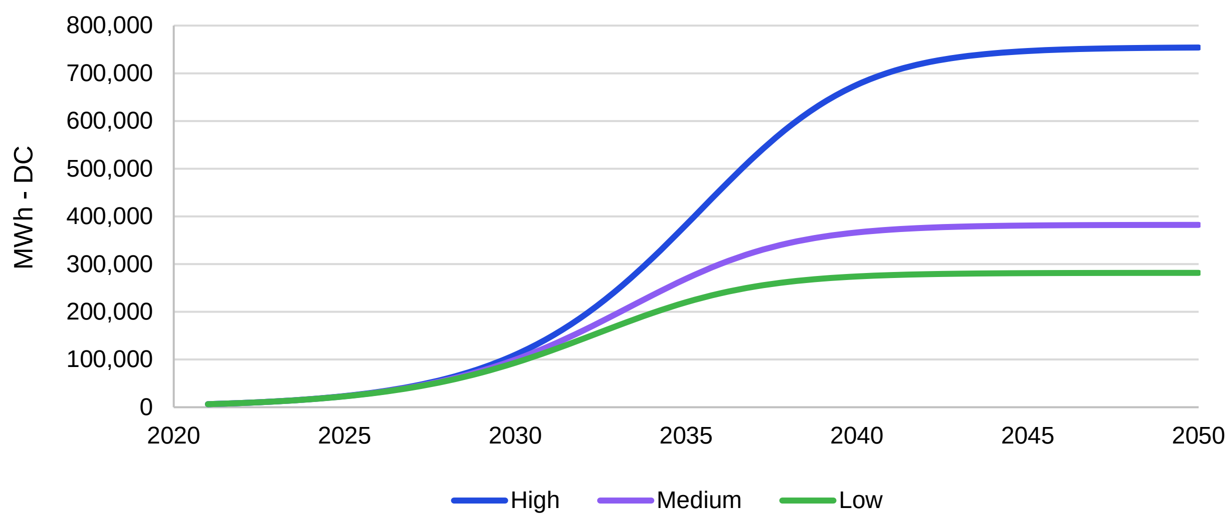


Figure 5-19: Residential Solar PV System Energy Production (MWh-DC) (Business-As-Usual)

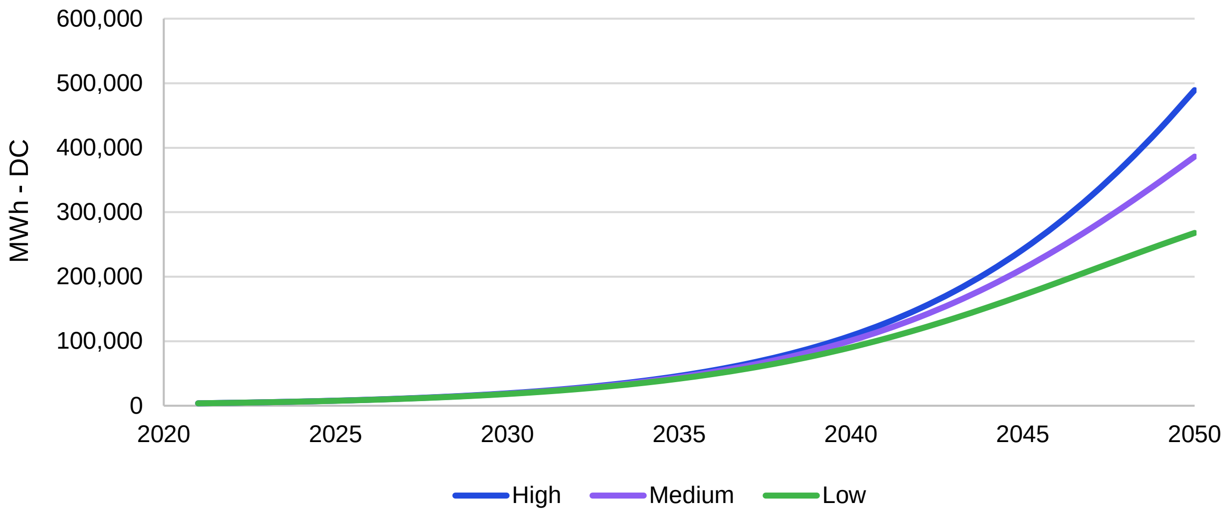


Three adoption scenarios for BAU solar PV installations are described below for the Non-residential sector:

- → Low; up to 7% market adoption
- → Medium; up to 19% market adoption
- → High; up to 35% market adoption

The BAU forecast for system energy production (MWh-DC) is shown in Figure 5-20.

Figure 5-20: Non-Residential Solar PV System Energy Production (MWh, DC)



5.4.5 Distributed Solar (Non-Net Metered/Rate REP)

The majority of AES Indiana's other distributed energy resources are related to the AES Indiana feed in tariff Rate Renewable Energy Production ("Rate REP"). Rate REP was initially offered in 2011 and is fully subscribed and not available to new participants. Under this offering, the total output from the 40 projects is approximately 96 MW.

5.5 Load Model Performance and Analysis

170 IAC 4-7-4(2) and 170 IAC 4-7-5(a)(10)

AES Indiana periodically evaluates the load forecast model performance: (1) when the model is created, (2) on a monthly basis as a variance analysis, and (3) after-the-fact as a year-end comparison.

During forecast development a number of models are analyzed at the rate level. The adjusted R-squared statistics, Mean Absolute Percent Error ("MAPE"), the Durbin-Watson statistics, and the reasonableness of each model to AES Indiana are statically evaluated. The target adjusted R-squared values are better than 90%, which is accomplished in nearly all cases. Further, MAPE needs to be less than 2%, and the Durbin-Watson statistic is targeted around 2.0. AES Indiana considers independent variables with T-statistics of at least 2.0 acceptable. This judgment is somewhat subjective and dependent upon the implied importance of the variable. Please see Attachment 5-2, Itron's Load Forecast report, for more information regarding these model statistics.

At the start of the COVID-19 pandemic, AES Indiana began seeing large deviations from its projected energy sales. During the start of the COVID-19 pandemic, AES Indiana started to update its load forecast on a rolling monthly basis. During these monthly updates, customer data is rolled forward to include the most recent data, along with expected weather, load, and shift variables related to COVID. Additionally, AES Indiana continues to evaluate the variance of energy sales each month and considers the impact of weather adjustments. AES Indiana's forecasting staff uses this information to evaluate model performance. If the monthly variance moves reasonably with the current "knowns," like economic factors and/or weather, a conditional approval supports the forecast. However, should variance move contrary to "knowns," an investigation of possible bias and other elements is undertaken. A similar determination, but with greater detail, is made at year-end.

Section 6: Resource Options

170 IAC 4-7-4(11) and 170 IAC 4-7-4(31)

AES Indiana has a diverse portfolio of existing resources to serve customers effectively, including coal, natural gas, wind, solar, and demand side management resources. The Company also received IURC approval to procure an additional solar resource, Hardy Hills Solar (IURC Cause No. 45493) ("Hardy Hills"), as well as a solar plus storage resource, Petersburg Energy Center (IURC Cause No. 45591) ("PEC"), as a result of the 2019 IRP process. For potential replacement resource options, AES Indiana examined natural gas, wind, solar, solar plus storage, stand-alone storage, and demand side management resources.

6.1 Existing AES Indiana Resources

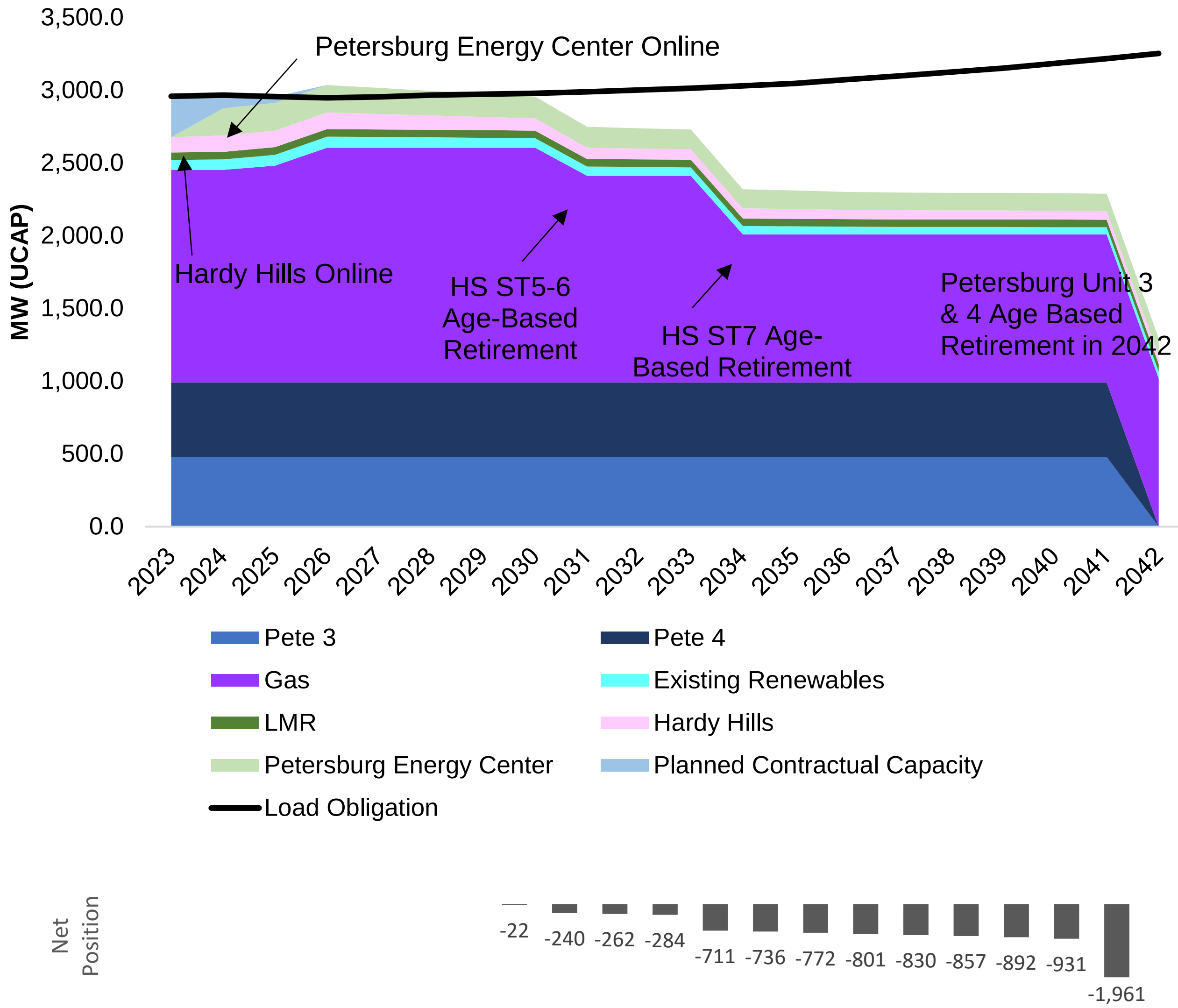
170 IAC 4-7-4(4) and 170 IAC 4-7-6(a)(2)

AES Indiana's portfolio has transformed over the last fifteen years, becoming less dependent on coal in particular. Figure 6-1 highlights the more substantial changes. The following sections provide high-level detail for existing plant capacity. Thermal resources' capacity credit is a function of its annual GVTC, which establishes its installed capacity ("ICAP") value, and its forced outage rate (i.e., XEFORd). These components are subject to small changes every year. AES Indiana uses a three-year average of these values to estimate the expected long-term unforced capacity credit ("UCAP") for planning purposes.

Figure 6-1: Transitions in the AES Indiana Portfolio

Many of AES Indiana's existing resources have age-based retirements near the end or outside the study period of this IRP. The exception is the Harding Street Steam Turbine units. Figure 6-2 shows the Company's capacity position allowing for age-based retirements and announced additions (i.e., Hardy Hills Solar and Petersburg Energy Center). The Company begins to develop a notable short capacity position with the age-based retirements of the Harding Street steam powered generators in the 2030s.

Figure 6-2: AES Indiana's Summer Capacity Position showing Age-Based Retirements



6.1.1 Existing Supply Side Resource

170 IAC 4-7-6(a)(1)

AES Indiana operates the coal-fired Petersburg Generating Station in Pike County, Indiana. This plant has four units. Unit 1 was retired May 31, 2021 and Unit 2 is scheduled to retire May 31, 2023 as a result of the 2019 IRP. Figure 6-3 further details AES Indiana's existing coal power units.

Figure 6-3: AES Indiana's Existing Coal Power Units

Coal Units	Technology	ICAP (MW)	UCAP (MW)	In-Service Year	Estimated Last Year In-Service
Petersburg					
Petersburg Unit 2	Coal ST	415	364	1969	2023
Petersburg Unit 3	Coal ST	529	481	1977	2042
Petersburg Unit 4	Coal ST	543	511	1986	2042
	Total Coal	**1,487**	**1,356**		

AES Indiana operates several natural gas-fired generators using steam turbines ("ST"), combustion turbines ("CT"), and CCGT technology. The Eagle Valley CCGT is located in Morgan County, Indiana, while the Harding Street and Georgetown plants are located in Marion County, Indiana. The Harding Street Diesel Units 1 ("GT1") and 2 ("GT2") are combustion turbines that burn No. 2 fuel oil. These units have age-based retirements set for 2024. Figure 6-4 below further describes AES Indiana's existing plants powered by natural gas and oil.

Figure 6-4: AES Indiana Existing Natural Gas and Oil Power Units

Natural gas Units	Reference Name	Technology	ICAP (MW)	UCAP (MW)	In-Service Year	Estimated Last Year In-Service
			Eagle Valley			
Eagle Valley CCGT	Eagle Valley CCGT	CCGT	664	601	2018	2055
			Harding Street			
Harding Street 5G	Harding Street 5	Natural Gas ST	97	96	1958	2030
Harding Street 6G	Harding Street 6	Natural Gas ST	100	97	1961	2030
Harding Street 7G	Harding Street 7	Natural Gas ST	421	402	1973	2033
Harding Street GT4	Harding Street GT4	Natural Gas CT	70	65	1994	2044
Harding Street GT5	Harding Street GT5	Natural Gas CT	72	68	1995	2045
Harding Street GT6	Harding Street GT6	Natural Gas CT	147	143	2002	2052
Harding Street GT1 & GT2	Harding Street GT1 & 2	Oil	36	35	1973	2024
			Georgetown			
Georgetown GT1	Georgetown 1	Natural Gas CT	75	68	2000	2050
Georgetown GT4	Georgetown 4	Natural Gas CT	75	74	2001	2052
		Total Natural Gas	1,723	1,613		
		Total Oil	36	35		

AES Indiana has Power Purchase Agreements ("PPA") with two wind farms: Hoosier Wind Park and Lakefield Wind Park. Hoosier Wind Park is located in northwest Indiana and the Lakefield Wind Park is located in southern Minnesota. Lakefield Wind Park does not receive capacity credit because of its interconnection service. Both wind PPAs expire within the next ten years. Hoosier Wind Park is advantageous because of its proximity to AES Indiana's load and firm capacity in MISO's Zone 6; therefore, the IRP analysis assumes the Company would negotiate to secure the continuation of this resource for the entire planning period. Lakefield Wind Park offers neither of these advantages, and the Company is unlikely to try to retain this contract past its expiration.

AES Indiana has contracted with several solar installations under its Rate REP structure on its distribution system in Marion County, Indiana. These solar resources effectively reduce AES Indiana's load obligation. AES Indiana has also announced the additions of Hardy Hills Solar, a solar resource in Clinton County, Indiana, and the Petersburg Energy Center, a solar plus Battery

Energy Storage System ("BESS") hybrid resource in Pike County, Indiana. These projects are expected to come online in 2023-2024 as a result of AES Indiana's 2019 IRP. Figure 6-5 details AES Indiana's existing and IURC-approved renewable energy resources.

Figure 6-5: AES Indiana Existing and IURC-Approved Renewable Energy Resources

Renewables	Technology	ICAP (MW)	UCAP (MW)	In-Service Year/ PPA Start	Estimated Last Year In-Service/ PPA End
Hardy Hills Solar					
Hardy Hills Solar	Solar Only	195	98	2023	TBD
Petersburg Energy Center					
PEC Solar	Solar + BESS	250	125	2024	TBD
PEC BESS	Solar + BESS	180 MWh	45 MW, 4-hour	2024	TBD
PPAs					
Hoosier Wind Park (IN)	PPA	100	7	2009	2029
Lakefield Wind (MN)	PPA	200	0	2011	2031
Solar (Rate REP)	PPA	96	54	Various	Various
Total Renewable		841	329		

6.2 Supply Side Resource Options

170 IAC 4-7-4(6), 170 IAC 4-7-4(7), 170 IAC 4-7-6(b)(3)(A), and 170 IAC 4-7-7

AES Indiana considered several commercially viable technologies for its supply side modeling:

Renewables and Storage

- Northern and Southern Indiana Wind
- Utility-Scale Single-Axis Tracking Photovoltaic Solar
- Stand-Alone Storage of 4- and 6-hour durations
- Solar Plus Storage Hybrid

Natural Gas

- Combined Cycle Natural Gas Turbine (CCGT)
- Simple Cycle Combustion Turbine ("Frame CT")
- Aeroderivative Combustion Turbine ("Aero CT")
- Reciprocating Engines ("Recip. Engines")
- Petersburg conversion from coal to natural gas steam turbines ("Petersburg Conversion")

The energy sector is transforming, and many new generation technologies are under development that can be utilized to support AES Indiana's commitment to achieve its customers' goals of reliability, affordability, and sustainability. These technologies include, but are not limited to, green hydrogen, small modular reactors, gravity storage, pumped-hydro storage, and carbon capture and sequestration. These technologies are providing optionality in a path towards reducing carbon and may be considered in future IRPs as they become commercially available. Figure 6-6 describes the replacement resources that were modeled in AES Indiana's 2022 IRP.

Figure 6-6: New Replacement Resources Modeled in AES Indiana's 2022 IRP

Ownership Structure

The Integrated Resource Plan is designed to select optimal portfolios for long term planning. This sheds light on technology types and relative timing. AES Indiana's EnCompass Model is agnostic to the ownership structure and captures all the costs associated with financing and operating new resources.

Capital Costs

Capital costs for newly constructed resources were split into low, base, and high costs. Low costs were formed from a blend of NREL's 2021 Annual Technology Baseline ("ATB"), Wood Mackenzie's 2021 Base Case Update, and Bloomberg New Energy Finance's ("BNEF") Second Half ("2H") 2021 Levelized Cost of Energy ("LCOE") Report. NREL's ATB is a public data source, while Wood Mackenzie and BNEF require subscriptions for access. In between the release of these reports and IRP modeling, the market was subject to fundamentally higher levels of inflation and supply chain constraints. These higher prices were realized in AES Indiana's 2022 RFP, administered by Sargent & Lundy, which received price information for new projects submitted in the spring of 2022. Base and high capital costs were determined from these RFP responses. RFP results provide a datapoint over a relatively short period of time, so AES Indiana used the learning curves from the low case to calculate longer term forecasts of capital costs in the base and high cases. Please see Section 9.3 for more information on the Replacement Resource Capital Cost Sensitivity Analysis that AES Indiana performed using the low, base, and high resource capital costs. Please see Confidential Attachment 6-1 for a detailed description of the capital cost assumptions used in AES Indiana's 2022 IRP.

In addition to project costs, AES Indiana added an interconnection cost to resource capital costs that varied by technology. Sargent & Lundy provided the basis for these interconnection expenses by analyzing MISO queue data. Sargent & Lundy also provided a levelized estimate of the cost of utilizing tax equity to fund projects that qualify for the production tax credit or investment tax credit.

Capacity Credit

New supply side resources are assumed to be in the state of Indiana, and capable of providing firm capacity to MISO's Zone 6. MISO's recently approved seasonal capacity construct makes it necessary to differentiate capacity credit across seasons. This has a profound effect on wind and solar, both of which have capacity credits determined by ELCC), or the amount of generation these resources provide during peak load hours. Thermal and storage resources are dispatchable and receive the same capacity credit across all four seasons.

6.2.1 Wind Resources

Figure 6-7 below provides a summary of the new wind resource characteristics included in AES Indiana's EnCompass Model.

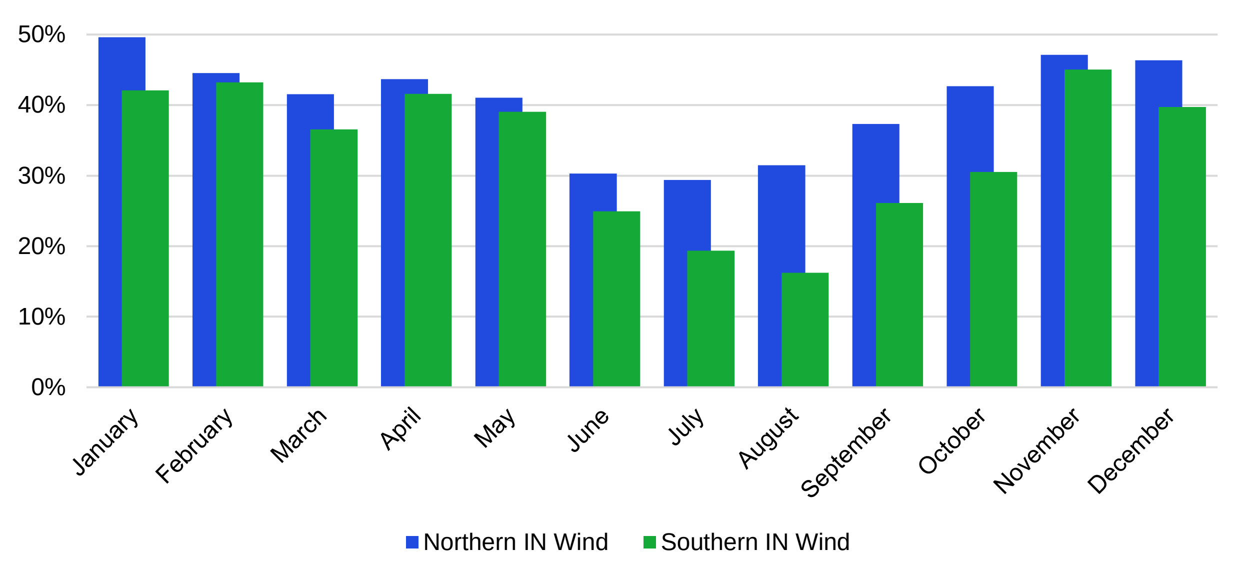
Figure 6-7: New Wind Resource Characteristics

New Wind Resource Summary	
Northern Indiana Wind	**Southern Indiana Wind**
→ **Location:** Northwest Indiana → **Capacity Factor:** 40.4% → **Source Profile:** NREL System Advisory Model → **LMP Basis to IN Hub (On-Peak)**: -19% → **LMP Basis to IN Hub (Off-Peak):** -21% → **Project Size:** 50 MW ICAP → **Useful Life:** 30 years → **Spring/Summer/Fall ELCC:** 8.9% → **Winter ELCC:** 20% → **Production Tax Credit:** varies by scenario	→ **Location:** Petersburg, Indiana → **Capacity Factor:** 33.6% → **Source Profile:** NREL System Advisory Model → **LMP Basis to IN Hub (On-Peak):** -6% → **LMP Basis to IN Hub (Off-Peak):** -3% → **Project Size:** 50 MW ICAP → **Useful Life:** 30 years → **Spring/Summer/Fall ELCC:** 8.9% → **Winter ELCC:** 20% → **Production Tax Credit:** varies by scenario

Differentiating Wind Resources; Location and Capacity Factor

Indiana has embraced utility-scale wind for well over a decade resulting in over three GW of installed capacity. Indiana wind farms are concentrated in the northwest portion of the state, which is the windiest portion of the state, such that 75% of Indiana's wind farms can be found in three northwest counties. This means there is limited availability for additional wind capacity along the windiest corridor of Indiana, and new wind resources may have to be sited in other parts of the state. Therefore, AES Indiana modeled two distinct wind resources: the first representing northern Indiana wind with a higher capacity factor (40.4%), and the second representing southern Indiana wind with a lower capacity factor (33.6%). Figure 6-8 displays monthly capacity factors.

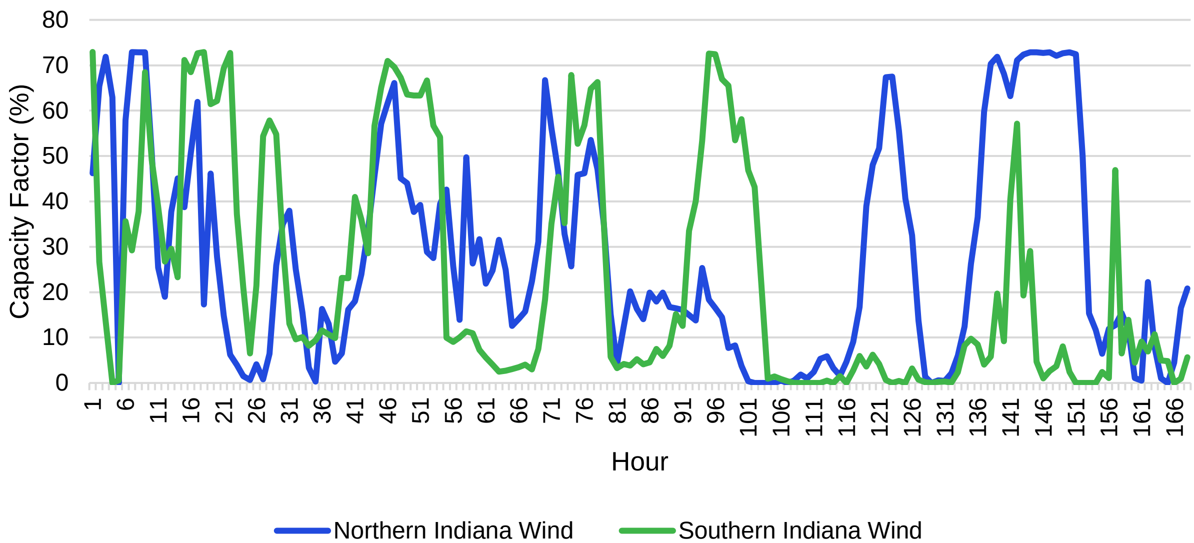
Figure 6-8: Replacement Wind Monthly Capacity Factors for Northern and Southern Indiana Wind



Profiles

Wind profiles and energy forecasts were developed using the NREL's SAM, which is available to the public. Northern Indiana wind used SAM's generic weather data for northwestern Indiana, and southern Indiana wind used Petersburg, Indiana weather data as a proxy for southern Indiana, or lower capacity factor, wind. Figure 6-9 provides sample data from NREL's SAM tool to demonstrate the volatility in hourly wind capacity factor profiles in northern and southern Indiana.

Figure 6-9: Sample Hourly Wind Profile Volatility for Northern and Southern Indiana Wind



Capital Cost and Operations and Maintenance

There are two other differences between northern Indiana wind and southern Indiana wind: subsidies and energy revenue (discussed later). Since northern Indiana wind has a higher capacity factor, it receives a more valuable PTC, which offsets the required investment for this resource relative to southern Indiana wind. Figure 6-10 shows how the PTC varies by scenario.

Figure 6-10: Production Tax Credit Assumptions by Scenario

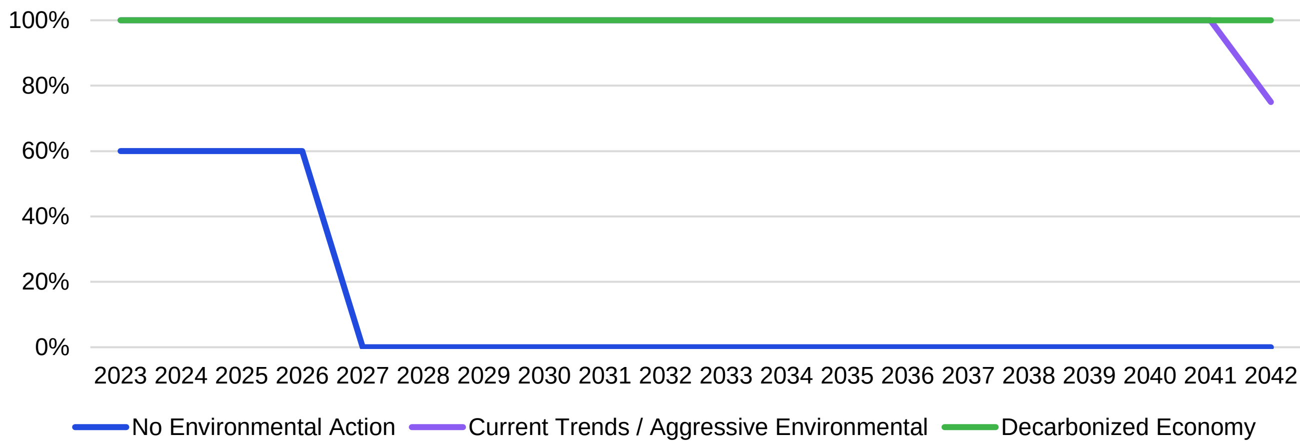
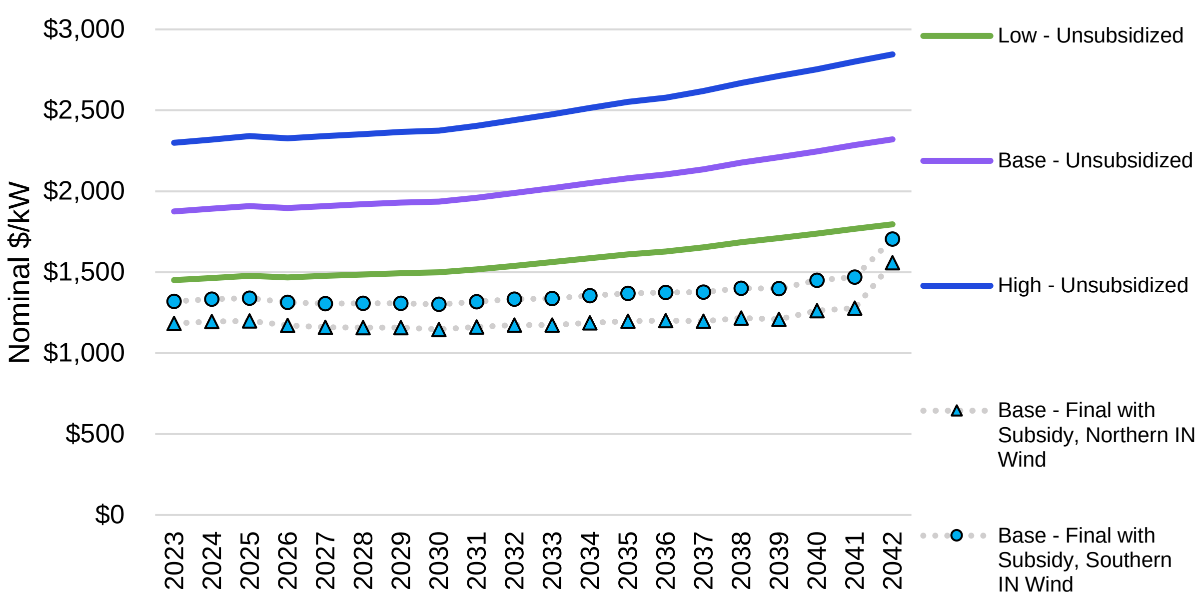


Figure 6-11 shows the low, base, and high unsubsidized capital costs for wind resources, as well as final costs for the Base Case capital costs. The NREL, Wood Mackenzie, and BNEF reports formed the low capital cost assumptions. The base costs come from the average of the spring 2022 RFP responses. The high cost assumptions are an equal amount higher than the base costs (i.e., the difference between the low and base costs is also the difference between the base and high costs). Interconnection costs are added to the unsubsidized costs, which are then reduced by the present value of the PTC. The assumed decrease in the PTC causes the marked increase in subsidized costs in 2042.

Figure 6-11: Base, and High Capital Costs for New Wind Resources[25]

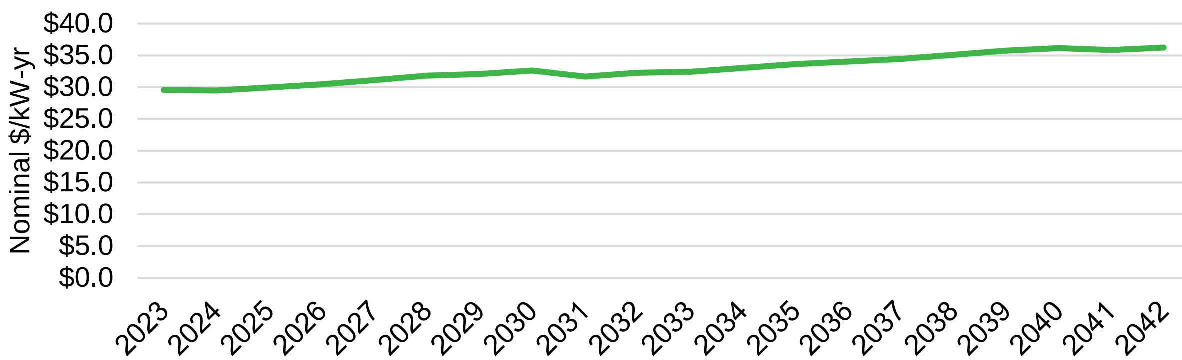


[25] Subsidized Costs (i.e., costs reflecting PTC benefits) shown for the base costs in the Current Trends scenario.

Wind resources do not have a variable cost component but still incur fixed operations and O&M costs, including general maintenance and land lease payments. The AES Corporation has experience with other wind operations across the country, and AES Indiana leveraged internal experts to derive an estimated fixed cost for wind resources. The fixed O&M costs were forecasted over time to follow a curve from the same third-party sources that provided capital cost learning curves: NREL's 2021 ATB, Wood Mackenzie's 2021 Base Case Update, and BNEF's 2H 2021 LCOE Report.

Figure 6-12 displays the fixed O&M forecast for wind. Property tax and insurance were considered separately within the EnCompass Model.

Figure 6-12: Fixed O&M Costs for Replacement Wind Resources



LMP Basis

Another difference between northern and southern Indiana wind is the forecasted LMP. LMP is the energy price at each location that determines how much energy revenue the wind resource is expected to produce for the benefit of AES Indiana customers. Northern Indiana wind is assumed to be located near the aforementioned concentration of existing Indiana wind projects and is more likely to see higher transmission congestion than southern Indiana wind. AES Indiana used price data from its existing Indiana wind resource, Hoosier Wind Park, as a proxy for northern Indiana wind's estimated energy price. As described in Figure 6-13, northern Indiana wind is approximately 19% below Indiana Hub for the on-peak hours, and 21% below Indiana Hub for the off-peak hours. LMP at specific generators is modeled as a basis to Indiana Hub because this is a liquid point that is used as the primary power price in the model. Petersburg Generating Station was used as a proxy for southern Indiana wind's energy price. As described in Figure 6-13, Southern Indiana wind is approximately 6% below Indiana Hub during the on-peak hours and approximately 3% below Indiana Hub for the off-peak hours. Southern Indiana wind is assumed to be located where there is less transmission congestion, which provides an advantage over northern Indiana wind.

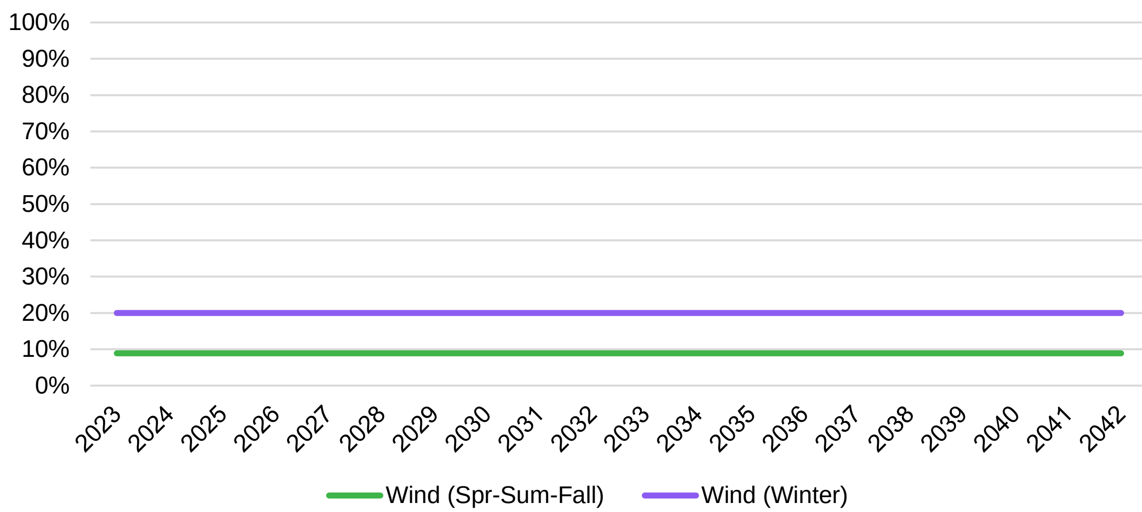
Figure 6-13: Indiana Wind LMP Compared to Indiana Hub LMP

Indiana Wind LMP Compared to Indiana Hub		
	On-Peak	Off-Peak
Northern Indiana Wind	-19%	-21%
Southern Indiana Wind	-6%	-3%

Capacity Credit

Wind resources were given an ELCC of 8.9% for the spring, summer, and fall seasons to align with MISO's most recent Wind and Solar Capacity Credit report for Zone 6. [26] As discussed in Section 2.2, this value is lower than other resources because wind historically generates less output during peak load hours, which for most of the year occurs in the afternoon. The exception is the winter when load typically peaks in the morning or late evening. MISO has performed preliminary analysis that suggests wind will generate more during these winter peak hours than it does during summer peak hours, so wind resources were given an ELCC value of 20% for the winter, as demonstrated in Figure 6-14. [27]

Figure 6-14: Wind ELCC by Season



[26] MISO's Planning Year 2022-2023 Wind and Solar Capacity Credit report, January 2022, https://cdn.misoenergy.org/2022%20Wind%20and%20Solar%20Capacity%20Credit%20Report618340.pdf.

[27] MISO's RAN Renewable Impact Analysis, September 2021, https://cdn.misoenergy.org/20210908%20RA%20Construct%20Tariff%20Review%20Workshop%20Item%2002%20Renewable%20Impact%20Analysis587681.pdf.

6.2.2 Solar Resources

Figure 6-15 below provides a summary of the new solar resource characteristics included in AES Indiana's EnCompass Model.

Figure 6-15: New Solar Resource Characteristics

New Solar Resource Summary
Utility-Scale Single-Axis Tracking Solar
→ **Location:** Petersburg, Indiana → **Capacity Factor:** 24.5% → **Source Profile:** NREL System Advisory Model → **LMP Basis to IN Hub (On-Peak):** -6% → **LMP Basis to IN Hub (Off-Peak):** -3% → **Project Size:** 25 MW ICAP (32.5 MW_{dc} | 25.0 MW_{ac}) → **Useful Life:** 35 years → **Spring/Summer/Fall ELCC:** ~58% in 2023, declines by scenario to less than half original ELCC → **Winter ELCC:** 0% → **Investment Tax Credit:** varies by scenario

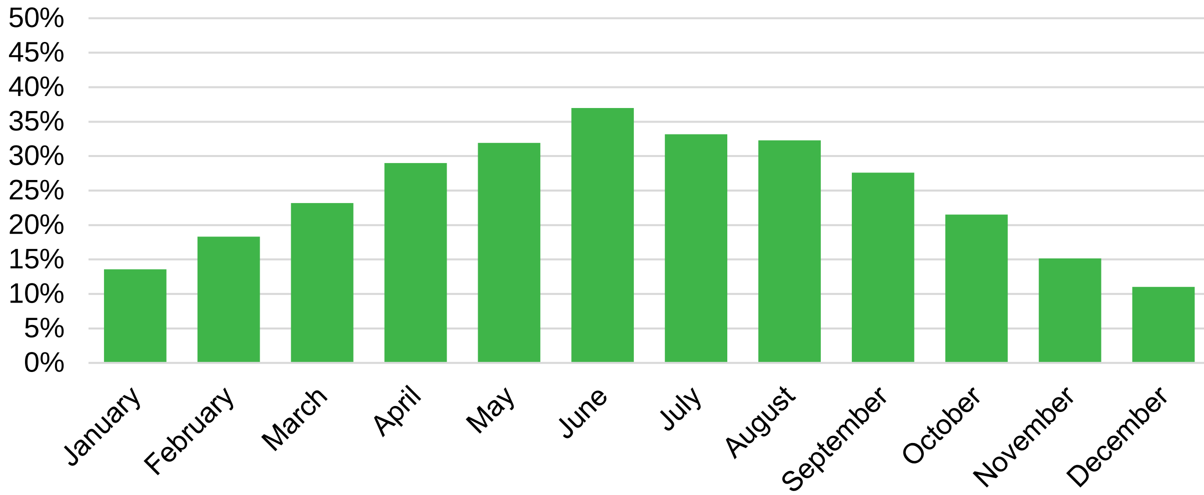
Location and Capacity Factor

Southern Indiana, and specifically Petersburg, Indiana, is a favorable site for AES Indiana to construct new resources due to the interconnection capacity already established there related to AES Indiana's Petersburg Generating Station. AES Indiana recognizes the value and benefit to customers of preserving interconnection rights and sees developers of new resources targeting these areas to take advantage of existing infrastructure. With this in mind, AES Indiana selected Petersburg, Indiana to represent a location where new solar resources could be built. This is intended to be representative rather than indicative of new resource placements.

NREL's SAM was used with weather data from Petersburg, Indiana to estimate the capacity factor for new utility-scale single axis-tracking photovoltaic solar resources. AES Indiana used an Inverter Loading Ratio ("ILR") of 1.3, meaning that a 25 MW solar resource actually has 32.5 MW of capacity behind its DC to AC inverter. Oversizing in this way is standard practice since most of the time a solar array is producing some amount less than its full output and using a smaller inverter is a cost savings. Inverter loading ratios vary widely. AES Indiana relied on market data from previous RFPs as well as experts, such as NREL, to select 1.3 as its assumption for new resources.[28] Knowing the ILR is critical for determining the expected capacity factor. The AC annual capacity factor of 24.5% can be seen in monthly terms in Figure 6-16.

[28] NREL's "Evaluating Utility-Scale PV-Battery Hybrids in Operational Models for the Bulk Power System", April 2021, https://www.nrel.gov/docs/fy21osti/78850.pdf#page=12.

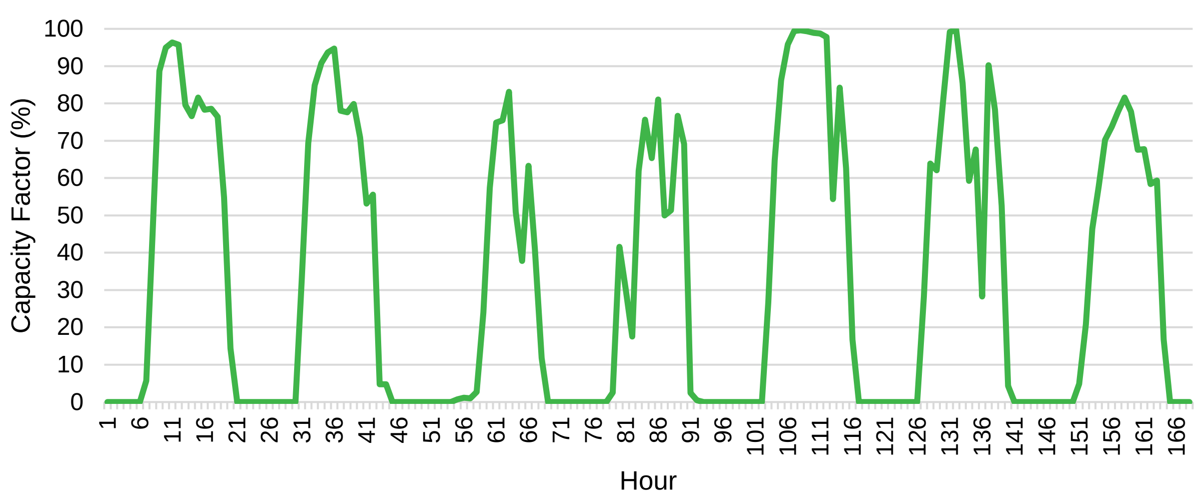
Figure 6-16: Monthly Capacity Factor (AC) for Replacement Solar Resources



Profile

The hourly profile was derived from NREL's SAM and a one-week sample from June can be seen in Figure 6-17.

Figure 6-17: Sample Hourly Generation Profile, as a Percentage of Max Inverter Capacity, for a New Solar Resource



Capital Costs and Fixed O&M

Solar resource capital costs were split into low, base, and high costs. The low costs are an average of NREL's 2021 ATB, Wood Mackenzie's 2021 Base Case Update, and BNEF's 2H 2021 LCOE Report. AES Indiana received a robust response of solar resource proposals from its spring 2022 RFP. An average of the lower half of those bids formed the base solar costs, which were forecasted using the same learning curve as the low costs. An average of the upper half of the bids from AES Indiana's 2022 RFP was used to form the high costs, which followed the same learning curve over the IRP's 20-year forecast as the low and base costs. AES Indiana also applied an interconnection cost to solar resources' capital cost.

Solar facilities qualify for the ITC, which allows the investor to reduce their federal tax liability by as much as 30% of the solar capital cost. This aligns with the current provisions of the IRA. While the IRA allows solar resources to qualify for both the ITC and PTC under, AES Indiana assumes solar resources would use the ITC because the ITC provides more predictable and favorable results. For more information on how the IRA was modeled in this IRP, see Section 8.4.2. AES Indiana models this benefit as reducing the overnight capital cost of the solar resource. One way to capture this benefit is to allow another investor with a tax liability to contribute funds toward the project and then receive payment over time to recoup their investment. Sargent & Lundy was able to provide an estimate of these costs, the costs of monetizing the tax credit, and AES Indiana added this to solar resources' final capital costs. Figure 6-18 depicts AES Indiana's ITC assumptions and how it varies by scenario. Figure 6-19 shows the unsubsidized capital costs as well as the final costs (after interconnection costs and tax credits are applied) for the Current Trends Scenario using base costs.

Figure 6-18: Investment Tax Credit Assumptions for Solar Resources by Scenario

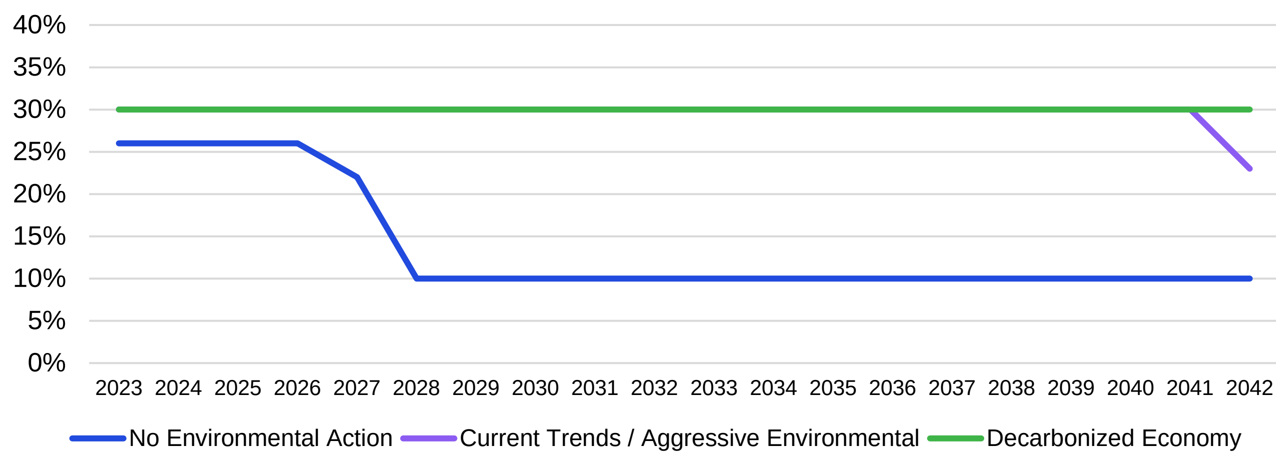
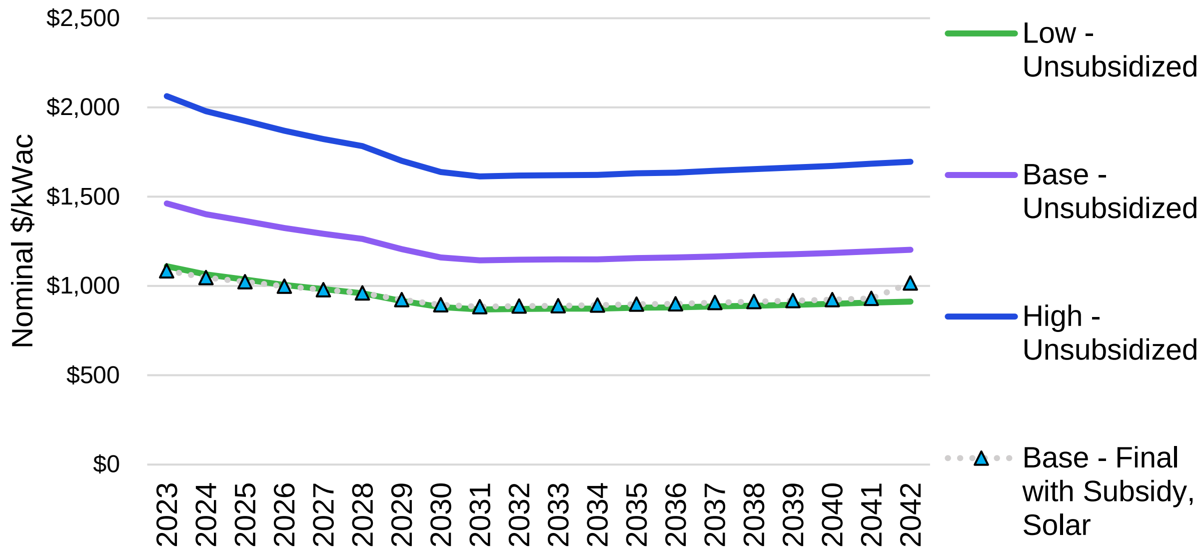
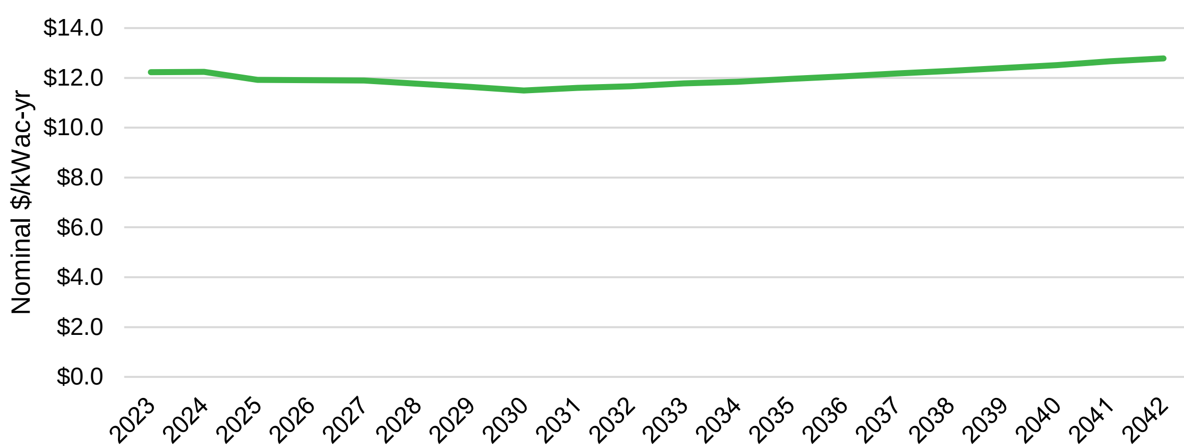


Figure 6-19: Low, Base, and High Capital Costs for New Solar Resources[29]



AES Indiana leveraged work it completed for its Hardy Hills IURC Certificate of Public Convenience and Necessity ("CPCN") filing to develop expected fixed O&M costs for solar resources. These fixed costs include a levelized component for inverter maintenance in addition to other typical costs, such as land lease payments. The fixed O&M costs, detailed in Figure 6-20, were forecasted over time to follow a curve from the same third-party sources that provided capital cost learning curves (i.e., NREL's 2021 ATB, Wood Mackenzie's 2021 Base Case Update, and BNEF's 2H 2021 LCOE Report).

Figure 6-20: Fixed O&M Costs for Solar Resources



[29] Subsidized Costs (i.e., costs reflecting ITC benefits) shown for the base costs in the Current Trends scenario.

LMP Basis

New solar resources are represented at Peterburg, Indiana, so similar to southern Indiana wind, the Petersburg LMP comparison to the Indiana Hub was used to model solar resources' energy revenue, as detailed in Figure 6-21.

Figure 6-21: Solar Resources' LMP Compared to Indiana Hub LMP

Solar Resources' LMP Compared to Indiana Hub		
	On-Peak	**Off-Peak**
New Solar Resources	-6%	-3%

Capacity Credit

Currently, MISO's solar resource capacity accreditation methodology provides solar resources a capacity credit of 50% of their installed capacity in the first year of operation. The capacity value in future years is determined by historical generation during select afternoon hours during the summer months. More solar resources are being developed and brought online, and MISO is in the early stages of a more robust process for determining solar capacity credit. This may take the form of a seasonal ELCC value. Regardless of the mechanism put in place, AES Indiana expects that solar resources' ability to contribute towards peak load hours will be reduced as more solar resources are added to the grid. When solar generation is netted against load obligations, it creates a net load obligation for other generation resources to fill. As more solar generation is added, the net load is shifted to later in the day to the point where no amount of additional solar energy can meet this new net peak load.

Figure 6-22 and Figure 6-23 use an AES Indiana load profile from July 20, 2022 to demonstrate how the hour when the net peak load occurs changes from a system with 100 MW of solar resources to a system with 1,000 MW of solar resources.

Figure 6-22: Installed Solar Capacity Shifts When Net Peak Load Occurs (100 MW of System Solar Resources)

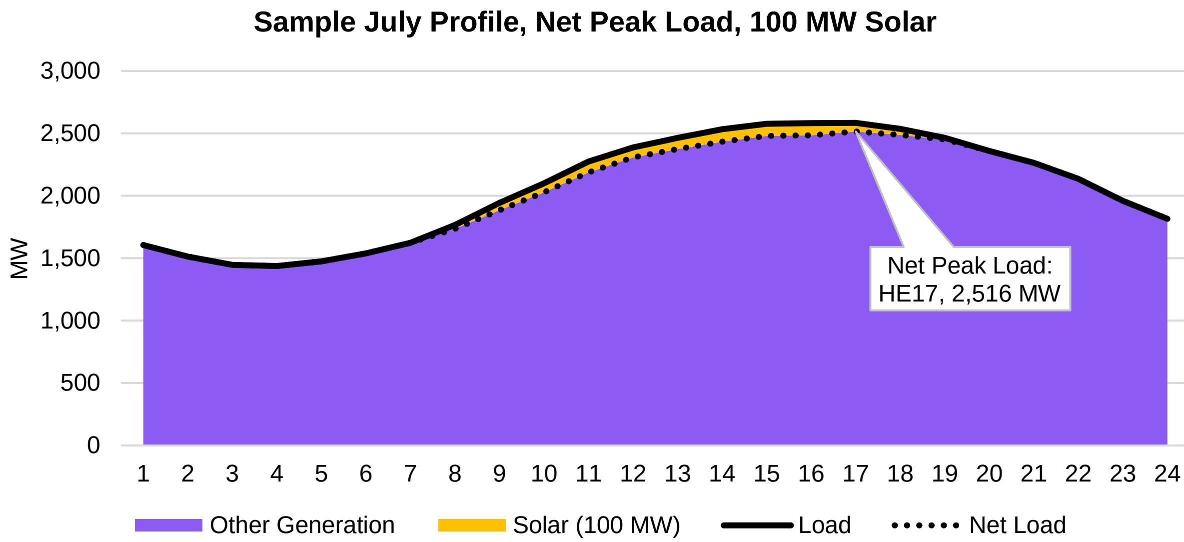
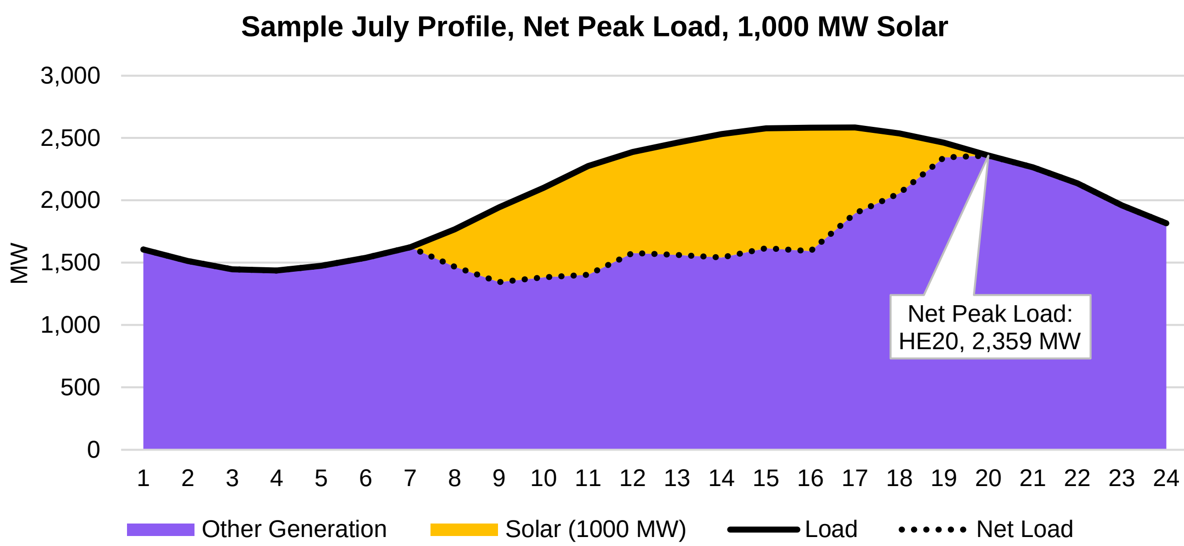


Figure 6-23: Installed Solar Capacity Shifts When Net Peak Load Occurs (1,000 MW of System Solar Resources)

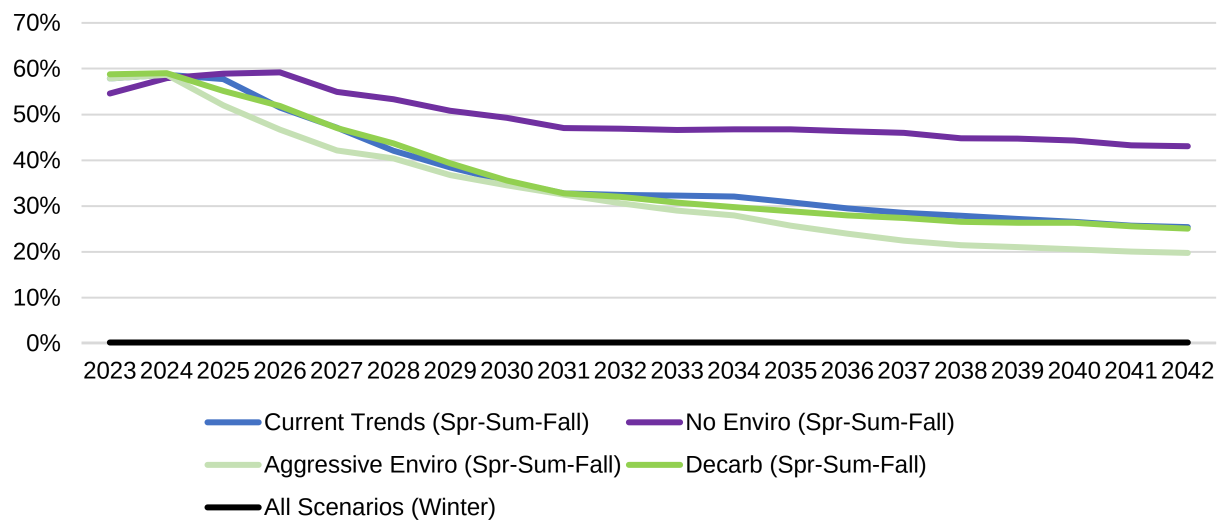


As a basis for forecasting solar resources' ability to meet peak load over time, MISO's Renewable Integration Impact Assessment provides analysis around the expected ELCC for solar as more capacity is added to the grid.[30] AES Indiana's consultant, Horizons Energy, LLC ("Horizons Energy"), used this analysis to forecast solar ELCC in their fundamental model for the different scenarios AES Indiana is examining in this IRP and these results can be seen in Figure 6-24.

[30] MISO's Renewable Integration Impact Assessment, February 2021, https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

Figure 6-24 provides the assumptions around solar resources' contribution to spring, summer, and fall peak load. However, winter peak load typically occurs outside the hours of solar generation and so solar resources are given a winter ELCC value of 0%.

Figure 6-24: Solar Resources' ELCC by Season and Scenario



6.2.3 Storage

Figure 6-25 below provides a summary of the new storage resource characteristics included in AES Indiana's EnCompass Model.

Figure 6-25: New Storage Resource Characteristics

New Storage Resource Summary
4- and 6-Hour Duration Lithium-ion ("Li-ion") Batteries
→ **Location:** Indianapolis, Indiana → **Project Size:** 25 MW ICAP, 80 MWh and 120 MWh (4 and 6 hour durations) → **Round Trip Efficiency:** 85% → **LMP Basis to IN Hub (On-Peak):** -1% → **LMP Basis to IN Hub (Off-Peak):** 0% → **Useful Life:** 20 years → **Capacity Credit:** 95%, year round → **Investment Tax Credit:** Varies by scenario for standalone storage

Resource Description

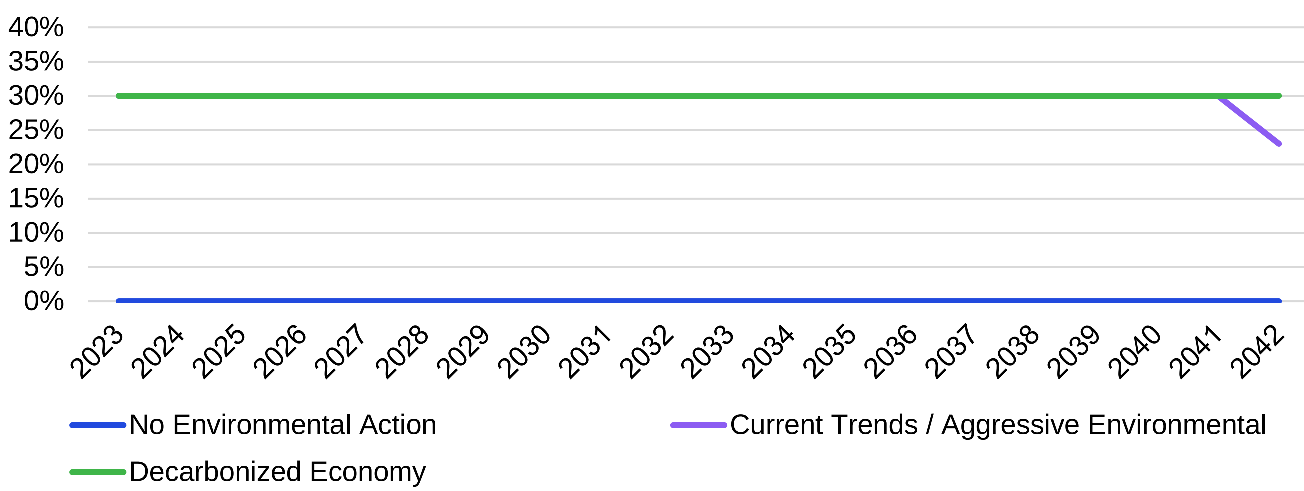
Energy storage can perform several roles ranging from providing transmission alternatives to meeting primary frequency response. In AES Indiana's 2022 IRP, AES Indiana considered storage as a capacity resource that charges in low-priced hours and discharges in high priced hours, a strategy called energy arbitrage. Storage resources were modeled as Li-ion batteries with at least four hours of discharge duration because this is the current requirement by MISO to provide capacity in the Planning Resource Auction. As more renewables are integrated onto the grid, the need for longer duration storage will arise. For this reason, AES Indiana also modeled six-hour storage. Li-ion batteries are more energy dense than renewables and have fewer locational constraints than thermal plants, which lends to more advantageous siting. Therefore, storage was modeled as if it were in the Indianapolis load zone.

AES Indiana used NREL's Annual Technology Baseline as guidance for storage parameters, which includes using an 85% Round Trip Efficiency ("RTE").[31] This means that for every one MWh that a battery stores from charging on the grid, it can only discharge 0.85 MWh that count towards its energy arbitrage revenue.

Capital Costs and Fixed O&M

Storage capital costs were split into low, base, and high costs using the same methodology that was applied to new solar resources. That is, third-party sources (i.e., Wood Mackenzie and BNEF) were used to form the low case as well as the learning curves for the base and high costs. NREL's ATB data was not used for storage because this was a new addition to their dataset and appeared as an outlier on the high end of prices. The base and high costs were derived from the lower (base costs) and upper (high costs) half of bids received from AES Indiana's spring 2022 RFP. Standalone storage recently became eligible for the investment tax credit (through the Inflation Reduction Act). This qualification was captured in three of the scenarios but was left out of the No Environmental Action Scenario for the unexpected reversal of qualification. This is summarized in Figure 6-26.

Figure 6-26: Investment Tax Credit Assumptions for Standalone Storage by Scenario



[31] https://atb.nrel.gov/electricity/2021/utility-scale_pv-plus-battery.

Interconnection costs were added to initial capital costs to derive the final capital costs for new storage resources. Four-hour storage is the standard and there is limited data on six-hour storage. As a simplification, AES Indiana scaled the capital costs of four-hour storage by six-fourths (6/4) to account for additional batteries, the primary cost of storage, needed for six-hour storage. There are likely additional savings associated with six-hour storage, but AES Indiana chose this conservative methodology given the nascent status of longer duration storage. Figure 6-27 and Figure 6-28 depicts the initial storage capital costs for four- and six-hour duration batteries, as well as the final Base costs in the Current Trends scenario.

Figure 6-27: Low, Base, and High Capital Costs for New Four-Hour Storage Resources[32]

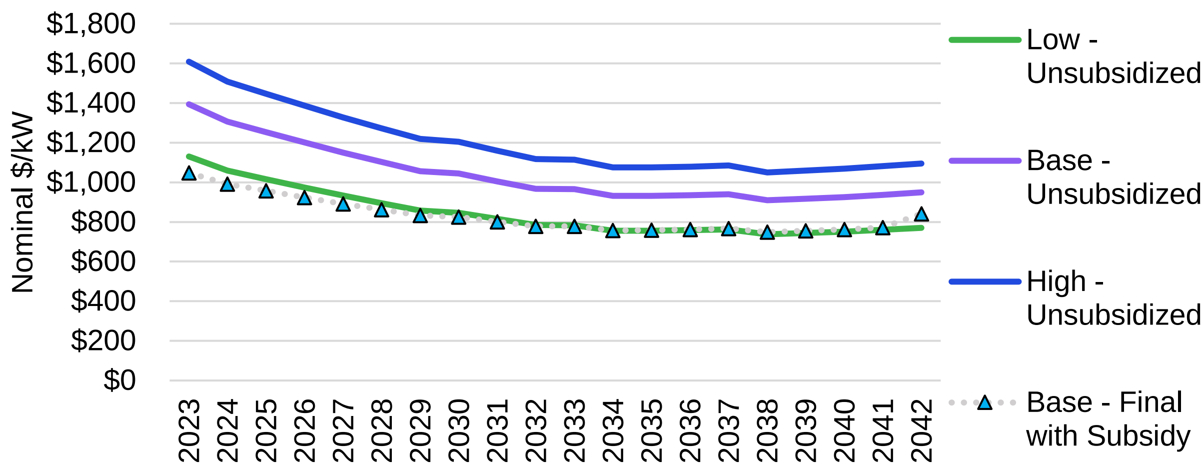
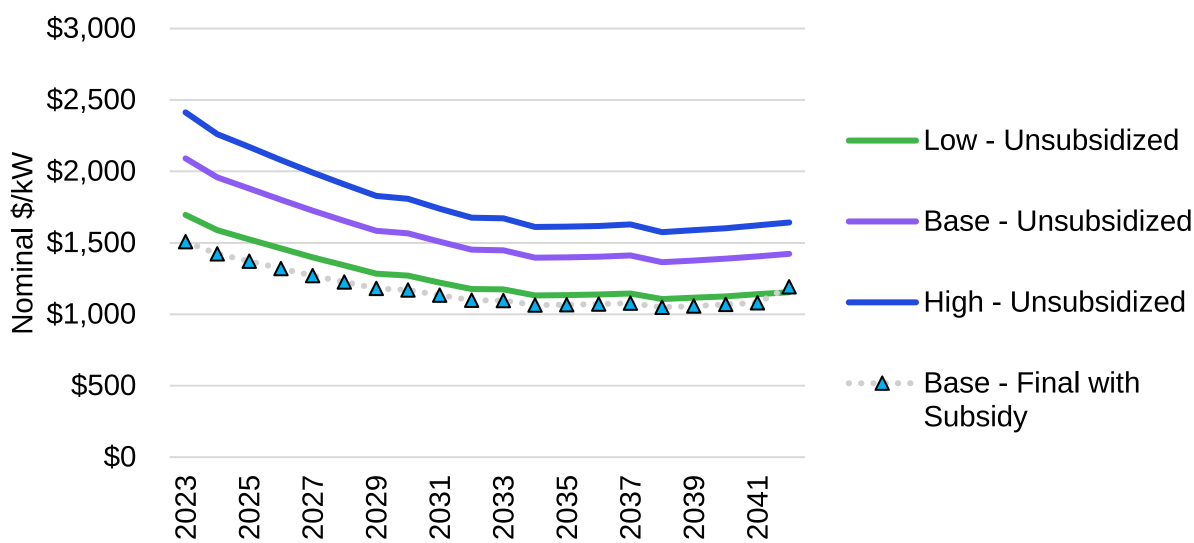


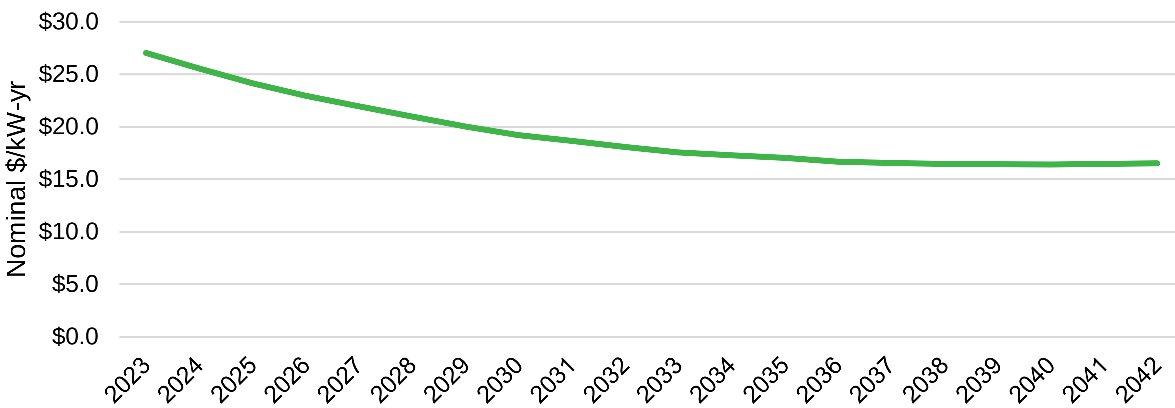
Figure 6-28: Low, Base, and High Capital Costs for New Six-Hour Storage Resources[33]



[32] Subsidized Costs (i.e., costs reflecting PTC benefits) shown for the base costs in the Current Trends scenario.
[33] Subsidized Costs (i.e., costs reflecting PTC benefits) shown for the base costs in the Current Trends scenario.

Fixed O&M costs for storage resources includes battery augmentation over time, powering auxiliary equipment such as climate control, and other costs associated with operating the storage resource. Wood Mackenzie and BNEF provided the learning curve for scaling storage's fixed costs over time, which can be seen in Figure 6-29. This demonstrates the expectation that storage resources will become cheaper to operate over time as the technology continues to advance.

Figure 6-29: Fixed O&M for Standalone Storage Resources



LMP Basis

New storage resources are assumed to be located in (or at least in proximity to) Indianapolis, Indiana, which happens to be near to Indiana Hub. This location has a small basis which means a new battery would see a power price very similar to Indiana Hub, as demonstrated in Figure 6-30.

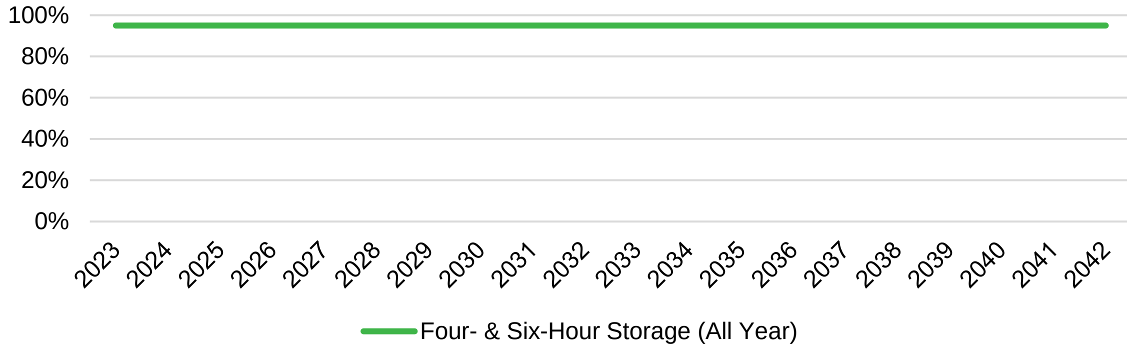
Figure 6-30: Storage Resources' LMP Compared to Indiana Hub LMP

Solar Resources' LMP Compared to Indiana Hub		
	On-Peak	Off-Peak
New Storage Resources	-1%	0%

Capacity Credit

Storage resources are dispatchable resources meaning they can follow dispatch signals from the grid operator and availability is not reliant on weather conditions. MISO's work to establish Electric Storage Resources ("ESR") as a participation model for batteries allows for batteries to receive capacity credit for their four-hour discharge capacity, discounted for their availability rate (i.e., XEFORD) similar to thermal resources. AES Indiana assumes storage resources have a 5% XEFORD, and so, they receive 95% of their installed capacity as capacity credit. Furthermore, because storage resources are dispatchable, they can provide this capacity any time of year (assuming they have a full state of charge), so storage resources receive this 95% capacity credit across all four capacity seasons, as shown in Figure 6-31.

Figure 6-31: Standalone Storage Resource Capacity Credit



Six-hour storage resources receive the same credit as four-hour storage resources, even though it has two additional hours of duration. This is because both four- and six-hour storage resources have the same size inverters and are capped at this capacity. If MISO requirements for storage increased to six hours, then the six-hour battery would still receive 95%, while the four-hour battery would receive some discounted amount because it would be forced to spread its four-hour discharge over the longer requirement.

6.2.4 Solar Plus Storage Hybrids Resources

Figure 6-32 below provides a summary of the new solar plus storage hybrid resource characteristics included in AES Indiana's EnCompass Model.

Figure 6-32: New Solar Plus Storage Resource Characteristics

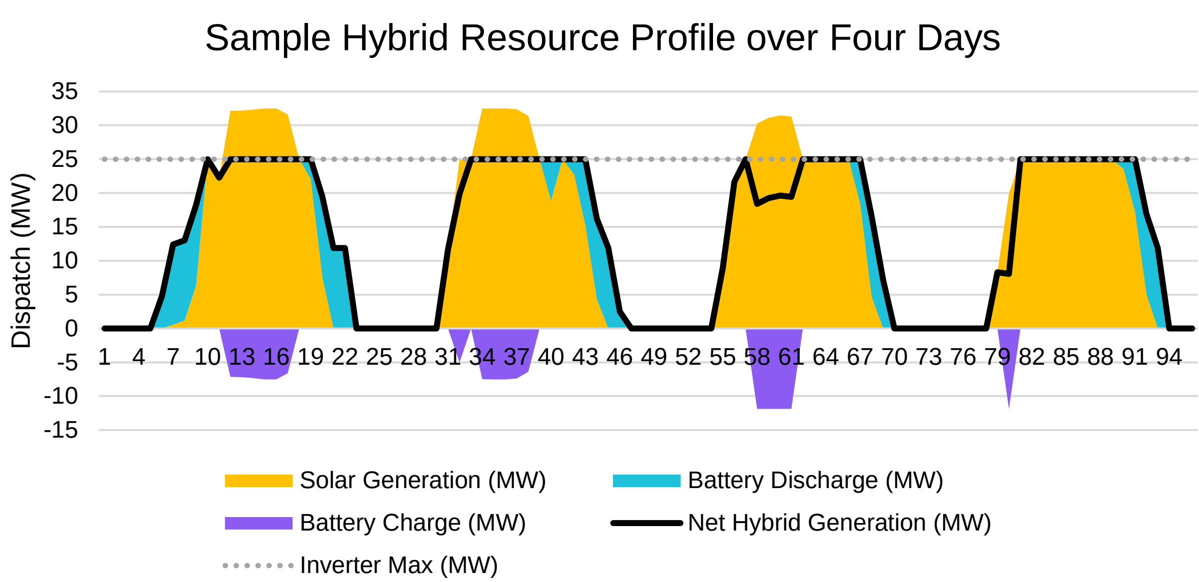
New Solar + Storage Hybrid Resource Summary
Utility-Scale Single-Axis Tracking Solar with DC-Connected Li-Ion Battery
→ **Location:** Petersburg, Indiana → **Solar Capacity Factor:** 24.5% → **Solar Profile Source:** NREL System Advisory Model → **LMP Basis to IN Hub (On-Peak):** -6% → **LMP Basis to IN Hub (Off-Peak):** -3% → **Project Size:** 25 MW ICAP (32.5 MW$_{dc}$ + 12.5 MW$_{dc}$ | 50 MWh$_{dc}$) → **Round Trip Efficiency:** 87% → **Useful Life:** 35 years for solar component, 20 years for storage component → **Capacity Credit:** a composite of solar and storage → **Investment Tax Credit:** varies by scenario

Resource Description

Hybrid resources are becoming more common with technology advancements and will have an important role as utilities look to meet winter reserve margin requirements. However, there is no standard hybrid resource configuration, and the appropriate sizing of a storage resource alongside the solar resource is dependent on the specific requirements of off takers. AES Indiana sees a critical benefit of hybrid resources is their ability to provide capacity through the winter season, which influenced the hybrid resource configuration used in AES Indiana's 2022 IRP. The solar resource component in the hybrid resource configuration was made to be identical to standalone solar, that is, 32.5 MWdc capacity behind a 25 MWac inverter. The storage component in hybrid resources is a Li-ion battery very similar to standalone storage resource option but scaled down to be half of the site's interconnection capacity (25 MWac), making the battery 12.5 MW with 50 MWh of energy storage capacity – or four hours of duration. NREL's 2021 ATB[34] analysis provided guidance for this sizing and also provided insight into certain synergies achieved through this integration of resources. For instance, a DC connected battery benefits from fewer inverter losses than an AC connected battery, so the RTE of a battery in the hybrid is 87%, a 2% increase from standalone storage at 85%. There are also capital cost savings that are discussed later.

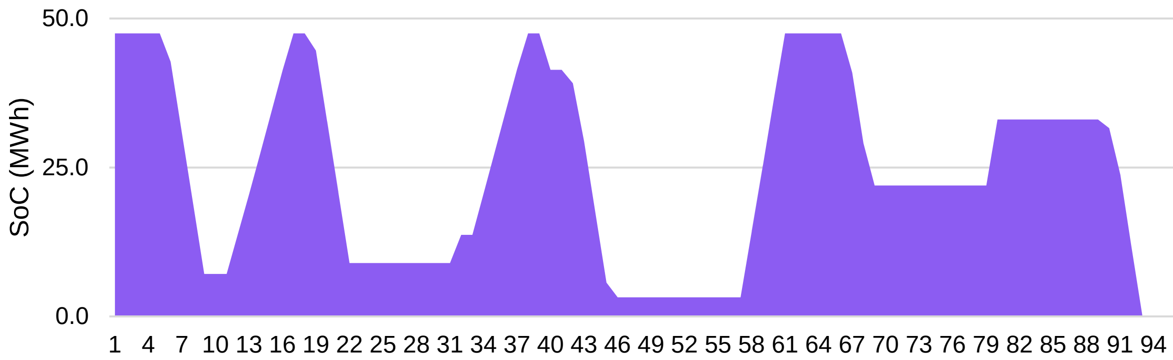
The solar array in the hybrid resource has a larger capacity than its inverter, so that at peak output, some of the generation would be curtailed. However, the DC connected battery is able to store this excess energy and discharge it at a later time. This is called clip-harvesting, as the battery stores energy that would otherwise be clipped and lost. Figure 6-33 shows a sample dispatch profile over a four-day period for this hybrid resource. Even before the passage of the Inflation Reduction Act, batteries charged from solar resources qualify for ITC. Figure 6-34 illustrates the sample state of charge for a solar plus DC connected battery hybrid resource.

Figure 6-33: Illustrative Hybrid Resource Profile (Solar Plus DC Connected Battery)



[34] NREL's 2021 Annual Technology Baseline, Utility-Scale PV-Plus Battery, https://atb.nrel.gov/electricity/2021/utility-scale_pv-plus-battery.

Figure 6-34: Illustrative Battery State of Charge for a Hybrid Resource (Solar Plus DC Connected Battery)

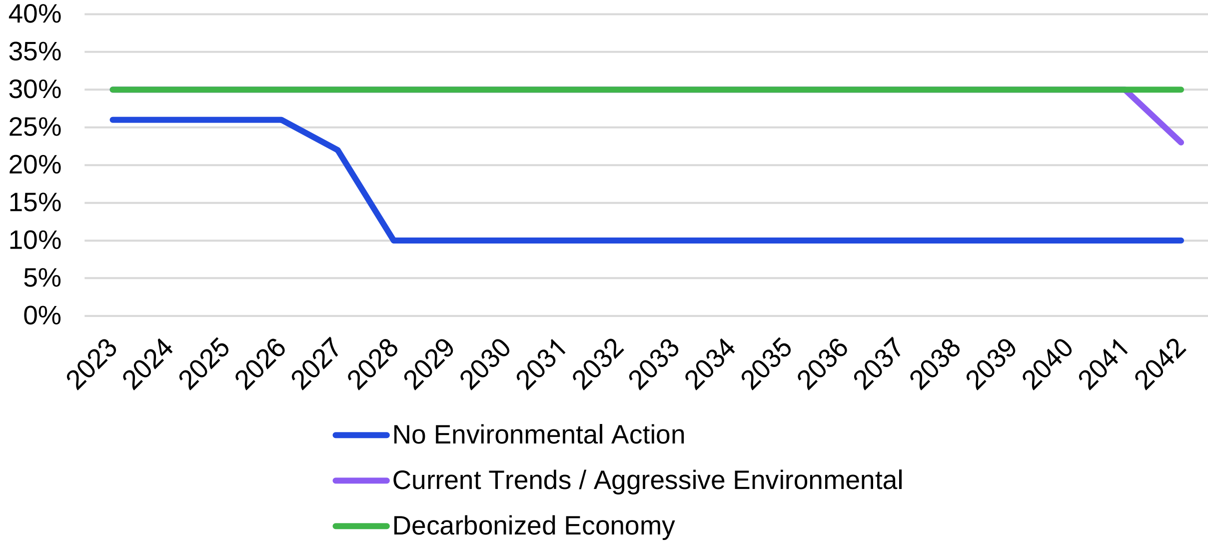


Generic hybrid resources were modeled as being located in Petersburg, Indiana, similarly to standalone solar resources. AES Indiana has an interest in preserving infrastructure and interconnection rights at this location if possible. Siting hybrids at the same location as standalone solar also allowed solar and hybrids to be compared on an apples-to-apples basis, highlighting any incremental value attributable to the storage component added to solar resources.

Capital Costs and Fixed O&M

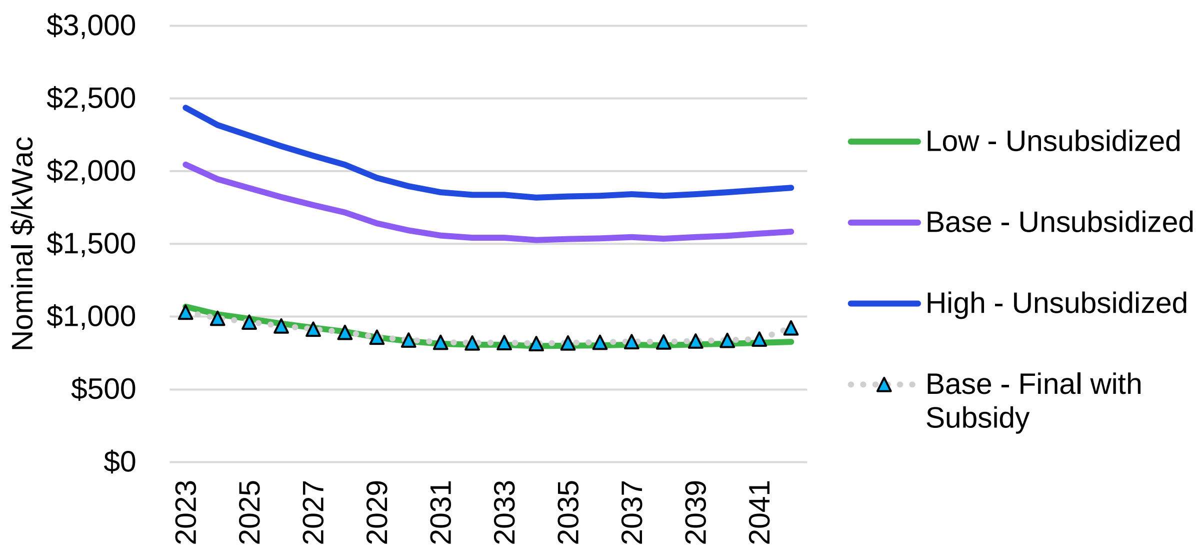
Because generic hybrid resources were composites of standalone solar and standalone storage, AES Indiana formulated the capital costs for hybrids from a weighted average of each component. This composite capital cost was then reduced by 4.3% to capture cost savings associated with installing this configuration of a hybrid resource rather than each component on its own. The 4.3% comes from NREL's 2021 ATB and provides consistency with other hybrid assumptions such as the RTE and configuration. Hybrid resources also qualify for the ITC, which can be seen in Figure 6-35 and varies by scenario.

Figure 6-35: Investment Tax Credit Assumptions for Hybrid Resources by Scenario[35]



After tax credits are applied, the cost of tax equity (estimated by Sargent & Lundy) and interconnection costs (based on MISO queue data) are added to estimate hybrids resources' final capital costs. These come in low, base, and high costs since they are composites of standalone solar and standalone storage.

Figure 6-36: Low, Base, and High Capital Costs for New Hybrids[36]

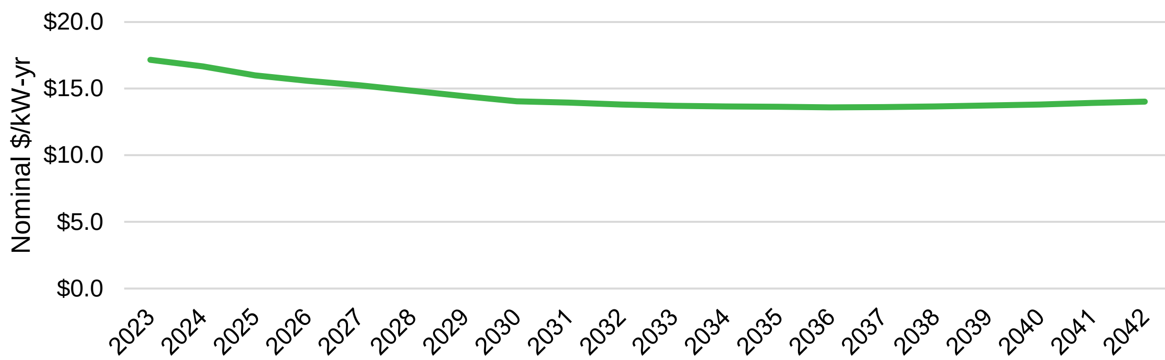


[35] Figure 6-35 shows the unsubsidized costs as well as the final Base costs in the Current Trends scenario.

[36] Subsidized costs shown for the base costs in the Current Trends Scenario.

Similar to the capital costs, the fixed costs for hybrid resources are a weighted average of the solar and storage components. Figure 6-37 shows the weighted average fixed O&M costs of hybrid resources.

Figure 6-37: Replacement Hybrid Resources Fixed O&M Costs



LMP Basis

New hybrid resources are modeled using Petersburg's LMP basis to Indiana Hub because this is where they are assumed to be located to take advantage of interconnection capacity. Figure 6-38 compares the LMPs hybrid resources are anticipated to receive to the Indiana Hub LMP.

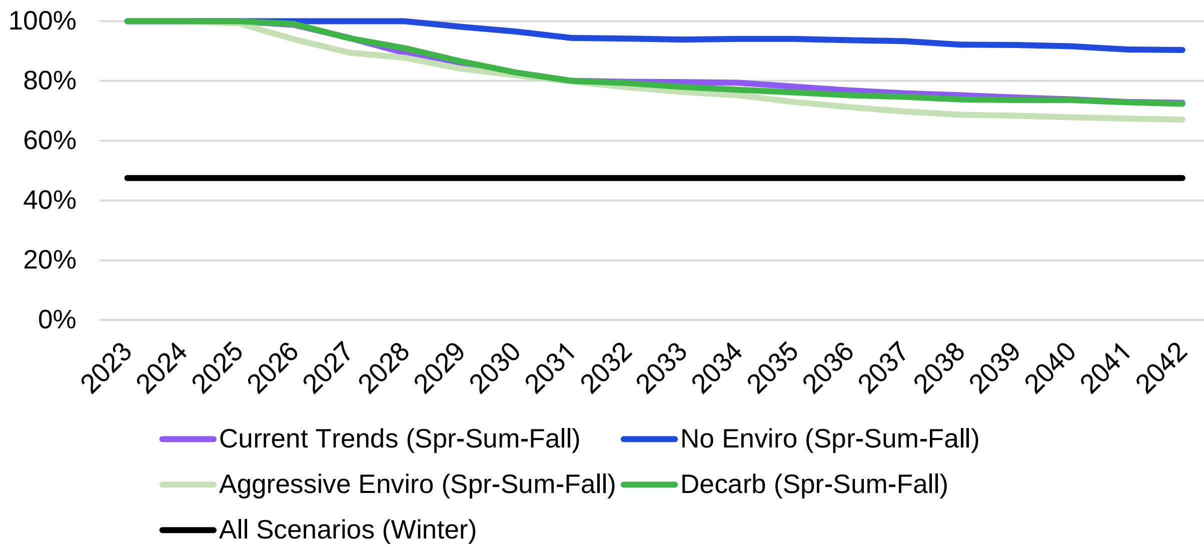
Figure 6-38: Hybrid Resources' LMP Compared to Indiana Hub LMP

Hybrid Resources' LMP Compared to Indiana Hub		
	On-Peak	Off-Peak
New Solar + Storage Hybrid	-6%	-3%

Capacity Credit

Hybrid resources receive capacity credit from their components up to their interconnection capacity. In the spring, summer, and fall, solar resources generate power while load is nearing its peak. The storage component can dispatch during the peak hours as well, so that the two resources maximize the interconnection point of 25 MW. As more solar is added to the grid, solar resources' ELCC values will decline (see Figure 6-38 above), but storage resources' capacity credit will remain constant over the asset life. The amount of solar on the grid varies by scenario, such that solar resources' ELCC also changes by scenario. In the winter season, solar resources do not receive any capacity credit due to their mismatch with load, but storage resources continue to receive four-hour capacity less its unavailability rate (i.e., XEFORD). Hybrid capacity credit by scenario and season is displayed in Figure 6-39.

Figure 6-39: Hybrid Resource Capacity Credit by Season and Scenario



6.2.5 Natural Gas Resources

Natural gas resources can fill a number of roles within a portfolio, providing dispatchability as either baseload or peaking capacity. This section provides a brief description of each natural gas resource that was modeled as well as important modeling assumptions.

→ Combined Cycle Natural Gas Turbine (CCGT)

→ Simple Cycle Combustion Turbine (Frame CT)

→ Aeroderivative Combustion Turbine (Aero CT)

→ Reciprocating Engines (Recip. Engines)

→ Petersburg conversion from coal to natural gas steam turbines (Petersburg Conversion)

For all new types of thermal resources (CCGT, Frame CT, Aero CT, and Reciprocating Engines) capital costs were split into low, base, and high. The low costs were developed using an average of NREL's 2021 ATB, Wood Mackenzie's 2021 Base Case Update, and BNEF's 2H 2021 LCOE Report. Responses to AES Indiana's 2022 RFP revealed inflationary pressures that formed the basis for deriving the base and high capital costs. Base costs are roughly 10% higher than the low, and high costs are roughly 20% higher than the low. Final capital costs include an interconnection cost estimate using MISO's queue data.

Combined Cycle Natural Gas Turbine

Figure 6-40 below provides a summary of the new CCGT resource characteristics included in AES Indiana's EnCompass Model.

Figure 6-40: New CCGT Resource Characteristics

CCGT Resource Summary
Combined Cycle Natural Gas Turbine
→ **Location:** Martinsville, Indiana → **Project Size:** 325 MW ICAP → **Heat Rate at Max Economic Load:** 6,700 British Thermal Units ("Btu") per kWh → **LMP Basis to IN Hub (On-Peak):** -4% → **LMP Basis to IN Hub (Off-Peak):** -3% → **Useful Life:** 30 years → **Capacity Credit:** 94.2% across all years

CCGT Resource Description

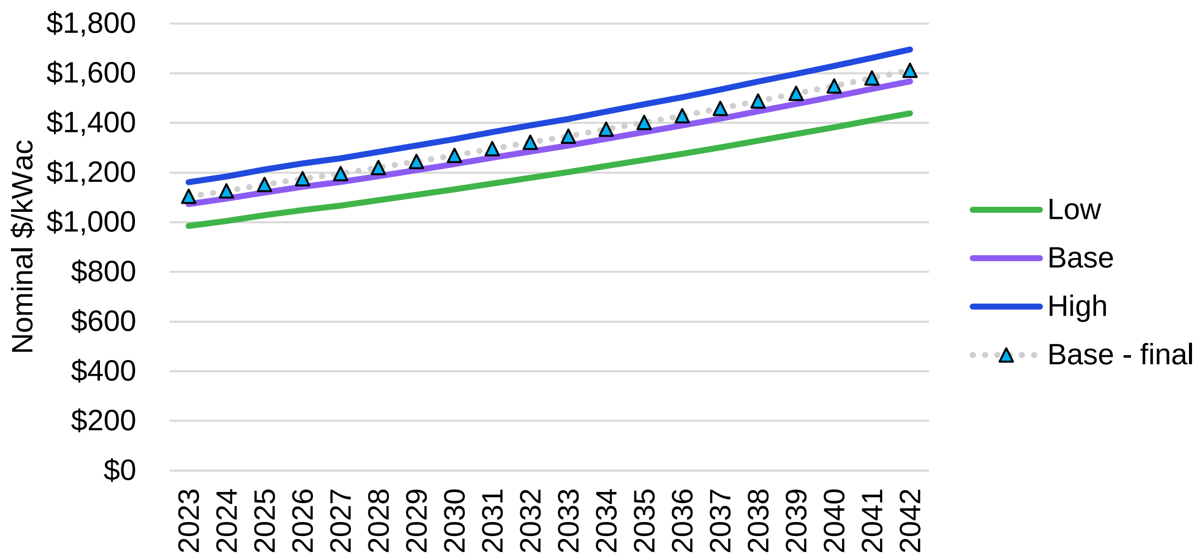
The typical combined cycle installation consists of natural gas turbines discharging waste heat into a heat recovery steam generator ("HRSG"). The HRSG supplies steam that is expanded through a steam turbine cycle driving an electric generator. Combined cycle units have the distinct advantage of being the most efficient fossil-fueled process available. Additionally, the units have relatively low pollutant emissions, low water consumption levels, reduced space considerations, and modular construction. AES Indiana modeled new generic CCGTs after AES Indiana's Eagle Valley CCGT, a 2x1 configuration with two F-class natural gas turbines each with a HRSG feeding a single steam turbine generator.

A generic new CCGT was modeled with a location that, like AES Indiana's Eagle Valley CCGT, offers existing infrastructure and natural gas capacity. The location also lends itself to the possibility of expanding the current site to achieve more modular sizing since CCGTs are typically larger plants. For this reason, AES Indiana used assumptions around Eagle Valley's natural gas pipeline access and LMP basis for a new generic CCGT. The size of a generic CCGT is roughly half the size of Eagle Valley CCGT, representing a 1x1 configuration that could be built stand-alone or added to the existing Eagle Valley CCGT site in a modular fashion.

Capital Costs and O&M

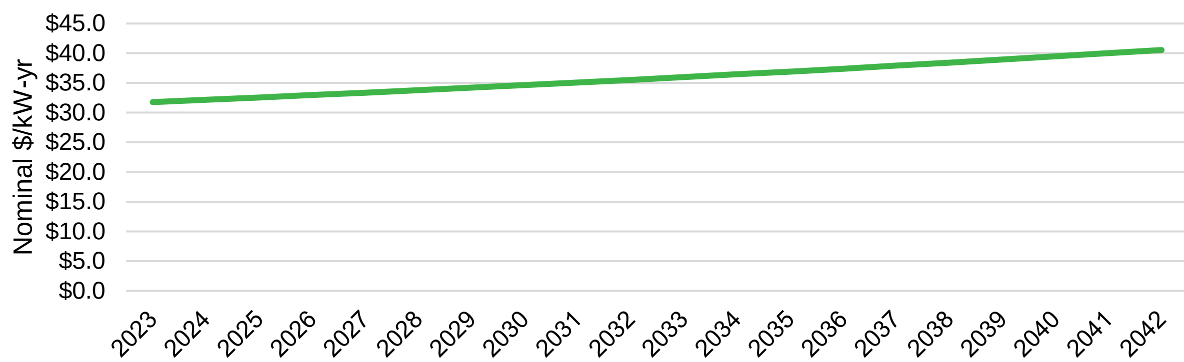
Capital costs were split into low, base, and high, as detailed at the beginning of Section 6.2 and displayed in Figure 6-41.

Figure 6-41: Low, Base, and High Capital Costs for New CCGT Resources[37]



Fixed O&M costs were based off Eagle Valley's costs, including an estimate for firm natural gas delivery costs. Fixed costs for thermal resources are levelized to remove the cyclical nature of maintenance outages. These costs are shown increasing with the rate of inflation, as seen in Figure 6-42. Variable O&M starts around $2 per MWh and escalates at 2% per year.

Figure 6-42: Fixed O&M for a New CCGT Resource, Including Firm Natural Gas Delivery



LMP Basis

New CCGT resources were modeled as being located alongside the existing Eagle Valley Plant and therefore receive a similar power basis to Indiana Hub. Figure 6-43 compares the LMPs new CCGT resources are anticipated to receive to the Indiana Hub LMP

[37] Final base costs are shown for the Current Trends Scenario.

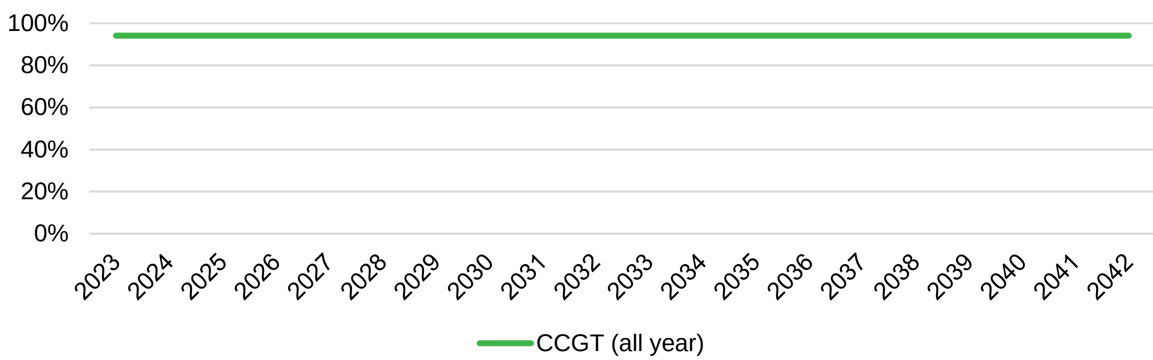
Figure 6-43: CCGT Resources' LMP Compared to Indiana Hub LMP

CCGT Resources' LMP Compared to Indiana Hub		
	On-Peak	Off-Peak
New CCGT	-4%	-3%

Capacity Credit

Capacity credit for thermal resources is determined by their GVTC results, which is then discounted by their unavailability rate (i.e., XEFORD). MISO calculates a class average XEFORD which is 5.85% for Combined Cycle Plants.[38] It receives this credit across all four seasons and for its operational life, as shown in Figure 6-44.

Figure 6-44: Capacity Credit for Replacement CCGT Resources



Simple Cycle Combustion Turbine (Frame CT)

Figure 6-45 below provides a summary of the new Frame CT resource characteristics included in AES Indiana's EnCompass Model.

Figure 6-45: New Frame CT Resource Characteristics

Frame CT Resource Summary
Frame CT
→ **Location:** Indianapolis, Indiana → **Project Size:** 100 MW ICAP → **Heat Rate at Max Economic Load:** 10,000 Btu per kWh → **LMP Basis to IN Hub (On-Peak):** -2% → **LMP Basis to IN Hub (Off-Peak):** -1% → **Useful Life:** 20 years → **Capacity Credit:** 95.6% across all years

[38] MISO class average XEFORD from the 2022-2023 LOLE Study Report, https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf#page=19.

Frame CT Resource Description

Frame CTs are combustion turbines designed for power generation. They are a mature technology, widely used for peaking applications. The units are characterized by relatively low capital costs, low non-fuel variable O&M, modular designs, and short construction lead times.

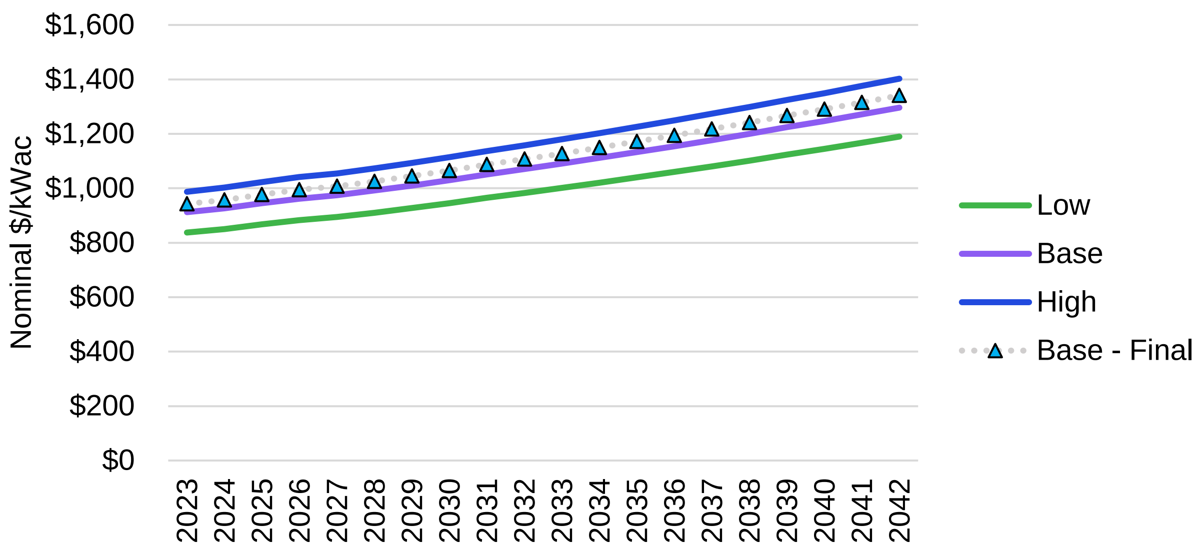
AES Indiana has substantial experience in both the construction and operation of simple-cycle CTs. AES Indiana's existing units include Georgetown Unit 1, which reached commercial operation in 2000, and Harding Street Unit 6, which reached commercial operation in 2002. AES Indiana also purchased Georgetown Unit 4 in 2007. Because of this experience, AES Indiana modeled new generic Frame CTs after Harding Street Unit 6.

New Frame CTs were modeled as if they were located at Harding Street, which offers natural gas and electrical interconnection capacity, especially to AES Indiana's 138 kV system. A new Frame CT would not necessarily be located at Harding Street but would likely be sited in a location with similar advantages.

Capital Costs and Fixed O&M

Capital costs were split into low, base, and high, as detailed at the beginning of Section 6.2 and displayed in Figure 6-46.

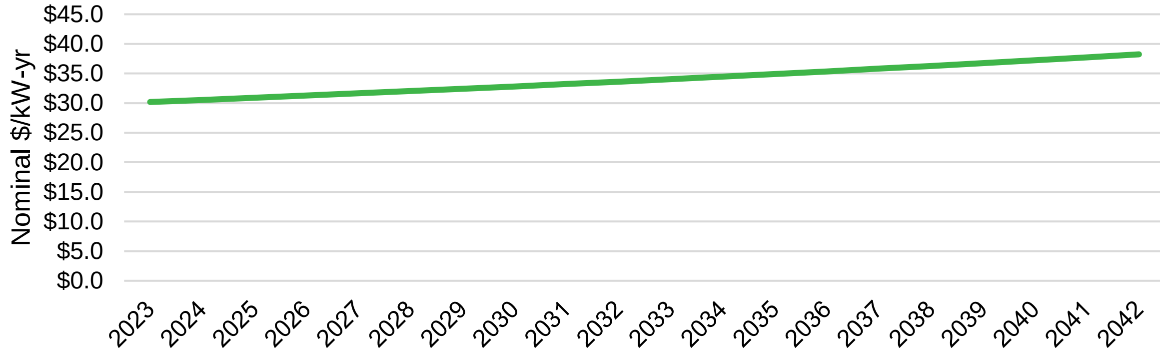
Figure 6-46: Low, Base, and High Capital Costs for New Frame CTs[39]



Fixed O&M costs were based off Harding Street's CT6 costs and includes an estimate for firm natural gas delivery. Fixed costs for thermal resources are levelized to remove the cyclical nature of maintenance outages. These costs are shown increasing with the rate of inflation, as seen in Figure 6-47. Variable O&M starts around $1 per MWh and escalates with inflation.

[39] Final base costs are shown for the Current Trends Scenario.

Figure 6-47: New Frame CT Resource Fixed O&M, Including Firm Natural Gas Delivery



LMP Basis

New Frame CTs were modeled as being located at Harding Street and therefore receive a similar power basis to Indiana Hub. Figure 6-48 compares the LMPs new Frame CT resources are anticipated to receive to the Indiana Hub LMP.

Figure 6-48: New Frame CT Resources' LMP Compared to Indiana Hub LMP

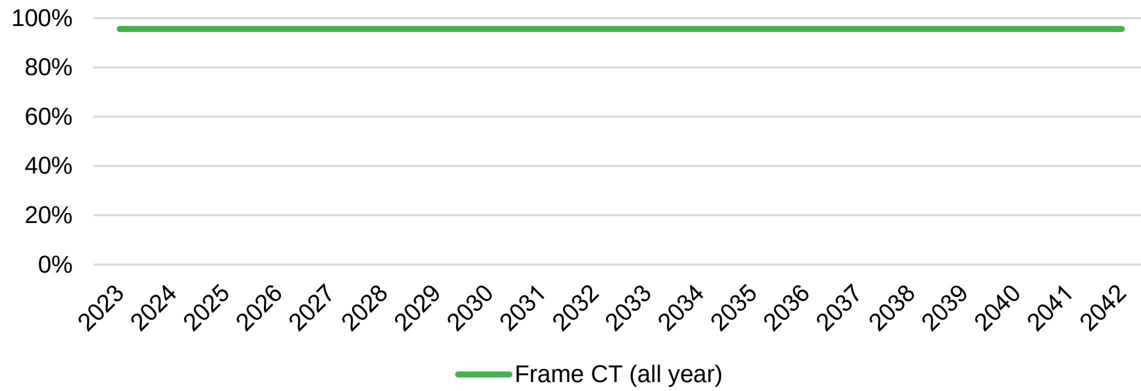
Frame CT Resources' LMP Compared to Indiana Hub		
	On-Peak	**Off-Peak**
New Frame CT	-2%	-1%

Capacity Credit

Capacity credit for thermal resources is determined by their GVTC, which is then discounted by their unavailability rate (i.e., XEFORD). MISO calculates a class average XEFORD which is 4.36% for combustion turbines.[40] It receives this credit across all four seasons and for its operational life, as shown in Figure 6-49.

[40] MISO class average XEFORD from the 2022-2023 LOLE Study Report, https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf#page=19.

Figure 6-49: Capacity Credit for Replacement Frame CT



Aeroderivative Combustion Turbine and Reciprocating Engines

Figure 6-50 below provides a summary of the new Aero CT and Recip. Engine resource characteristics included in AES Indiana's EnCompass Model.

Figure 6-50: New Aero CT and Recip. Engine Resource Characteristics

Aero CT and Recip. Engines Resource Summary	
Aero CT	**Recip. Engine**
→ **Location:** Indianapolis, Indiana → **Project Size:** 90 MW ICAP → **Heat Rate at Max Economic Load:** 8,227 Btu per kWh → **LMP Basis to IN Hub (On-Peak):** -2% → **LMP Basis to IN Hub (Off-Peak):** -1% → **Useful Life:** 20 years → **Capacity Credit:** 95.6% across all years	→ **Location:** Indianapolis, Indiana → **Project Size:** 54 MW ICAP → **Heat Rate at Max Economic Load:** 7,400 Btu per kWh → **LMP Basis to IN Hub (On-Peak):** -2% → **LMP Basis to IN Hub (Off-Peak):** -1% → **Useful Life:** 20 years → **Capacity Credit:** 95.6% across all years

Aero CT and Recip. Engine Resource Description

Aero CTs and Recip. Engines are less standard than other replacement resources but offer highly flexible resources that may prove invaluable as more intermittent generation comes online. Data sources, such as NREL, Wood Mackenzie, and BNEF, do not usually provide detail on these resources, so AES Indiana consulted with Sargent & Lundy for modeling assumptions, including capital costs and operating parameters.

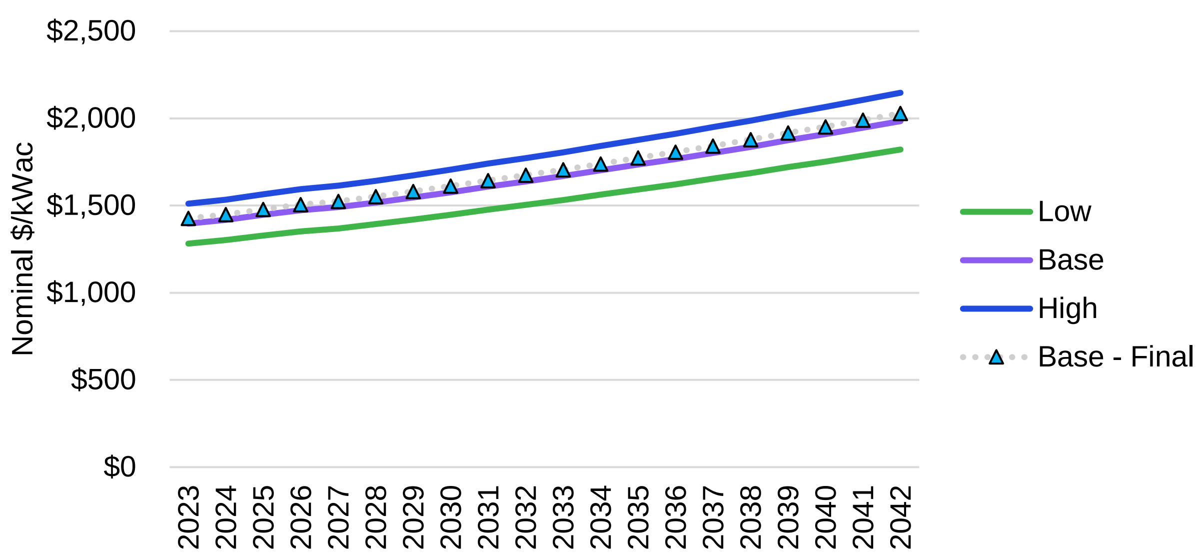
Aero CTs vary from Frame CTs in that they tend to come in smaller sizes and are designed for more cycling than a Frame CT. They have faster ramp rates and lower start costs making them highly flexible. Sargent & Lundy provided insight that Aero CTs are often installed as a pair at minimum, so Aero CTs were modeled as two 45 MW turbines for a total of a 90 MW selectable resource.

Recip. Engines come in sizes from three to eighteen MWs but are installed as a bank of engines. With guidance from Sargent & Lundy, AES Indiana's 2022 IRP analysis assumed a bank of three 18 MW units for a total of 54 MW as a selectable resource. Recip. Engines are characterized by low startup costs, fast ramp rates, and the ability to turn engines off to run at very low minimums. This makes Recip. Engines very flexible. Newer versions also have relatively efficient heat rates, which are partially offset by higher variable operating expenses, such as lubricating oil.

Capital Costs and Fixed O&M

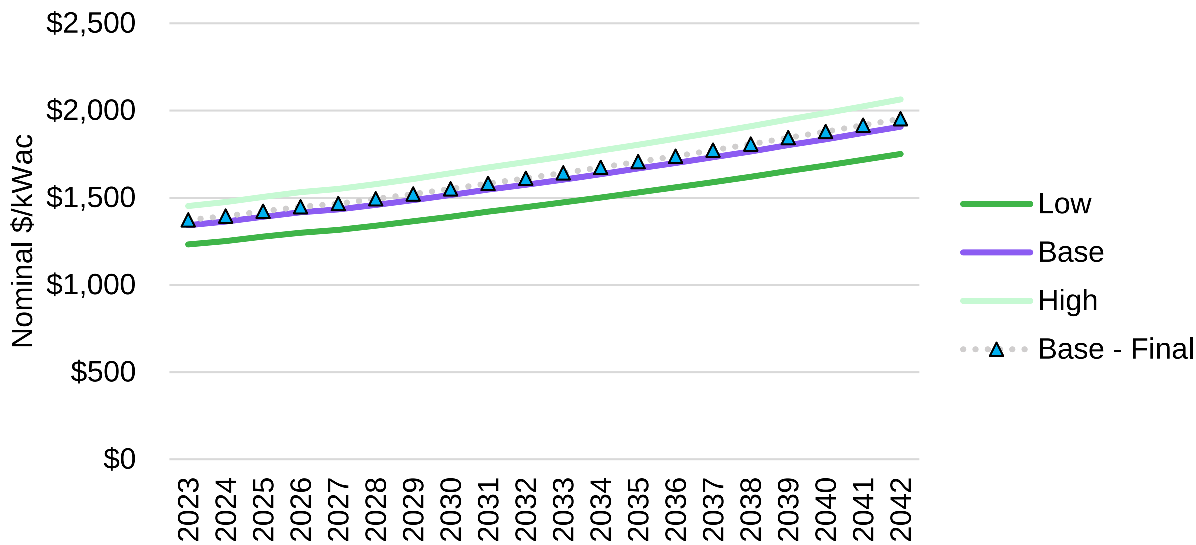
Capital costs were split into low, base, and high, as detailed at the beginning of Section 6.2. Aero CT and Recip. Engine capital costs are shown in Figure 6-51 and Figure 6-52, respectively.

Figure 6-51: Low, Base, and High Capital Costs for New Aero CTs[41]



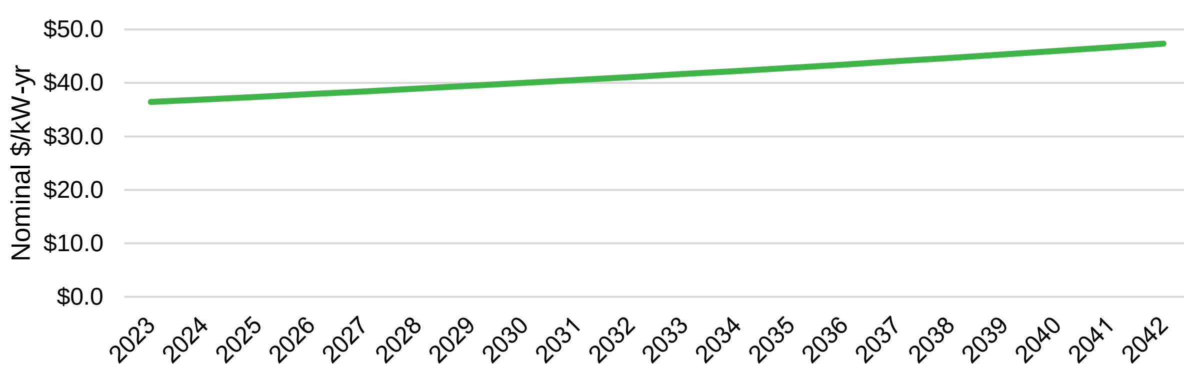
[41] Final base costs are shown for the Current Trends Scenario.

Figure 6-52: Low, Base, and High Capital Costs for Recip. Engines[42]



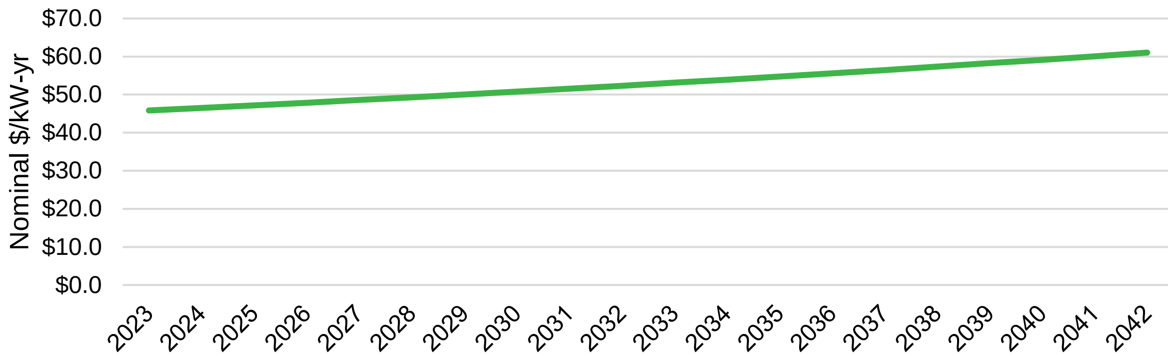
Estimates for fixed operating and maintenance costs for Aero CTs and Recip. Engines were supplied by Sargent & Lundy and are shown in Figure 6-53 and Figure 6-54, respectively. As with all replacement natural gas resources in AES Indiana's 2022 IRP, the cost estimates include a fixed cost for firm natural gas delivery. This ensures the resources can provide capacity when called upon. Variable O&M starts around $5 per MWh for an Aero CT and $6 per MWh for a Recip. Engine and both escalate with inflation.

Figure 6-53: Fixed O&M, Including Firm Natural Gas Delivery, for a New Aero CT Resource



[42] Final base costs are shown for the Current Trends Scenario.

Figure 6-54: Fixed O&M, Including Firm Natural Gas Delivery, for a New Recip. Engine Resource



LMP Basis

New Aero CTs and Recip. Engines were modeled as being located at Harding Street due to the existing infrastructure and proximity to load, and therefore receive a similar power basis to Indiana Hub. Figure 6-55 compares the LMPs new Aero CT and Recip. Engine resources are anticipated to receive to the Indiana Hub LMP.

Figure 6-55: Aero CT and Recip. Engine Resources' LMP Compared to Indiana Hub LMP

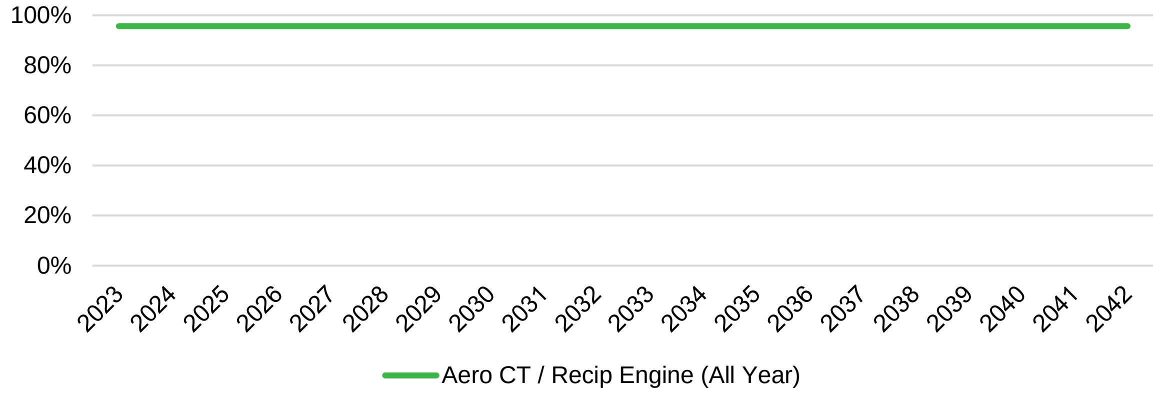
Aero CT and Recip. Engine Resources' LMP Compared to Indiana Hub		
	On-Peak	Off-Peak
New Aero CTs or Recip. Engines	-2%	-1%

Capacity Credit

Capacity credit for thermal resources is determined by their GVTC, which is then discounted by their unavailability rate (i.e., XEFORD). MISO calculates a class average XEFORD, which is 4.36% for Combustion Turbines. [43] There is limited data for Reciprocating Engines, so AES Indiana's 2022 IRP assumes both would have a similar XEFORD as combustion turbines. These resources receive this credit across all four seasons and for their operational life, as shown in Figure 6-56.

[43] MISO class average XEFORD from the 2022-2023 LOLE Study Report, https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf#page=19.

Figure 6-56: Capacity Credit for Replacement Aero CT or a Recip. Engine



Petersburg Conversion to Natural Gas (Petersburg Conversion)

Figure 6-57 below provides a summary of the Petersburg Conversion resource characteristics included in AES Indiana's EnCompass Model.

Figure 6-57: Petersburg Conversion Resource Characteristics

Petersburg Conversion Resource Summary	
Petersburg Unit 3	**Petersburg Unit 4**
→ **Location:** Petersburg, Indiana → **Econ Max Capacity:** 526 MW ICAP → **Heat Rate at Max Economic Load:** 10,800 Btu per kWh → **LMP Basis to IN Hub (On-Peak):** -6% → **LMP Basis to IN Hub (Off-Peak):** -3% → Useful Life: 20 years → **Long Term Capacity Credit:** ~480 MW	→ **Location:** Petersburg, Indiana → **Econ Max Capacity:** 526 MW ICAP → **Heat Rate at Max Economic Load**: 10,800 Btu per kWh → **LMP Basis to IN Hub (On-Peak):** -6% → **LMP Basis to IN Hub (Off-Peak):** -3% → **Useful Life:** 20 years → **Long Term Capacity Credit:** ~510 MW

Petersburg Conversion Resource Description

AES Indiana considered converting Petersburg Units 3 and 4 in recognition that natural gas is a bridge fuel to enable renewable resource development. Additionally, the transition from an annual capacity construct with a focus on summer to a seasonal construct that identifies winter capacity requirements has placed increasing importance on maintaining thermal assets that can provide firm capacity year-round.

A Petersburg Conversion resource involves switching the fuel burned from coal to natural gas at Petersburg. The existing boilers would be used to generate steam that is run through the existing steam turbines to generate electricity.

Most of the costs and operating parameters for the Petersburg Conversion come from an updated engineering analysis of the Harding Street Unit 7 coal to natural gas conversion, completed in 2016. With a conversion, the coal units are expected to experience a slight gain in net capacity as certain auxiliary systems are no longer needed. They have lower variable operating costs and substantially lower fixed costs and capital requirements. As converted units, they have faster startups, lower startup costs, and become more flexible. They also experience an increase in heat rate. The increased heat rate and increased flexibility generally causes the Petersburg units to have lower capacity factors that continue to provide firm capacity.

Capital Costs and O&M

The capital costs for converting Petersburg Unit 3 and Petersburg Unit 4 to operate on natural gas is approximately $160 per kW. This comes from the updated engineering study of Harding Street Unit 7's conversion costs. The cost includes connecting units to a natural gas pipeline, boiler upgrades, and other necessary changes to allow the units to burn natural gas. Additionally, annual capital expenditures at the plant are cut in half with a natural gas conversion relative to the units continuing to burn coal.

Fixed O&M is reduced by roughly 65% and variable O&M is about a tenth of what it is for the units on coal. These reductions are largely driven by less auxiliary equipment being needed to handle coal and emissions associated with burning coal. The fixed O&M includes about ten million dollars per year for the whole plant to account for firm gas delivery and pipeline upgrades on site.

LMP Basis

Petersburg on natural gas is expected to have a similar LMP basis to Indiana Hub as it does on coal. Historical data shows that this is usually a negative basis of a few percent. Figure 6-58 compares the LMPs Petersburg Conversion resources are anticipated to receive to the Indiana Hub LMP.

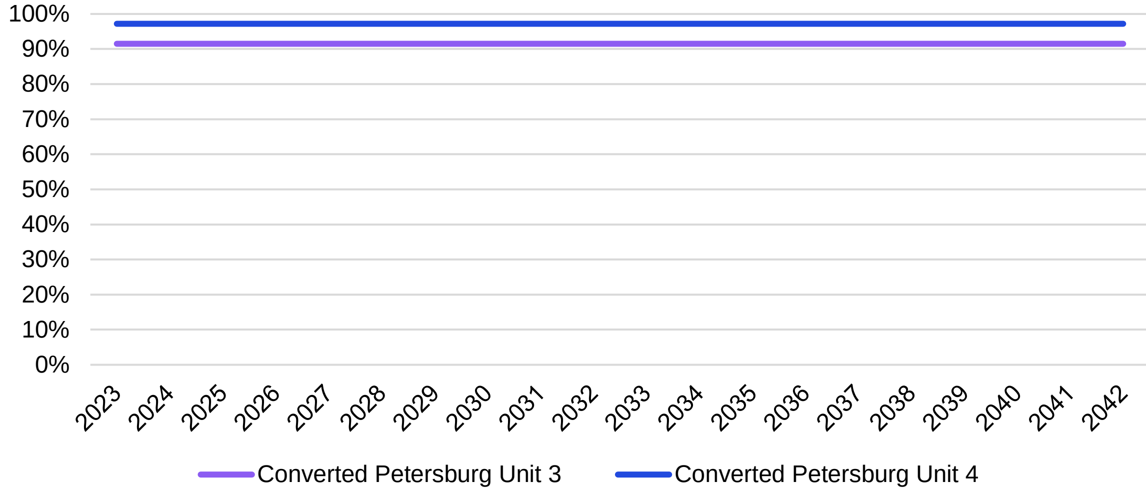
Figure 6-58: Petersburg Conversion Resources' LMP Compared to Indiana Hub LMP

Petersburg Conversion Resources' LMP Compared to Indiana Hub		
	On-Peak	**Off-Peak**
Petersburg	-6%	-3%

Capacity Credit

Petersburg on natural gas will receive similar capacity credit as Petersburg on coal. As with all thermal resources, capacity credit is determined by GVTC results, which are then discounted by their unavailability rate (XEFORD). For Petersburg Units 3 and 4, the past few years' operational history is used to estimate capacity credit, as seen in Figure 6-59.

Figure 6-59: Capacity Credit for Petersburg Unit 3 and Petersburg Unit 4 Converted to Natural Gas



6.3 Summary of Supply Side Resources

170 IAC 4-7-4(6) and 170 IAC 4-7-6(b)(3)(A)

Supply side replacement resource options represent a wide variety of commercially viable technologies. Renewable energy technologies are represented by wind and solar resources. Wind resources are considered at two different locations representing strong and moderate capacity factors but also congestion and siting limitations. Solar resources are represented by utility-scale single-axis tracking photovoltaic resources. Solar resources can also be paired with storage as a hybrid resource, which allows for energy from the solar array to be stored rather than curtailed and dispatched at more optimal times. Renewable energy resources' capacity credit varies widely by seasons.

Dispatchable resources are represented by standalone storage resources with at least a four-hour discharge duration and thermal resources. The thermal resources all use natural gas as a fuel to generate electricity. The thermal options present different application options ranging from efficient baseload energy resources, as with CCGT resources, to relatively cheap capacity with low-capacity factor resources, as with the Frame CTs. The Aero CTs and Recip. Engines fall somewhere between those two bookends and offer flexibility with quick starts and fast ramp rates. The Petersburg Conversion provides a low-cost option for maintaining the existing Petersburg assets for capacity while reducing many of the associated costs. Dispatchable resources maintain a constant capacity credit throughout the year.

6.4 Demand Side Resource Options

170 IAC 4-7-4(6), 170 IAC 4-7-6(a)(6), and 170 IAC 4-7-6(b)(2)(A)

6.4.1 Existing Demand Side Resources

170 IAC 4-7-6(b)(2)(C) and 170 IAC 4-7-6(b)(2)(F)

AES Indiana's current portfolio of DSM resources (2021-2023) was approved on December 29, 2020 in IURC Cause No. 45370. This comprehensive set of programs provides energy efficiency opportunities for all AES Indiana customers. Through 2021, AES Indiana's current demand side management programs have contributed an estimated 111,669 MWh of annual energy savings benefits and approximately 56.9 MWs of demand savings benefits through the first year of the three-year plan.

Current DSM Programs

The actual 2021 evaluated energy savings are listed in Figure 6-60. The 2022 contributions are forecast to be approximately 103,000 Net MWh.

Figure 6-60: 2021 DSM Program Savings

DSM Program	Evaluated 2021 Program Achievement (Ex Post Net kWh)[44]
Residential Programs	-
Demand Response	-
Appliance Recycling	1,626,621
Income Qualified Weatherization	10,389,647
Multifamily Direct Install	2,228,153
Home Energy Reports	22,624,217
School Kits	4,189,087
Efficient Products	10,086,893
Total Residential	**51,144,617**
Business Programs	-
Demand Response	-
Custom	31,912,738
Prescriptive	47,422,373
Small Business Direct Install	3,312,745
Total Business	**82,647,856**
Total All Programs	**133,792,473**

[44] Ex Post Net reflects the net impact of DSM programs following annual third-party evaluation. More information can be found in the AES Indiana 2021 Demand Side Management Portfolio Evaluation Report that was filed with the IURC on September 7, 2022 under AES Indiana's DSM Plan docket (IURC Cause No. 45370).

AES Indiana's ACLM program, CoolCents®, and its Income Qualified Weatherization Programs are AES Indiana's longest continually offered DSM programs. The Residential ACLM program has been offered since 2003 and represents the largest DSM program in terms of customer participation and peak demand reduction. As of the end of 2021, AES Indiana has deployed approximately 52,000 residential demand response devices, including ACLM switches and smart thermostats, and has 80 participating C&I customers, which in total contribute approximately 35.3 MW of demand reduction opportunity.[45] New ACLM participants are mainly acquired through AES Indiana's energy efficiency smart thermostat offerings.

Of current offerings, the most significant DSM programs in terms of energy efficiency savings in 2021 were the C&I Prescriptive Program (with approximately 47,422 ex-post net MWh in 2021) and the Residential Peer Comparison Report (with approximately 22,624 ex-post net MWh).

Current Demand Response ("DR") Programs

In addition to the energy efficiency DSM programs and the ACLM demand response program described above, AES Indiana has several Load Curtailment/Interruptible programs that are tariff offerings targeted to C&I customers. Since 2014, these programs have seen a significant decrease in participation and the amount of capacity that is being provided. The programs have been targeted primarily at customers that have emergency back-up generation. Customers are called upon from time to time to operate emergency generation equipment on AES Indiana's behalf to reduce load. However, due to the 2014 National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines rulemaking, most customer generation is no longer available to participate in utility sponsored programs due to air emission constraints.

At the end of 2021, AES Indiana has approximately 1 MW of demand response programs under contract with C&I customers. This is a decrease from the 45 MW that was available in 2014, largely because of departures by participating customers and EPA restrictions on emissions from diesel generators. In most cases, the incentives offered are adjusted annually to reflect changes in power market conditions. The currently approved programs are described in Figure 6-61 below. In most cases, the incentives offered are adjusted annually to reflect changes in power market conditions.

Figure 6-61 shows the demand response resources for which AES Indiana receives capacity credit from MISO totaling 52 MW in 2021. There is no end of useful life shown since AES Indiana plans to support this program through customer enrollment and replacement technologies as needed throughout the study period.

As of 2021, AES Indiana has launched pilot demand response programs for water heater switches and electric chargers. The water heater switch pilot has a targeted audience of multifamily units. The electric chargers are eligible to all AES Indiana residential customers. The water heater switches and electric chargers are in the infancy stage of the pilot and being tested thoroughly to

[45] 2015 Demand Side Management Evaluation Report, Indianapolis Power & Light Company, June 30, 2016, Table 7, p. 10.

determine optimal times to call on the devices. Initial results from this pilot are expected to be available in 2023.

Figure 6-61: Capacity Credit of AES Indiana's 2021 Demand Response Programs

Demand Response Program	UCAP (MW)
Conservation Voltage Reduction	12
ACLM	29
Rider 17	1
Rider 14	10
Total Demand Response	**52**

6.4.2 AES Indiana's Demand Side Management Guiding Principles

170 IAC 4-7-6(b)(2)(F)

AES Indiana has continuously offered DSM programs to benefit customers and optimize demand side resources for over twenty-five years and AES Indiana remains dedicated to offering DSM programs. AES Indiana developed this list of guiding principles that characterize DSM offerings.

AES Indiana's DSM guiding principles shape future DSM program offerings. Therefore, AES Indiana used the following guiding principles in its 2022 IRP:

- → DSM programs are inclusive for customers in all rate classes;
- → DSM programs are appropriate for AES Indiana's market and customer base;
- → DSM programs are cost effective;
- → DSM programs modify customer behavior; and
- → DSM programs should provide continuity from year to year.

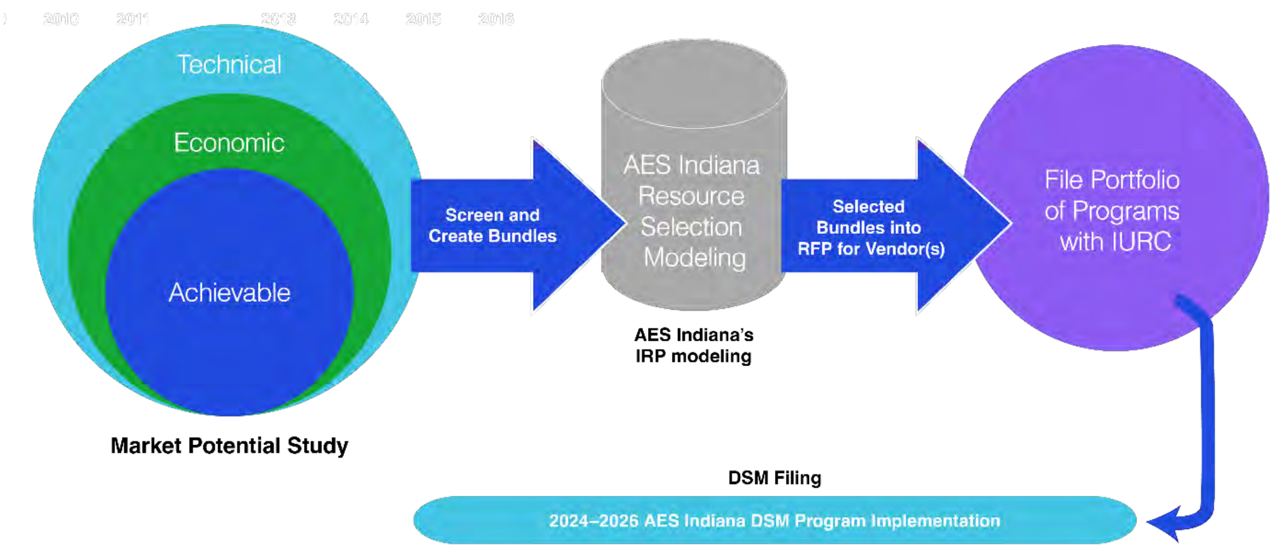
The Company expects to continue to propose and deliver additional cost effective programs consistent with the IURC's IRP and CPCN rules for DSM options. The specific programs to be delivered will be identified and proposed in subsequent AES Indiana's DSM plans to be filed with the IURC.

6.4.3 Demand Side Management Planning Overview

170 IAC 4-7-6(b)(2)(C)

Figure 6-62 below illustrates the stages of AES Indiana's DSM planning process. The objective of this process is to identify AES Indiana's opportunities to provide DSM for the 20-year IRP planning period in a manner that aligns with direction provided by the IURC and that is consistent with the IRP rules. DSM opportunities identified in the IRP process will be used as the starting point to develop a cost effective DSM Action Plan for consideration and approval by the IURC. AES Indiana's DSM Action Plan will be consistent with Ind. Code § 8-1-8.5-10, which requires public utilities to provide DSM with energy efficiency goals that are: 1) reasonably achievable; 2) consistent with the utility's IRP; and 3) designed to achieve an optimal balance of energy resources in the utility's service territory.

Figure 6-62: Overview of DSM Process



AES Indiana initiated the current DSM planning process by contracting with GDS to complete a MPS and End-Use Analysis. GDS is an engineering and consulting firm with a practice that includes energy efficiency planning for utilities. The MPS determined an achievable level of DSM in AES Indiana's service territory by estimating customer adoption rates for a comprehensive list of DSM measures. The MPS helped to ensure that the level of DSM that is optimized within the IRP is "reasonably achievable" as discussed in more detail in part 2 of this section.

Per 170 IAC § 4-7-8(c)(4), demand-side resources should be modeled on a consistent and comparable basis with supply-side resources. To accomplish this, AES Indiana took the Realistic Achievable Potential ("RAP") results from the MPS and created IRP model inputs (see Stage 2 in Figure 6-62) with a load shape and levelized costs similar to a supply-side resource. The RAP results were then divided into twenty selectable "bundles," including DR (three income-qualified weatherization bundles will be predefined in the model; therefore, the model must select the three income-qualified weatherization bundles). This bundling approach is discussed in more detail in Section 6.4.5.

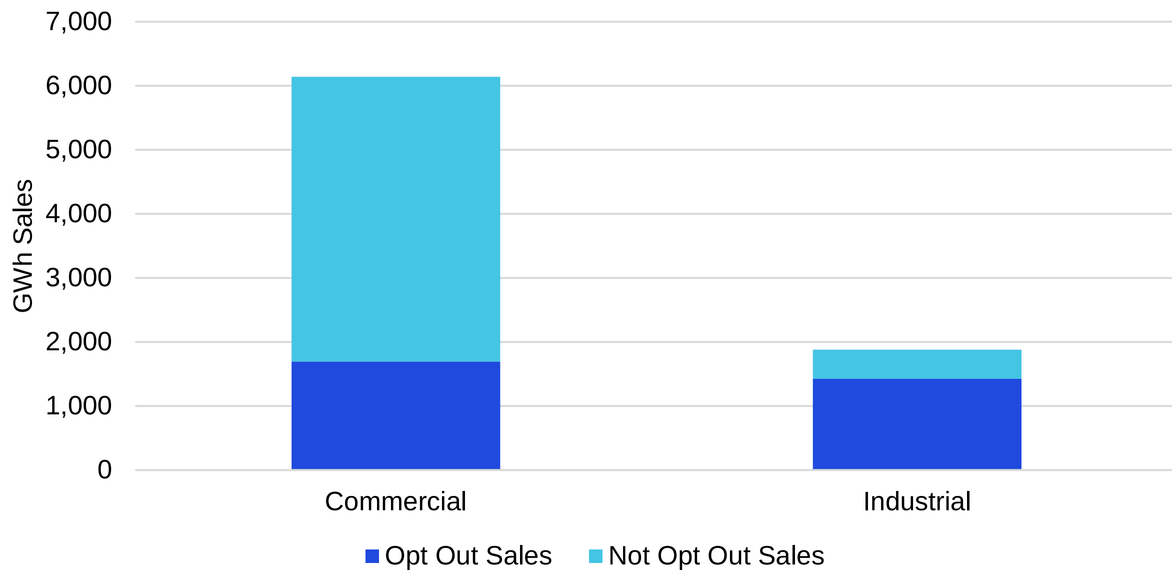
The DSM bundles were evaluated alongside supply-side resources in the EnCompass Resource Selection Model and an optimized level of DSM was selected for AES Indiana's 2022 IRP study period (2022 – 2042). The results will be used to inform the DSM Action Plan for the 2024-2026 period. DSM measures from the bundles will be developed into deliverable programs and a DSM plan, which will be filed with the IURC for its consideration and approval. The EnCompass DSM resource selection process and DSM Action Plan is discussed in more detail in Section 8.1 and Section 10.1.2.

Opt-Out Customers

In Indiana, individual commercial or industrial customer sites with a peak load greater than one MW are eligible to opt out of utility-funded electric energy efficiency programs. In the AES Indiana service territory, approximately 28% of total reclassified retail commercial sales have opted out of utility-funded electric energy efficiency programs, while roughly 76% of total reclassified retail industrial sales have opted out.

Figure 6-63 below shows the total sales for the C&I sectors, as well as the sales, by sector, that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e., does not meet the one MW peak demand requirement) as well as eligible load that has not yet opted out.

Figure 6-63: C&I Customer Opt Out Compared to Non-Opt Out Sales



GDS removed the sales from opt out customers in the assessment of technical, economic, and achievable potential reflected in this report. As a sensitivity (included in Appendix A of Attachment 6-3), GDS also examined the full potential in the C&I sector if these customers were no longer able to opt-out of utility-funded electric energy efficiency programs.

DSM Stakeholder Engagement

AES Indiana has maintained a strong collaborative relationship with its stakeholders throughout the MPS and IRP process, making all MPS documents available to stakeholders with nondisclosure agreements. Additionally, AES Indiana has welcomed stakeholder input into the process and made an effort to incorporate stakeholder ideas into its methodology (e.g., the bundling methodology described later). Over the past year, AES Indiana has held five technical meetings with stakeholders to share findings and to receive feedback during the MPS process. A list of Stakeholder technical meetings dates relevant to AES Indiana's DSM modeling activities are as follows:

→ 2021 MPS Meeting – September 9, 2021

→ IRP Technical Workshop #1 – January 14, 2022

→ Review to discuss DSM IRP inputs – February 15, 2022

→ Meeting to discuss interruptible tariff – March 18, 2022

→ IRP Technical Workshop #2 – April 7, 2022

→ Between September 2021 and May 2022, AES Indiana hosted bi-weekly meetings with GDS Associates and the AES Indiana DSM Over Sight Board members.

6.4.4 Market Potential Study and End Use Analysis

170 IAC 4-7-4(15), 170 IAC 4-7-6(b)(2)(B), and 170 IAC 4-7-6(b)(2)(C)

The primary objective of the MPS was to establish Technical, Economic, Maximum Achievable, and Realistic Achievable potentials for DSM in the AES Indiana's service territory. More simply, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost effective, or could be realized through the implementation of energy efficiency programs and policies. AES Indiana contracted with GDS to conduct this analysis, which began in the fall of 2021. GDS developed the potential savings estimates by: 1) creating AES Indiana's market characterization or establishing a forecast of the saturation and efficiency levels of existing equipment used by AES Indiana's customers; 2) creating the measure characterization or developing a comprehensive list of cost effective energy efficiency measures; and 3) developing potentials or estimating adoption of the listed energy efficiency measures using the saturation and efficiency forecast as a basis for efficiency uptake. Through this approach, the Technical, Economic, Maximum Achievable, and Realistic Achievable Potential estimates were developed which are graphically illustrated in Figure 6-64 and defined as follows:

→ *Technical Potential* – potential for DSM adoption that assumes no barriers to customer adoption, e.g., financial limitations, customer awareness, and willingness to participate.

→ *Economic Potential* – potential for DSM that only includes measures that are deemed to be cost effective based on a measure-level screening using the Utility Cost Test ("UCT").

→ *Achievable Potential* – potential from DSM that assumes certain market and adoption barriers, e.g., incentive levels and barriers to participation. GDS considered two levels of Achievable Potential:

  - *Maximum Achievable Potential ("MAP")* – potential for DSM that assumes paying an incentive equal to 100% of the measure incremental cost and limited barriers to participation.

- *Realistic Achievable Potential* – is the subset of maximum achievable potential for DSM that assumes the incentives paid for DSM and barriers to participation are aligned with historic levels with no constraints placed on spending.

Figure 6-64: Types of Energy Efficiency Potential

GDS took the initial step of conducting market research that would inform critical elements of the market potential study. Primary market research activities were focused on collecting updated equipment penetration, saturation, and efficiency characteristics; as well as customer Willingness to Participate ("WTP") in the program offerings across selected end-uses and measures. The resulting data was used to develop updated estimates of the baseline and efficient equipment saturation estimates in the MPS and develop expected long-term adoption rates of energy efficiency, demand response, and DER over the study horizon. The GDS team conducted surveys of business and residential AES Indiana customers during January and February of 2022 with the objectives of gathering primary data on the following topics:

→ Willingness to participate in a variety of energy efficiency and demand response program scenarios;

→ Baseline/saturation of energy-using equipment;

→ Program awareness; and

→ Market barriers.

GDS conducted 787 residential and 38 C&I baseline surveys, and 462 residential and 97 C&I WTP surveys. The full breakdown of the survey sampling targets and responses are summarized in Figure 6-65. These survey results served as inputs for the MPS and enabled GDS to consider the specific market conditions that exist in AES Indiana's service territory.

Figure 6-65: Survey Sampling Targets and Response

Group	Emailed	Target Completes	Completed (Partial Survey)	Completed (Entire Survey)
C&I Baseline Survey				
Commercial	2,975	65	48	36
Industrial	249	3	3	2
Total	3,224	68	51	38
C&I Willingness to Participate Survey				
Commercial	5,880	62	144	92
Industrial	545	6	9	5
Total	6,425	68	153	97
Residential Baseline Survey				
Multifamily	2,720	68	44	135
Non-Multifamily	12,280	316	137	652
Total	15,000	384	181	787
Residential Willingness to Participate Survey				
Multifamily	2,720	68	57	74
Non-Multifamily	12,280	316	186	388
Total	15,000	384	243	462

GDS used this survey data and its subsequent analysis to gather a clear understanding of the current market segments in the AES Indiana service territory. The GDS team coordinated with AES Indiana to gather utility sales, customer data, and existing market research to define appropriate market sectors, market segments, vintages, saturation data, and end uses. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and non-residential sectors.

GDS also disaggregated the baseline forecast by sector and end-use. The residential forecast was broken out by housing type between existing income qualified and market-rate customers as well as new construction. The commercial forecast was disaggregated based on major EIA Commercial Buildings Energy Consumption Survey ("CBECS") business types: retail, warehouse, food sales, office, lodging, health, food services, education, and miscellaneous. The industrial forecast break down was determined by actual load consumption shares and major industry types as defined by EIA's Manufacturing Energy Consumption Survey ("MECS") data. The segmentation analysis was performed by applying AES Indiana- specific segment and end-use consumption shares, derived from AES Indiana's customer database and SIC code analysis (i.e., building segmentation), and by EIA CBECS and MECS data (i.e., end-use segmentation) to forecast year sales. Within the residential, commercial, and industrial market segments, the sector level disaggregated forecasts were further segmented by the major end uses shown in Figure 6-66 below.

Figure 6-66: Major End Uses by Customer Class

Residential	C&I	
	Commercial	***Industrial***
Heating	**Interior Lighting**	**Lighting**
Cooling	**Exterior Lighting**	**HVAC**
Water Heating	**Refrigeration**	**Machine Drive**
Cooking	**Space Cooling**	**Process Heat**
Refrigerator	**Space Heating**	**Process Cool / Refrigeration**
Freezer	**Ventilation**	**Other Process**
Dishwasher	**Water Heating**	**Process – Machine Drive**
Clothes Washer	**Plug Loads / Office Equipment**	**Other Facility**
Dryer	**Cooking**	**Compressed Air**
Television	**Other**	**Water / Wastewater**
Light	**Whole Building / Behavioral**	**Process – Agriculture**
Miscellaneous		**Whole Building / Behavior**

Next, GDS developed a comprehensive list of energy efficiency technologies suitable for AES Indiana's market. The sector-level energy efficiency measure lists were informed by a range of sources including the Illinois Technical Resource Manual, current AES Indiana program offerings, measures included in other recent Indiana utility market potential studies, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with AES Indiana and stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process. The annual and lifetime energy and demand savings associated with decrement bundles is attached to this Report as Attachment 6-2. AES Indiana's MPS completed by GDS is attached to this Report as Attachment 6-3.

Achievable Potential Savings: Residential

Figure 6-67 below presents the MAP and RAP across the 19-year timeframe of the study. The purple and light blue bars on Figure 6-67 provide the respective incremental annual MAP and RAP as a percentage of the forecasted annual sales. The MAP rises to 23% and the RAP rises to 18% by 2042. Heating, Ventilation, and Air Conditioning ("HVAC") is the leading end-use, accounting for 37% of the total savings. The shell and water heating end-uses combine to account for an additional 36% of the RAP. The single-family housing segment represents 59% of the potential and the multifamily segment represents 20% of the potential. The new construction segment accounts for 10% of potential, and measures dedicated to low-income customers account for 11% of potential.

Figure 6-67: Residential MAP and RAP Results

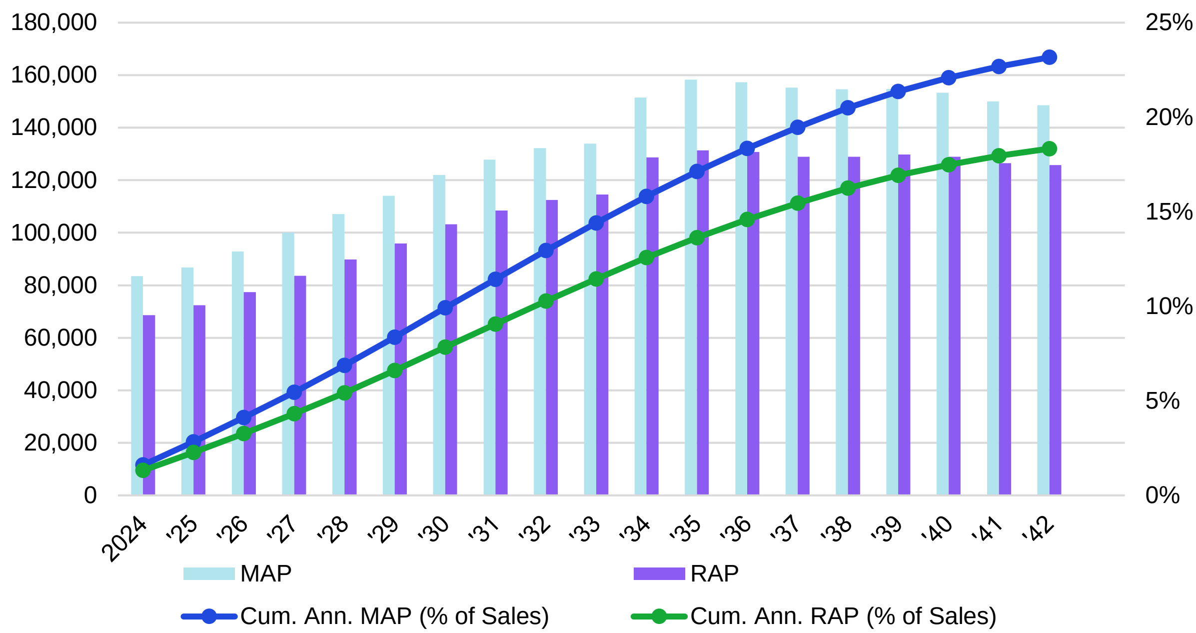


Figure 6-68 below shows the incremental and cumulative annual residential sector energy and demand savings for MAP and RAP across the next three years as well as over the 10-year and 19-year time horizons. Incremental RAP energy savings begin at roughly 68,600 MWh in 2024 followed by an increase over the next several years. Cumulative RAP energy savings rise to approximately 1.2 million MWh by 2042. These correspond to an overall UCT ratio in the RAP scenario of 1.17 and an overall UCT ratio in the MAP scenario of 0.95 due to the higher assumed incentive cost.

Figure 6-68: Incremental and Cumulative Annual Residential Sector MAP and RAP Energy and Demand Savings

	2024	2025	2026	2033	2042
			Incremental Annual Energy (MWh)		
MAP	83,453	86,756	92,822	133,956	148,545
RAP	68,585	72,355	77,385	114,551	125,716
			Incremental Annual Energy (MW)		
MAP	25.8	27.7	29.5	38.8	43.2
RAP	19.3	21.1	22.6	33.3	36.2
			Cumulative Annual Energy (MWh)		
MAP	83,453	147,566	216,208	816,496	1,457,663
RAP	68,585	118,341	171,696	648,357	1,153,791
			Cumulative Annual Energy (MW)		
MAP	25.8	50.9	77.5	293.0	486.5
RAP	19.3	37.9	57.7	229.1	394.2

Achievable Potential Savings: Commercial and Industrial

Figure 6-69 below provides the MAP and RAP for the C&I sector across the 19-year timeframe of the study. The purple and light blue bars provide the respective incremental annual MAP and RAP in MWh per year of energy savings. The green and orange lines provide the corresponding annual MAP and RAP as a percent of the forecasted annual sales. The MAP rises to 25% by 2042 and the RAP rises to approximately 20%. HVAC and lighting are the leading end-uses, accounting for 46% of the total RAP, with refrigeration, office equipment, and whole building end-uses combining to account for an additional 36% of RAP. The commercial sector represents 93% of the potential and the industrial sector represents the remaining 7% of the potential.

Figure 6-69: C&I MAP and RAP Results

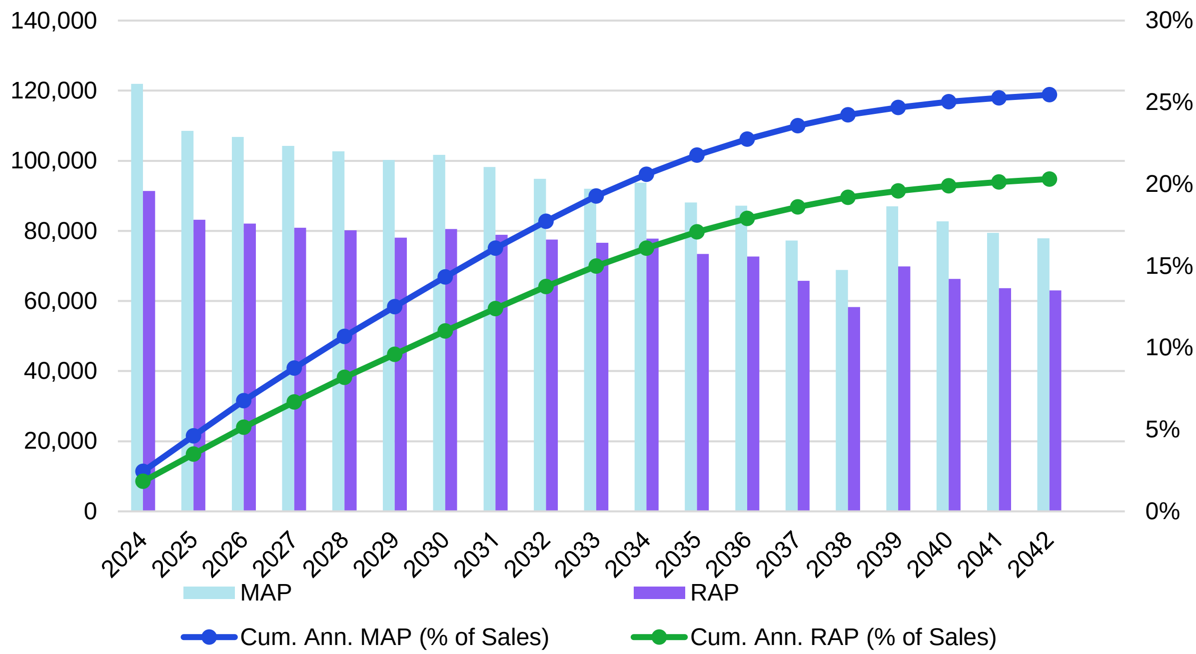


Figure 6-70 below provides the incremental and cumulative annual C&I sector energy and demand savings for MAP and RAP across the next three years as well as over the 10-year and 19-year time horizon. Incremental RAP energy savings begin at roughly 91,400 MWh in 2024 followed by an increase over the next several years. Cumulative RAP energy savings rise to approximately one million MWh by 2042.

Figure 6-70: Incremental and Cumulative Annual C&I Sector MAP and RAP Energy and Demand Savings

	2024	2025	2026	2033	2042
Incremental Annual Energy (MWh)					
MAP	121,920	108,570	106,840	92,060	77,940
RAP	91,365	83,157	82,103	76,579	63,010
Incremental Annual Energy (MW)					
MAP	21.8	22.5	22.4	19.6	15.5
RAP	16.3	16.6	16.5	14.4	11.8
Cumulative Annual Energy (MWh)					
MAP	121,920	230,491	337,295	969,667	1,313,569
RAP	91,365	174,522	256,589	754,309	1,048,015
Cumulative Annual Energy (MW)					
MAP	21.8	44.4	66.8	198.7	287.5
RAP	16.3	32.9	49.4	143.0	210.5

Interruptible Rate Program

One of the most prominent forms of demand response among non-residential customers is load curtailment agreements in which the utility enters financial agreements with businesses to reduce load when dispatched. Load curtailment potential is driven by a few key factors: incentive payments, the frequency of events, the duration of events, and the level of notification participants are given about pending events. GDS examined an interruptible rate program for demand response potential as part of the larger demand response potential study. The program would initially be offered as a pilot in 2026 and expand in the following years. GDS made several simplifying assumptions regarding program design. Components of program design include how many demand response events will be called, how long the demand response events will last, how far in advance participants are notified of the upcoming demand response event, and the incentive payment participants receive (i.e., the amount and how it is distributed – annually, monthly, per event, etc.).

GDS's previous Indiana research suggests relatively short curtailment demand response events would serve the region better than relatively long events, as summer peaks are concentrated between 2:00 PM and 6:00 PM. Thus, AES Indiana's estimates of potential assume a four-hour event duration. AES Indiana also assumes there will be an average of seven summer events called (28 total event hours for the summer).

Results were calculated for both a "day-ahead" notification design and a "day-of" notification design. "Day-ahead" notification assumes a 24-hour notice, and "day-of" notification assumes a 3- to 6-hour notice. Potential is higher under the "day-ahead" notification design, as this provides participants greater opportunities to shift energy-intensive tasks to off-peak periods

For C&I Curtailable demand response, the GDS team modeled the incentive as a reservation payment. This is an annual payment provided to the participant. In exchange, the participant agrees to curtail load when events are dispatched. For RAP, GDS's approach is to set incentive levels to optimize net benefits. To determine the optimal incentive level, the research team performed a simulation where the critical input was the incentive level and the critical output was the net benefit of the demand response program. The simulation leveraged several of the inputs discussed herein. The results indicated that the optimal incentive level in 2020 is $21 per kW-year.

For MAP, the goal of the simulation was not to optimize net benefits. Instead, GDS used the simulation to determine the greatest possible incentive level that would produce a cost effective program (e.g., largest incentive value such that the UCT ratio does not fall below one). The results indicated an incentive level of $39 per kW-year should be used in estimating MAP for summer 2020.

In both cases, the incentive level is escalated annually at a rate that matches the growth rate of avoided costs. This growth rate is largely driven by the generation component (avoided cost of generation capacity was provided by AES Indiana). Additional detail on the MAP and RAP of the curtailment program is provided in the demand response section below.

Demand Response

Figure 6-71 and Figure 6-72 below show the achievable cumulative annual potential savings for years one through three, 10, and 19. Achievable potential includes a participation rate to estimate the realistic number of customers that are expected to participate in each cost effective demand response program option. Here again, MAP is defined as the maximum participation that would occur under realistic assumptions, and RAP further considers additional barriers to program implementation and participation that would be expected to occur. Programs marked with an asterisk were those that were found not to be cost effective, and therefore do not provide any achievable potential. Two scenarios were evaluated for the curtailable rate program: day of notifications and day ahead notifications. The non-residential sector sub-totals and residential and non-residential combined totals reflect these two scenarios.

Figure 6-71: Demand Response MAP

Sector	Program	2024	2025	2026	2033	2042
Residential	Direct Load Control ("DLC") Air Conditioning – Switch	13	13	12	7	0
	DLC Air Conditioning - Thermostat	22	29	36	89	163
	DLC Space Heating	0	0	5	50	53
	DLC Water Heating	2	5	8	65	147
	DLC Electric Vehicles*	0	0	0	0	0
	DLC Room Air Conditioning*	0	0	0	0	0
	Battery Storage*	0	0	0	0	0
	Behavioral DR	0	0	2	14	9
	Time of Use with Enabling Technology	0	0	2	13	7
	Time of Use without Enabling Technology	0	0	1	8	5
	Sector Total	**38**	**47**	**66**	**247**	**385**
C&I	DLC Air Conditioning - Switch*	0	0	0	0	0
	DLC Air Conditioning - Thermostat	2	4	6	19	38
	DLC Space Heating	0	0	0	5	5
	DLC Water Heating	1	2	4	6	6
	Ice Storage Cooling Rate*	0	0	0	0	0
	DLC Lighting*	0	0	0	0	0
	Curtailable (Day Of)	0	0	34	68	70
	Curtailable (Day Ahead)	0	0	62	127	129
	Capacity Bidding	7	23	48	74	78
	Demand Bidding*	0	0	0	0	0
	Time of Use with Enabling Technology	0	0	1	7	3
	Time of Use without Enabling Technology	0	0	1	4	3
	Sector Total (Curtailable Day Of)	**9**	**29**	**94**	**184**	**203**
	Sector Total (Curtailable Day Ahead)	**9**	**29**	**122**	**242**	**263**
Residential & Non-Residential Total (Curtailable Day Of)		**48**	**76**	**160**	**430**	**588**
Residential & Non-Residential Total (Curtailable Day Ahead)		**48**	**76**	**188**	**489**	**648**

Figure 6-72: Demand Response RAP

Sector	Program	2024	2025	2026	2033	2042
Residential	DLC Air Conditioning – Switch	13	13	12	7	0
	DLC Air Conditioning – Thermostat	19	23	27	55	94
	DLC Space Heating	0	0	4	38	40
	DLC Water Heating	1	3	4	35	79
	DLC Electric Vehicles*	0	0	0	0	0
	DLC Room Air Conditioning *	0	0	0	0	0
	Battery Storage*	0	0	0	0	0
	Behavioral DR	0	0	1	9	8
	Time of Use with Enabling Technology	0	0	2	13	12
	Time of Use without Enabling Technology	0	0	1	8	7
	Sector Total	**34**	**39**	**50**	**166**	**241**
C&I	DLC Air Conditioning – Switch*	0	0	0	0	0
	DLC Air Conditioning – Thermostat	1	2	3	10	21
	DLC Space Heating	0	0	0	1	1
	DLC Water Heating	0	1	2	3	3
	Ice Storage Cooling Rate*	0	0	0	0	0
	DLC Lighting*	0	0	0	0	0
	Curtailable (Day Of)	0	0	18	36	36
	Curtailable (Day Ahead)	0	0	33	67	68
	Capacity Bidding	1	3	7	8	6
	Demand Bidding*	0	0	0	0	0
	Time of Use with Enabling Technology	0	0	1	7	5
	Time of Use without Enabling Technology	0	0	0	4	3
	Sector Total (Curtailable Day Of)	**2**	**6**	**30**	**69**	**76**
	Sector Total (Curtailable Day Ahead)	**2**	**6**	**45**	**99**	**107**
Residential & Non-Residential Total (Curtailable Day Of)		**36**	**45**	**81**	**235**	**317**
Residential & Non-Residential Total (Curtailable Day Ahead)		**36**	**45**	**96**	**265**	**348**

Industrial Electrification

GDS utilized data from NREL's Electrification Futures Study to estimate the possible impact of electrification growth in AES' industrial sector. The NREL study provides national-level estimates of industrial electrification, with NREL's reference case indicating zero industrial electrification. NREL's low and medium case envision nearly zero industrial adoptions of electrification. Only in NREL's high case does industrial electrification exhibit meaningful growth.

GDS began with AES' forecast of industrial sales across the forecast period. GDS notes that industrial electricity sales are approximately 15 percent of AES' total electricity sales, indicating that the industrial sector makes up a relatively small portion of AES' customer base, further suggesting caution at making assumptions for electrification for a specific service territory. To estimate the impact of NREL's high case for industrial electrification, GDS analyzed the NREL assumption regarding overall industrial load growth and removed the share of load growth already accounted for in AES' forecast. The remaining share was assumed to be driven by electrification. The growth occurs in the last decade of the forecast.

To model adoptions of industrial electrification and the resulting increase in electricity sales above the current forecast, GDS applied a compound annual growth rate that models the entire period's growth in industrial electrification. Three scenarios were developed to estimate the load impacts:

- → A high scenario that utilizes NREL's high case
- → A medium scenario that assumes two-thirds the growth of the high case occurs
- → A low scenario that assumes one-third the growth of the high case occurs

AES Indiana utilized the high industrial electrification case in the Decarb Economy Scenario.

6.4.5 Demand Side Management Bundles in Model

For the IRP Resource Selection Model to evaluate DSM on a consistent and comparable basis with supply-side resources, the DSM potential, defined by the MPS, needed to be disaggregated into smaller bundles with supply-side characteristics that act as model inputs. AES Indiana worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules, and fit the EnCompass Model requirements.

AES Indiana used the realistic achievable potential identified in the MPS as the starting point for developing energy efficiency bundles to be modeled in the IRP. GDS provided the energy efficiency IRP inputs across three sector categories (residential, income-qualified, and C&I). The residential and C&I bundles were modeled as selectable resources in the EnCompass Model. The income-qualified bundle was treated as a 'going-in' resource, as the high costs of program delivery would likely prevent its selection in the IRP, and AES Indiana anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost effectiveness.

In addition to the sector segmentation, the three difference vintage bundles, 2024-2026, 2027-2029, and 2030-2042, allow the model to optimize the value of energy efficiency over different time periods. The first vintage (2024-2026) was designed to align with AES Indiana's next DSM program planning period, and the energy efficiency achievable potential was grouped into program bundles that are similar to AES Indiana's current portfolio of DSM programs. The second and third time-vintages (2027-2029 and 2030-2042) were provided at the aggregate sector level to minimize the risk that the IRP would only select low-cost measures in the future, thereby limiting AES Indiana's ability to offer a comprehensive set of programs. Following a review of these initial cost and savings inputs, GDS further segmented the residential sector savings into high-cost measures (Tier 2) and low- and mid-cost measures (Tier 1) across each vintage time-series. Figure 6-73 below shows possible programs to be included in each vintage bundle.

Figure 6-73: Possible Programs to be Included in Each Vintage Bundle

Vintage 1 (2024-2026)	Vintage 2 (2027-2029)	Vintage 3 (2030-2042)
1. Residential Efficient Products (Low/Medium Cost Measures) 2. Residential Efficient Products (High-Cost Measures) 3. Residential Behavioral 4. Residential School Education 5. Residential Appliance Recycling 6. Residential Multifamily 7. C&I Prescriptive 8. C&I Custom 9. C&I Custom Retro-commissioning 10. C&I Custom SEM 11. Income-Qualified	1. Residential Sector (Low/Medium Cost Measures) 2. Residential (High-Cost Measures 3. C&I Sector 4. Income Qualified	1. Residential Sector (Low/Medium Cost Measures) 2. Residential (High-Cost Measures 3. C&I Sector 4. Income Qualified

In addition, two adjustments to the MPS realistic achievable energy efficiency potential savings and one direct adjustment to costs were necessary prior to inclusion in AES Indiana's IRP analysis. The first adjustment converted the energy efficiency achievable potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of AES Indiana's programs. Net savings were calculated by applying AES Indiana's most current net-to-gross ratios from the AES Indiana 2021 DSM Portfolio Summary to the MPS estimates of gross achievable savings.

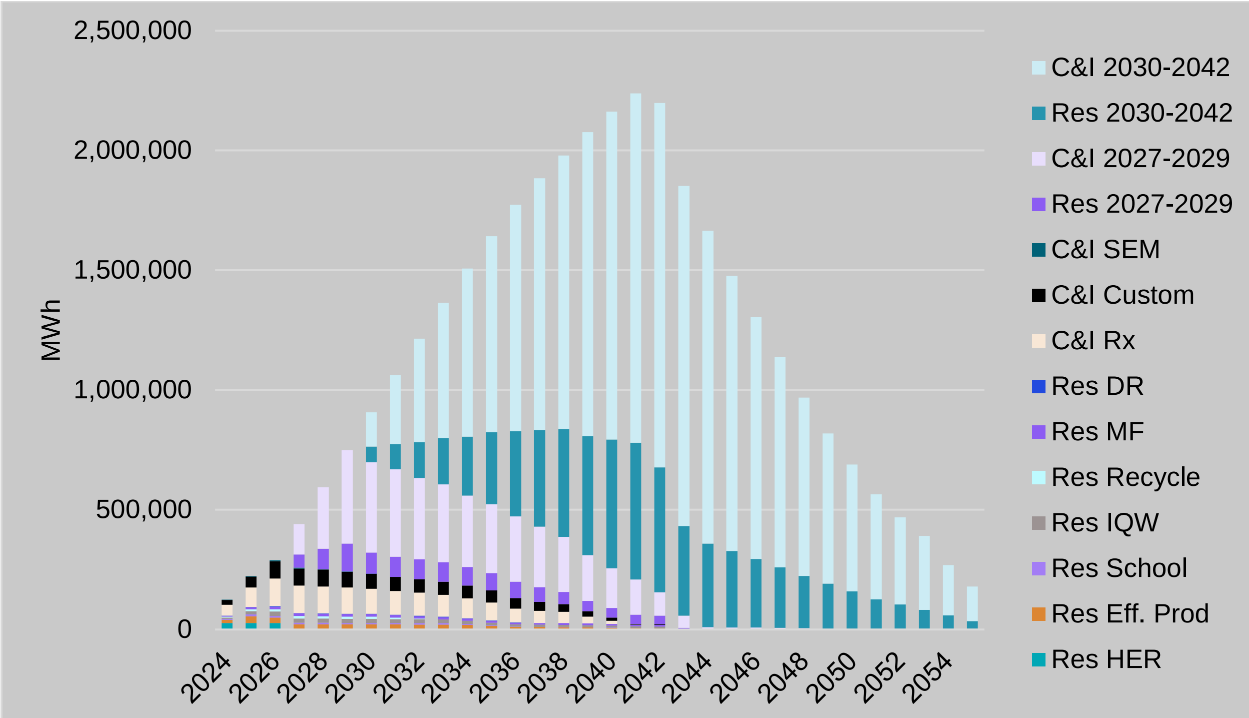
Due to small annual differences in the mix of energy efficiency measures included in the realistic achievable scenario and associated net-to-gross ratios, the energy efficiency impacts modeled in the IRP ranged from 84% of the gross realistic achievable potential identified in the MPS in 2024 to 83% in 2042.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on Company line losses to convert savings from the meter level up to the generator level.

On the cost side, because the IRP's EnCompass Model does not calculate the avoided T&D benefits associated with DSM measures, GDS provided AES Indiana with energy efficiency bundle costs that have been adjusted to net out the avoided NPV lifetime T&D benefit based on the project MW savings of the respective vintage-based bundles.

The energy efficiency impacts provided to AES Indiana for IRP modeling, by vintage block, are summarized in Figure 6-74. Additional annual detail by program (Vintage 2024-2026) and by sector (Vintage 2027-2029 and 2030-2042) are provided in detail in Attachment 6-3. As shown in the tables provided in Attachment 6-3, the impacts for each vintage block provide cumulative annual lifetime savings. Conversely, because EE program costs only occur during the year of measure installation, budgets align more directly with the specified vintage timeframes.

Figure 6-74: Summary of EE IRP Bundle Savings



Note: Acronyms used in Figure 6-73: Efficiency Products ("Eff. Prod"); Home Energy Report ("HER"); Income Qualified Weatherization ("IQW"); Multifamily ("MF"); Prescriptive ("Rx"); and Strategic Energy Management ("SEM").

In addition to the annual impacts shown in Figure 6-74, hourly (or 8,760) shapes that reflect the various measures and end-use mix reflected in each EE resource bundle were provided to AES Indiana to permit the EnCompass Model to assess the value of energy savings on an hourly basis. These 8,760 shapes were based on residential and commercial end-use load shapes for Indiana from NREL's End-Use Load Profiles database. The ultimate 8,760 shapes are unique for each EE sector and vintage bundle.

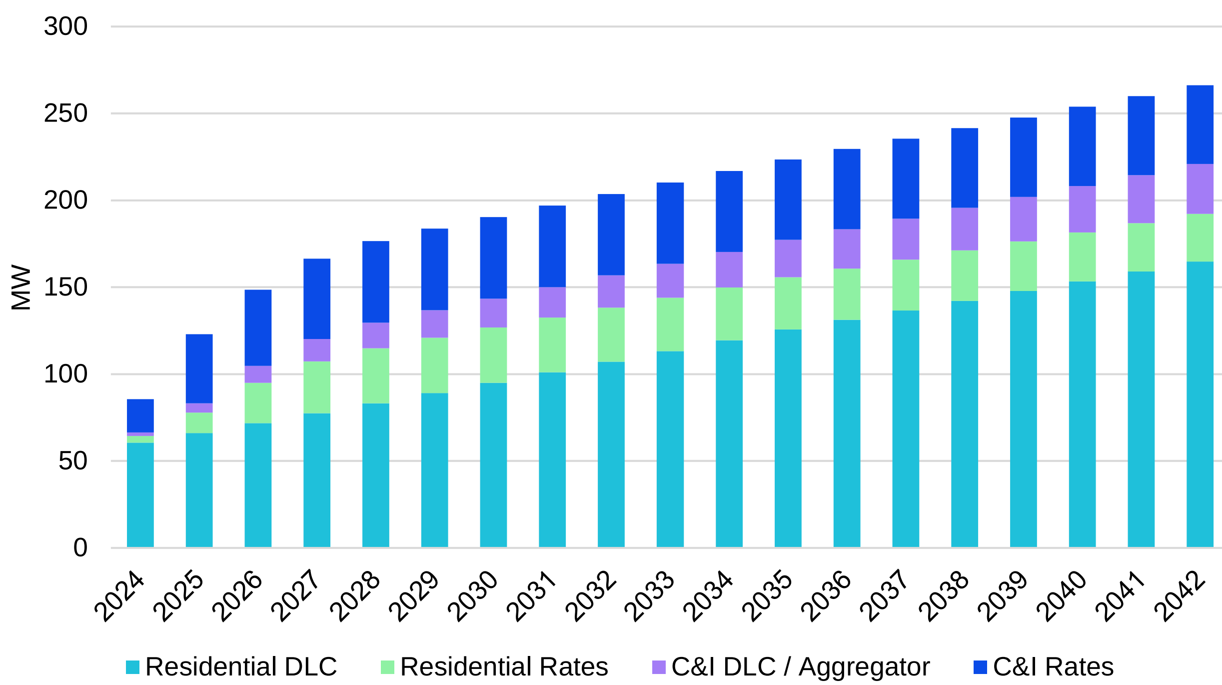
In the IRP modeling, AES Indiana also considered demand response alongside other supply resources to supply capacity needs. Levels of DR potential associated with the realistic achievable potential scenario from the MPS were provided as inputs to the EnCompass Model. Demand response savings were divided into four bundles based on sector and resource type (i.e., direct load control or DR rates). Figure 6-75 provides the DR inputs used in the IRP modeling.

Figure 6-75: Demand Response Inputs Used in the IRP Modeling

Bundle 1 – Residential DLC	Bundle 2- Residential Rates	Bundle 3 – C&I DLC / Aggregator	Bundle 4 – C&I Rates
DLC AC Switch DLC AC Thermostat DLC Electric Vehicles	Time of Use Rate Behavioral DR	DLC AC Thermostat DLC Water Heating Capacity Bidding	Time of Use Rate Interruptible Rate

Summer demand impacts (in MW) are shown but select DR programs provide opportunities for capacity savings in other seasons, and these impacts were considered in AES Indiana's 2022 EnCompass Model. In general, the analysis assumed that demand response programs are net neutral with regard to annual energy (MWh) impacts. As with the EE inputs, the costs were adjusted to represent programs costs less the avoided NPV lifetime T&D benefit from the programs. Due to the annual accrual of savings and costs for DR programs, it was not necessary to develop distinct vintage bundles of DR. However, the IRP model did assess DR over the same three defined time periods as the energy efficiency input bundles. Annual demand response savings and costs, by bundle, are provided in Attachment 6-3. Figure 6-76 provides the annual demand response savings by bundle.

Figure 6-76: Annual Demand Response Savings by Bundle



6.4.6 Avoided Cost Calculation

170 IAC 4-7-4(29) and 170 IAC 4-7-6(b)(2)(B)

To screen DSM measures for cost effectiveness in the MPS analysis, GDS used avoided energy, capacity and T&D costs to monetize savings associated with the measures. AES Indiana provided GDS these avoided cost assumptions in April 2022. As detailed further below, the avoided cost values for energy and capacity are driven by fundamental forecasts from Horizons Energy and are intended to align with the commodity assumptions used in the IRP modeling. However, in June 2022, AES Indiana had Horizon Energy update the commodities for the IRP modeling to include the most contemporary fundamental price curves given the ongoing market volatility. These updates occurred after GDS had performed the DSM screening in the MPS and were therefore not included in their analysis. AES Indiana anticipates that these updates would have had a very minor impact on the DSM that was modeled in the IRP had GDS had sufficient time to include them in the screening. Confidential Attachment 6-4 includes the avoided cost assumptions that GDS used for the DSM screening in the MPS (see sheet titled "MPS Avoided Costs") and the final commodities used in the IRP Current Trends/Reference Case modeling (see sheet titled "Final Current Trends Com Inputs"). For purposes of calculating cost effectiveness in DSM filings that are driven by the outcome of this IRP, the IRP Current Trends/Reference Case inputs (see sheet titled "Final Current Trends Com Inputs") should be used to remain consistent with the assumptions used for the DSM selections in the IRP analysis. The Current Trends/Reference Case scenario commodity calculations are discussed in more detail in Section 8.4.1.

Section 2 AES Indiana provided GDS with annual on- and off-peak avoided energy costs from Horizons Energy custom fundamental forecast (April 2022). GDS used this data to create 8,760 hourly avoided cost values for each forecast year. GDS then applied these avoided costs to the 8,760 savings from each measure based on assigned end-use load shapes[46] to determine the value of measures that save more energy during peak periods than those that might saving during off-peak periods.

Section 3 In addition, GDS used avoided capacity cost from Horizons Energy custom fundamental forecast (April 2022) and T&D avoided costs to estimate coincident peak demand savings for each measure.

Transmission and distribution avoided costs were calculated based upon avoiding upgrades to circuits that may be needed to serve additional load. The transmission costs are assumed to be negligible due to the robust interconnections of the 34 kV and 138 kV systems. Significant upgrades are not needed for load growth. The majority of recent transmission and substation projects focus on integrating new generating resources and mitigate import limitations, not load growth. A proxy value of 10% of the avoided distribution costs was included in the avoided cost calculation for potential avoided transmission costs.

[46] End-use load shapes were derived from building energy simulation models created by housing type and building type, specific to the AES Indiana service territory.

The distribution costs were calculated based on an equally weighted average costs to build new overhead and underground circuits to serve 10 MW which is the standard circuit capacity design. The cost per mile was divided by the circuit capacity of 10 MW or 10,000 kW to arrive at a cost per kW. Annual fixed charges were calculated based on this cost times the levelized fix charge rate in AES Indiana's most recent Rate GCS filing. The sum of these costs were multiplied by 20% to reflect the approximate number of the distribution circuits that would likely require upgrades based on current circuit loading.

In future IRPs, the Company aspires to use Integral Analytics' LoadSEER to quantify the time and locational avoided costs associated with DSM. This type of analysis will help identify particular circuits that may benefit from DERs and DSM. See the Distribution System Planning section (Section 4) for more detail regarding LoadSEER.

6.5 Rate Design

170 IAC 4-7-4(16) and 170 IAC 4-7-6(b)(1)

Rate design is typically considered in the context of a rate case but could also be addressed in other proceedings in order to allow other parties, commission staff, and commissioners to evaluate the reasonableness of such proposals. In the context of an IRP, rate design is important because it can impact and drive changes in system peak demand and customer usage. In this IRP, AES Indiana used potential rate designs to shift demand through the selectable demand response bundles. See Section 6.4.5 for more information on AES Indiana selective demand response bundles.

As the energy industry evolves through increasing adoption levels of emerging technologies, such as DERs, EVs, and overall electrification, uncertainty in electric demand, supply, and use is increasing. Rate design is becoming an increasingly important tool of utility regulation and resource planning to manage this increasing uncertainty. Rate design can strategically impact the manner and time in which electricity is supplied and used, thus providing greater certainty to the impacts created by emerging technologies. Further, AMI technology and the associated data will allow AES Indiana to increase its understanding of its load characteristics and bolster the effectiveness of the strategic rate design AES Indiana may seek in future rate cases or other relevant proceedings. See Section 4.3.2 for more information on AES Indiana's AMI program.

AES Indiana plans to evaluate rate design alternatives, including interruptible tariffs. AES Indiana considers and reviews rate design options, which include appropriate cost of service and recovery mechanisms and encompass innovative approaches. Through its current energy efficiency programs, demand response programs, Rate CGS, curtailable energy riders, and load displacement rider, AES Indiana employs a range of rate options.

Section 7: Environmental Considerations

170 IAC 4-7-4(23) and 170 IAC 4-7-6(a)(4)

7.1 Environmental Overview

Environmental regulations significantly affect AES Indiana's resource planning efforts due to their dynamic and, in many cases, uncertain nature. The majority of these regulations are promulgated by EPA and enforced by EPA or the Indiana Department of Environmental Management ("IDEM"). AES Indiana stays informed of proposed and final rules and determines their effects on Company assets and customer impacts. The most significant changes in recent history focus on fossil fuel-fired plants. AES Indiana's natural gas-fired Eagle Valley CCGT was designed in accordance with the most up-to-date regulations to ensure compliance. This section of the IRP focuses on compliance aspects of environmental regulations.

The most relevant recent activities related to environmental regulations include the following:

- → Revisions and actions have followed and remain under development related to EPA's finalized 2015 regulations for Coal Combustion Residuals ("CCR") regulating CCRs as a solid waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA").
- → In August 2020, AES Indiana reached a settlement in the form of a Consent Decree with EPA, the U.S. Department of Justice ("DOJ"), and IDEM resolving alleged violations of the Clean Air Act ("CAA") with respect to the coal-fired generation at Petersburg Generating Station.
- → In August 2021, IDEM updated its water quality criteria for specific metals, including selenium, to reflect EPA's 2016 criterion.
- → In April 2021, EPA issued a final rule addressing CAA "good neighbor" obligations related to the 2008 National Ambient Air Quality Standard ("NAAQS") for ozone. Then, in April 2022, EPA proposed a rule addressing "good neighbor" obligations related to the 2015 ozone NAAQS.

Some of these rules have required additional investments for compliance, and some rules may require future investments. Planning for compliance with environmental regulations can be complicated due to uncertainty surrounding the final outcome of the regulations and their impacts, including timing as well as potential legal and legislative activity.

These types of uncertainties and environmental regulations are incorporated into AES Indiana's IRP process and discussed in detail later in this section following a review of the existing environmental rules and regulations.

7.2 Existing Environmental Regulations

Existing environmental regulations associated with air emissions, water, and wastes that impact AES Indiana's resources are described below.

7.2.1 Air Emissions

170 IAC 4-7-4(21)

AES Indiana is subject to various regulations related to air emissions.

In response to Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), AES Indiana developed an Acid Rain Compliance Plan that was submitted to the IURC on July 1, 1992, (IURC Cause No. 39437) and subsequently approved on August 18, 1993 ("39437 Order").[47] This plan called for the installation of SO2 retrofit Flue Gas Desulfurization ("FGD") units on Petersburg Units 1 and 2. These FGD units were placed in-service in 1996. FGD is the technology used for removing SO2 from the exhaust flue gases from coal-fired power plants.

Thereafter, SO2 regulations remained relatively unchanged as did AES Indiana's compliance plan until March 10, 2005, when EPA issued Clean Air Interstate Rule ("CAIR"), which established a regional cap-and-trade program for SO2 and NOx. Phase I of CAIR for SO2 had an effective date of January 1, 2010 and Phase II of CAIR was scheduled to become effective on January 1, 2015.

In anticipation of this CAIR regulatory program and to help meet the existing CAAA regulatory requirements, AES Indiana developed a Multi-Pollutant Plan ("MPP"). AES Indiana's MPP was submitted to the IURC on July 29, 2004, (IURC Cause No. 42700), in which AES Indiana requested approval of certain core elements of the plan. AES Indiana's MPP was initially approved on November 30, 2004. In order to reduce SO2 emissions, AES Indiana completed the Petersburg Unit 3 FGD enhancement by May 2006 and the new HSS Unit 7 FGD by September 2007. AES Indiana also identified the enhancement of the Petersburg Unit 4 FGD as a core element of its MPP and completed the Petersburg Unit 4 FGD upgrade project (IURC Cause No. 43403, approved April 2, 2008) in 2011 to help meet the additional SO2 emission reduction requirements. AES Indiana met the CAIR requirements for SO2 upon completion of these projects and by supplementing its compliance plan with the purchase of emission allowances on the open market as needed.

As a result of legal proceedings related to CAIR, EPA issued a final replacement rule, known as Cross State Air Pollution Rule ("CSAPR") in July 2011. Following resolution of legal proceedings, CSAPR became effective on January 1, 2015, and CAIR ceased to apply at that time. Phase II of

[47] The 39437 Order was subsequently reversed by the Court of Appeals and the matter was remanded by the Commission. *General Motors Corporation et al v. Indianapolis Power & Light Company*, 654 N.E. 2d 752 (Ind. Court of Appeals. June 30, 1995). While the appeal was being heard, AES Indiana, on April 8, 1994, filed a general rate case (IURC Cause No. 39938) which was ultimately resolved by settlement ("39938 Settlement). In the 39938 Settlement, the parties committed to take no further action to oppose the affirmative relief sought by AES Indiana as approved in the Commission August 8, 1993 Order. Following IURC approval of the 39938 Settlement, the remand proceeding was dismissed. See Order in Cause No. 39437 dated August 21, 1996.

CSAPR became effective on January 1, 2017. AES Indiana meets CSAPR requirements through the operation of its existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and AES Indiana plans to continue to comply with Phase II of CSAPR using these measures.

Additional SO2 requirements and compliance plans are discussed below under NAAQS.

Oxides of Nitrogen (NOx)

In order to meet more stringent NOx emission reduction requirements, which became effective in 2004 related to the NOx State Implementation Plan ("SIP") Call, AES Indiana installed Selective Catalytic Reduction ("SCR") equipment on Petersburg Generating Station Units 2 and 3 and HSS Unit 7 along with several low NOx Clean Coal Technology ("CCT") projects on other units. The Petersburg SCR units commenced operations in May 2004, whereas the HSS Unit 7 SCR came online in May 2005.

As previously discussed, EPA issued CAIR in May 2005, which was subsequently replaced by CSAPR requirements. On September 7, 2016, EPA finalized the CSAPR Update Rule, which established NOx reductions during ozone season for 22 states, including Indiana, to address downwind attainment with the 2008 Ozone NAAQS of 75 parts per billion (“ppb”). Following legal challenges related to the CSAPR Update Rule, on April 30, 2021, EPA issued the Revised CSAPR Update Rule, which required Electric Generating Units (“EGU”) in certain states, including Indiana, to participate in a new trading program. These affected EGUs received fewer ozone season NOx allowances beginning in 2021. At this time, it is uncertain whether future revisions to CSAPR could further impact AES Indiana’s NOx emissions limits.

AES Indiana currently meets requirements for NOx through the operation of existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and currently plans to continue to comply using these measures.

Regional Haze

EPA’s 1999 Regional Haze Rule established timelines for states to improve visibility in national parks and wilderness areas by establishing reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064 through submittal of a series of State Implementation Plans (“SIP”). Indiana’s SIP for the first planning period (through 2018) did not require any additional controls to be installed or operated on AES Indiana’s generating facilities. For all future SIP planning periods, states must evaluate whether additional emissions reduction measures may be needed to continue making reasonable progress toward natural visibility conditions. The deadline for submittal of the SIP covering the second planning period was extended to July 31, 2021. While Indiana did not meet this deadline, on December 30, 2021, IDEM submitted the Draft Indiana Regional Haze SIP for the Second Implementation period to EPA. The draft SIP does not include additional requirements for AES Indiana EGUs or other EGUs in Indiana. However, it remains uncertain whether the final outcome of a revised Regional Haze SIP could result in more stringent emissions limitations for AES Indiana.

Mercury and Air Toxics Standard ("MATS")

In February 2012, EPA issued the final MATS Rule, which placed stringent emission limits on Hazardous Air Pollutants ("HAP"), as defined in Section 112 of the CAA.

AES Indiana developed a MATS Compliance Plan, which included activated carbon injection and sorbent injection for mercury control and upgraded FGDs for acid gas control on all coal-fired units. The Plan also included upgraded electrostatic precipitators on Petersburg Units 1 and 4, and Harding Street Unit 7, in addition to baghouses on Petersburg Units 2 and 3 for particulate and mercury control. In development of AES Indiana's MATS Compliance Plan, it also was determined that installation of the necessary controls was not economical for the smaller, less controlled units, Eagle Valley Units 3-6, and Harding Street Units 5 and 6.

AES Indiana received IURC approval in IURC Cause No. 44242 to proceed with its MATS Compliance Plans, and the construction of controls at Petersburg was completed. However, it was later determined when considering new National Pollutant Discharge Elimination System ("NPDES") requirements and other potential future environmental regulations for HSS Unit 7 that the MATS controls were no longer the reasonable least cost solution. AES Indiana received IURC approval in Cause No. 44540 to convert HSS Unit 7 from coal to natural gas instead of pursuing the previously approved retrofit. See Section 7.2.2 below for more detail on NPDES requirements.

National Ambient Air Quality Standards

EPA is required under the CAA to set NAAQS for air pollutants that endanger public health or welfare. There are several NAAQS, but typically three directly impact fossil-fuel fired power plants: SO2, ozone, and particulate. NAAQS do not directly limit emissions from utilities, but states must develop SIPs to achieve emissions reductions to address each NAAQS when an area is designated as nonattainment. EPA reviews NAAQS and the science on which they are based on a five-year basis. This review process includes gathering input from the scientific community and the public, an integrated science assessment, a risk and exposure assessment, and a policy assessment.

On June 22, 2010, EPA revised the NAAQS for SO2 from 140 ppb on 24-hour basis to 75 ppb on a one-hour basis. The areas in which Harding Street, Eagle Valley, and Petersburg operated were designated as nonattainment with the lowered standard. As a result, IDEM developed a SIP to address the 2010 SO2 NAAQS, and on September 30, 2015, published revisions to 326 IAC § 7-4-15 establishing new and more stringent emission limits for Petersburg Units 1-4 with compliance required by January 1, 2017. Measures needed to enhance the performance and integrity of the FGD systems at Petersburg in order to meet these more stringent limits were approved by the IURC in IURC Cause No. 44794. On August 7, 2019, IDEM issued a Notice and Order of the Commissioner, as a result of an updated evaluation implementing the revised SO2 emissions limitations (i.e., 30-day rolling average) which became effective on September 24, 2019. As required, AES Indiana has been complying with these limits since they became effective through the operation of pollution controls equipment.

Currently, the counties in which AES Indiana operates fossil-fuel power generation facilities are all currently designated as attainment for all air pollutants.

New Source Review

On August 31, 2020, AES Indiana reached a settlement with EPA, the DOJ, and IDEM resolving the purported violations of the CAA and alleged in NOVs issued by EPA in 2009, 2015, and 2016, with respect to the coal-fired generation units at AES Indiana's Petersburg Generating Station. The alleged violations were included in NOVs AES Indiana received in 2009, 2015, and 2016. The settlement agreement, in the form of a proposed judicial consent decree, was approved and entered by the U.S. District Court for the Southern District of Indiana on March 23, 2021, and includes, among other items, the following requirements: annual caps on NOx and SO2 emissions and more stringent emissions limits than AES Indiana's prior Title V air permit; payment of civil penalties totaling $1.525 million (the payment of which was satisfied by AES Indiana in April 2021); a $5 million environmental mitigation project consisting of the construction and operation of a new, non-emitting source of generation at the site; expenditure of $0.325 million on a state-only environmentally beneficial project to preserve local, ecologically-significant lands; and retirement of Petersburg Units 1 and 2 prior to July 1, 2023. If AES Indiana does not meet this retirement obligation, it would be required to install a Selective Non-Catalytic Reduction (“SNCR”) on Petersburg Unit 4.

Existing Controls to Reduce Air Emissions

As shown in Figure 7-1 below, AES Indiana has already installed environmental pollution control equipment at its facilities.

Figure 7-1: AES Indiana's Existing Pollution Control Equipment

Unit	Fuel	Summer Output (MW)	Environmental Controls
Petersburg Unit 1	Retired 2021	232	Retired 2021
Petersburg Unit 2	Coal	435	FGD, SCR, LNB/OFA, ESP, ACI, SI
Petersburg Unit 3	Coal	540	FGD, SCR, BH, ACI, SI
Petersburg Unit 4	Coal	545	FGD, NN, LNB, ESP, ACI, SI
Petersburg DG	Diesel	8	
HSS Unit 5	Natural Gas	100	
HSS Unit 6	Natural Gas	100	
HSS Unit 7	Natural Gas	430	SCR
HSS CTs 1-2	Oil	60	
HSS CT 4	Oil/Natural Gas	82	Water injection
HSS CT 5	Oil/Natural Gas	82	Water injection
HSS CT 6	Natural Gas	158	LNB
HSS DG	Diesel	3	
Georgetown GT1	Natural Gas	79	LNB
Georgetown GT2	Natural Gas	79	LNB

Note: Acronyms used in Figure 7-1: Activated Carbon Injection ("ACI"); Electrostatic Precipitator ("ESP"), Flue Gas Desulfurization (FGD), Low NOx Burner ("LNB"), Neural Net ("NN"), Overfire Air ("OFA"), Selective Catalytic Reduction ("SCR"), Sorbent Injection ("SI"), and Selective Non-Catalytic Reduction (SNCR).

7.2.2 Water Standards

The NPDES permit program obtains its authority from Clean Water Act ("CWA"). Section 402 requires permits for the direct discharge of pollutants to the waters of the U.S. These permits, which AES Indiana maintains for Harding Street, Eagle Valley CCGT, and Petersburg have three main components: technology based and water quality based effluent limitations; monitoring requirements; and reporting requirements. The AES Indiana facilities' NPDES permits are in the process of being renewed. IDEM may determine that new or revised water quality-based or technology-based limits apply or that additional parameter specific monitoring and reporting may be required.

Effluent limitations identify the nature and amount of specific pollutants that facilities may discharge from regulated outfalls, which are identified by unique numbers and internal wastewater streams as defined by 40 CFR Part 423. Currently, the NPDES permits require that the outfalls be monitored regularly for specified parameters.

In 2012, the IDEM issued NPDES permit renewals to Petersburg and Harding Street containing new Water Quality Based Effluent Limits ("WQBEL") and Technology-Based Effluent Limits ("TBEL") for the regulated facility NPDES discharges with a compliance date of October 1, 2015 for the new WQBELs, which was later extended. New metal limits drove the need for additional wastewater treatment technologies at Petersburg and Harding Street. However, AES Indiana determined the installation of the necessary wastewater treatment technologies and other potential future environmental requirements in addition to the necessary MATS controls described in AES Indiana's case-in-chief in IURC Cause No. 44242 were no longer the reasonable least cost plan for Harding Street. Instead, AES Indiana obtained approval in Cause No. 44540 to convert HSS Unit 7 to operate using natural gas, which reduced the cost to comply with environmental regulations and reduced the impact on the environment. AES Indiana also received approval of wastewater treatment systems necessary to comply with the new limits in the 2012 NPDES permit renewals in AES Indiana's IURC Cause No. 44540. For Petersburg Generating Station, this included dry fly ash handling, zero liquid discharge systems for FGD wastewater, and a tank-based treatment system of other wastewaters generated at Petersburg.

On November 3, 2015, EPA published the final revisions to the Effluent Limitations Guidelines ("ELG") Rule. The revised ELG regulations require dry fly ash handling, dry or closed-loop bottom ash handling, and apply numerical limits on FGD Wastewater. Eagle Valley CCGT and Harding Street no longer generate these wastewater streams as they have ceased coal combustion. Petersburg Generating Station will comply with the dry fly ash handling and limits on FGD Wastewater as a result of the NPDES Wastewater treatment project in IURC Cause No. 44540. In addition, the ELG will require dry or closed-loop bottom ash handling at Petersburg with compliance required by a date to be specified by the NPDES permitting authority that is between November 1, 2018, and December 31, 2023. Petersburg will comply with this ELG requirement as a result of the closed-loop bottom ash dewatering system included in the Compliance Project in IURC Cause No. 44794 and described below for compliance with the CCR Rule. Following legal challenges to the 2015 ELG Rule, in 2020, EPA issued the ELG Reconsideration Rule, which did not have a significant impact on AES Indiana. Additional legal challenges are pending and further revisions to the ELG Rule are possible.

In addition to establishing effluent limits, the NPDES permit also includes compliance requirements with Section 316(a) and Section 316(b) of CWA and water quality criteria. Sections 316(a) and 316(b) and revised Selenium water quality criterion are described below.

Clean Water Act Section 316(a)

327 IAC 5-7 and Section 316(a) of the CWA authorizes the NPDES permitting authority, IDEM, to impose alternative effluent limitations for the control of the thermal component of a discharge in lieu of the effluent limits that would otherwise be required under sections 301 or 306 of the CWA. Regulations implementing Section 316(a) are codified in 40 CFR Part 125, subpart H. These regulations identify the criteria and process for determining whether an alternative effluent limitation (i.e., a thermal variance from the otherwise applicable effluent limit) may be included in an NPDES permit and, if so, what that limit should be. This means that before a thermal variance can be granted, the permittee must demonstrate that the otherwise applicable thermal discharge effluent limit is more stringent than necessary to assure the protection and propagation of the waterbody's Balanced Indigenous Population ("BIP") of shellfish, fish, and wildlife. If the variance study determines there is an impact, AES Indiana Petersburg may need to employ additional thermal reduction technology, such as closed cycle cooling in order to meet the temperature water

quality standards. AES Indiana is currently in the process of conducting thermal studies at the Petersburg and Harding Street facilities based on guidance developed by IDEM, which includes conducting comprehensive monitoring programs for temperature in the waterbody, conducting comprehensive monitoring programs to delineate the thermal discharge plume in the receiving waterbody, and conducting biological community assessments. The results of these studies are included in the Section 316(a) demonstration submitted to IDEM. Petersburg submitted its Section 316(a) demonstration to IDEM in December 2017. Harding Street submitted its Section 316(a) demonstration to IDEM in December 2019. If AES Indiana is unable to obtain an acceptable Section 316(a) variance based on the submitted demonstrations, Indiana thermal water quality standards would apply. In this scenario, the potential impact could be similar to the range of impacts described under Section 316(b) and will be included in subsequent IRP analyses.

Cooling Water Intake Structures – Clean Water Act Section 316(b)

Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of Cooling Water Intake Structures ("CWIS") reflect the best technology available for minimizing adverse environmental impacts. Specifically, the Section 316(b) is intended to reduce the impacts to aquatic organisms through impingement and entrainment due to the withdrawal of cooling water by facilities. On August 15, 2014, EPA published a final rule which would set requirements that establish the Best Technology Available ("BTA") to minimize these impacts.

The entrainment BTA could be determined to be closed cycle cooling systems or significant modifications to the intake structure itself. Alternatively, utilities could be faced with installing less costly controls, such as modified travelling screens and fish handling and return systems to address impingement BTA. One of the three EGUs at Harding Street is currently equipped with closed cycle cooling systems. Petersburg Units 3 and 4 currently employ closed cycle cooling systems as well. The impact of this rule will be dependent upon IDEM's determination for impingement and entrainment BTAs for both Petersburg and Harding Street.

7.2.3 Solid Waste Standards

The solid waste generated at AES Indiana's power plants is classified as either non-hazardous waste or hazardous waste. AES Indiana generates hazardous and non-hazardous waste with the handling of both waste streams regulated under the Resource Conservation and Recovery Act ("RCRA").

Hazardous Waste

Hazardous waste is regulated under RCRA Subtitle C. There are three categories of hazardous waste generators for industry with each category having its own scope of regulations that must be met. The more hazardous waste that is generated, the higher the risk to the environment, hence the more regulation and oversight is imposed.

The three categories of hazardous waste are: 1) Large Quantity Generator ("LQG"); 2) Small Quantity Generator ("SQG"); and 3) Very Small Quantity Generator ("VSQG"). AES Indiana's generating plants are historically categorized as SQG and VSQG. As such, AES Indiana faces relatively minimal regulations and risk in this area.

Non-Hazardous Waste

Solid waste is regulated under Subtitle D of RCRA. AES Indiana's coal-fired operations have historically generated a large amount of solid waste every year that must be handled in accordance with this regulation. The primary sources of non-hazardous waste in the coal-fired steam electric industry are fly ash and bottom ash generated from coal combustion, and scrubber sludge or gypsum resulting from the FGD process.

Ash was historically placed in ponds for treatment via sedimentation, from which the effluent is regulated pursuant to NPDES. Ash dredged from the ponds has historically been shipped back to mines or otherwise beneficially used in an environmentally sound manner. In addition, fly ash has been mixed with dewatered scrubber sludge and lime to make a stabilized product, which is disposed of in a permitted, on-site landfill at Petersburg. Further, the Petersburg Units 2 and 4 (and Petersburg Unit 1 prior to retirement and HSS Unit 7 FGD prior to conversion to natural gas), produce commercial grade gypsum from FGD operations that can be beneficially used for wallboard manufacturing, cement manufacturing, and agricultural use. In general, ash management activities did not change for several years.

On April 17, 2015, EPA published the final CCR Rule, which regulates CCR as non-hazardous waste under Subtitle D of the RCRA. The CCR Rule establishes national minimum criteria for existing CCR surface impoundments (ash ponds), including location restrictions, structural integrity, design and operating criteria, groundwater monitoring and corrective action, closure requirements, and post closure care. Failure to demonstrate compliance with the national minimum criteria results in the requirement to cease use of and close existing active ponds within five years, with potential for extensions, as needed. In 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act authorized states to establish CCR permitting programs and required EPA to establish a program for states that do not adopt one. AES Indiana Petersburg was unable to successfully demonstrate compliance with certain safety factor requirements set forth in the CCR rule at Petersburg, which are required to maintain operation of the ponds. As a result, AES Indiana has removed the ponds from service and made modifications to handle the material that was previously sent to the ash ponds. Specifically, as approved in IURC Cause No. 44794, AES Indiana installed a closed-loop bottom ash handling system to dewater the bottom ash that would otherwise have been sluiced to the ponds.

AES Indiana Harding Street and Eagle Valley have ceased coal combustion and must close their ponds in accordance with applicable local, state, and federal regulations. These ponds have also been removed from service. Petersburg, Harding Street, and Eagle Valley are collecting groundwater monitoring data as required by the CCR Rule. The data indicates exceedances of certain groundwater protection standards in the groundwater on AES Indiana's property, and on adjacent properties, in some cases. As a result, AES Indiana is currently in the process of determining the nature and extent of groundwater impacts and completed the assessment of corrective measures in 2019. Any corrective action plan will be subject to public notice, including a public meeting, and AES Indiana will take into consideration any community concerns. Post-closure groundwater monitoring results could be different than past results due to measures included in AES Indiana's ash pond closure plans. AES Indiana's closure plans include the installation of a 30-inch protective layer over a waterproof liner on the pond preventing rainwater from carrying coals ash constituents into groundwater. Additionally, six inches of topsoil will be laid on top and seeded with vegetative cover.

7.3 Pending and Future Environmental Regulations

170 IAC 4-7-6(a)(4)

There are several environmental initiatives that are being considered at the federal level that may impact the cost of electricity. This section discusses these pending and future federal environmental regulations.

7.3.1 Greenhouse Gases ("GHG")

On October 23, 2015, EPA finalized CO2 emission rules for existing power plants under CAA Section 111(d), called the Clean Power Plan ("CPP"). On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the CPP pending resolution of legal challenges to the rule. On July 8, 2019, EPA published the final Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, known as the Affordable Clean Energy ("ACE") Rule along with associated revisions to implementing regulations. The final ACE Rule established CO2 emission rules for existing power plants under CAA Section 111(d) and replaced EPA's 2015 CPP. In accordance with the ACE rule, EPA determined that heat rate improvement measures are the Best System of Emissions Reductions for existing coal-fired electric generating units. The final rule required the state of Indiana to develop a state plan to establish CO2 emission limits for designated facilities, including Petersburg's coal-fired electric generating units. States had three years to develop their plans under the rule. However, on January 19, 2021, the D.C. Circuit Court of Appeals vacated and remanded to EPA the ACE Rule but withheld issuance of the mandate that would effectuate its decision. On February 22, 2021, the D.C. Circuit Court of Appeals granted EPA's unopposed motion for a partial stay of the issuance of the mandate on vacating the repeal of the CPP. On March 5, 2021, the D.C. Circuit Court of Appeals issued the partial mandate effectuating the vacatur of the ACE Rule. In effect, the CPP did not take effect while EPA would be addressing the remand of the ACE rule by promulgating a new Section 111(d) rule to regulate greenhouse gases from existing electric generating units. On June 30, 2022, the U.S. Supreme Court reversed the decision of the D.C. Circuit Court of Appeals' January 2021 decision and held that the "generation shifting" approach in the CPP exceeded the authority granted to EPA by Congress under CAA Section 111(d). Impacts from this decision will not be fully known until further proceedings are held at the D.C. Circuit Court of Appeals on remand and a final regulation under CAA Section 111(d) is implemented by EPA and affected states.

7.3.2 National Ambient Air Quality Standards

As discussed above, NAAQS are routinely reviewed, and potentially lowered by EPA. It is also possible that revised NAAQS may result in future revisions to CSAPR. As a result, future required reductions of SO2 and NOx are possible.

7.3.3 Cross State Air Pollution Rule

On April 6, 2022, EPA published a proposed Federal Implementation Plan ("FIP") to address air quality impacts with respect to the 2015 Ozone NAAQS. The rule would establish a revised CSAPR NOx Ozone Season Group 3 trading program for 25 states, including Indiana. In addition to other requirements, if finalized, EGUs in these states would begin receiving fewer allowances as soon as 2023, which may result in the need to purchase additional allowances along with higher allowance prices.

7.3.4 Coal Combustion Residuals

On February 20, 2020, EPA published a proposed rule to establish a federal CCR permit program that would operate in states without approved CCR permit programs. If this rule is finalized before Indiana establishes a final state-level CCR permit program, AES Indiana could eventually be required to apply for a federal CCR permit from EPA. On October 13, 2021, IDEM issued a First Notice of Comment Period regarding establishment of a state-level CCR permit program.

On August 28, 2020, EPA published the CCR Part A Rule that, among other amendments, required certain CCR units to cease waste receipt and initiate closure by April 11, 2021. The CCR Part A Rule also allowed for extensions of the April 11, 2021 deadline if EPA determines certain criteria are met. Facilities seeking such an extension were required to submit a demonstration to EPA by November 30, 2020. On January 11, 2022, EPA released its first proposed determinations regarding a set of nine CCR Part A Rule demonstrations. On the same day, EPA issued four compliance-related letters notifying certain other facilities of their compliance obligations under the federal CCR regulations. While AES Indiana did not receive a proposed determination or a letter, the determinations and letters include interpretations regarding implementation of the CCR Rule that could potentially impact AES Indiana.

Additionally, EPA is in the process of developing amendments to the 2015 CCR Rule and has indicated that they will implement a phased approach to amending the CCR Rule. It is possible that these amendments could change the impact of the Rule on AES Indiana. However, it is too early to determine the potential impact. Corrective actions or remedies related to the CCR Rule would occur regardless of a generating station's operating scenario as these costs would be related to remedies for impacts related to ash ponds that are being phased out.

7.3.5 Selenium Water Quality Criteria

In June 2016, EPA published the final national chronic aquatic life criterion for the pollutant, selenium, in fresh water. On August 11, 2021, updates to IDEM's water quality criteria for specific metals, including selenium, were adopted as final to reflect EPA's criterion. AES Indiana facilities' NPDES permits may be updated to include selenium water-quality based effluent limits based on a site-specific evaluation process, which includes determining if there is a reasonable potential to exceed the revised final selenium water quality standards for the specific receiving water body utilizing actual or projected discharge information for AES Indiana generating facilities.

7.4 Summary of Potential Impacts

These regulations would potentially require AES Indiana to incur additional expenses for compliance in the future. Figure 7-2 below provides a summary of these potential regulations including potential timing and preliminary cost estimates available at this time.

Figure 7-2: Estimated Cost of Potential Environmental Regulations

Rule	Expected Implementation Year	Capital Cost Range Estimate ($MM)	Assumed Technology
CWIS 316(b)*	2022-2025	10-160	Closed cycle cooling
Ozone NAAQS	2028	0-17	SNCR
ELG	2020	0	None
Selenium WQS	2022-2025	12-16	Outfall(s) Relocation

**If AES Indiana is unable to renew the existing Petersburg Section 316(a) variance, the Section 316(b) technology listed is the same technology which would be needed for compliance with the temperature water quality standards.*

AES Indiana incorporated the expected impact of the regulations described above in the Current Trends/Reference Case Scenario in this IRP. Specifically, the cost for the Ozone NAAQS compliance are represented in the IRP analysis as additional NOx allowance purchases that would be needed in 2028. This cost serves as a proxy for the cost of compliance, which can be accomplished by a number of solutions of varying effectiveness and cost. Costs associated with corrective actions or remedies related to the other noted rule changes in Figure 7-2 (CWIS, ELG and Selenium) occur before any IRP decisions are made regarding the Petersburg units (2025). These costs would occur in all strategies and, therefore, did not need to be included in the IRP analysis.

Additionally, the Current Trends/Reference Case Scenario assumes a carbon price of $6.49 per ton starting in 2028 and escalating by 4.6% per year. This price is consistent with 1/3 of the social cost of carbon as calculated by the U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases.[48] This carbon price is not included in Figure 7-2 and was included in the IRP analysis based on collaboration and consensus with stakeholders. AES Indiana will continue to monitor changes in environmental regulations and incorporate compliance requirements into short-term and long-term plans.

[48] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

Section 8: Resource Portfolio Modeling

170 IAC 4-7-4(5), 170 IAC 4-7-4(11), 170 IAC 4-7-4(22), 170 IAC 4-7-8(a), and 170 IAC 4-7-8(c)(4)

8.1 Modeling Overview for the 2022 IRP

170 IAC 4-7-4(8) and 170 IAC 4-7-4(19)

8.1.1 Model Overview

AES Indiana conducted a thorough review of future IRP modeling needs at the conclusion of its 2019 IRP. The review considered feedback received from stakeholders and the IURC in the "Director's Report for Indianapolis Power and Light's 2019 Integrated Resource Plan." The Company recognized the need for more modeling transparency, faster modeling runtimes that would enable a more complete scenario analysis, and proven capability to run DSM as a resource.

In the fall of 2020, AES Indiana issued a Request for Information ("RFI") for capacity expansion and production cost models to be used in its 2022 IRP. Through the RFI, the Company selected Anchor Power's EnCompass Power Planning Software based on EnCompass's capabilities and recommendations from industry experts. EnCompass provides fast runtimes that allow for more capacity expansion portfolios to be evaluated in the scenario analysis and greater transparency to the model database. AES Indiana provided stakeholders access to its model database, which allowed stakeholders that had EnCompass licenses to run AES Indiana's IRP portfolios. To support EnCompass modeling efforts, AES Indiana contracted with ACES Power Marketing LLC to provide consulting services in AES Indiana's 2022 IRP.

Key Modeling Highlights

- → AES Indiana utilized Anchor Power's EnCompass modeling platform for capacity expansion (utility capital accounting) and production cost modeling.
- → As a modeling framework, the Company performed traditional deterministic capacity expansion scenario analysis of five strategies and one Encompass Optimization analysis across four scenarios, resulting in 24 portfolios for evaluation.
- → The modeling framework was a systematic evaluation of coal unit retirement or natural gas conversion modeled across a wide range of scenarios, which provided insight into resource viability now and in the future.
- → AES Indiana utilized fundamentals-based forward curves provided by Horizons Energy. The team at Horizons Energy has decades of experience in integrated resource planning and provides EnCompass-ready price forecasts, allowing for a single software solution.
- → For the Scorecard Evaluation, AES Indiana conducted deterministic sensitivities for key variables to stress portfolios and identify the impacts of sources of future uncertainty.
- → For the Scorecard Evaluation, Stochastic simulations were run for the Reference Case Scenario across the five strategies and Encompass Optimization using EnCompass. This captured volatility around commodity prices, load, and renewable generation.

8.1.2 EnCompass

EnCompass performs hourly dispatch of resources taking into account power prices, fuel prices, variable operating costs, emission allowance costs, and startup costs. It follows unit constraints such as minimum down time between starts, dispatch blocks and heat rates, minimum capacities, and ramp rates. Scheduled maintenance outages can be input and forced outage rates can be applied at random across a year of simulation. There are also a number of constraints that can be used such as limiting how much power can be sold or purchased net of the Company's load over a specified time period.

The software is also very convenient for modeling hybrid resources through the use of constraints and the specification of DC and AC capacities. This is covered in more detail in Section 6.2.

The capacity expansion component of the EnCompass Model uses Mixed Integer Programming. This means that the model finds an optimal solution, and then solves for the solution given constraints such as building/selecting integer amounts of resources (e.g., the model will build a whole battery, not a third of a battery).

Capacity expansion runs create optimized portfolios, then EnCompass is able to take the portfolio and perform a more detailed production cost run to calculate the final revenue requirement that is used to evaluate portfolios.

8.1.3 Power Shapes

Horizons Energy fundamental commodity curves provided hourly power shapes for each scenario that reflect the generation mix of the grid over time. Power shapes are how the price of power changes hour by hour throughout the day. Flat shapes, where the price does not change much throughout the day, incentivizes resources that run well as baseload, such as steam turbines. More volatility where there is at least one peak in the day can reward quicker resources such as natural gas peakers. Increasing amounts of variable generation resources such as wind and solar can cause additional power price volatility, which can create an opportunity for battery storage resources. Battery resources respond quickly to differences in power prices – the greater the difference, the greater the value for batteries. However, a saturation of batteries on the grid reduces the volatility of the power prices and the power shape begins to revert towards a flat shape. Thus, power price shapes are a crucial input for optimizing a portfolio with the right mix of resources. Figure 8-1 and Figure 8-2 show summer and winter power shapes at the beginning and the end of the IRP study period. The summer shape transitions from being highest to lowest in the middle of the day, reflecting the increased penetration of solar output over the decades. The winter shape's double peak begins to erode as more storage on the grid is able to shift energy from one part of the day to another.

Figure 8-1: Reference Case Sample Summer Power Shape for 2023 and 2042

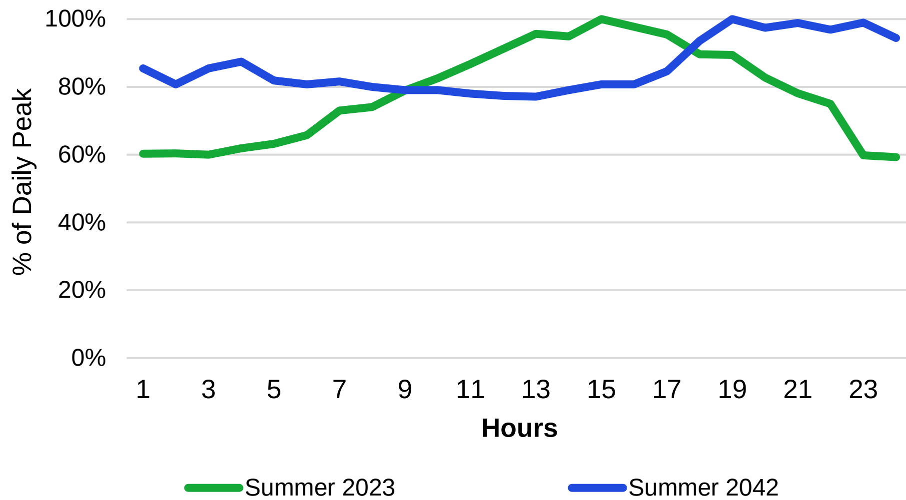
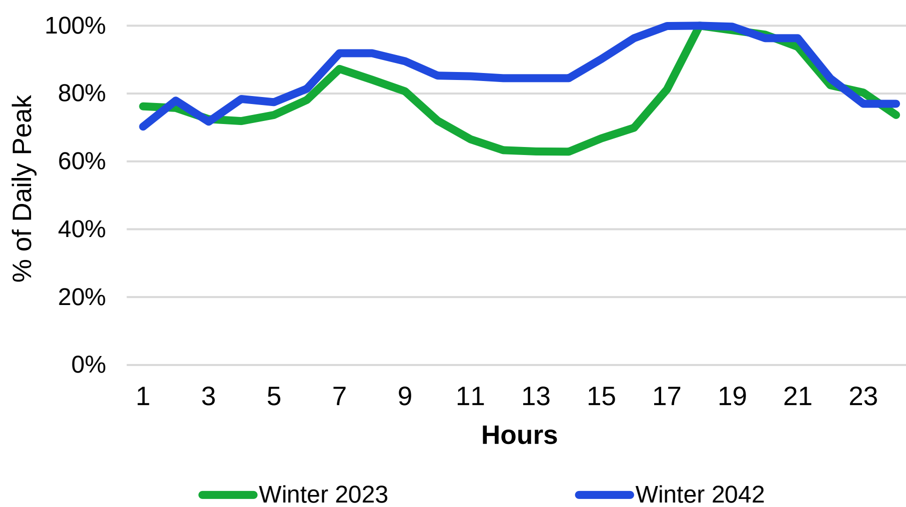


Figure 8-2: Reference Case Sample Winter Power Shape for 2023 and 2042



In addition to hourly power shapes, AES Indiana modeled hourly load shapes, which are covered in more detail in Section 5.3, and renewable generation shapes, which are covered in more detail in Section 6.2.

8.2 Modeling Tools

170 IAC 4-7-4(19) and 170 IAC 4-7-4(28)

AES Indiana began a transition to Anchor Power's EnCompass software in mid-2021. The EnCompass platform provides a comprehensive suite of modeling capability, including capacity expansion optimization, utility capital accounting, and hourly production cost modeling optimization over a 20-plus year horizon.

Using a structured scenario approach, EnCompass capacity expansion portfolios feed seamlessly into child scenarios in which detailed simulation evaluations can be performed. Fully integrated capital accounting functionality translates power system investments into utility revenue requirements for all scenarios in a transparent and documented manner.

AES Indiana also used the NREL's SAM tool, a publicly available model that uses weather data to generate hourly production profiles for wind and solar resources. These production profiles were input into EnCompass. More detail related to the inclusion of these profile in EnCompass is provided in Section 6.2.

8.3 Key Modeling Assumptions, Parameters, and Constraints

170 IAC 4-7-4(23), 170 IAC 4-7-4(28), and 170 IAC 4-7-8(c)(3)

8.3.1 Commodity Forecasts

AES Indiana contracted Horizons Energy to provide custom fundamental power price forecasts for AES Indiana's 2022 IRP. Horizons Energy's power price forecasts were custom modeled using the natural gas, coal, NOx, ITC and PTC, and carbon price assumptions for each scenario as inputs into EnCompass for the fundamental modeling. Thus, each scenario has a unique set of custom fundamental power prices.

AES Indiana initially used Horizons Energy Fall 2021 price outlook for natural gas and coal to inform the custom fundamental power price forecasts performed by Horizons Energy. However, in March and April of 2022, prices for natural gas, coal, and power increased largely due to an energy crisis in Europe that was exacerbated by Russia's military invasion of Ukraine, along with other economic factors. Commodity shortages in Europe prompted increased exports of U.S. coal and natural gas, which drove the market for natural gas and coal in the U.S. to levels not seen in over 10 years. In response to stakeholder comments and to ensure reasonable forecasts are included in AES Indiana's 2022 IRP, AES Indiana had Horizon Energy update the custom fundamental power price studies using the Spring 2022 natural gas and coal price outlook. Thus, AES Indiana's 2022 IRP reflects the upward trend in natural gas, coal, and power prices. The commodity price forecasts AES Indiana used for each of its scenarios in its 2022 IRP is attached to this Report as Confidential Attachments 8-1.

Methodology: Blending Curves

In order to capture the near-term increase in natural gas, coal, and power prices, AES Indiana blended the International Exchange, Inc. ("ICE") Forward Curve (Source: ICE 5/31/2022) and

Horizon Fundamental Curves for these commodities for the first three years of the study, as illustrated in Figure 8-3 below. By the fourth year in the planning period, the curves revert entirely to the fundamental forecast. Figure 8-4 below provides the blending percentages used by the Company for the first three years of the planning period.

Figure 8-3: Example of the Fundamental Curve Blending Methodology using Power[49]

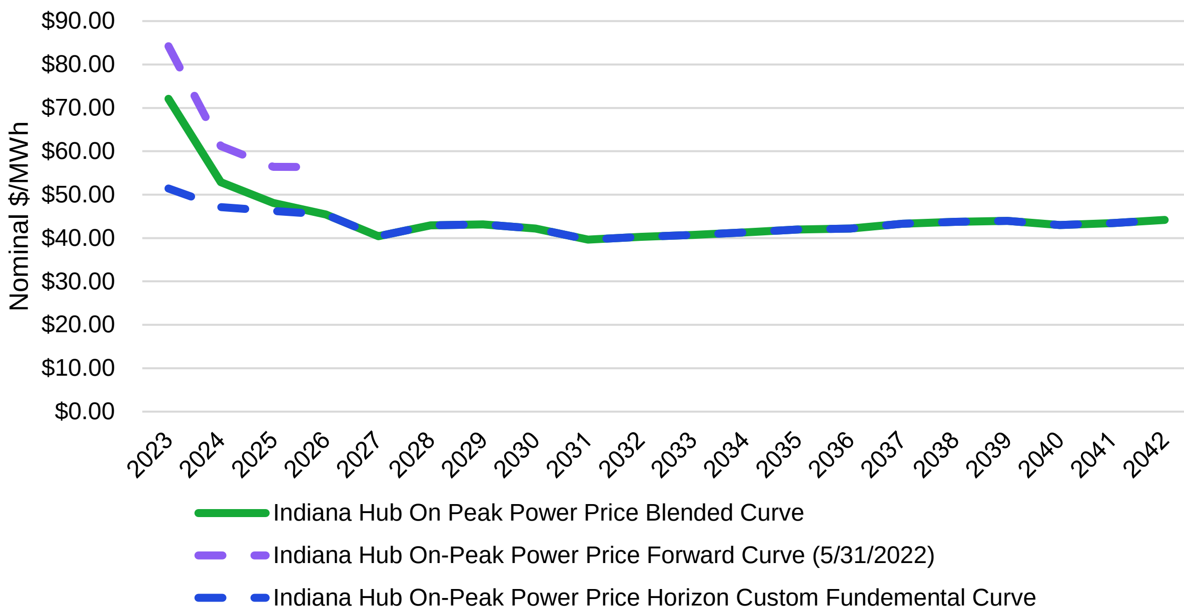


Figure 8-4: Approximate Fundamental Curve Blending Methodology by Year

Approximate Blending by Year

2023: 40% Horizon Curve; 60% Forward Curve

2024: 65% Horizon Curve; 35% Forward Curve

2025: 85% Horizon Curve; 15% Forward Curve

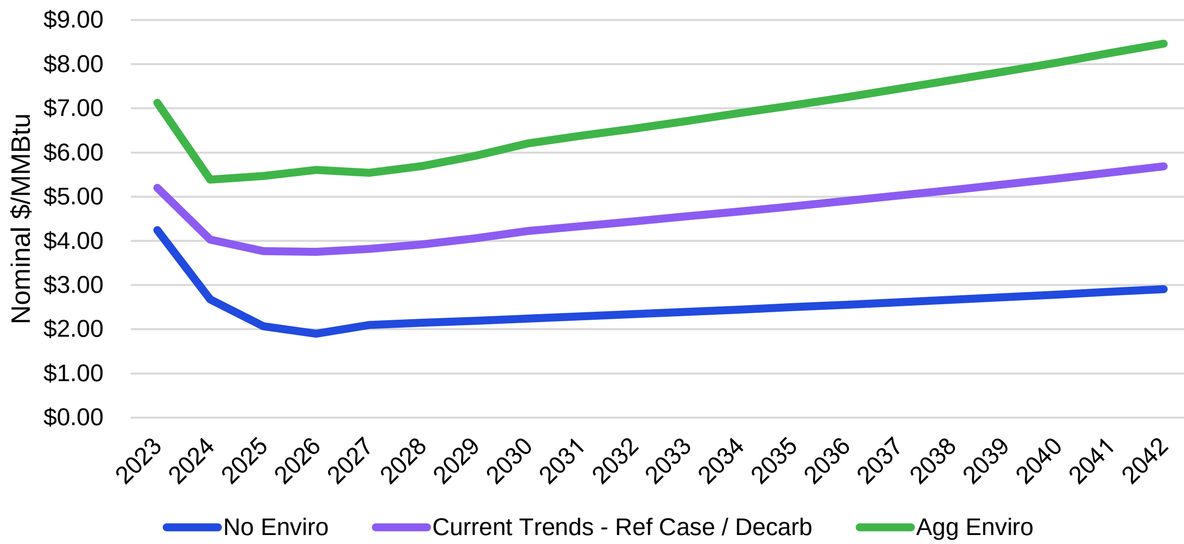
2026 through 2042: 100% Horizon Curve

Natural gas prices are a blend of the Henry Hub ICE Forward Curve (Source: ICE 5/31/2022) and the Horizon 2022 Spring Case for Henry Hub. The forecast was created using the blending methodology described above for power. AES Indiana utilized low, base, and high forecasts from Horizons Energy, blending each in the near term with forward curves from ICE. The low, base, and high forecasts were included in the different IRP planning Scenarios based on the outlook of each scenario. As depicted below in Figure 8-5, the No Environmental Action scenario includes low natural gas prices, the Current Trends (Reference Case), and Decarbonized Economy scenarios include the base natural gas prices, and the Aggressive Environmental scenario

[49] This methodology was used for natural gas and coal prices in addition to power.

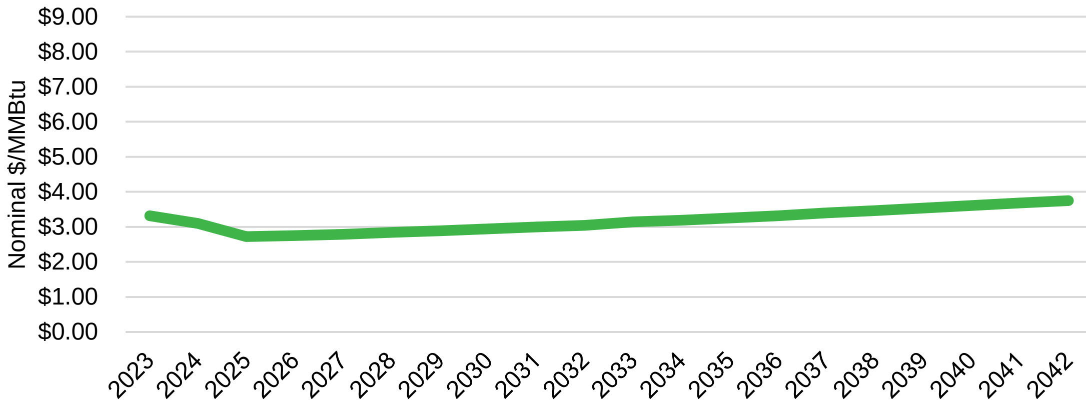
includes high natural gas prices. For more description of the commodity prices used in the scenarios, see Section 8.4.2 and Confidential Attachment 8-2.

Figure 8-5: Blended Long-Term Natural Gas Prices



AES Indiana used a combination of market intelligence and the Horizon Energy Fundamental Spring Case for Illinois Basin coal to project coal prices included in AES Indiana’s 2022 IRP. To capture elevated market prices for coal, the near-term was based on responses to AES Indiana's most recent RFP for coal procurement. AES Indiana contracted for the lowest offer in the RFP and used the next highest offer as the starting point for coal prices in the IRP coal price forecast. The Company then applied the growth rate in the Horizon Energy Fundamental Spring Case for Illinois Basin coal to the starting point price from the RFP to project prices for the rest of the planning period. The Company used a base coal price forecast in all IRP planning scenarios. See Section 8.4.2 for more information on the commodities included in the IRP planning scenarios. Figure 8-6 below provides the final delivered coal forecast used in the IRP planning scenarios.

Figure 8-6: Blended Long-term Delivered Coal Prices (All Scenarios)[50]



In 2022, the MISO PRA for MISO's 2022/2023 planning year cleared at the Cost of New Entry ("CONE") in all zones except the southern states, which are subject to a transmission constraint. This is the maximum price allowed by the market. These results reflect capacity shortages in many MISO zones driven by thermal retirements and general unit outages. This result will likely become a trend as MISO load serving entities continue to transition from thermal generation to renewable resources. Additionally, MISO received approval in the summer of 2022 to switch from an annual PRA represented by summer to a four-season capacity construct. This means that load serving entities will now have to meet their load plus PRMR in fall, winter, and spring in addition to summer. To reflect these near-term changes in the value and treatment of capacity, AES Indiana used the price of CONE to value capacity in all four seasons. Being short in a season means new resources need to be built to provide capacity. This is priced at CONE for a 365-day period. Therefore, each season's capacity is valued at four times CONE for 90 days (90 days represents the number of days in the season). Previously, in a summer-only capacity market, CONE would be represented for 365 days consistent with a full year. Thus, under this new seasonal construct, if a utility is short capacity in one single season, summer for example, then the utility will incur a capacity penalty of four times CONE for 90 days, which is generally equal in terms of total penalty to CONE for 365 days under a summer-only construct. The utility will likely not incur additional capacity penalty charges in other seasons because if the utility meets its highest seasonal requirement (i.e., summer in this case), it is not likely to be short in other seasons. For modeling purpose, AES Indiana also allowed the model to value excess capacity at CONE; however, sales of excess capacity were constrained in the model to no more than 50 MWs per season. Figure 8-7 below provides the capacity price forecast used for planning in EnCompass. Prices start at $244 per MW-day and increase at the rate of inflation.

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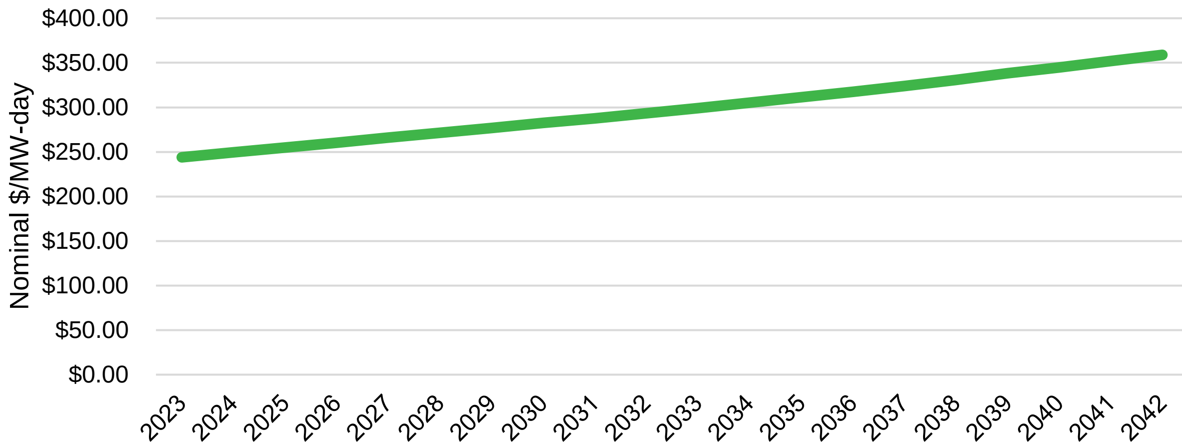
[50] For 2023 through 2025, AES Indiana utilized a Blend of internal market intelligence using results from its most recent coal procurement RFP. For 2026 through 2042, AES Indiana utilized a blend of internal market intelligence and Horizon Energy Spring Case growth rate for Illinois Basin coal.

Figure 8-7: Long-term Capacity Prices for 2023 through 2042 (All Scenarios)[51]



In the spring of 2022, seasonal NOx prices rose to unseen levels due to uncertainty around changes to the CSAPR causing NOx emitters to ration allowances. This created scarcity in the NOx allowance market and caused NOx prices to significantly increase throughout 2022. AES Indiana adjusted NOx price forecasts to account for these changes midway through the planning process in 2022. Figure 8-8 through Figure 8-10 below provides the NOx price forecasts included in the planning scenarios. The charts also illustrate the changes made during 2022 to account for the price volatility in the NOx allowance market. Note that near-term prices are kept confidential because AES Indiana is a participant in this highly illiquid market.

→ Low NOx forecast: modest NOx price forecast in the near-term and held flat at $1,700 per ton from 2029 through 2042. This was included in the No Environmental Action Scenario and is illustrated in Figure 8-8.

→ Mid NOx forecast: NOx prices start high in the near-term due to allowance scarcity in the NOx market. Market resolves at $8,500 per ton, which is held flat from 2029 through 2042. This was included in the Current Trends (Reference Case) Scenario and is illustrated in Figure 8-9.

→ High NOx forecast: NOx prices start very high in near-term and resolves to $8,500 per ton from 2029 through 2042. This was included in the Aggressive Environmental and Decarbonized Economy scenarios and is illustrated in Figure 8-10.

[51] CONE was captured in all four seasons based on MISO's Seasonal Capacity Construct.

Figure 8-8: No Environmental Action Scenario NOx Allowance Prices

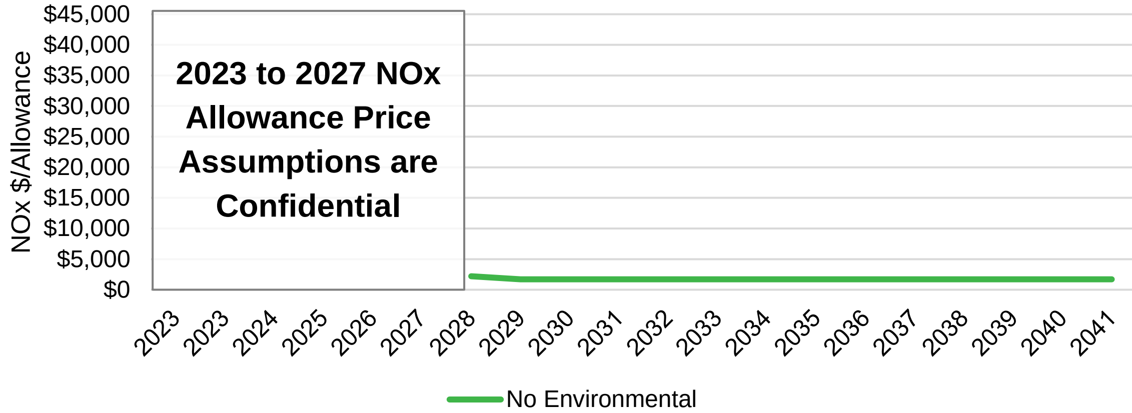


Figure 8-9: Current Trends Scenario NOx Allowance Prices

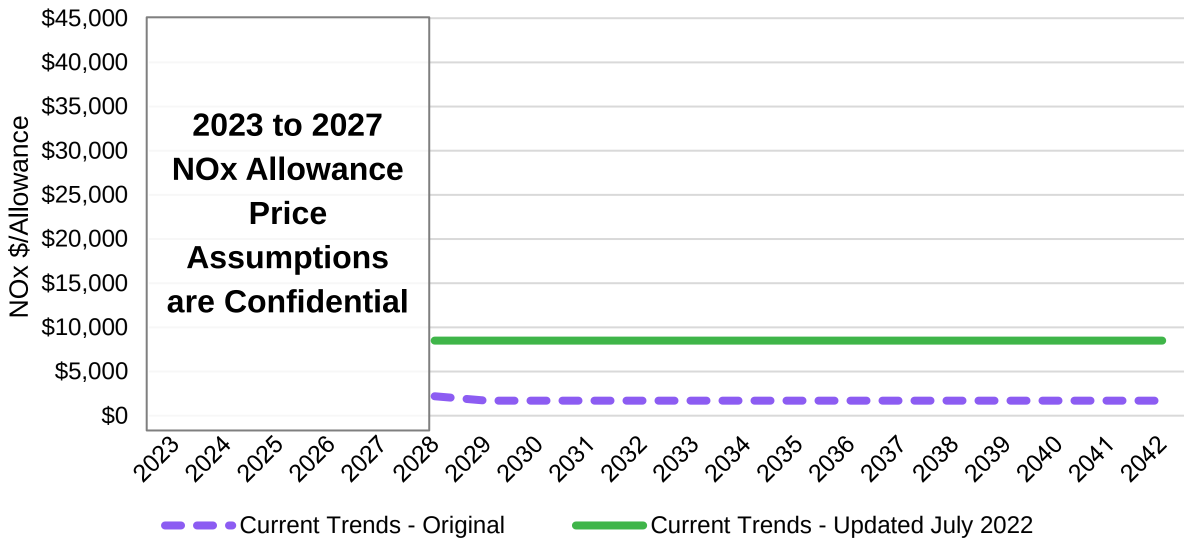
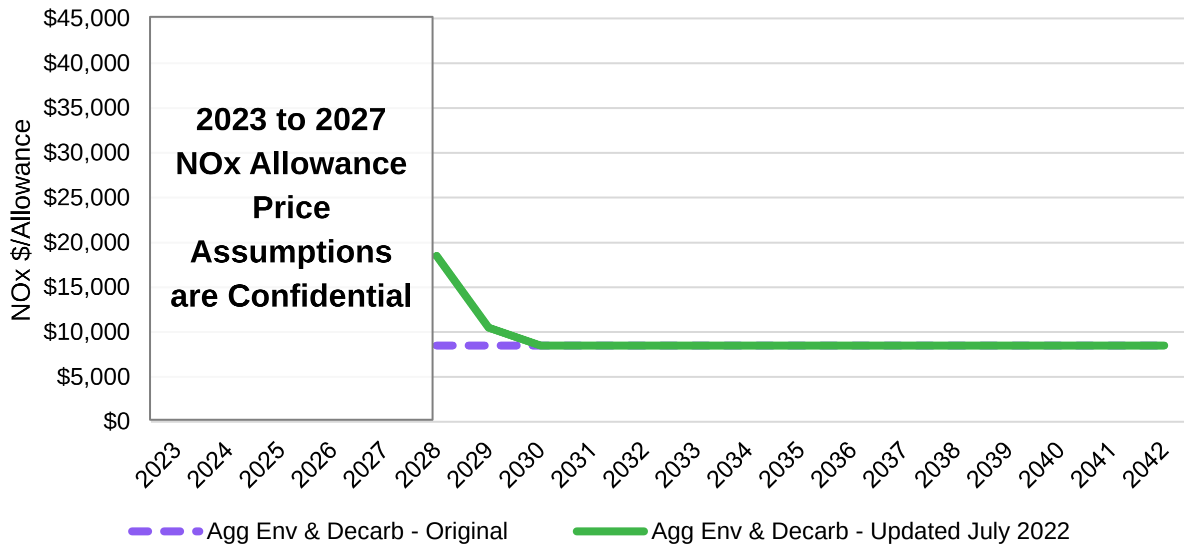


Figure 8-10: Aggressive Environmental Scenario and Decarbonized Economy Scenario NOx Allowance Prices



8.3.2 Capacity Expansion Setup and Constraints

Capacity Surplus and Penalties

The EnCompass capacity expansion optimization uses mixed integer programming techniques to optimize resource decisions, with the objective of minimizing the present value of portfolio costs.

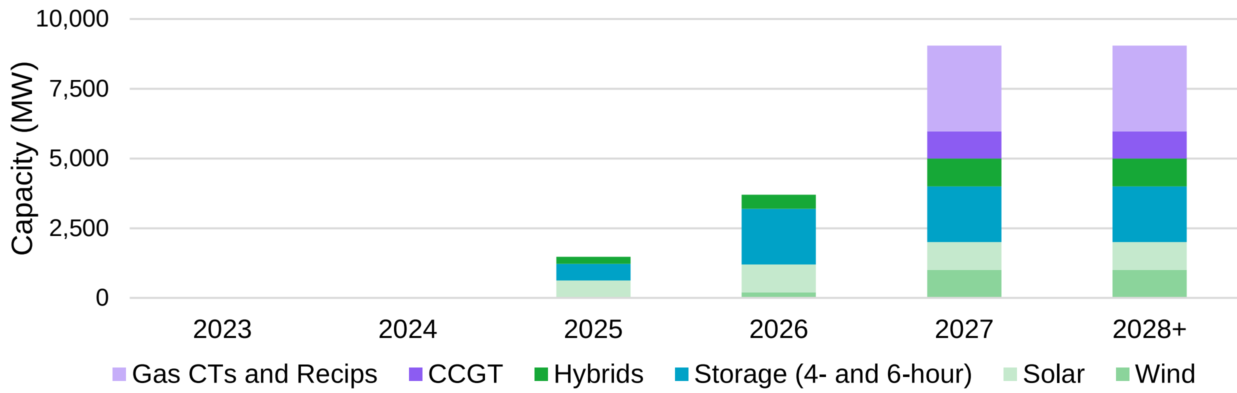
The following are model settings utilized to constrain the results in a realistic and risk adjusted manner:

3. The proposed MISO seasonal construct was modeled for required reserve margin.
4. Bilateral capacity market risk was reduced by limiting interaction to 50 MW of purchases or sales per season.
5. Energy market risk was reduced by limiting interaction to 10% of load for purchases or sales per year.
6. Selection of new resources was limited to 1) prevent selecting near term resources that cannot practically be executed or are not supported by recent RFP responses; 2) prevent selecting more resources than would be practical over the study period; and 3) prevent an overreliance on a single resource type. All new resource capacity limitations are represented in ICAP (AC).
    a. Earliest selectable build is approximately 1,500 MW (ICAP) of solar, storage, and hybrid resources in 2025.
    b. By 2027, the EnCompass Model can build approximately 1,000 MW (ICAP) of any technology per year.

c. Over the 20-year IRP study period, can build a max of approximately 2,000 MW (ICAP) of any one technology.

Figure 8-11 demonstrates the total selectable capacity (ICAP) in each year of the IRP planning period given the constraints noted above.

Figure 8-11: Total Selectable Capacity (ICAP)



8.3.3 Financial Assumptions

Figure 8-12 and Figure 8-13 contain assumptions on AES Indiana's capital structure, the discount rate used in the model, the Allowance for Funds Used During Construction ("AFUDC"), inflation, property tax, and other relevant financial assumptions used in the revenue requirement financial model.

Figure 8-12: Capital Structure and Discount Rate Assumptions

	Capital Mix	Cost of Capital	WACC	Discount Rate
Debt	50.78%	4.75%	2.412%	1.812%
Preferred Equity	1.68%	5.37%	0.090%	0.090%
Common Equity	47.54%	9.99%	4.749%	4.749%
Total	**100.00%**		**7.252%**	**6.652%**
			Actual	**Effective**
		State Tax	4.90%	4.90%
		Federal Tax	21.00%	19.97%
		Effective Tax Rate		**24.87%**

Figure 8-13: Other Financial Model Assumptions

AFUDC Rate (%)	6.13%
Property Tax Rate (%)	2.74%
Annual Inflation Assumption (%)[52]	
2023	3.10%
2024	2.30%
2025	2.10%
2026	2.10%
2027	2.20%
2028	2.10%
2029	2.00%
2030	2.00%
2031	1.90%
2032	1.90%
2033	2.00%
2034	2.00%
2035	2.00%
2036	2.00%
2037	2.10%
2038	2.10%
2039	2.20%
2040	2.00%
2041	2.00%
2042	2.00%

8.4 Modeling Framework

The IRP Modeling Framework centers around five generation strategies that focus on the future of AES Indiana's remaining coal units, Petersburg Units 3 and 4. These strategies were evaluated under four different scenarios.

For the purposes of the IRP Modeling Framework, strategies and scenarios are defined as:

Strategies

- AES Indiana's potential future strategies for the generation portfolio.
- Retirement dates, capital expenditures, and cost treatments are anticipated and defined for each strategy and included in the EnCompass planning model.

[52] These inflation values are a GDP deflator percentages from spring 2022. Decisions were not made until 2025, when AES Indiana assumes inflation will level out at approximately 2%. These same rates were applied throughout the evaluation, so all project types are affected equally.

Scenarios

- → Scenarios are views of the futures defined by external influences, such as political outcomes, economics, regulations, etc.
- → In the planning model, each scenario was modeled with a unique set of input assumptions that correspond to the external influences defining the scenario.

This section will first review the five strategies, including the additional stakeholder requested strategy, and then review the four scenarios used to evaluate these strategies. The section will conclude with a review of the 2022 IRP Portfolio Matrix that combines the strategies and scenarios into a matrix for comparison.

8.4.1 Generation Strategies & Retirement Analysis

In this IRP, AES Indiana evaluated five generation strategies that focused on the future of AES Indiana's remaining coal units, Petersburg Units 3 and 4. Those strategies include: 1) No Early Retirement, which includes no early retirements or changes to the existing portfolio; 2) Petersburg Conversion, which includes converting Petersburg Units 3 and 4 in 2025 to natural gas; 3) One Petersburg Unit Retires, in which Petersburg Unit 3 retires in 2026, AES Indiana continues to operate Petersburg Unit 4 on coal through the IRP study period, and conversion from coal to natural gas is not a selectable resource for Petersburg Unit 3; 4) Both Petersburg Units Retire, in which AES Indiana retires Petersburg Unit 3 in 2026, Petersburg Unit 4 in 2028, and conversion from coal to natural gas is not a selectable resource for either Petersburg unit; and 5) Clean Energy Strategy, which is similar to Both Petersburg Units Retire but with the additional constraint that the model cannot select thermal resources as replacements, including the exclusion of conversion from coal to natural gas is not a selectable resource for either Petersburg unit. This strategy was requested by stakeholders as a "Clean Energy Strategy" for Petersburg.

Figure 8-14 below outlines the five generation strategies. AES Indiana also conducted a sixth optimization analysis that allowed the EnCompass Model to select a portfolio independently using least cost economics. In this optimization, Encompass could choose to operate Petersburg on coal or convert or retire the Petersburg units at any point over the planning period, either together or separately. Retirements and conversions were limited to the Petersburg units in this optimization. Results from this analysis provide good insight into the most cost effective portfolio for customers; however, due to challenges with fully capturing costs when using this approach, the results should be viewed as a general gauge for decision making rather than a defined plan or strategy. In Figure 8-14 below, this is referred to as the "EnCompass Optimization."

Figure 8-14: Overview of Generation Strategies

Generation Strategy	Characteristics
No Early Retirement	→ Status Quo → Petersburg Units 3 and 4 remain in service through useful life of 2042
Petersburg Conversion (approximately 2025)	→ Petersburg Units 3 and 4 converted to natural gas in 2025
One Petersburg Unit Retires (2026)	→ Petersburg Unit 3 retired early in 2026 → Petersburg Unit 4 remains in service through useful life of 2042 → Replacement capacity starting in 2026
Both Petersburg Units Retire (2026 and 2028)	→ Petersburg Unit 3 retires in 2026 → Petersburg Unit 4 retires in 2028
Clean Energy Strategy (2026 and 2028)	→ Petersburg Unit 3 retires in 2026 → Petersburg Unit 4 retires in 2028 → Only clean energy resources can replace retired units
EnCompass Optimization without a Predefined Strategy	→ Allows EnCompass Model to select new resources and retire or convert Petersburg based on least cost portfolio economics without a predefined strategy

Generation Strategies and Capacity Expansion Analysis

To evaluate and compare the generation strategies, AES Indiana used EnCompass to perform a retirement and replacement (EnCompass Model) analysis that determined the appropriate generation resources when capacity was needed during the planning period due to unit retirements or general capacity shortages. Except for the Encompass Optimization analysis described above, these generation strategies are predefined in the EnCompass capacity expansion analysis. In other words, the EnCompass Model is not calibrated to move the retirement or converting dates of the Petersburg units. These retirement and conversion dates are hardcoded into the EnCompass Model, and replacement capacity is selected in EnCompass targeting least cost portfolio economics.

The following figures provide an illustrative representation of AES Indiana's capacity position in each of the predefined strategies to help in understanding the capacity expansion (i.e., retirement and replacement) analysis that EnCompass performs.

Figure 8-15 below provides the anticipated unit retirements and capacity position for the No Early Retirement Strategy, which keeps Petersburg Units 3 and 4 on coal through the entire planning period. Note that despite Petersburg remaining in-service through the planning period, there is still a need for replacement capacity when Harding Street Units ST5 and ST6 and Harding Street Unit ST7 reach age-based retirement in 2031 and 2034, respectively. The EnCompass Model will determine the least cost, most economic replacement capacity for these retirements in the EnCompass Model. This replacement capacity mix may change depending on the unique Scenario assumptions. The IRP Scenarios will be discussed later in this section.

Figure 8-15: No Early Retirement Strategy Capacity Position

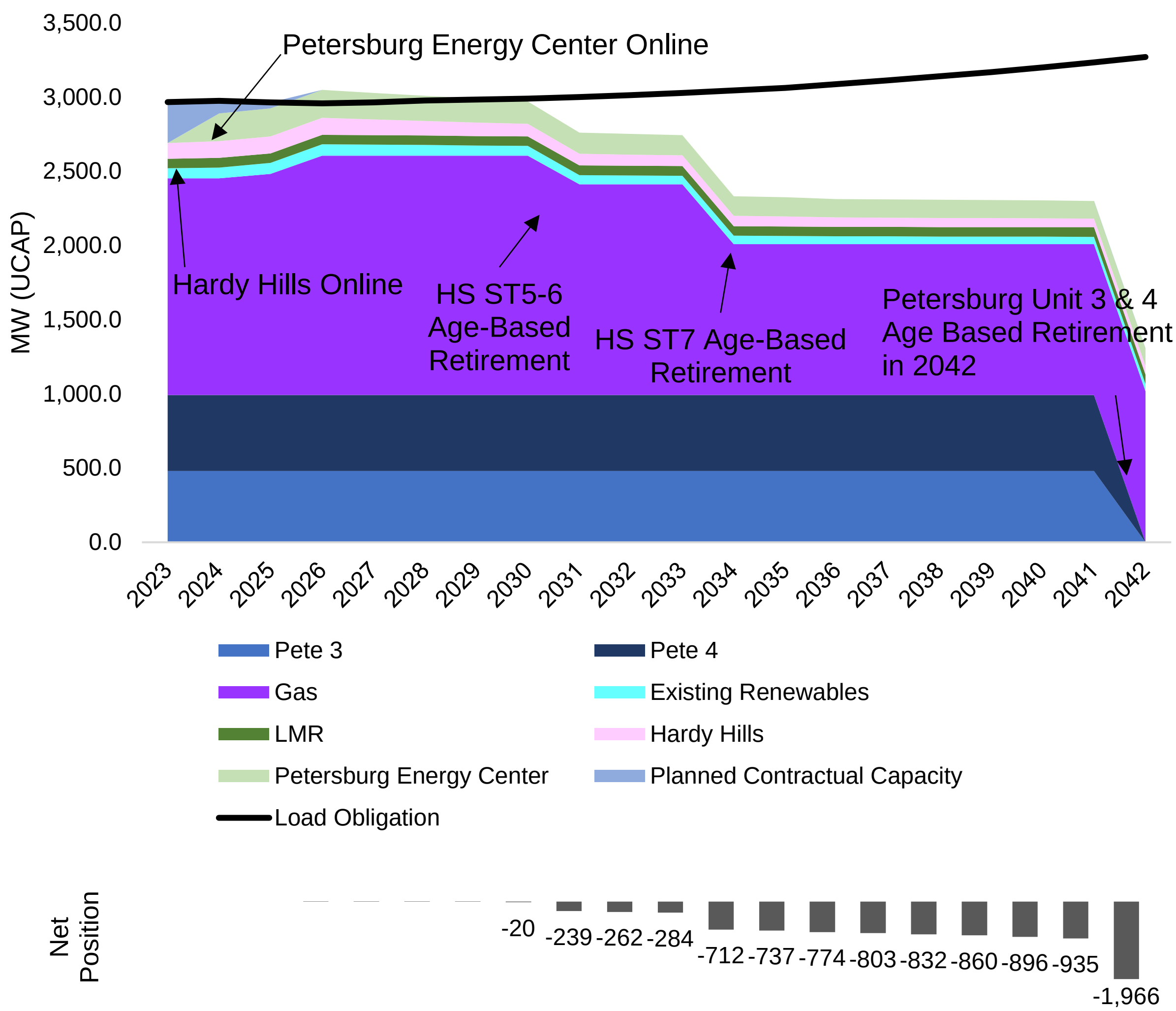


Figure 8-16 below illustrates the retirements and capacity position over the 20-year planning period of the Petersburg Conversion Strategy, in which Petersburg Units 3 and 4 convert to operate using solely natural gas in 2025. The capacity position in this strategy is identical to the strategy that keeps Petersburg Unit 3 and 4 on coal through the planning period because the natural gas conversion is a one-for-one replacement of the capacity of Petersburg on coal.

Figure 8-16: Petersburg Conversion Strategy Capacity Position

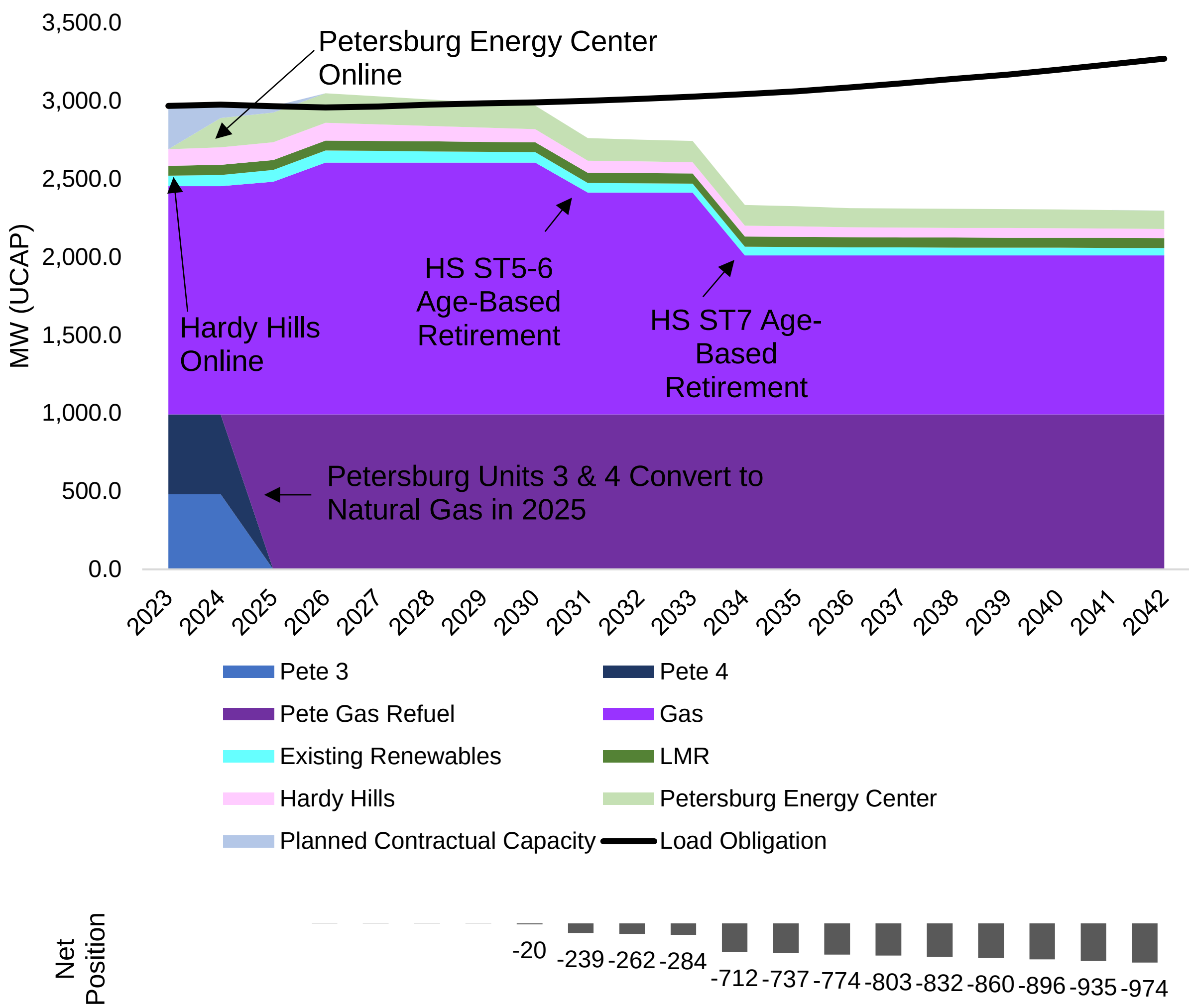


Figure 8-17 below shows the retirements and capacity position of the One Petersburg Unit Retires Strategy, in which Petersburg Unit 3 retires in 2026 and Petersburg Unit 4 remains in-service and on coal through the planning period. With the retirement of Petersburg Unit 3, the portfolio now has a capacity need of ~390 MW starting in 2026. EnCompass will optimally replace this capacity with other resources in the capacity expansion analysis.

Figure 8-17: One Petersburg Unit Retires Strategy Capacity Position

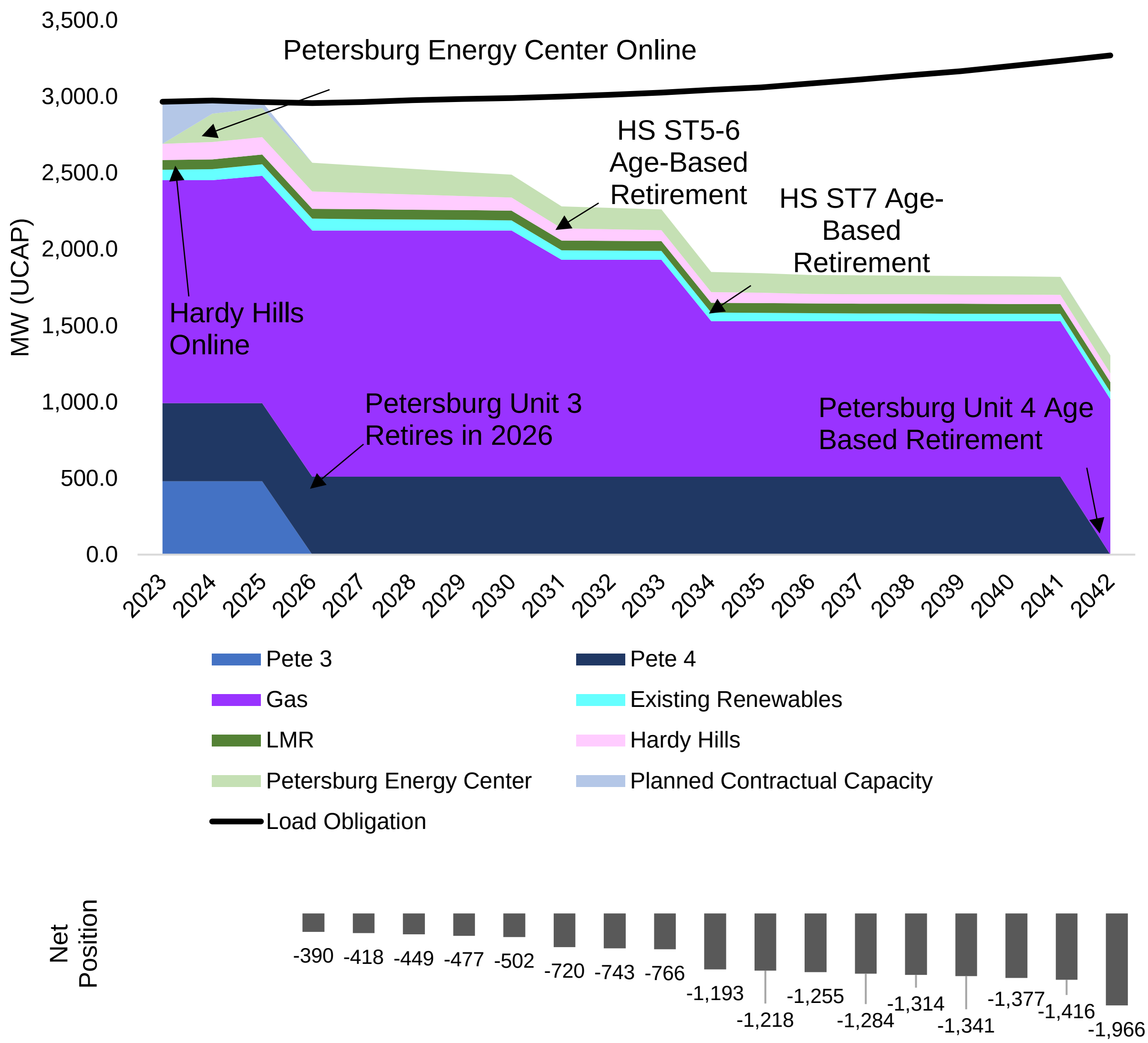
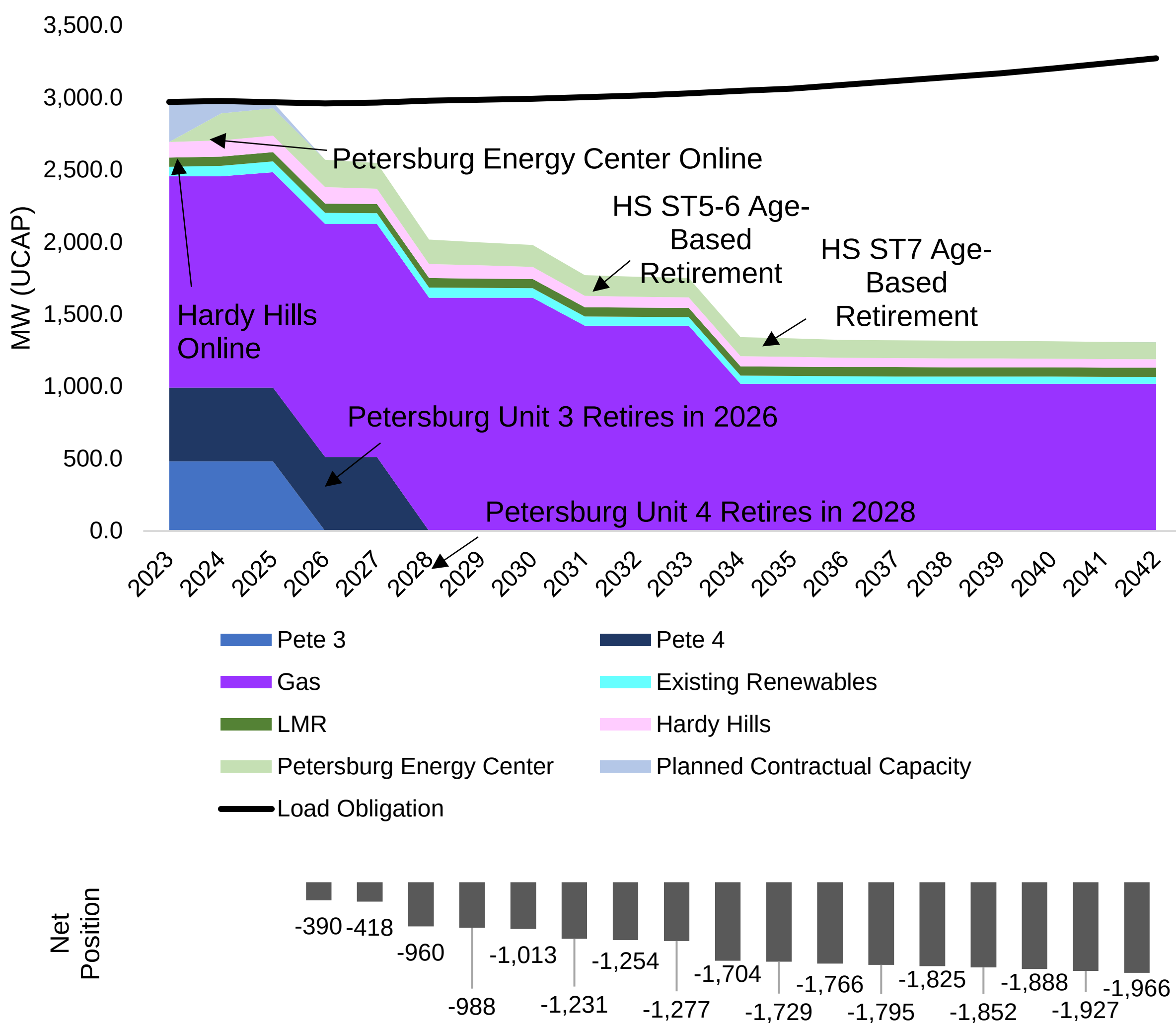


Figure 8-18 below shows the retirements and capacity position of the Both Petersburg Units Retire Strategy and the Clean Energy Strategy. Both strategies require Petersburg Unit 3 to retire in 2026 and Petersburg Unit 4 to retire in 2028. Over 1,000 MW of capacity is needed by the early 2030s, reaching nearly 2,000 MW by 2042. EnCompass will optimally select replacement capacity in 2026 when Petersburg Unit 3 is retired and again in 2028 when Petersburg Unit 4 is retired. The Clean Energy Strategy limits the replacement resources the EnCompass Model can select to clean resources (i.e., renewable and storage resources), while the Both Petersburg Units Retire Strategy allows the EnCompass model to optimally select any replacement technology included as a resource option.

Figure 8-18: Both Petersburg Units Retire and Clean Energy Strategies Capacity Position



Clean Energy Strategy

Through collaboration with key IRP stakeholders, AES Indiana added a fifth strategy to the analysis that retires both Petersburg units (Unit 3 in 2026 and Unit 4 in 2028) and replaces the associated capacity with solar, wind, and storage resources. This strategy is referred to as the Clean Energy Strategy. While this strategy focuses on the replacement of the Petersburg coal units with renewable generation and storage resources, the remaining natural gas-fired generation in AES Indiana's portfolio does not retire early and get replaced with renewable generation. Natural gas retirements are still age-based.

Rationale for Predefining Strategies

Aside from the EnCompass Optimization analysis, AES Indiana decided to predefine the Petersburg Generating Station strategies as opposed to allowing the EnCompass Model to optimize on its own. The Company notes two primary reasons for taking this approach:

→ **Predefining the retirement and conversion dates of the Petersburg Generating Station guarantees the Company will have sufficient lead time to replace the capacity or convert the remaining coal units.** AES Indiana took due diligence to determine the earliest possible retirement timeline for the remaining Petersburg Units 3 and 4. This was achieved by revisiting the execution timelines of the Hardy Hills and Petersburg Energy Center projects that occurred as a result of AES Indiana's 2019 IRP and 2020 RFP process. Applying these approximate timelines to the 2022 IRP and RFP process indicates the earliest feasible retirement and replacement dates of Petersburg Unit 3 and Unit 4 as 2026 and 2028, respectively. Additionally, staggering the retirement dates provides sufficient time for the replacement resource market to stabilize. As demonstrated by AES Indiana's 2022 RFP results, which contained lower capacity volumes and higher prices compared to AES Indiana's 2020 RFP results, the replacement resource market (renewable resources in particular) is faced with supply constraints that have impacted replacement resource availability and prices. In order to evaluate replacement resource availability and pricing as the market stabilizes, AES Indiana plans to issue additional RFPs in 2023 and beyond to procure capacity identified in the Preferred Resource Portfolio. For more information regarding AES Indiana's 2022 RFP, please see Section 6.2 of this IRP.

→ **Predefining the retirement and conversion dates provides the opportunity to model strategies that may not get selected if the EnCompass model was to optimize on its own.** AES Indiana has included the No Early Retirement Strategy, which keeps Petersburg operating on coal through the entire planning period and the Clean Energy Strategy (as requested from stakeholders) which retires and replaces Petersburg with all clean energy. These very different strategies may not get picked when allowing EnCompass to optimize on its own. Modeling these very different "bookend" strategies allows the Company and its stakeholders to see how they perform in very different future scenarios and alongside other Petersburg options like conversion.

Modeling System Blackstart & Stability Requirements

The Harding Street diesel Units 1 and 2, which have installed capacities of 38 MW, are scheduled for age-based retirement by the end of 2024. Located inside the 138kV network, these units are part of AES Indiana's blackstart plan. To ensure an effective blackstart plan continues, AES Indiana has given the EnCompass model the ability to select either a 3.5 MW reciprocating engine or a 3.5 MW diesel cranking unit to replace the existing Harding Street Units 1 and 2 upon their retirement. The difference between these two options is that a diesel cranking unit is an inefficient unit that is only expected to run in emergency situations, while a reciprocating engine is a very efficient unit that can produce energy margins for the benefit of customers but has larger capital costs. The EnCompass model will optimize this selection based on least cost economics. These replacement units will need to provide rotating generation inside the 138kV network.

Additionally, Harding Street Unit 7, which is a 420 MW ICAP natural gas-fired steam turbine, is scheduled to retire in 2033. This unit is also located inside AES Indiana's 138kV network and provides critical stability to the system. To ensure system stability continues, AES Indiana needs approximately 300 MW of dispatchable generation connected to the 138kV network. AES Indiana included a selectable replacement for Harding Street Unit 7 in the EnCompass model for when it retires. The EnCompass model can select either a 325 MW CCGT, a 300 MW Frame CT, a 270 MW Aero CT, a 270 MW bank of reciprocating engines or a 300 MW four-hour BESS as a replacement for this capacity. In the Clean Replacement Strategy, a 300 MW four-hour BESS replaces Harding Street Unit 7 upon its retirement as the cleanest replacement option. A more robust analysis is needed to understand the exact type of battery that could be used to meet this stability requirement – it is possible that it would require more than four hours of duration. These unit replacement options are assumed to be within the 138kV network but not necessarily at Harding Street.

8.4.2 Scenario Framework

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AES Indiana included four scenarios in the Scenario Analysis. These scenarios are views of the futures defined by external influences like political outcomes, economics, regulations, etc.

The nomenclature of the four scenarios reflects the range of environmental policy and regulation futures. These scenarios include, from least aggressive to most aggressive on environmental policy:

1. No Environmental Action
2. Current Trends (Reference Case)
3. Aggressive Environmental
4. Decarbonized Economy

Each scenario uses a unique set of driving assumptions that align with the future view of the corresponding scenario and act as defining inputs into the EnCompass model. The assumptions categories include:

→ *Load Forecast* – As discussed in Section 5.3 of this report, AES Indiana and Itron modeled three load forecasts (low, base, and high) to serve as load scenarios that correspond to IRP scenario outlooks. AES Indiana and Itron used three different economic forecasts from Moody's to drive the differences in the three load forecast scenarios. In the low load forecast, Moody's assumes a slow economy with persistent inflation and recession. Moody's high forecast assumes a near term economic boom. Moody's base forecast assumes modest economic growth. For more information on these forecasts and the Moody's economic drivers please see Section 5.3.

→ *Electric Vehicle and Distributed Solar Forecasts* – In addition to the three load scenarios, AES Indiana also worked with GDS Associates and the Brightline Group ("Brightline") to forecast different levels of electric vehicle and distributed solar adoption in AES Indiana's service territory. The electric vehicle and distributed solar forecasts are key contributors to load differences in the IRP scenarios and do a nice job of capturing risk and uncertainty associated with load. GDS and Brightline developed four different electric vehicle forecasts (low, base, high, and very high) and three different distributed solar forecasts (low, base, and high). For more information on these forecasts please see Section 5.4.

→ *Commodity Forecasts* – The commodity assumptions that serve as drivers to the IRP scenarios include price forecasts for natural gas, coal, on- and off-peak power, capacity, and NOx. Each scenario in this IRP uses a commodity forecast that reasonably represents the scenario's outlook. For example, the No Environmental Action scenario assumes future deregulation on natural gas development and production and, in turn, an increase in natural gas supply; therefore, the scenario includes the low forecast for natural gas prices assuming a natural gas surplus. For more information on the sources for these commodity forecasts and as reference for the discussion below, please see Section 8.3.1.

→ *Environmental Policy Assumptions* – The driving environmental policy assumptions for the scenarios include forecasts for the ITC for solar and storage resources, PTC for wind resources, and forecasts of future carbon prices. Details will be provided for these assumptions in the following scenario sections.

Figure 8-19 provides an overview of the input assumptions included in each scenario. The following scenario sections will discuss these assumptions in more detail.

Figure 8-19: Overview of Input Assumptions by Scenario

Scenario	Load Forecast	Electric Vehicle/ Distributed Solar	Natural Gas Prices	Coal Prices	Power Prices	Capacity Prices	Nox Prices	ITC/PTC	Carbon Prices
No Environmental Action	Low	Low/Low	Low	Base	Custom	Base	Low	Tax Credits Expire/No Extension	None
Current Trends (Reference Case)	Base	Base/Base	Base	Base	Custom	Base	Base	Five Year Extension	Base
Aggressive Environmental	High	High/High	High	Base	Custom	Base	High	10-year Extension; ITC for Standalone Storage	High

Scenario 1: No Environmental Action

The No Environmental Action scenario, as the name would imply, uses the least aggressive environmental policy assumptions of the scenarios modeled. Included as a "bookend", this scenario is characterized by the following key features:

- → The future is defined by relaxed regulations on natural gas and coal resulting in expanded natural gas development and production, which puts downward pressure on natural gas prices.
- → Inflation is assumed to persist driving low GDP growth, and in turn, low customer growth. This results in a lower demand for electricity, which is captured through a lower load forecast with low customer EV and PV adoption.
- → With no regulation on the coal industry, coal is expected to stay in operation on the MISO system.

Figure 8-20 below provides an overview of the key driving input assumptions to the No Environmental Action Scenario.

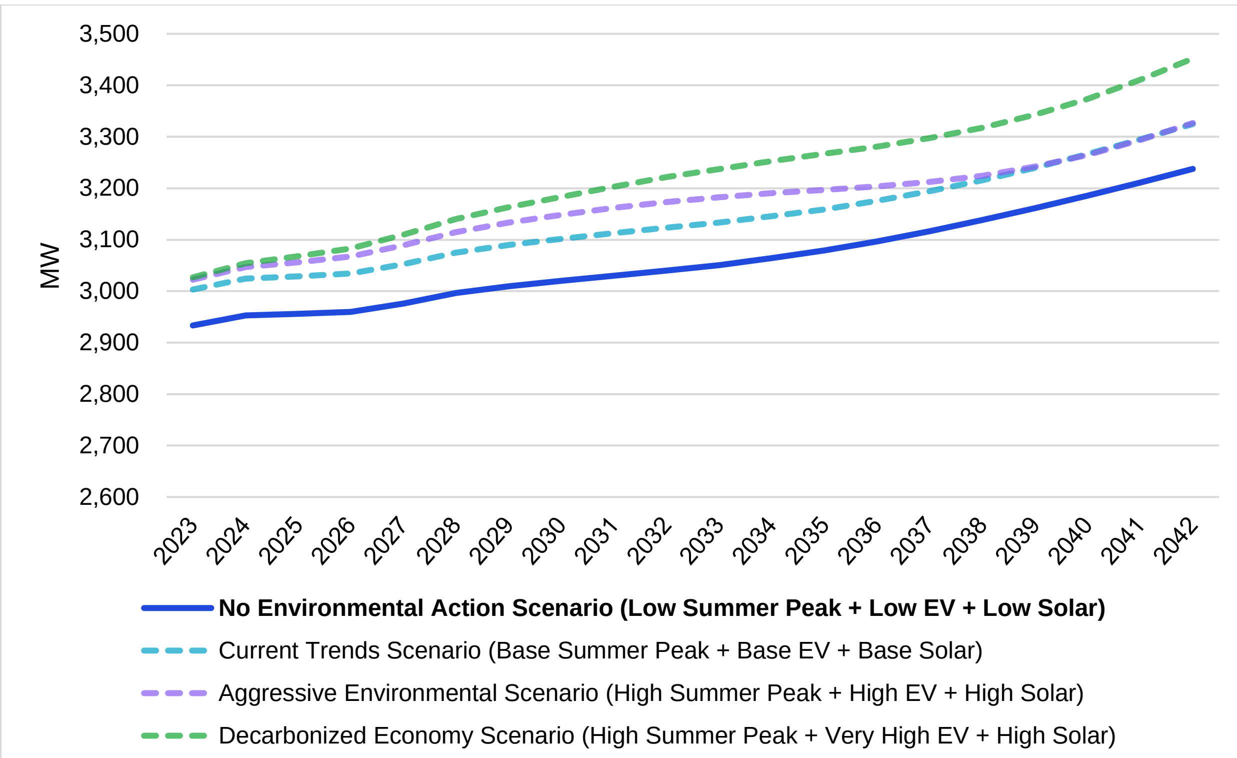
Figure 8-20: No Environmental Action Scenario Input Assumptions

Driving Assumptions							
	Load	EV	PV	Power	Natural Gas	Coal	CO2
No Environmental Action Scenario	Low	Low	Low	Custom	Base	Base	None

No Environmental Action Scenario: Load Assumptions

Figure 8-21 below provides a comparison of the four different peak forecasts that correspond to the four different IRP scenarios. The solid blue line represents the load forecast included in the No Environmental Action scenario. This load forecast is driven by high inflation and low GDP growth assumptions. In addition, the forecast assumes low electric vehicle and distributed solar penetrations among AES Indiana customers over the planning period as these technologies do not receive subsidies under the No Environmental Action scenario. For more information on these forecasts please see Section 5.3 and Section 5.4.

Figure 8-21: No Environmental Action Load Forecast



Note: The load forecast depicted in Figure 8-21 excludes future DSM. Future DSM is modeled as a selectable resource in AES Indiana's 2022 IRP.

No Environmental Action Scenario: Commodity Assumptions

The No Environmental Action scenario includes the following commodity assumptions:

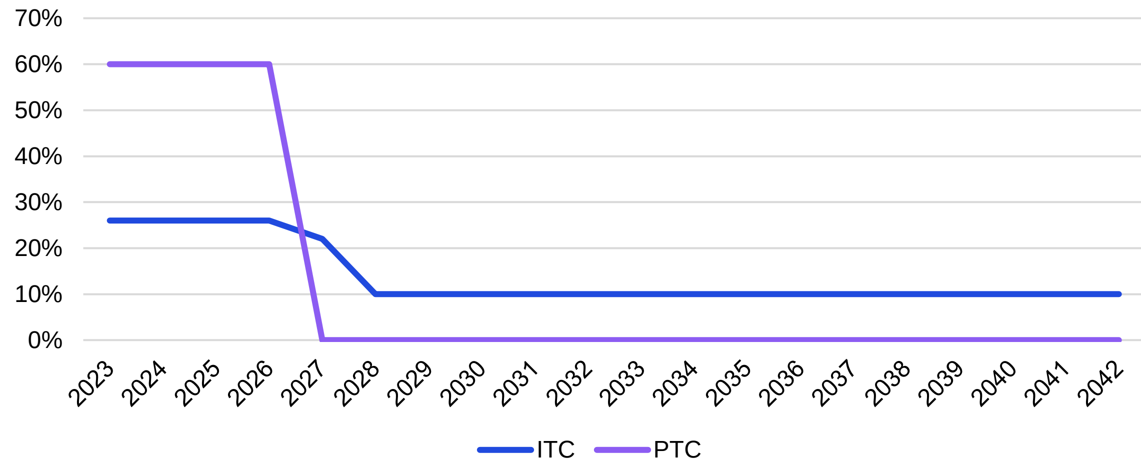
- → *Natural Gas Price Forecast* – As noted above, the No Environmental Action scenario uses the low natural gas price fundamental forecast provided by Horizons Energy. The forecast is blended in the near term with the May 31, 2022 natural gas forward curve from ICE to capture near term market prices. The low forecast is used to represent the relaxed regulation on natural gas production that results in a surplus of natural gas supply.
- → *Coal Price Forecast* – AES Indiana included the base coal price forecast in the No Environmental Action scenario. As described in the Commodity Forecasts section (Section 8.3.1), the coal price forecast is for delivered coal. AES Indiana used information from its most recent coal RFP to estimate the contract price for coal in 2023 and grew that price based on the growth rates in Horizon Energy's Spring Coal Forecast.
- → *On-Peak and Off-Peak Power Price Forecast* – As detailed in the Commodity Forecasts section (Section 8.3.1), Horizon Energy used the corresponding natural gas price forecast, coal price forecast, NOx price forecast, ITC, and PTC assumptions, and carbon price assumptions as inputs in EnCompass to perform custom fundamental MISO power price forecasts for each scenario. The power price forecasts for the different scenarios are presented graphically in Figure 8-3 in the Commodity Forecasts section (Section 8.3.1). Horizons Energy fundamental forecasts produced hourly power price shapes that were included in the EnCompass modeling, tailored to this scenario.
- → *Capacity Price Forecast* – AES Indiana modeled the seasonal construct as proposed by MISO starting in the 2023/2024 planning year. For capacity price, the Company assumes the market will be at CONE in all four seasons. The capacity price forecast is presented graphically in Figure 8-7 in the Commodity Forecasts section (Section 8.3.1).
- → *NOx Price Forecast* – AES Indiana included the low NOx price forecast in the No Environmental Action scenario. See Commodity Forecasts section (Section 8.3.1) for more detail regarding the NOx forecasts included in this IRP.

For more information on the sources for these commodity forecasts and as reference for the discussion below, please see Section 8.3.

No Environmental Action Scenario: Environmental Policy Assumptions

The No Environmental Action scenario assumes that the current ITC and PTC are allowed to expire in the near term. Figure 8-22 below provides a summary of the ITC and PTC assumptions over the planning period. For IRP modeling, both the ITC and PTC are assumed to include the Safe Harbor provision, which allows a developer to take advantage of the tax credits if the developer begins construction of the project within the tax credit window, as long as the project is completed within four years of initial construction. Therefore, the tax credits persist to 2026 in Figure 8-22 below even though they technically expire at the end of 2022. As shown, the ITC continues at 26% through 2026 and then gradually decreases to 10% through the IRP planning period. The PTC remains at 60% through 2026 and then drops to zero starting in 2027.

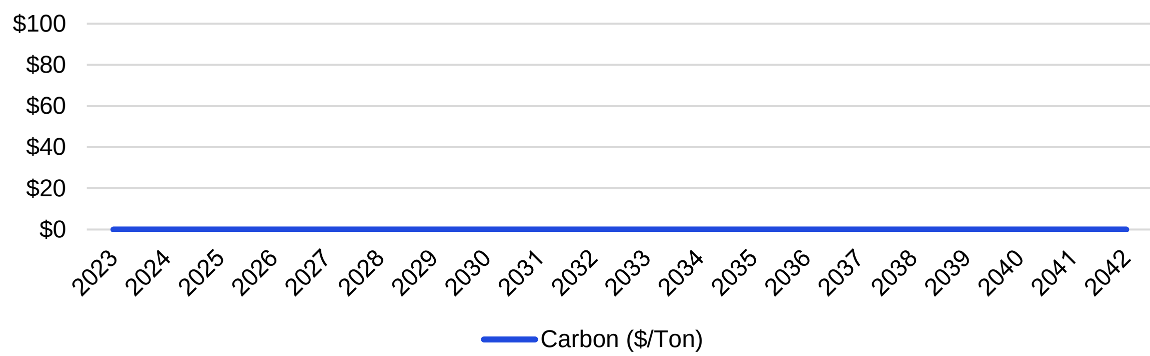
Figure 8-22: No Environmental Action Scenario ITC and PTC Assumptions



Note: Years correspond to years projects first produce energy

No carbon price is included in the No Environmental Action scenario as illustrated in Figure 8-23 below.

Figure 8-23: No Environmental Action Scenario Carbon Price Assumptions



Scenario 2: Current Trends/Reference Case (Candidate Portfolios)

The Current Trends scenario is consistent with current progress and action on environmental policy through 2021. Early in IRP planning, this scenario included only five one-year extensions of the ITC and PTC; however, with the passage of the IRA in August of 2022 the scenario was modified to reflect the tax provisions consistent with the IRA.[53] The existence and level of these tax incentives have an important impact on the replacement costs for renewable resources in the modeling. Accordingly, the passage of the IRA positively impacted the selection of solar, wind and storage and replacement resources, particularly battery energy storage, which now receives an ITC as a standalone resource.

This scenario is characterized by the following key features:

[53] https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

- → Reflects tax provision included in the IRA passed in August 2022.
- → The ITC and PTC extended for ten years and were restored to full levels.
- → ITC extended to battery energy storage as a standalone resource.
- → Assumes modest price for carbon starting at $6.49 per ton in the late 2020s escalating at 4.6%.

Figure 8-24 below provides an overview of the key driving input assumptions to the Current Trends scenario.

Figure 8-24: Current Trends Scenario Input Assumptions

Driving Assumptions							
	Load	EV	PV	Power	Natural Gas	Coal	CO2
Current Trends Scenario	Base	Base	Base	Custom	Base	Base	Low

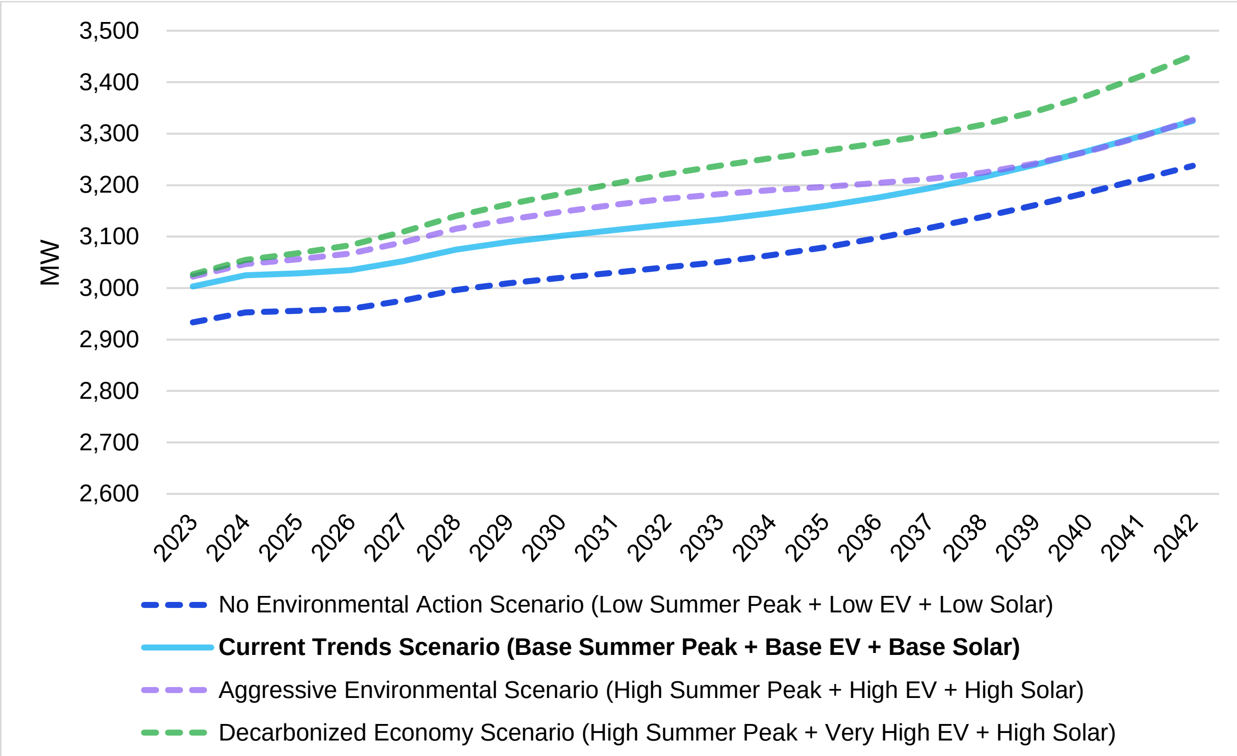
Current Trends Scenario: Load Assumptions

Figure 8-25 below provides a comparison of the four different peak forecasts that correspond to the four different IRP scenarios. The solid turquoise line represents the load forecast included in the Current Trends scenario. This load forecast is driven by moderate inflation and normal GDP growth assumptions with no recession. The load forecast uses Moody's economic outlook from the fourth quarter of 2021.

The base load forecast also assumes the base electric vehicle and distributed solar adoption forecasts among AES Indiana customers over the planning period.

For more information on the load, EV, and distributed solar forecasts, please see Section 5.3 and Section 5.4.

Figure 8-25: Current Trends Load Forecast



Note: The load forecast depicted in Figure 8-23 excludes future DSM. Future DSM is modeled as a selectable resource in AES Indiana's 2022 IRP.

Current Trends Scenario: Commodity Assumptions

The Current Trends Scenario includes the following assumptions for commodities:

→ *Natural Gas Price Forecast* – The Current Trends scenario uses the base natural gas price fundamental forecast provided by Horizons Energy. The forecast is blended in the near term with the May 31, 2022 natural gas forward curve from ICE to capture near term market prices. The base natural gas forecast aligns with the Current Trends view that natural gas-fired generation will continue to be a relevant resource with continued demand through the planning period which includes modest environmental regulation and a small carbon price.

→ *Coal Price Forecast* – AES Indiana included the base coal price forecast in the Current Trends Scenario. As described in the Commodity Forecasts section (Section 8.3.1), the coal price forecast is for delivered coal. AES Indiana used information from its most recent coal RFP to estimate the contract price for coal in 2023 and grew that price based on the growth rates in Horizon Energy's Spring Coal Forecast.

→ *On-Peak and Off-Peak Power Price Forecast* – As detailed in the Commodity Forecasts section of this Report (Section 8.3.1), Horizon Energy used the corresponding natural gas price forecast, coal price forecast, NOx price forecast, ITC and PTC assumptions and carbon price assumptions as inputs in EnCompass to perform custom fundamental MISO power price forecasts for each scenario. The power price forecasts for the different scenarios are presented graphically in Figure 8-3 in the Commodity Forecasts section of this Report (Section 8.3.1). Horizons Energy fundamental forecasts produced hourly power price shapes that were included in the EnCompass modeling, tailored to this scenario.

→ *Capacity Price Forecast* – AES Indiana modeled the seasonal construct as proposed by MISO starting in the 2023/2024 planning year. The Company assumes the capacity market will clear at CONE in all four seasons. The capacity price forecast is presented graphically in Figure 8-7 in the Commodity Forecasts section (Section 8.3.1).

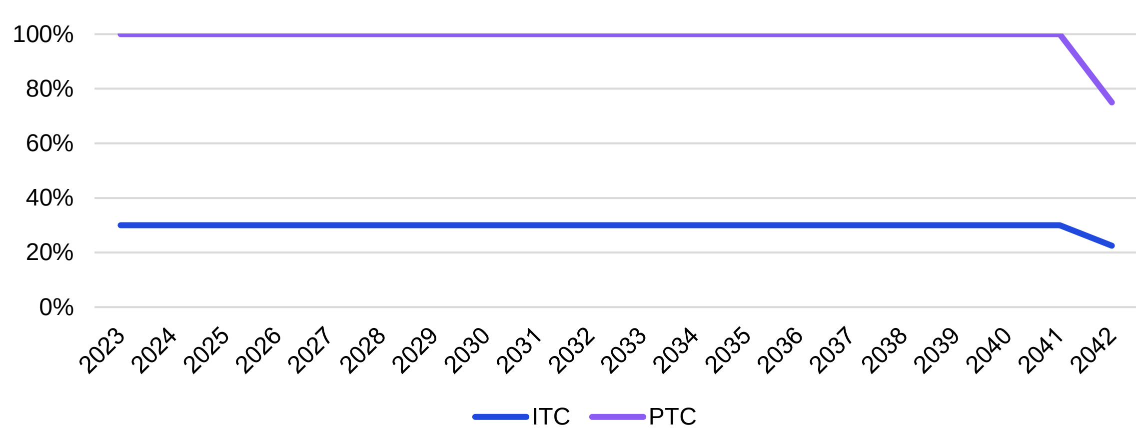
→ *NOx Price Forecast* – AES Indiana included the base NOx price forecast in the No Environmental Action scenario. See Commodity Forecasts section (Section 8.3.1) for more detail regarding the NOx forecasts included in this IRP.

For more information on the sources for these commodity forecasts and as reference for the discussion below, please see Section 8.3.

Current Trends Scenario: Environmental Policy Assumptions

The Current Trends scenario assumes that the current ITC and PTC are consistent with the provisions in the IRA. Figure 8-26 below provides a summary of the ITC and PTC assumptions over the Current Trends planning period. For IRP modeling, both the ITC and PTC are assumed to include the Safe Harbor provision, which allows a developer to take advantage of the tax credits if they begin construction of the project within the tax credit window as long as the project is completed within four years of initial construction. As shown, the ITC remains at 30% and PTC at 100% through nearly the entire planning period when factoring in Safe Harbor.

Figure 8-26: Current Trends Scenario ITC and PTC Assumptions



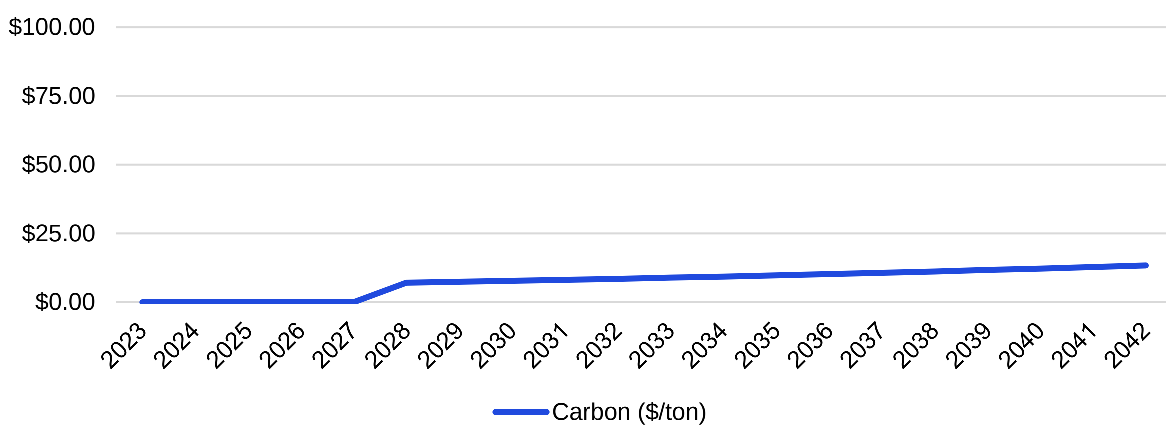
Note: Years correspond to years projects first produce energy

The Current Trends scenario assumes a carbon price starting at $6.49 per ton beginning in 2028 and escalating at 4.6% through planning period as displayed in Figure 8-27. This estimate is consistent with 1/3 the value of the Social Cost of Carbon as calculated by the U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases.[54]

170 IAC § 4-7-4(25) requires a description and analysis of the utility's reference case scenario. Subpart 25(D) provides the reference case scenario should not include future resources, laws, or policies unless: (i) a utility solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A reference case scenario need not align with the utility's preferred resource portfolio.

AES Indiana received significant input from stakeholders regarding the importance of carbon reduction throughout its IRP stakeholder process. This input led AES Indiana to seek stakeholder input regarding the inclusion of a tax on carbon emissions in its reference case scenario (i.e., the Current Trends scenario). AES Indiana balanced a variety of stakeholders' viewpoints around future carbon tax policy. However, AES Indiana found stakeholders largely supported the inclusion of a carbon tax in AES Indiana's base case scenario. AES Indiana acknowledges there is uncertainty around the prospect and magnitude of a future federal price on carbon. AES Indiana believes there is a high probability the U.S. federal government takes some form of action on carbon emissions during the 20-year IRP planning period. Therefore, AES Indiana included a small carbon price assumption in its base case scenario that, while modest compared to the Social Cost of Carbon as calculated by the U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases, effectively captures action on carbon.

Figure 8-27: Current Trends Scenario Carbon Price Assumptions



[54] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

Scenario 3: Aggressive Environmental

The Aggressive Environmental Scenario assumes legislation is passed by Congress that institutes significant environmental policy over the planning period.

This scenario assumes the ITC and PTC are consistent with provisions included in the IRA. Additionally, this scenario assumes additional legislative action passes an aggressive carbon tax starting in 2028 at $19.47 per ton and escalating at 4.6% through the planning period.

This scenario uses the assumptions detailed in Figure 8-28 and is characterized by the following key features:

- → ITC and PTC extensions and levels are consistent with those included in the Inflation Reduction Act of 2022.
- → Congress passes a second round of environmental legislation later in the planning period that includes carbon tax starting in 2028.
- → Includes high demand scenario with high electric vehicle and distributed solar forecasts.
- → Across the industry, near term transition from coal to natural gas and tightened regulation on natural gas development and production results in high natural gas prices.
- → Tighter seasonal NOx emission regulations.
- → Tighter regulation of Coal Combustion Products ("CCP") resulting in higher operating costs for coal units.

Figure 8-28: Aggressive Environmental Scenario Input Assumptions

Driving Assumptions							
	Load	EV	PV	Power	Natural Gas	Coal	CO2
Aggressive Environmental Scenario	High	High	High	High	High	Base	High

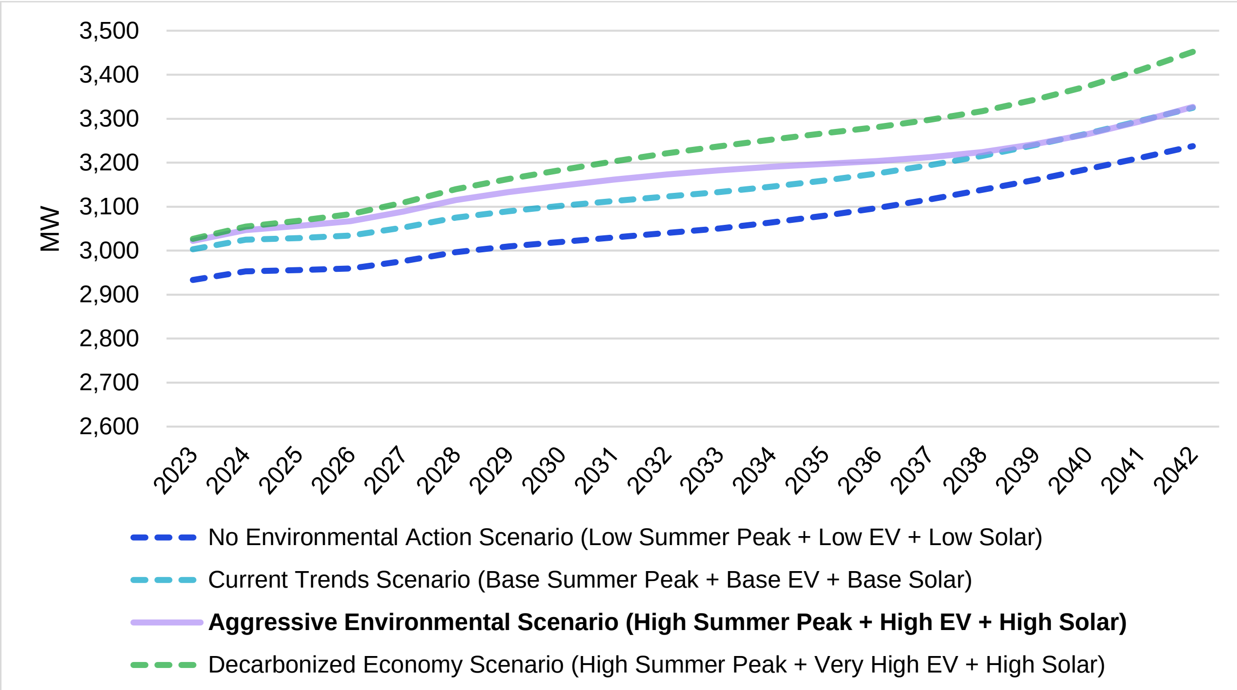
Aggressive Environmental Scenario: Load Assumptions

Figure 8-29 below provides a comparison of the four different peak forecasts that correspond to the four different IRP scenarios. The solid purple line is the load forecast included in the Aggressive Environmental scenario. This "high" load forecast is driven by a growing economy with high GDP growth assumptions using Moody's S1: Alternative Scenario 1 – Upside – 10th Percentile. These economic assumptions are consistent with the idea that investment in green energy resources, consistent with the policy assumptions in this scenario, will drive economic growth or the idea of a Green Energy Economy.

The load forecast in this scenario also assumes the high electric vehicle and distributed solar adoption forecasts among AES Indiana customers over the planning period.

For more information on the load, EV and distributed solar forecasts please see Section 5.3 and Section 5.4.

Figure 8-29: Aggressive Environmental Scenario Load Forecast



Note: The load forecast depicted in Figure 8-29 excludes future DSM. Future DSM is modeled as a selectable resource in AES Indiana's 2022 IRP.

Aggressive Environmental Scenario: Commodity Assumptions

The Aggressive Environmental Scenario includes the following assumptions for commodities:

→ *Natural Gas Price Forecast* – The Aggressive Environmental scenario uses the high natural gas price fundamental forecast provided by Horizons Energy. The forecast is blended in the near term using the May 31, 2022 natural gas forward curve from ICE to capture near term market prices. The high natural gas forecast aligns with the Aggressive Environmental view that utilities use natural gas as a transitional fuel creating higher natural gas demand and regulation tightens natural gas development and production reducing natural gas supply.

→ *Coal Price Forecast* – AES Indiana included the base coal price forecast in the Aggressive Environmental Scenario. As described in the Commodity Forecasts section of this Report (Section 8.3.1), the price forecast is for delivered coal. AES Indiana used information from its most recent coal RFP to estimate the contract price for coal in 2023 and grew that price based on the growth rates in Horizon Energy's Spring Coal Forecast.

→ *On-Peak and Off-Peak Power Price Forecast* – As detailed in the Commodity Forecasts section (Section 8.3.1), Horizon Energy used the corresponding natural gas price forecast, coal price forecast, NOx price forecast, ITC and PTC assumptions and carbon price assumptions as inputs in EnCompass to perform custom fundamental MISO power price forecasts for each scenario. The power price forecasts for the different scenarios are presented graphically in Figure 8-3 in the Commodity Forecasts section (Section 8.3.1). Horizons Energy fundamental forecasts produced hourly power price shapes that were included in the EnCompass modeling, tailored to this scenario.

→ *Capacity Price Forecast* – AES Indiana modeled the seasonal construct as proposed by MISO starting in the 2023/2024 planning year. For capacity price, the Company assumes the market will be at the Cost of New Entry (CONE) in all four seasons. The Capacity price forecast is presented graphically in Figure 8-7 in the Commodity Forecasts section (Section 8.3.1).

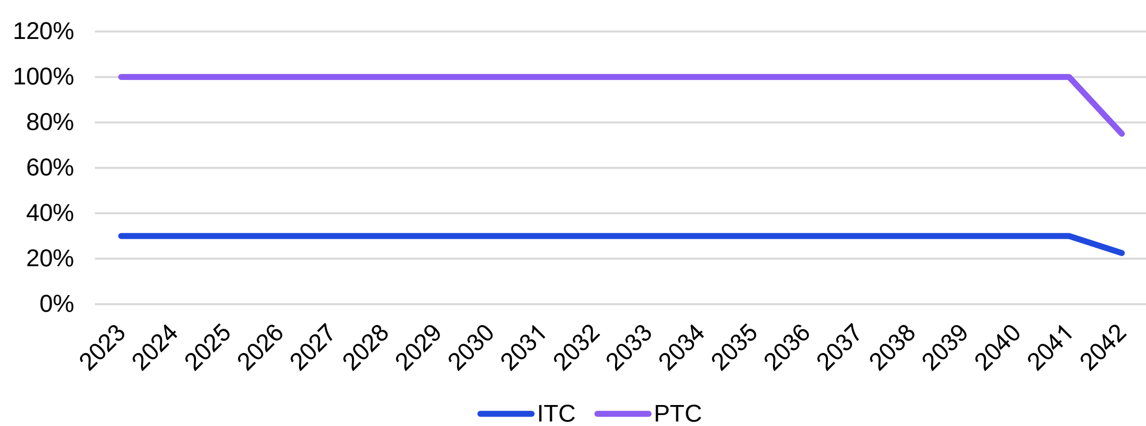
→ *NOx Price Forecast* – AES Indiana included the high NOx price forecast in the Aggressive Environmental scenario. See Commodity Forecasts section (Section 8.3.1) for more detail regarding the NOx forecasts included in this IRP.

For more information on the sources for these commodity forecasts and as reference for the discussion below, please see Section 8.3.

Aggressive Environmental Scenario: Environmental Policy Assumptions

The Aggressive Environmental scenario assumes that the current ITC and PTC are extended for the next ten years consistent with IRA. Additionally, the ITC is increased to 30% and the PTC is increased to 100% of the eligible incentive. Figure 8-30 below provides a summary of the ITC and PTC assumptions over the planning period. For IRP modeling, both the ITC and PTC are assumed to include the Safe Harbor provision which allows a developer to take advantage of the tax credits if they begin construction of the project within the tax credit window as long as the project is completed within four years of initial construction. The ITC and PTC are available through the entire planning period when considering the Safe Harbor provision. Additionally, this scenario also makes standalone storage eligible for the ITC.

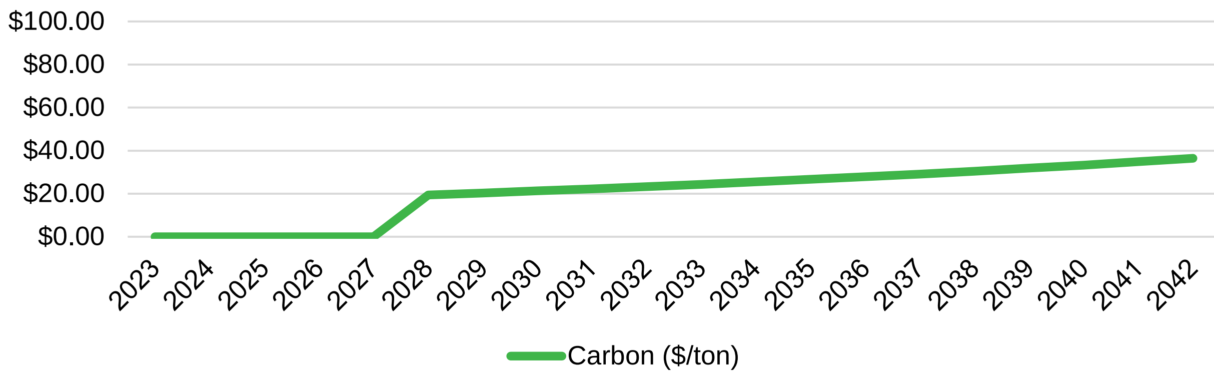
Figure 8-30: Aggressive Environmental Scenario ITC and PTC Assumptions



Note: Years in Figure 8-30 correspond to years projects first produce energy.

The Aggressive Environmental scenario assumes a carbon price set at $19.47 per ton starting in 2028 and escalating at 4.6% through remainder of the planning period. This carbon price is consistent with the value of the Social Cost of Carbon as calculated by the U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases using a 5% discount rate.[55] Figure 8-31 below graphically illustrates the carbon price over the planning period.

Figure 8-31: Aggressive Environmental Scenario Carbon Price Assumptions



Scenario 4: Decarbonized Economy

The Decarbonized Economy scenario is the most environmentally aggressive of the four scenarios. It assumes aggressive decarbonization policy measures achieved through a Renewable Portfolio Standard ("RPS"). The RPS is similar to the Clean Energy Performance Program ("CEPP") proposed in early iterations of the Build Back Better bill in 2021. The RPS requires electric utilities to meet a certain percentage their load obligation through clean energy. This percentage increases over the planning period starting at 11% in 2023 and ending at 85% in 2042. Utilities incur a $40 per MWh annual penalty for any of their load target that is not served by clean energy resources (i.e., solar, wind, or storage resources) in the IRP modeling. If a utility surpasses their clean energy annual target, they receive annual reward of $150 per MWh for every MWh in excess.

As described in Figure 8-32, this scenario is characterized by the following key features:

- → Congress passes aggressive decarbonization mandate on power sector with explicit clean energy generation targets.
- → High ITC/PTC runs through planning horizon.
- → Carbon targets achieved through a Renewable Portfolio Standard that targets net zero emissions; not a market mechanism like a carbon tax or cap and trade.
- → High load driven by very high electrification captures risk and uncertainty associated with load volatility.

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55 https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

→ Base natural gas prices driven by low demand due to reduced natural gas resources.

Figure 8-32: Decarbonized Economy Scenario Input Assumptions

Driving Assumptions							
	Load	EV	PV	Power	Natural Gas	Coal	CO2
Decarbonized Economy Scenario	High	Very High	High	Base	Base	Base	None

Decarbonized Economy Scenario: Load Assumptions

Figure 8-33 below provides a comparison of the four different peak forecasts that correspond to the four different IRP scenarios. The green line is the load forecast included in the Decarbonized Economy scenario. This high load forecast is driven by a growing economy with high GDP growth assumptions using Moody's S1: Alternative Scenario 1 – Upside – 10th Percentile. Like the Aggressive Environmental scenario, these economic assumptions are consistent with the idea that investment in green energy resources, consistent with the policy assumptions in this scenario, will drive economic growth or the idea of a Green Energy Economy.

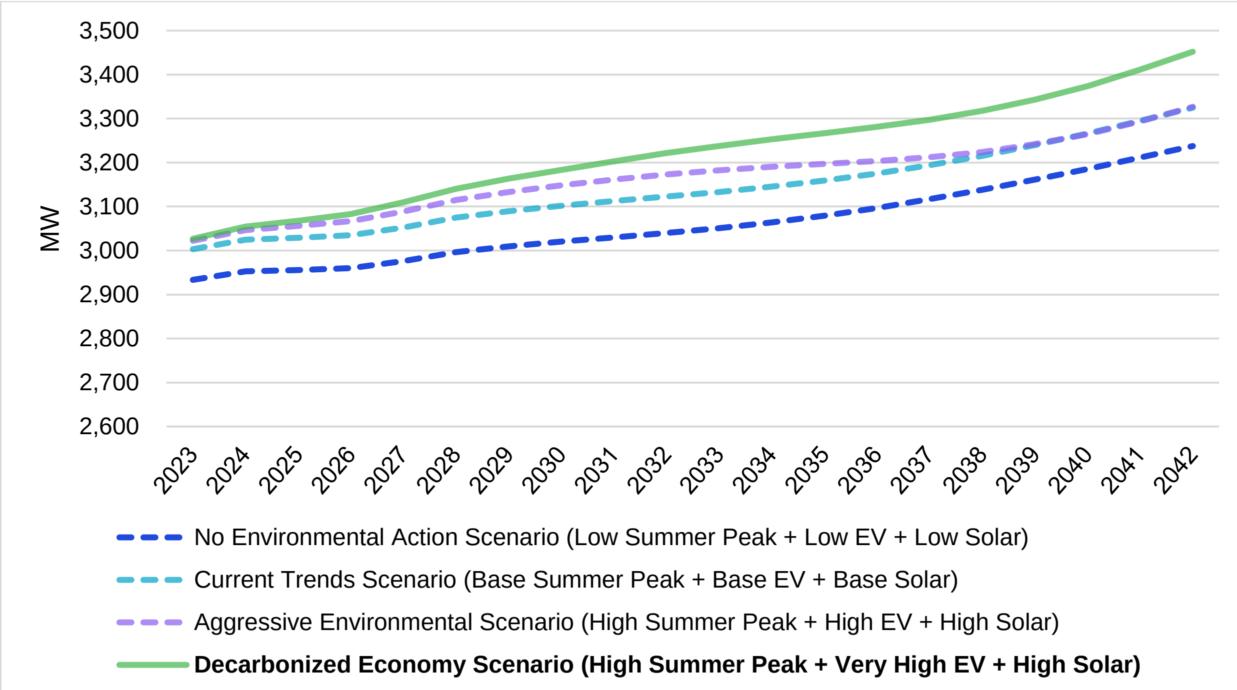
The load forecast in this scenario assumes the very high electric vehicle forecast with electric vehicles making up 85% of vehicle sales by 2043. The forecast also includes high distributed solar adoption forecasts among AES Indiana customers over the planning period.

Additionally, during the planning process, the Citizens Action Coalition ("CAC") requested an industrial decarbonization forecast be added to the IRP planning scenarios. Because AES Indiana was advanced in the planning process, the Company proposed adding a high electrification forecast that represents industrial decarbonization to the Decarbonized Economy scenario. The CAC agreed and the forecast was included. See Section 5.3 for more detail regarding this forecast.

Modeling aggressive electrification in this scenario has a significant impact on customer load. Capturing this potential addresses some of the risk and uncertainty associated with load volatility.

For more information on the load, EV and distributed solar forecasts please see Section 5.3 and Section 5.4.

Figure 8-33: Decarbonized Economy Scenario Load Forecast



Note: The load forecast depicted in Figure 8-33 excludes future DSM. Future DSM is modeled as a selectable resource in AES Indiana's 2022 IRP.

Decarbonized Economy Scenario: Commodity Assumptions

The Decarbonized Economy Scenario includes the following assumptions for commodities:

→ *Natural Gas Price Forecast* – The Decarbonized Economy scenario uses the base natural gas price fundamental forecast provided by Horizons Energy. The forecast is blended in the near term using the May 31, 2022 natural gas forward curve from ICE to capture near term market prices. The Decarbonized Economy scenario assumes a Renewable Portfolio Standard will increasingly drive down the demand for natural gas-fired generation over the planning period. Accordingly, the base natural gas price forecast reflects the moderate demand for natural gas in this scenario.

→ *Coal Price Forecast* – AES Indiana included the base coal price forecast in the Decarbonized Economy scenario. As described in the Commodity Forecasts section (Section 8.3.1), the price forecast is for delivered coal. AES Indiana used information from its most recent coal RFP to estimate the contract price for coal in 2023 and grew that price based on the growth rates in Horizon Energy's Spring Coal Forecast.

→ *On-Peak and Off-Peak Power Price Forecast* – As detailed in the Commodity Forecasts section (Section 8.3.1), Horizon Energy used the corresponding natural gas price forecast, coal price forecast, NOx price forecast, ITC and PTC assumptions and carbon price assumptions as inputs in EnCompass to perform custom fundamental MISO power price forecasts for each scenario. The power price forecasts for the different scenarios are presented graphically in Figure 8-3 in the Commodity Forecasts section (Section 8.3.1). Horizons Energy fundamental forecasts produced hourly power price shapes that were included in the EnCompass modeling, tailored to this scenario.

→ *Capacity Price Forecast* – AES Indiana modeled the seasonal construct as proposed by MISO starting in the 2023/2024 planning year. For capacity price, the Company assumes the market will be at the Cost of New Entry (CONE) in all four seasons. The Capacity price forecast is presented graphically in Figure 8-7 in the Commodity Forecasts section (Section 8.3.1).

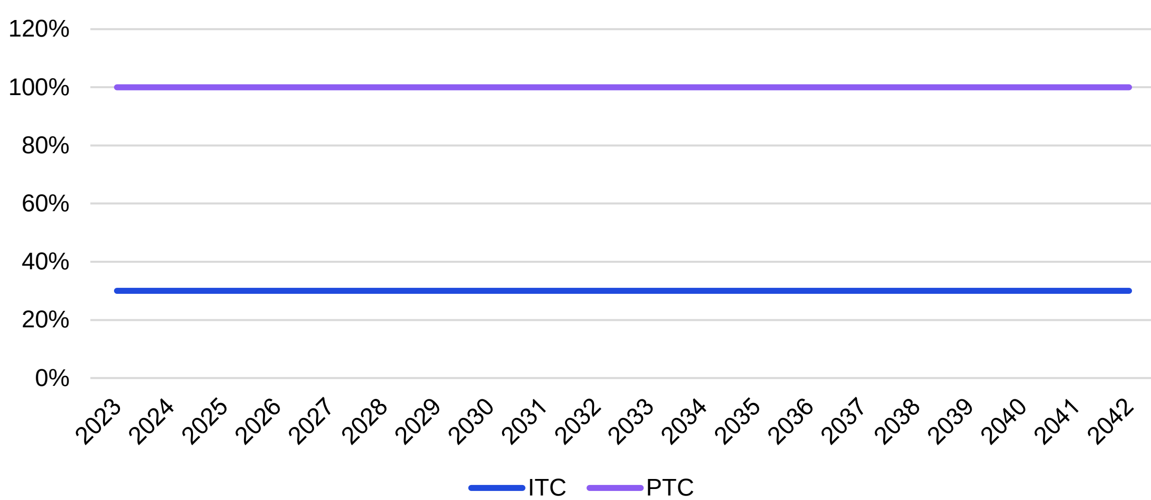
→ *NOx Price Forecast* – AES Indiana included the high NOx price forecast in the Decarbonized Economy scenario. The high NOx forecast assumes aggressive NOx regulation and some scarcity in the NOx market. See Commodity Forecasts section (Section 8.3.1) for more detail regarding the NOx forecasts included in this IRP.

For more information on the sources for these commodity forecasts and as reference for the discussion below, please see Section 8.3.

Decarbonized Economy Scenario: Environmental Policy Assumptions

The Decarbonized Economy scenario assumes the ITC and PTC are extended indefinitely to support utilities' efforts to meet the Renewable Portfolio Standard. Figure 8-34 below provides a summary of the ITC and PTC assumptions over the Decarbonized Economy planning period. For IRP modeling, both the ITC and PTC are assumed to include the Safe Harbor provision which allows a developer to take advantage of the tax credits if they begin construction of the project within the tax credit window as long as the project is completed within four years of initial construction. The ITC is held at 30% and the PTC at 100% of the available incentive over the planning period.

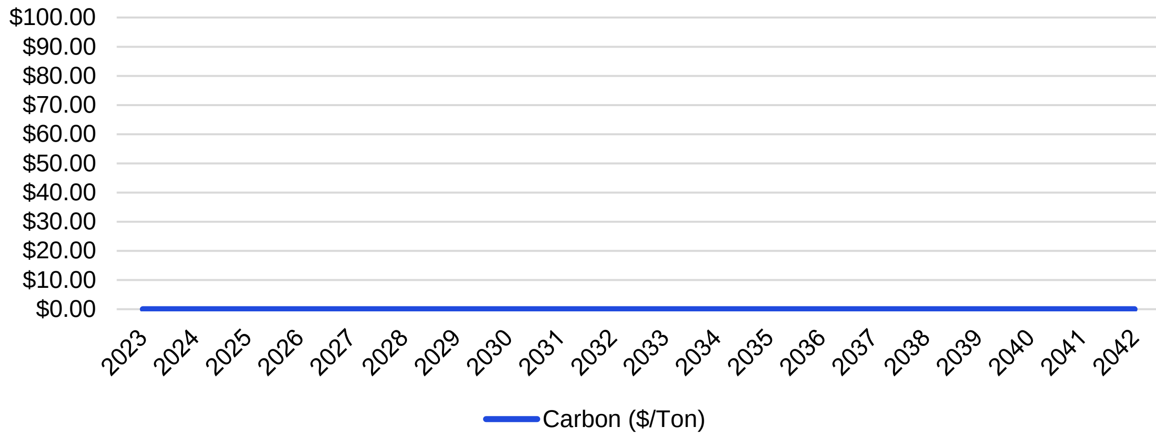
Figure 8-34: Decarbonized Economy Scenario ITC and PTC Assumptions



Note: The years in Figure 8-34 correspond to years projects first produce energy.

The Decarbonized Economy scenario does not include a carbon price. Instead, the Renewable Portfolio Standard acts as the primary driver for decarbonization. Figure 8-35 below illustrates the lack of carbon price over the planning period.

Figure 8-35: Decarbonized Economy Scenario Carbon Price Assumptions



The Decarbonized Economy scenario also includes a Renewable Portfolio Standard which is very similar to the CEPP that was proposed in very early iterations of the Build Back Better legislation in 2021. The standard requires utilities to supply a certain percentage of the load they serve with renewable energy. Figure 8-36 below shows the clean energy percentage targets over the planning period. The standard starts at 11% in 2023 and ends at 85% in 2042. Utilities that fail to meet the target pay a $40 per MWh penalty. These components are captured in the scenario modeling.

Figure 8-36: Decarbonized Economy Scenario Clean Energy Portfolio Constraints

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Clean Energy Portfolio Constraint	11%	15%	19%	23%	27%	31%	35%	39%	43%	47%	51%	55%	59%	63%	67%	71%	75%	79%	83%	85%

Ozone NAAQS and NOx

As noted in Section 7.4, AES Indiana anticipates changes in the State Ozone NAAQS requirements in 2028 that would require AES Indiana to install an SNCR on Petersburg Unit 4 to meet compliance. To account for this in the IRP modeling, the Company included additional NOx allowance purchases for Petersburg Unit 4 starting in 2028 in the strategies where Petersburg Unit 4 remains on coal through this date. This was calculated as 1,000 tons (the estimated quantity of NOx emissions that would need allowances) times the NOx allowance price – which varies by scenario. This cost serves as a proxy for the cost of compliance, which can be accomplished by a number of solutions of varying effectiveness and cost.

8.4.3 Final Portfolio Matrix

Combining the strategies and scenarios described above results in the Portfolio Matrix in Figure 8-37 below. The Portfolio Matrix acts as the modeling framework for the capacity expansion analysis. AES Indiana modeled capacity expansion for each strategy under each scenario – resulting in a total of 24 capacity expansion portfolios for comparison. Please see Section 9.2.2 for the results from this analysis.

In addition to the five prescribed generation strategies detailed in Section 8.4.1, AES Indiana modeled a sixth analysis, the EnCompass Optimization analysis, which appears in the Portfolio Matrix. As noted in Section 8.4.1, this analysis allowed the EnCompass Model to optimize without any predefined strategies. The results provide for a comparison of the optimized portfolios Encompass determines as most cost effective to the predefined generation strategies. Please see Section 9.2.2 for the completed Portfolio Matrix with portfolio PVRR comparisons. Figure 8-37 below presents a sample of AES Indiana's final Portfolio Matrix.

Figure 8-37: Final Portfolio Matrix

		Scenarios			
		No Environmental Action	**Current Trends/Reference Case**	**Aggressive Environmental**	**Decarbonized Economy**
Generation Strategies	**No Early Retirement**				
	Petersburg Conversion (est. 2025)				
	One Petersburg Unit Retires (2026)				
	Both Petersburg Units Retire (2026 and 2028)				
	Clean Energy Strategy (2026 and 2028)				
	Encompass Optimization without predefined Strategy				

See Section 9.2.2 for Completed Portfolio Matrix

8.4 Sensitivity Analysis

A sensitivity analysis stresses a single variable while holding other assumptions constant to isolate the impact of that variable. This provides clear insight into the risk associated with key variables that are difficult to know with certainty. This differs from a scenario analysis, which changes many assumptions at once that reflect a much different overall view of the future rather than a single specific variable.

8.4.1 Replacement Resource Capital Cost Sensitivity Analysis

AES Indiana used responses to its 2022 all-source RFP to inform the costs of replacement resources that are included as assumptions in the EnCompass Model. These costs are important because they determine whether alternative resources are cost effective replacements for retiring resources. The higher the cost of a replacement resource, the less likely the model is to select it as a replacement resource if there are more cost effective alternatives.

When compared to the Company's 2020 RFP, AES Indiana experienced price increases across all resources in the responses to its 2022 RFP, which was issued in April 2022. These increases are attributed to significant supply constraints that have resulted from COVID-driven manufacturing shortages combined with high demand for renewable technologies. Additionally, the solar market has experienced uncertainty due to potential Anti-Dumping Countervailing Duties ("AD/CVD") that were under review by the Department of Commerce. The Biden Administration delayed a decision on these tariffs until 2024, which means there is still significant uncertainty for most of the IRP planning period. Despite the AD/CVD pause, at present, the Uyghur Forced Labor Prevention Act ("UFLPA") is delaying the importation of solar modules due to the documentation required to disprove the "rebuttable presumption" that all goods produced or manufactured wholly or in part in China's Xinjiang region are presumed to be made with forced labor and are prohibited from entry into the US.

Given the uncertainty and volatility that the drivers noted above have created, AES Indiana conducted a Replacement Resource Capital Cost Sensitivity Analysis as part of the capacity expansion analysis to understand how the portfolio mixes and costs under the Current Trends/Reference Case scenario or Candidate Portfolios (i.e., all strategies under Current Trends) would change if prices for replacement resources ultimately end up very different from those being used as a base case. The Company established three tiers of replacement resource costs – low, base, and high. The basis for these cost tiers are described below:

→ *Low* – low replacement resource costs are based on the average of Wood Mackenzie's North American Long Term Outlook 2021 Base Case Update, NREL's 2021 ATB, and BNEF's 2H 2021 LCOE Report, and benchmarked against the responses from AES Indiana's 2020 RFP.

→ *Base* – base costs were based on the lower half (below and including the median) of the 2022 RFP responses.

→ *High* – high costs were based on the upper half (above the median) of the 2022 RFP responses.

Figure 8-38 below provides the cost tiers in 2023 by resource that were included in the Replacement Resource Capital Cost Sensitivity Analysis. Cost forecasts were derived for the entire period by applying the learning curves (2023 - 2042) from the Wood Mackenzie, NREL and BNEF forecasts (noted above for the low tier) to the base 2023 costs identified in the table. Please see Section 9.3.2 for the Replacement Resource Capital Costs Sensitivity Analysis results.

Figure 8-38: Replacement Resource Capital Cost Sensitivity Analysis Cost Tiers[56]

	Low	Base	High
Wind	$1,477	$1,909	$2,340
Solar	$1,036	$1,364	$1,925
4-hr Storage	$1,016	$1,253	$1,447
6-hr Storage	$1,525	$1,880	$2,170
Hybrid	$985	$1,270	$1,689
CCGT	$1,028	$1,120	$1,212
Frame CT	$868	$945	$1,023
Aero CT	$1,328	$1,447	$1,566
Recip. Engine	$1,277	$1,391	$1,505

8.5 Portfolio Metrics & Scorecard

AES Indiana compiled a comprehensive set of portfolio metrics that make up the IRP Scorecard Evaluation that was used to evaluate the candidate portfolios and ultimately select the Company's Preferred Resource Portfolio and Short Term Action Plan. The Scorecard Evaluation uses a categorical framework as guidance for the Scorecard Evaluation portfolio metrics. This framework was based upon the "Five Attributes or Pillars of Electric Utility Service" as defined by Indiana's 21st Century Energy Policy Development Task Force ("Task Force"). The Task Force was created through House Enrolled Act 1278 of the 2019 session of the Indiana General Assembly. The Task Force's mission is to conduct a comprehensive study of statewide impacts, both near and long term, of:

1. Transitions in the fuel sources and other resources used to generate electricity by electric utilities; and
2. New and emerging technologies for the generation of electricity, including the potential impact of such technologies on local grids or distribution infrastructure; on electric generation capacity, system reliability, system resilience, and the cost of electric service for consumers. In conducting the study required, the Commission shall consider the likely timelines for the transitions in fuel sources and other resources described in subdivision (1) and for the implementation of new and emerging technologies described in subdivision (2).

In its 2020 report to the Indiana General Assembly, the Task Force defined "The Five Attributes or Pillars of Electric Service" as its Framework #1. These attributes serve as "the lens through which the Task Force would view all potential policy options," as well as the framework for their findings and recommendations. These attributes or "pillars" are:

[56] These costs were calibrated using the average of the Wood Mackenzie, NREL and BNEF experience curves over the planning period.

1. **Reliability** – Consisting of Adequacy and Operating Reliability.
    a. Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonable expected unscheduled outages of system components.
    b. Operating Reliability is the ability of the electric system to withstand sudden disturbances such as electric circuits or unanticipated loss of system components.
2. **Resilience** is the ability of a system or its components to adapt to changing conditions, and to withstand and rapidly recover from disruptions.
3. **Stability** is the ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbance.
4. **Affordability** (to the customer).
5. **Environmental Sustainability**.

AES Indiana's Scorecard Evaluation metrics were guided by these five pillars. In addition, the Company included two extra categories for Risks and Opportunities and Social and Economic Impact. AES Indiana's 2022 IRP Scorecard Evaluation includes a total of five categories (note that Reliability, Resilience and Stability are combined into one):

1. Affordability;
2. Environmental Sustainability;
3. Reliability, Resilience, and Stability;
4. Risks and Opportunities; and
5. Social and Economic Impact.

AES Indiana calculated Scorecard Evaluation metrics for only the strategies in the Current Trends (Reference Case) scenario. This is because the Current Trends (Reference Case) scenario aligns with the Company's policy and commodity assumption outlook; therefore, the strategies in the Current Trends (Reference Case) scenario are ultimately the Candidate Portfolios from which the Company will select its Preferred Resource Portfolio.

Note for the discussion that follows – Candidate Portfolios are the strategies modeled through the Current Trends (Reference Case) scenario.

The following section reviews the Scorecard Evaluation metrics under each of these categories.

8.5.1 Affordability

The IRP Scorecard Evaluation metric used to evaluate portfolio affordability is the 20-year PVRR. PVRR is the standard portfolio metric that compares the present value cost to customers. PVRR evaluates the incremental impact on the cost to generate and does not include transmission and distribution revenue requirement. AES Indiana assumed that cost recovery for all approved and in-service generation does not change across portfolios or scenarios. Any change to existing depreciation schedules would be considered in a future regulatory filing, such as a rate case. AES Indiana's primary objective in this IRP was to focus on the economic value of existing resources versus alternatives. Additionally, the Company has included the average and levelized rate impacts to customers to help with evaluation. These additional metrics do not appear on the IRP Scorecard Evaluation because the average and levelized rate impact analysis produces the same portfolio ranking results as the 20-year PVRR analysis.

Figure 8-39 below provides the components and calculation of the PVRR. As described at the beginning of this section, AES Indiana used EnCompass for capacity expansion and hourly production cost modeling. Encompass provides the PVRR calculation as output from the hourly production cost analysis.

Figure 8-39: Revenue Requirement Components and Calculation

8.5.2 *Environmental Sustainability*

Under the Environmental Sustainability category AES Indiana included a robust set of metrics including:

- → Carbon Dioxide (CO2) Emissions
  - Calculation: Total portfolio short tons of CO2
- → Sulfur Dioxide (SO2) Emissions
  - Calculation: Total portfolio short tons of SO2
- → Nitrous Oxide (NOx) Emissions:
  - Calculation: Total portfolio short tons of NOx
- → Water Use
  - Calculation: Total gallons of water used
- → Coal Combustion Residuals – including various components of coal ash
  - Calculation: Total tons of CCP

Additionally, through collaboration with stakeholders, the Company included a metric that quantifies each portfolios progress on clean energy. This is measured as the percentage of clean energy generated by each portfolio's resource mix in 2032.

8.5.3 Reliability, Resilience, and Stability

As utilities transition to renewable resources which typically provide non-dispatchable and intermittent generation, reliability, resiliency, and stability have come to the forefront as planning considerations. In addition to including contemporary resource adequacy planning requirements, such as MISO's seasonal construct (approved by FERC on August 31, 2022) and appropriate ELCC estimates (see Section 2 for more details on reliability and resource adequacy planning) as assumptions in the IRP modeling, AES Indiana also contracted Quanta to help evaluate reliability of the portfolios in terms of energy adequacy. Quanta also assessed resilience and system stability of the portfolios. Since Quanta's analysis effectively evaluates reliability, resilience, and stability, these "Pillars" have been grouped into one category on AES Indiana's IRP Scorecard Evaluation.

Quanta evaluated nine key components of reliability, resilience, and stability, including:

- → Energy Adequacy
- → Operational Flexibility and Frequency Support
- → Short Circuit Strength Requirement
- → Power Quality (Flicker)
- → Blackstart
- → Dynamic VAR Deliverability
- → Dispatchability and Automatic Generation Control
- → Predictability and Firmness of Supply
- → Geographic Location Relative to Load

Quanta, in collaboration with AES Indiana, scored each portfolio on these components and created a composite score which was used for overall evaluation on the final IRP Scorecard. For more detail on these components and Quanta's analysis and results can be found attached as Attachment 8-3. Also, see Section 9.4.4 for the results summary from Quanta's analysis.

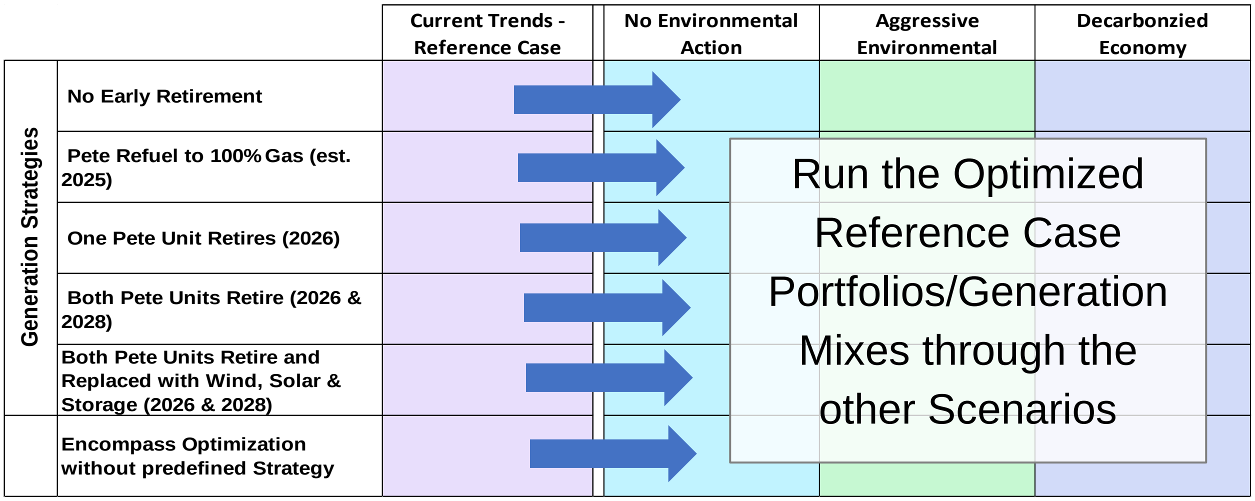
8.5.4 Risks and Opportunities

In this IRP, AES Indiana considered both downside risk and upside opportunity to the Candidate Portfolios. Portfolio Risk and Opportunity were viewed through four metrics that evaluate potential impacts from environmental policy (sensitivity analysis), general cost (stochastic analysis), market interaction and exposure, and renewable capital cost (sensitivity analysis).

Environmental Policy Sensitivity Analysis

The first Risk and Opportunity metric that AES Indiana considered was uncertainty associated with the environmental policy outlook. To understand this uncertainty, the Company ran production cost analysis (8,760 dispatch analysis) of the Candidate Portfolios through the other Environmental Policy scenarios. Figure 8-40 below provides a visual representation of how this analysis was conducted.

Figure 8-40: Environmental Policy Sensitivity Analysis



In this analysis, the generation mix that was selected through the capacity expansion analysis for each strategy in the Candidate Portfolios was dispatched using the assumptions of each of the other scenarios. For example, the strategies in the Current Trends scenario dispatched under the Decarbonized Economy scenario would include all of the Decarbonized Economy assumptions as inputs in the production cost analysis, including ITC and PTC assumptions, power prices, natural gas prices, and NOx prices.

The intention of this analysis was to evaluate how well the candidate portfolios (i.e., all strategies under the Current Trends scenario) would perform in a very different policy and commodity future. Please see Section 9.4.5 for the results of the Environmental Policy Sensitivity Analysis.

Cost Risk and Opportunity Metric (Stochastic Analysis)

To evaluate general cost risk and opportunity of the candidate portfolios, AES Indiana used stochastic analysis to evaluate uncertainty in power prices, natural gas prices, coal prices, load, and renewable energy generation.

The Company chose to stochastically vary these five components for the following reasons:

→ *Power, Natural Gas, and Coal Prices* – In early 2022, regional power and natural gas prices rose to levels not seen in more than 10 years. The increases were largely driven by an ongoing energy crisis in Europe exacerbated by Russia's invasion of Ukraine, along with other economic factors. These price spikes have raised focus on understanding the sensitivity of the candidate portfolios to the volatility in these commodities. As an example, a candidate portfolio that relies heavily on natural gas may become relatively costly in a future with high natural gas prices and low power prices. Including energy and natural gas prices in the stochastic analysis allows us to understand the risk and opportunity associated with these commodities.

→ *Load* – Variability in load is a key driver to portfolio cost risk through changes in assumed energy sales and purchases and capacity requirements. The risk and uncertainty captured by stochastically varying load is primarily associated with weather volatility.

→ *Renewable Energy Generation* – A candidate portfolio may contain a significant amount of renewable generation in the resource mix that provides energy revenue that contributes favorably to the PVRR (affordability to customers). If the generation profile of the renewable resources ends up very different than what was assumed in the deterministic modeling, then this could ultimately cost (less renewable generation) or benefit (more renewable generation) customers.

For the analysis, stochastic distributions for power prices, natural gas prices, coal prices, and load were estimated in spreadsheet models as follows:

Commodity price and load distributions were developed through a two-step process in which 1) statistical models were calibrated to historical price and load data, and 2) scenarios of future price and load outcomes were simulated using a stochastic Monte Carlo analysis. Commodity prices (e.g., energy LMPs, natural gas, fuel oil, and coal) and load were assumed to follow a three-factor mean reverting random walk process. Under this type of statistical model, a price (or load) exhibits unexpected movements from one period to the next, but also tends to trend back toward a long-term average after experiencing an excursion away from the long-term average. The parameters used to describe the statistical nature of these movements include volatility, mean-reversion, and correlations with other variables.

These parameters were calibrated using historical price and load data using a maximum likelihood algorithm. In a maximum likelihood algorithm, AES Indiana calculates the probability that the exact price movements observed occurs, given a set of assumptions about volatility, mean reversion, and correlation. The algorithm then modifies those parameters to increase the likelihood of having experienced the outcomes observed. The final parameters are those that maximize this likelihood.

The calibration dataset consisted of monthly average spot prices for Henry Hub natural gas, Indiana Hub (Peak and Wrap) power, fuel oil, and average AES Indiana load. The historical coal data consisted of annual average values. Data for each variable covered a 10-year historical period spanning October 2012 through September 2022. After the parameters for the statistical model had been calibrated, AES Indiana simulated 100 future time-series outcomes of monthly values for each commodity price and for load using a stochastic Monte Carlo model. The simulated outcomes for each variable were centered around the appropriate forward-looking forecast expectation.

In addition to power (on- and off-peak) prices, natural gas prices, coal prices, and load (energy and peak), renewable generation was also varied in the stochastic runs.

For the 100 unique iterations, the planned Hardy Hills solar and Pete Energy Center hybrid solar, new solar, new hybrid solar, and new wind were given different hourly generation profiles. These different hourly generation profiles were created using historic data. Simulated historic generation from 2007 to 2013 was simulated using NREL's System Advisor Model.[57] For each day in the forward looking study, a random day from the same month in the 2007 to 2013 historical study

[57] https://sam.nrel.gov.

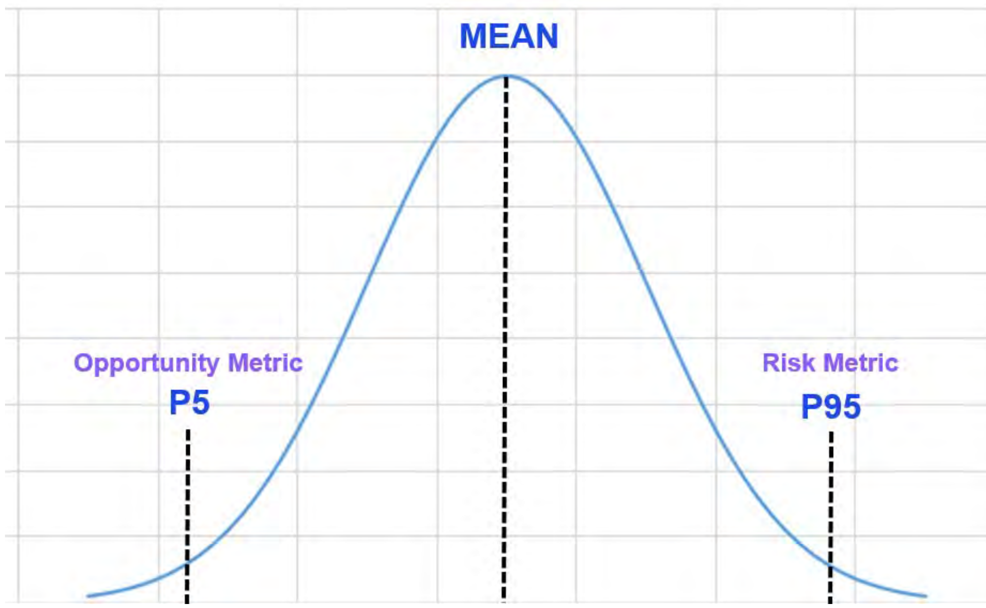
period was picked. Because of this, capacity factors across months for these resources (and the daily shaped that underpin them) changed over time.

Simulated historic data for Hoosier Wind and Lakefield Wind were not indicative of conditions at the facilities, so these wind farms did not have their generation varied in the stochastic runs.

These distributions served as inputs into EnCompass for the stochastic production cost hourly dispatch runs over all 100 distributions.

For the Scorecard Evaluation, AES Indiana included the PVRR 95th Percentile ("P95") as the risk metric and the PVRR Fifth Percentile ("P5") as the Opportunity metric for each candidate portfolio distribution. Figure 8-41 below provides a graphical example of the risk and opportunity metric calculations. Please see Section 9.4.5 for the results from Cost Risk and Opportunity results.

Figure 8-41: Cost Risk and Opportunity Metric Calculations



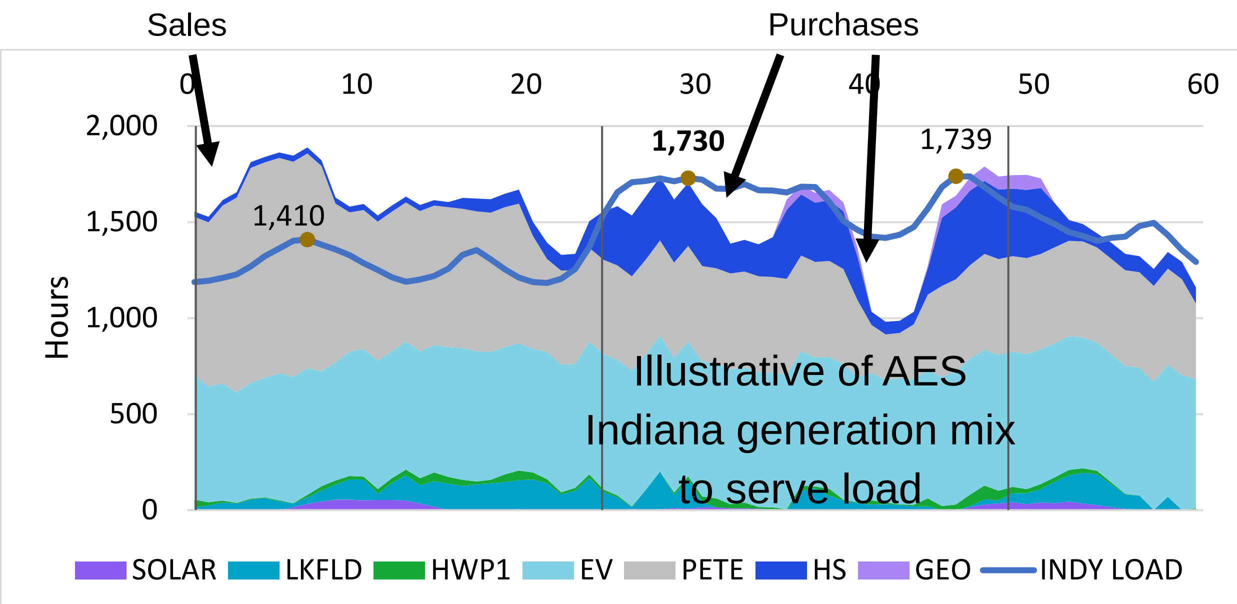
Market Interaction & Exposure

AES Indiana also considered risk associated with exposure to the energy market. This metric is based on annual market purchases and sales for each of the candidate portfolios. Due to hourly fluctuations in load, wholesale market prices, and unit availability, AES Indiana can be net long or short energy throughout the year, which as a MISO market participant is characterized as market purchases and market sales. This is uncontrolled for intermittent resources in the portfolio. Figure 8-42 provides an example using AES Indiana load and generation. Across these three days, AES Indiana was long and short in hours as load moved and units were committed and dispatched.

AES Indiana included market interaction as a risk metric because heavy reliance on the market could introduce market price and volume risk going forward if AES Indiana does not have a balanced portfolio. Overreliance on market purchases to serve load or overreliance on market energy sales to create value equally present risk to customers.

While there is not a "correct" level of market interaction, this is a useful metric to compare the relative risk of portfolios and the ability of portfolios to serve hourly load and not just produce enough energy on an annual basis.

Figure 8-42: Example of Energy Sales and Purchases Market Exposure (MW)



Please see Section 9.4.5 for Market Interaction & Exposure Metric results.

Renewable Resource Capital Costs Sensitivity Analysis

AES Indiana experienced significant increases in the capital cost of generation resources identified in responses to its 2022 all-source RFP as compared to its 2020 all-source RFP. Solar, wind, and storage resource costs were most impacted. Given the extreme volatility the market is experiencing, the Company performed a capacity expansion Replacement Resource Capital Cost Sensitivity Analysis as detailed in Section 9.3. This analysis evaluated how the generation resource mix (resulting from Capacity Expansion analysis) would change if replacement resource capital costs ended up being higher or lower than those included as the base.

In addition to this analysis, AES Indiana wanted to understand how affordability of the candidate portfolios would change if renewable resource costs ended up being very different than anticipated. To evaluate this, AES Indiana performed a Renewable Resource Capital Cost Sensitivity Analysis as an additional sensitivity analysis.

AES Indiana varied only the capital costs of the planned replacement renewable resources in each of the Candidate Portfolios when performing this additional sensitivity analysis. The

Company ran high and low cost sensitivities using the solar, wind, storage, and solar plus storage high and low capital costs, as described in Section 9.4.5. This analysis evaluates how much the cost to customers would change for the Candidate Portfolios if, upon execution, the renewable costs end up being higher or lower than anticipated. Please see Section 9.4.5 for results from the Renewable Resource Capital Cost Sensitivity Analysis.

8.5.5 Social and Economic Impact

AES Indiana included two Social and Economic Impact Metrics that gauge the general impact that the candidate portfolios will have on local economies. The two metrics that the Company included are:

- → *Total Employees* – This metric captures the total change in the number of employees associated with generation in each portfolio over the 20-year planning period including non-AES owned generation, e.g., PPA. So, for example, a portfolio may retire units. This will result in a reduction in the employee headcount. The portfolio will then replace the retired units with replacement capacity which will increase the employee headcount. This metric simply sums up these changes over the planning period to calculate a total change in employees from the current state. This metric is agnostic to who owns the resource.
- → *Property Taxes* – This metric includes total property taxes paid on all generation included in each portfolio. This metric is agnostic to who owns the resource.

AES Indiana recognizes these Social & Economic Metrics, including the number of Full-Time Employees ("FTE") related to generation and Property Taxes, are not exhaustive and provide a general impact resulting from Company decisions. Please see Section 9.4.6 for the Social and Economic Impact results.

8.5.6 IRP Scorecard for Evaluation Portfolio Evaluation

Figure 8-43 provides the IRP Scorecard used in its IRP Scorecard Evaluation with the categories and metrics included. Please see Section 9.5 for IRP Scorecard Evaluation results.

Figure 8-43: IRP Scorecard

	Affordability	Environmental Sustainability						Reliability, Stability, and Resiliency	Risk and Opportunity							Social and Economic Impact	
	20-yr PVRR	*CO_2 Emissions*	*SO_2 Emissions*	*NO_x Emissions*	*Water Use*	*Coal Combustion Products (CCP)*	*Clean Energy Progress*	*Reliability Score*	*Environmental Policy Opportunity*	*Environmental Policy Risk*	*General Cost Opportunity **Stochastic Analysis***	*General Cost Risk **Stochastic Analysis***	*Market Exposure*	*Renewable Capital Cost Opportunity (Low Cost)*	*Renewable Capital Cost Risk (High Cost)*	*Generation Employees (+/-)*	*Property Taxes*
	Present Value of Revenue Requirements ($000,000)	Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)	% Renewable Energy in 2032	Composite score from Reliability Analysis	Lowest PVRR across policy scenarios ($000,000)	Highest PVRR across policy scenarios ($000,000)	P5 [Mean - P5]	P95 [P95 – Mean]	20-year avg sales + purchases (GWh)	Portfolio PVRR w/ low renewable cost ($000,000)	Portfolio PVRR w/ high renewable cost ($000,000)	Total change in FTEs associated with generation 2023 - 2042	Total amount of property tax paid from AES IN assets ($000,000)
1																	
2																	
3																	
4																	
5																	
6																	

See Section 9.5 for Scorecard Results

Note: Calculations for each scoring metric will be included in completed IRP Scorecard.

Strategies

1. No Early Retirement
2. Petersburg Conversion (est. 2025)
3. One Petersburg Unit Retires in 2026
4. Both Petersburg Units Retire in 2026 and 2028
5. Clean Energy Strategy – Both Petersburg Units Retire and replaced with Renewables in 2026 and 2028
6. Encompass Optimization without Predefined Strategy

Section 9: IRP Results

170 IAC 4-7-4(24), 170 IAC 4-7-4(25), 170 IAC 4-7-8(a), 170 IAC 4-7-8(c)(4), and 170 IAC 4-7-8(c)(8)

9.1 Executive Summary

170 IAC 4-7-4(8)

In order to select the Preferred Resource Portfolio and Short Term Action Plan in this IRP, AES Indiana:

1. Conducted a Retirement and Replacement Analysis that optimized five strategies and one strategy in which EnCompass optimally selected a portfolio without a predefined strategy across four different scenarios or policy and commodity futures. The results were represented and evaluated using a Portfolio Matrix. See Section 8.4 for details on the strategies and scenario assumptions used in this analysis.
2. Conducted a Replacement Resource Capital Cost Sensitivity Analysis that optimized the strategies under the Current Trends/Reference Case scenario at low, base, and high replacement resource capital cost levels.
3. Took the optimized strategies that resulted from the Retirement and Replacement Analysis Current Trends/Reference Case scenario (Candidate Portfolios) and evaluated them using a Scorecard Evaluation framework with five metric categories, including:
    a. Affordability;
    b. Sustainability;
    c. Reliability, Resiliency and Stability;
    d. Risk and Opportunity; and
    e. Social and Economic Impact.

    See Section 8.5 for details on the Scorecard Evaluation framework.
4. Utilized the results from the Scorecard Evaluation framework and Replacement Resource Capital Cost Sensitivity Analysis to select the Preferred Resource Portfolio and Short Term Action Plan.

This section provides an evaluation of the results from the Retirement and Replacement Analysis (Section 9.2), Replacement Resource Capital Cost Sensitivity Analysis, and the Scorecard Evaluation (Section 9.3) and concludes with a review of the Preferred Resource Portfolio (Section 9.5) that was selected through the evaluation process.

9.2 Retirement & Replacement Analysis

170 IAC 4-7-4(8) and 170 IAC 4-7-4(25)

9.2.1 Overview

170 IAC 4-7-4(26)

The Retirement and Replacement (capacity expansion) modeling framework of AES Indiana's 2022 IRP was a scenario analysis that included five generation strategies for the Petersburg Generating Station. These strategies are detailed in Section 8.4.1 and include: 1) no early retirement of the Petersburg coal Units 3 and 4 or status quo; 2) converting Petersburg Units 3 and 4 to operate using natural gas in 2025; 3) retiring Petersburg Unit 3 in 2026 and leaving Petersburg Unit 4 on coal through its age-based retirement; 4) retiring both Petersburg Units 3 and 4 in 2026 and 2028, respectively; and 5) retiring both Petersburg Units 3 and 4 in 2026 and 2028, respectively, and replacing them with only wind, solar and storage resources – also known as the Clean Energy Strategy. The conversion of Petersburg Units 3 and 4 to operate using natural gas was not a selectable resource for the One Petersburg Unit Retires strategy, the Both Petersburg Units Retire strategy, or the Clean Energy Strategy. The framework also included a sixth analysis that allowed the EnCompass Model to optimize the retirement and replacement of Petersburg Units 3 and 4 without any dates or conversions predefined.

The Retirement and Replacement modeling framework optimized the strategies described above across four scenarios that varied in terms of environmental policy, commodity, and load assumptions. These scenarios detailed in Section 8.4.2 and include: 1) No Environmental Action Scenario; 2) Current Trends/Reference Case; 3) Aggressive Environmental; and 4) Decarbonized Economy. The environmental policy, commodity, and load assumptions included in each of these scenarios are shown in Figure 9-1 below.

For a complete review of the key assumptions underlying the Retirement and Replacement analysis, please see Section 8.4.1.

Figure 9-1: Summary of Retirement and Replacement Analysis Assumptions

Scenario	Load	EV	Distributed Solar	Power	Gas	Coal	CO2
No Environmental Action	Low	Low	Low	Horizon Fundamental Forecast	Low	Base	None
Current Trends (Reference Case)	Base	Base	Base	Horizon Fundamental Forecast	Base	Base	Low
Aggressive Environmental	High	High	High	Horizon Fundamental Forecast	High	Base	High
Decarbonized Economy	High	Very High	High	Horizon Fundamental Forecast	Base	Base	None*

9.2.2 *Retirement and Replacement Analysis Results*

170 IAC 4-7-4(3), 170 IAC 4-7-4(5), 170 IAC 4-7-4(26), 170 IAC 4-7-8(b)(1), 170 IAC 4-7-8(c)(4)(D)-(E), and 170 IAC 4-7-8(c)(5)

The completed Retirement and Replacement Analysis Portfolio Matrix is shown in Figure 9-2 and Figure 9-3 below.[58] Portfolio Matrix provides PVRR and average rate impacts for the five generation strategies, including a strategy that allowed EnCompass to optimize a portfolio without a predefined strategy, across the four different scenarios or environmental policy futures for a total of 24 portfolios for comparison. The EnCompass Optimization without a Predefined Strategy resulted in the following strategies for Petersburg when optimized across the different Scenarios:

1. No Environmental Action – Converts Petersburg Units 3 and 4 in 2025
2. Current Trends/Reference Case – Converts Petersburg Unit 3 in 2025 and Unit 4 in 2027
3. Aggressive Environmental – Converts Petersburg Unit 3 in 2025 and Retires Unit 4 in 2027
4. Decarbonized Economy – Converts Petersburg Unit 3 in 2025 and Unit 4 in 2027

These optimizations are the result of allowing EnCompass to optimize the generation portfolio without any strategy predefined, in other words, the model determined these selected results to be most cost effective for customers under these scenarios. However, it is important to note that, under certain scenarios, the model is choosing to split conversion into different years or convert only one unit. In these instances, there are additional costs associated with splitting the conversion that were difficult to capture in the model when allowing EnCompass to optimize without a strategy predefined. Ideally, the conversion of Petersburg would happen in the same year to take advantage of efficiencies associated with the labor force and construction.

Key observations from the Retirement and Replacement analysis include:

1. Converting Petersburg to natural gas performs the best in the No Environmental Action, Current Trends/Reference Case, and Decarbonized Economy scenarios. These scenarios included low gas (No Environmental Action) or base gas (Current Trends/Reference Case and Decarbonized Economy) prices. The Aggressive Environmental scenario includes high gas prices, which causes the most cost effective strategy to be to convert one Petersburg unit in 2026 and retire and replace the second unit in 2027 (using EnCompass optimization results), which burns less gas over the planning period.
2. Continuing to operate Petersburg Units 3 and 4 on coal over the planning period performs competitively in the No Environmental Action scenario but becomes progressively more costly and less competitive as the environmental policy strengthens.

[58] The columns of the figures compare the results of across the alternative future scenarios.

3. Converting Petersburg to natural gas is more cost effective than continuing to burn coal in every scenario.
4. Retiring Petersburg Unit 3 in 2026 and leaving the Petersburg Unit 4 operating as coal-fired is generally the least cost effective strategy because the fixed costs of coal-fired operation continue to exist while the generation from the asset is cut in half, which causes Petersburg to become very costly to operate on a per MWh basis.
5. The strategies that retire both units require the most capital investment or power purchase agreements to replace Petersburg's capacity. Particularly, the Clean Energy Strategy, which replaces Petersburg with only wind, solar, and storage resources, requires significantly more investment in wind and solar resources in order to meet the MISO Seasonal Capacity requirements. This is the result of the low MISO ELCC/capacity accreditation of these resources – see Section 6.2 for more detail on the inclusion of ELCC for wind and solar resources.
6. The Clean Energy Strategy PVRR improves and becomes more competitive as environmental policy strengthens.

Figure 9-2: Retirement and Replacement Analysis Portfolio Matrix[59,60]

Candidate Portfolios

	20-Year PVRR	Scenarios: No Environmental Action	Current Trends (Reference Case)	Aggressive Environmental	Decarbonized Economy
Generation Strategies	**No Early Retirement**	$7,111	$9,572	$11,349	$9,917
	Petersburg Conversion to Natural Gas (est. 2025)	$6,621	$9,330	$11,181	$9,546
	One Petersburg Unit Retires (2026)	$7,462	$9,773	$11,470	$9,955
	Both Petersburg Units Retire (2026 and 2028)	$7,425	$9,618	$11,145	$9,923
	Clean Energy Strategy Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage Resources (2026 and 2028)	$9,211	$9,711	$11,184	$9,690
	EnCompass Optimization without Predefined Strategy	$6,610	$9,262	$10,994*	$9,572

Encompass Optimization Results by Scenario:

No Environmental Action	Current Trends (Reference Case)	Aggressive Environmental	Decarbonized Economy
Converts Petersburg Units 3 and 4 in 2025	Converts Petersburg Unit 3 in 2025 and Converts Petersburg Unit 4 in 2027	Converts Petersburg Unit 4 in 2027*	Converts Petersburg Unit 3 in 2025 & Converts Petersburg Unit 4 in 2027

Less Favorable — **More Favorable**

**Converting Petersburg Units 3 and 4 at the same time provides cost efficiencies. These efficiencies are not captured when only one unit is converted.*

[59] 20-year PVRR (2023 dollars in millions from 2023-2042).
[60] All Portfolio Matrix and Candidate Portfolio comparisons use the same color legend. On a continuum, green represents more favorable results, while red represents less favorable results.

Figure 9-3: Retirement and Replacement Analysis Portfolio Matrix Presented as 20-Year Average Rate Impact[61]

		Scenarios			
	20-Year Average Rate Impact	**No Environmental Action**	**Current Trends (Reference Case)**	**Aggressive Environmental**	**Decarbonized Economy**
Generation Strategies	**No Early Retirement**	$0.038	$0.051	$0.058	$0.050
	Petersburg Conversion to Natural Gas (est. 2025)	$0.035	$0.050	$0.057	$0.048
	One Petersburg Unit Retires (2026)	$0.040	$0.052	$0.059	$0.050
	Both Petersburg Units Retire (2026 and 2028)	$0.040	$0.051	$0.057	$0.049
	Clean Energy Strategy Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage Resources (2026 and 2028)	$0.052	$0.052	$0.057	$0.048
	EnCompass Optimization without Predefined Strategy	$0.035	$0.049	$0.056	$0.048

The Candidate Portfolios for selecting the Preferred Resource Portfolio are the strategies optimized in the Current Trends/Reference Case scenario. They are considered the Candidate Portfolios because they are optimized assuming AES Indiana's most probable view of the future (i.e., the Current Trends scenario). These portfolios were evaluated exclusively in the Replacement Resource Capital Cost Sensitivity Analysis and Scorecard to select the Preferred Resource Portfolio and Short Term Action Plan.

The next section (Section 9.2.3), Candidate Portfolio Summaries, summarizes the generation mixes, unforced capacity position, installed capacity over the planning period, percentage of the energy mix to serve load, and DSM selections in each of the Candidate Portfolios. The summaries for the other portfolios (portfolios under the No Environmental Action, Aggressive Environmental, and Decarbonized Economy scenarios) are provided in Attachment 1-2 – Public Advisory Meeting #4 Supplemental Materials. The results from the Replacement Resource Capital Cost Sensitivity Analysis and Scorecard are detailed in Section 9.3 and Section 9.4 that follow.

9.2.3 Candidate Portfolio Summaries

170 IAC 4-7-4(8), 170 IAC 4-7-8(b)(2)-(3), and 170 IAC 4-7-8(c)(5)

This section provides the Candidate Portfolio summaries as follows:

[61] 20-year PVRR (2023 dollars per kWh from 2023-2042). The present value was calculated using the discount rate included in the IRP analysis.

1) No Early Retirement Results

a. Portfolio Overview
b. Unforced Capacity Position – Summer and Winter
c. Installed Capacity over the Planning Period
d. Percentage of the Energy Mix to Serve Load
e. DSM Selections

2) Peterburg Conversion to Natural Gas in 2025 Results

a. Portfolio Overview
b. Unforced Capacity Position – Summer and Winter
c. Installed Capacity over the Planning Period
d. Percentage of the Energy Mix to Serve Load
e. DSM Selections

3) Petersburg Unit 3 Retires in 2026; Petersburg Unit 4 Remains on Coal Results

a. Portfolio Overview
b. Unforced Capacity Position – Summer and Winter
c. Installed Capacity over the Planning Period
d. Percentage of the Energy Mix to Serve Load
e. DSM Selections

4) Petersburg Unit 3 Retires in 2026 and Petersburg Unit 4 Retires in 2028 Results

a. Portfolio Overview
b. Unforced Capacity Position – Summer and Winter
c. Installed Capacity over the Planning Period
d. Percentage of the Energy Mix to Serve Load
e. DSM Selections

5) Clean Energy Strategy: Petersburg Unit 3 Retires in 2026 and Petersburg Unit 4 Retires in 2028 and Replaced with Wind, Solar and Storage Resources Results

a. Portfolio Overview
b. Unforced Capacity Position – Summer & Winter
c. Installed Capacity over the Planning Period
d. Percentage of the Energy Mix to Serve Load
e. DSM Selections

6) EnCompass Optimization without a Predefined Strategy: Converts Petersburg Unit 3 in 2025 and Petersburg Unit 4 in 2027 Results

a. Portfolio Overview
b. Unforced Capacity Position – Summer & Winter
c. Installed Capacity over the Planning Period
d. Percentage of the Energy Mix to Serve Load
e. DSM Selections

No Early Retirement Results

In the No Early Retirement strategy, Petersburg remains on coal throughout the planning period. Therefore, the EnCompass Model is not making any capacity retirement and replacement decisions in the near-term. The Harding Street Steam Units 5 and 6 retire in 2030 and steam Unit 7 retires in 2033. These are age-based retirements and occur in every strategy analyzed in this IRP. A summary of the total change in retirements and replacements over the planning period resulting from the No Early Retirement strategy is provided below.

Retirements

Harding Street

→ HS ST5 Natural Gas: 2030

→ HS ST6 Natural Gas: 2030

→ HS ST7 Natural Gas: 2033

- **Total Nat Gas Retired MW: 618 MW**

Replacement Additions by 2042[62]

→ DSM: 490 MW

→ Wind: 2,500 MW

→ Solar: 2,080 MW

→ Storage: 700 MW

→ Solar + Storage: 45 MW

→ Thermal: 0 MW

Figure 9-4 below provides the PVRR results for the No Early Retirement Strategy compared to the other Candidate Portfolios.

[62] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC ratio is treated as being equal to 1.

Figure 9-4: PVRR Overview of the Candidate Portfolios (Current Trends Scenario) PVRR Summary[63]

Strategy	PVRR
No Early Retirement	$9,572
Petersburg Conversion to Natural Gas (est. 2025)	$9,330
One Petersburg Unit Retires (2026)	$9,773
Both Petersburg Units Retire (2026 and 2028)	$9,618
Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)	$9,711
EnCompass Optimization without Predefined Strategy – Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027	$9,262

Figure 9-5 and Figure 9-6 provides the firm unforced capacity position for the No Early Retirement strategy during the summer and winter, respectively. In the chart, the PRMR less DSM (i.e., the PRMR that has been reduced for the DSM selected in the optimization) is the capacity target for which the EnCompass Model optimized. Under the new MISO seasonal resource adequacy construct for the No Early Retirement scenario, AES Indiana is building to meet a winter capacity shortfall in the near-term. This is mainly due to a planning reserve margin of 21.3% that MISO anticipated during the winter season. The Company is anticipated to be short approximately 240 MW of capacity during the winter season starting in 2025 without retiring the Petersburg units. The model chose battery energy storage resources (approximately 240 MW shown in light blue) to fill this capacity need. The model also adds significant volumes of solar and storage resources starting in 2031 to replace the energy and capacity of Harding Street ST5, ST6, and ST7 following their age-based retirements. Note that solar resources receive approximately zero winter capacity credit based on anticipated MISO accreditation, and therefore, does not appear in the winter capacity chart.

[63] 20-year PVRR (2023 dollars in millions from 2023-2042).

Figure 9-5: No Early Retirement: Firm Unforced Capacity Position – Summer

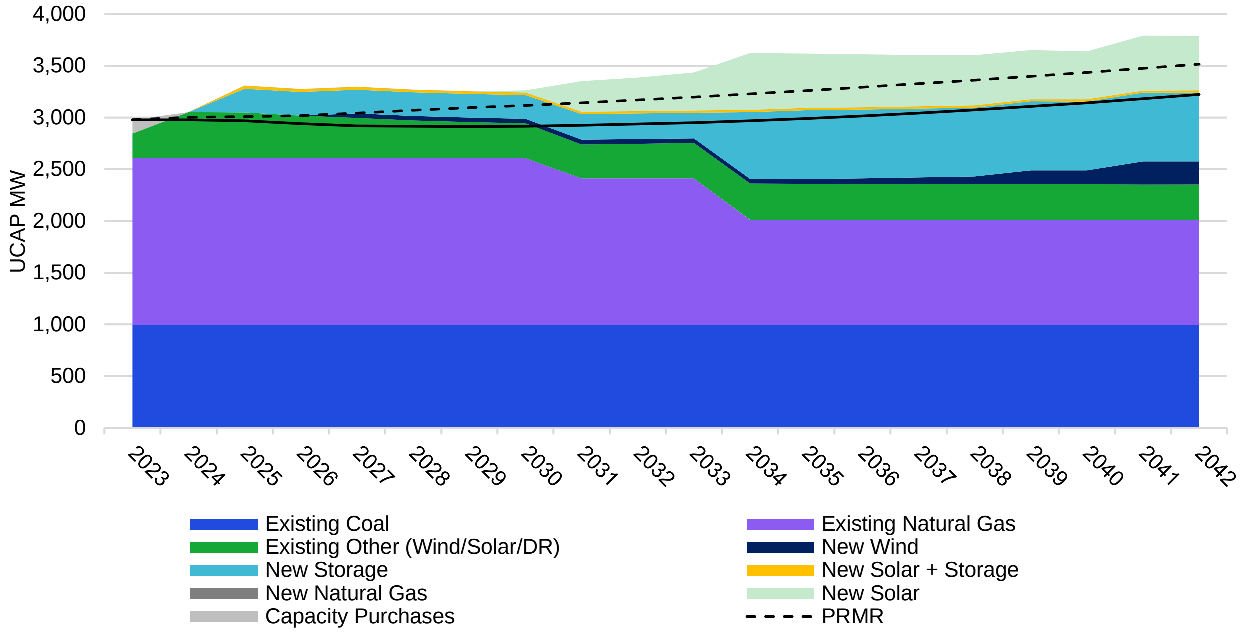


Figure 9-6: No Early Retirement: Firm Unforced Capacity Position – Winter

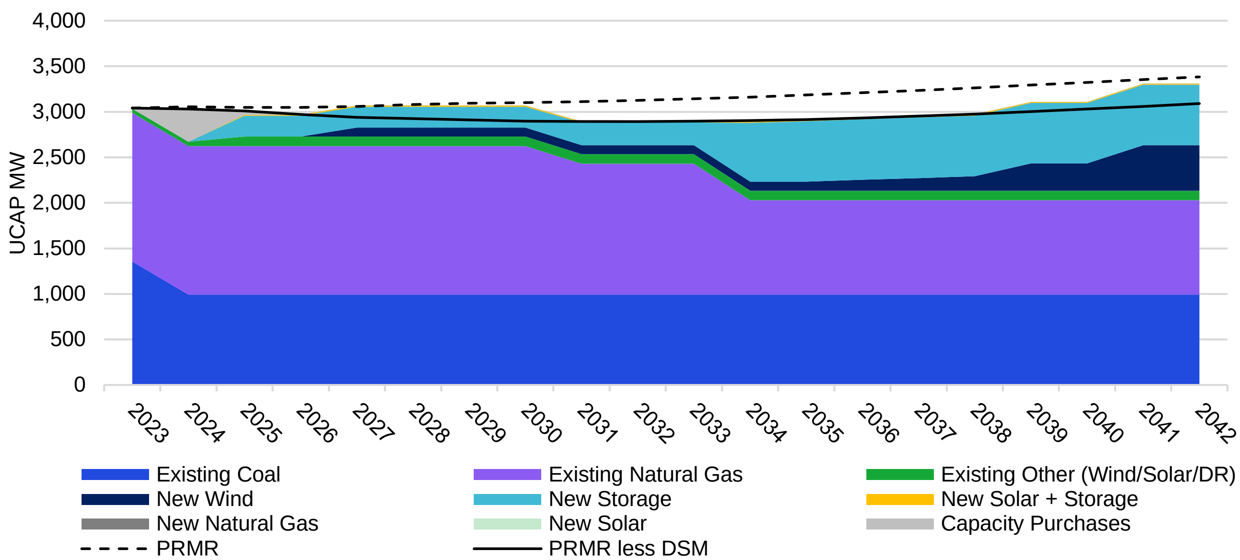
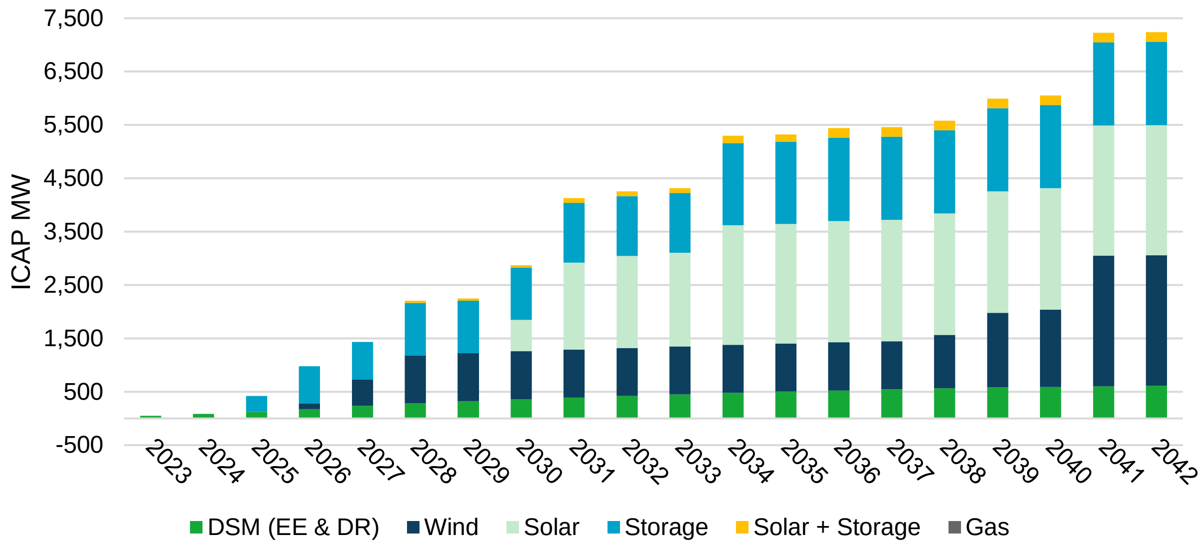


Figure 9-7 provides the total installed capacity over the IRP planning period. The EnCompass Model is choosing to add a large volume of storage resources over the planning period primarily for their winter capacity contribution. Significant amounts of solar resources are selected to help fill summer capacity when the Harding Street ST5, ST6, and ST7 reach age-based retirement in the early 2030s.

Figure 9-7: No Early Retirement: Installed Capacity Cumulative Additions (MW)[64]



Resource Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
DSM (EE & DR)	52	85	113	164	218	259	294	324	349	372	396	416	434	448	463	475	482	484	488	490
Wind	0	0	0	0	500	500	500	500	500	500	500	500	500	600	700	800	1,500	1,500	2,500	2,500
Solar	0	0	0	0	0	0	0	65	910	1,008	1,138	1,723	1,723	1,755	1,755	1,755	1,755	1,755	2,080	2,080
Storage	0	0	240	240	240	240	240	240	260	260	260	680	700	700	700	700	700	700	700	700
Solar + Storage	0	0	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Petersburg Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 9-8 below provides the incremental installed capacity additions through 2028 for the No Early Retirement strategy. The figure shows the 240 MW battery energy storage project added in 2025 to fill the near-term winter capacity need. Additionally, the model is selecting a 45 MW solar plus battery energy storage project in 2025 and 500 MW of wind in 2027.

Figure 9-8: No Early Retirement Strategy Near-term Incremental Installed Capacity Additions (MW)

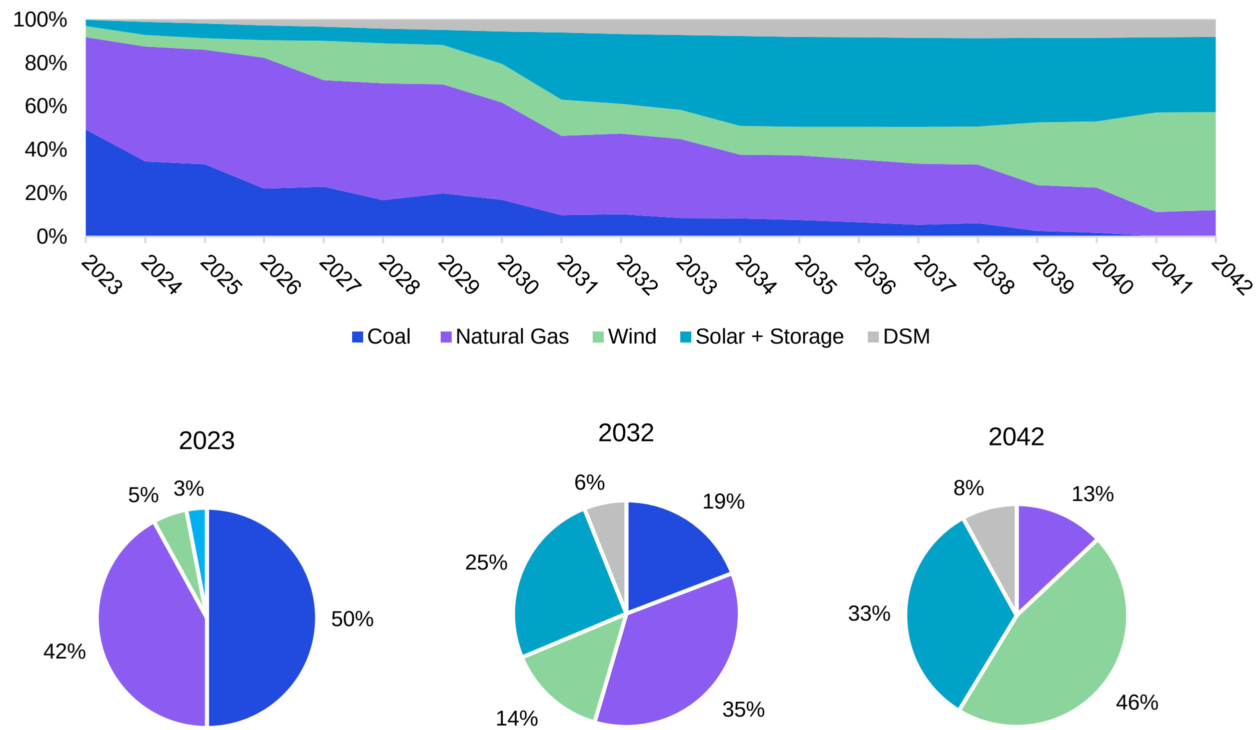
	2023	2024	2025	2026	2027	2028
Wind	0	0	0	0	**500**	0
Solar	0	0	0	0	0	0
Storage	0	0	**240**	0	0	0
Solar + Storage	0	0	**45**	0	0	0
Natural Gas	0	0	0	0	0	0

Figure 9-9 and Figure 9-10 shows the change in energy mix of the No Early Retirement strategy over the planning period. All strategies using the Candidate Portfolio commodity assumptions

[64] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC ratio is treated as being equal to 1.

start at approximately the same point in 2023 (before any portfolio changes are made) and end at approximately the same point in 2042. This is largely due to the change in implied heat rate over the planning period driven by the fundamental commodity assumptions included in the scenario. In other words, as renewable resources eventually make up a larger portion of the MISO resource and energy mix, the market causes thermal resources to dispatch less for their energy. As demonstrated in the energy mix pie charts shown in Figure 9-9, variation between the different strategies starts in 2032. This is also a metric included on the Scorecard for sustainability – "Percent Renewable Energy in 2032." AES Indiana anticipates 55% of its energy generation coming from thermal resources under the No Early Retirement strategy. Figure 9-10 presents the energy position throughout the IRP planning period under the No Early Retirement strategy in GWh.

Figure 9-9: No Early Retirement Strategy Percentage of Energy Mix by Resource Type



Thermal MWh %	92%	Thermal MWh %	54%	Thermal MWh %	13%
Renewable/DSM MWh %	8%	Renewable/DSM MWh %	45%	Renewable/DSM MWh %	87%

Figure 9-10: No Early Retirement Strategy Energy Position by Resource Type 2023 – 2042 in GWh

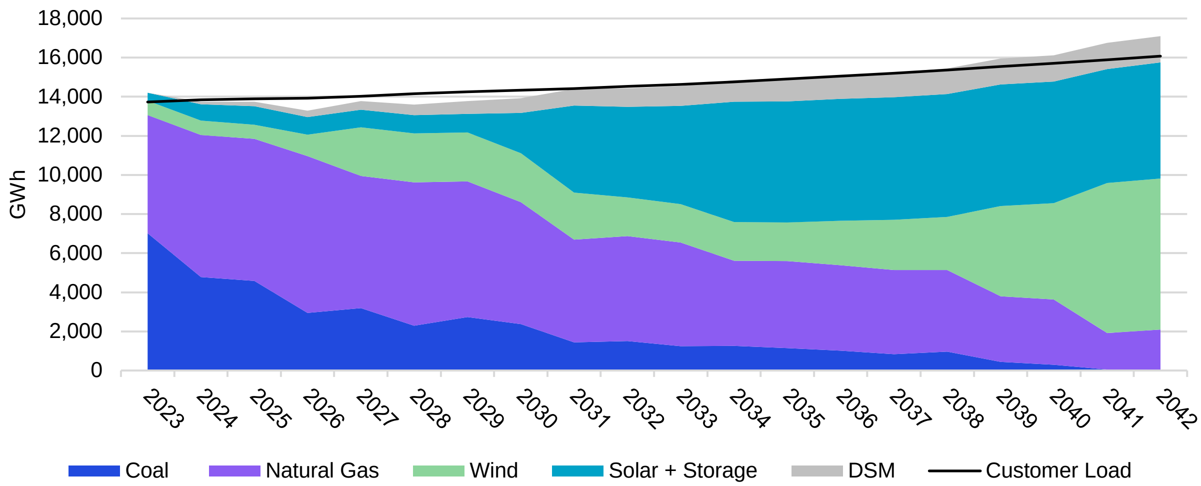


Figure 9-11 provides a summary of the DSM selected in the No Early Retirement strategy. All bundles except the Efficient Products – Higher Cost bundle were selected from Vintage 1. Implementing the selected programs in Vintage 1 results in 134,263 MWh of annual DSM on average over the three-year period. For Vintage 2 (2027 – 2029) and 3 (2030 – 2042), the Lower Cost Residential bundle, and all C&I energy efficiency bundles were selected. For Vintage 2 (2027 – 2029) and 3 (2030 – 2042), the Lower Cost Residential bundle and all C&I energy efficiency bundles were selected. IQW was predefined in the model and not treated as selectable because the Company intends to maintain offerings for this segment of customers regardless of cost effectiveness. For demand response, the model selected the Residential and C&I rates programs which would result in a cumulative summer peak impact of 75 MW.

Figure 9-11: No Early Retirement Strategy DSM Selections

Energy Efficiency:

		Vintage 1	Vintage 2	Vintage 3
		2024 - 2026	**2027 - 2029**	**2030 - 2042**
Residential		Efficient Products - Lower Cost	Lower Cost Residential (excluding IQW))	Lower Cost Residential (excluding IQW)
		Efficient Products - Higher Cost		
		Behavioral		
		School Education	Higher Cost Residential (excluding IQW)	Higher Cost Residential (excluding IQW)
		Appliance Recycling		
		Multifamily		
		IQW	IQW	IQW
C&I		Prescriptive	C&I	C&I
		Custom		
		Custom RCx		
		Custom SEM		
Impacts		Avg Annual MWh	Avg Annual MWh	Avg Annual MWh
		134,263	141,526	146,428
		% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out
		1.1%	1.1%	1.2%
		Cumulative Summer MW	Cumulative Summer MW	Cumulative Summer MW
		89 MW	92 MW	303 MW

Demand Response:

	2026 - 2042
Residential	Direct Load Control
	Residential Rates
C&I	Direct Load Control
	C&I Rates
	Cumulative Summer MW
	75 MW

Note: Boxes highlighted in purple denote DSM bundles that were selected by EnCompass.

Petersburg Units 3 and 4 Conversion to Natural Gas in 2025 Results

In the Petersburg Conversion strategy, the Petersburg coal units are converted to operate using natural gas in 2025 offering a near one-for-one replacement of 1,000 MW of capacity. As a result, the model is not making any capacity retirement and replacement decisions in the near-term. The Harding Street steam Units 5 and 6 retire in 2031 and steam Unit 7 retires in 2034. These are age-based retirements that occur in every strategy analyzed in this IRP. A summary of the total change in retirements and replacements over the planning period resulting from the Petersburg Conversion strategy is provided below.

Retirements & Conversions

Petersburg:

→ Petersburg Units 3 and 4 Coal: 2025 Conversion to Natural Gas

- **Total Converted MW: 1,040 MW**

Harding Street:

→ HS ST5 Nat Gas: 2030

→ HS ST6 Nat Gas: 2030

→ HS ST7 Nat Gas: 2033

- **Total Nat Gas Retired MW: 618 MW**

Replacement Additions by 2042[65]

→ DSM: 490 MW

→ Wind: 2,500 MW

→ Solar: 1,983 MW

→ Storage: 620 MW

→ Solar + Storage: 225 MW

→ Thermal: 0

→ Petersburg Units 3 and 4 Converted to Nat Gas: 1,052 MW

Figure 9-12 below provides the PVRR results for the Petersburg Conversion strategy compared to the other Candidate Portfolios. This strategy provides an economic opportunity to convert the existing Petersburg generation infrastructure to natural gas. The conversion results in $242M reduction in PVRR over the 20-year planning period.

[65] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC ratio is treated as being equal to 1.

Figure 9-12: PVRR overview of the Candidate Portfolios Current Trends PVRR Summary[66]

Strategy	PVRR
No Early Retirement	$9,572
Petersburg Conversion to Natural Gas (est. 2025)	$9,330
One Petersburg Unit Retires (2026)	$9,773
Both Petersburg Units Retire (2026 and 2028)	$9,618
Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar and Storage (2026 and 2028)	$9,711
EnCompass Optimization without Predefined Strategy – Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027	$9,262

The summer and winter capacity position and generation mix for the Petersburg Conversion strategy are very similar to the No Early Retirement strategy because converting Petersburg offers approximately a one-for-one replacement of Petersburg coal capacity. Like the No Early Retirement strategy, the Petersburg Conversion adds a significant amount of solar and storage resources as replacement for the age-based Harding Street Units ST5, ST6, and ST7 retirements in the 2030s. Note that solar resources do not contribute winter capacity under MISO's seasonal resource adequacy construct; therefore, solar resources do not appear in the winter position chart. See Figure 9-13 and Figure 9-14 below for the UCAP position results for summer and winter, respectively.

[66] 20-year PVRR (2023 dollars in millions from 2023-2042).

Figure 9-13: Petersburg Conversion Strategy Firm Unforced Capacity Position – Summer

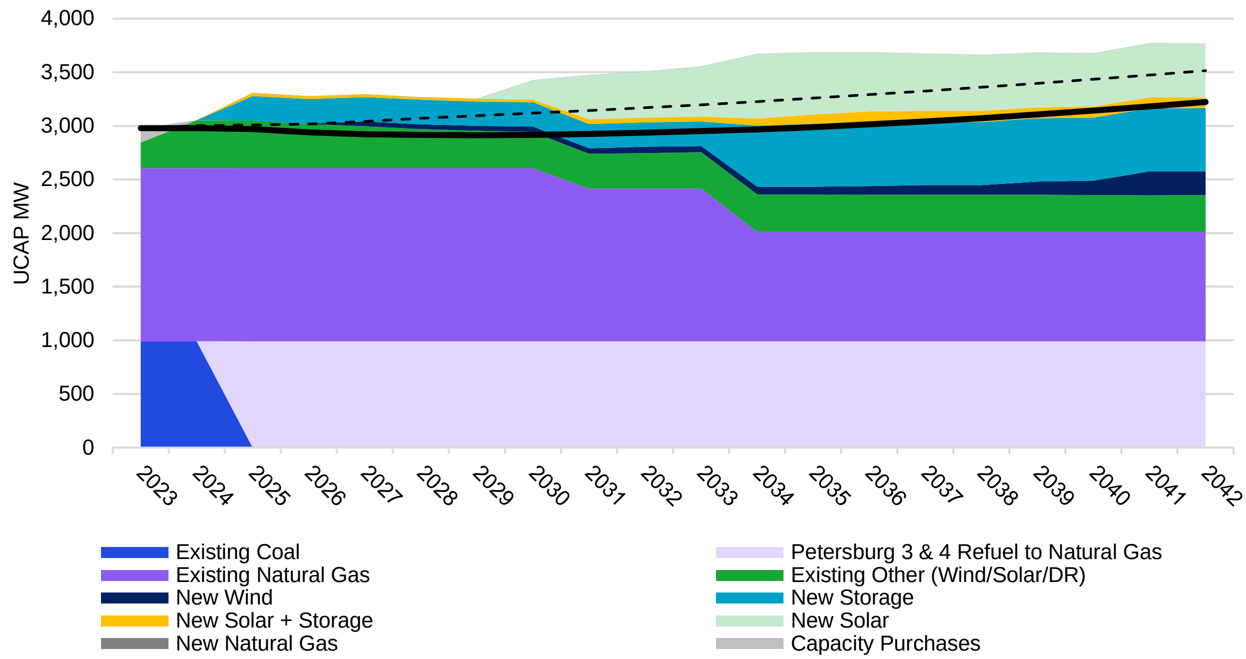


Figure 9-14: Petersburg Conversion Strategy Firm Unforced Capacity Position – Winter

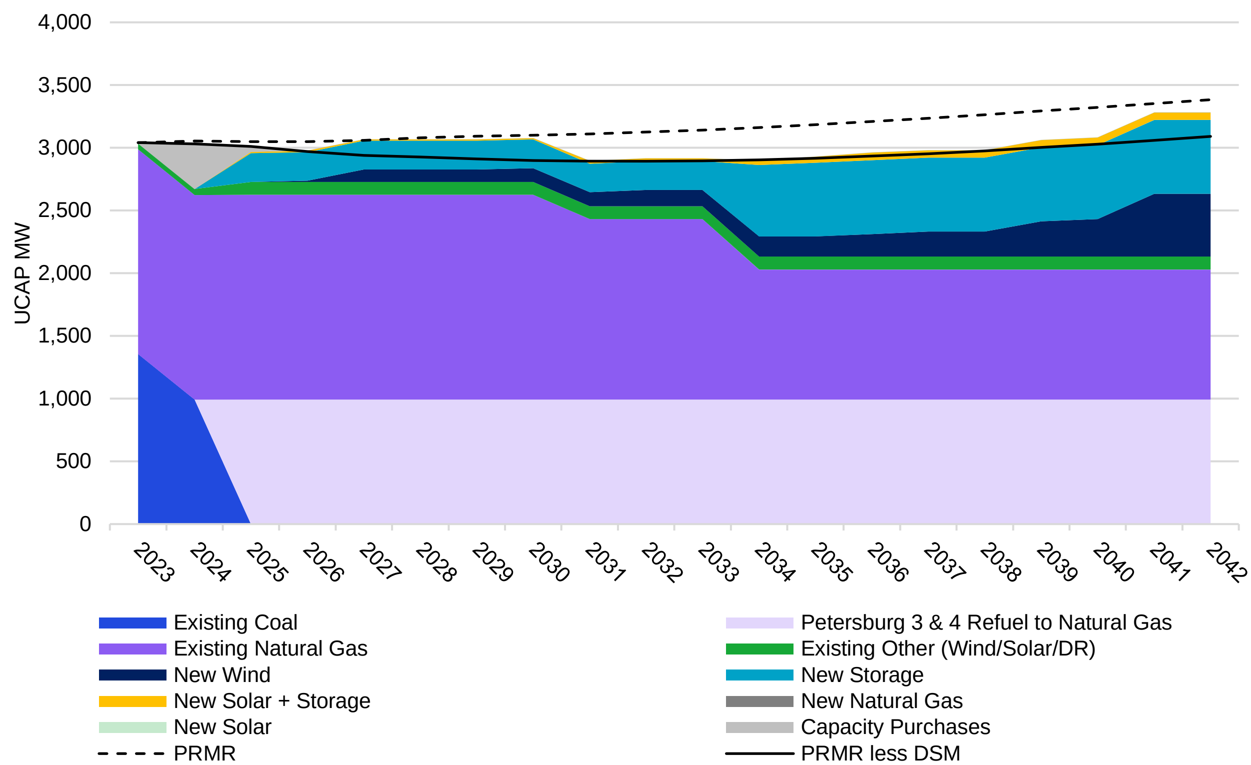
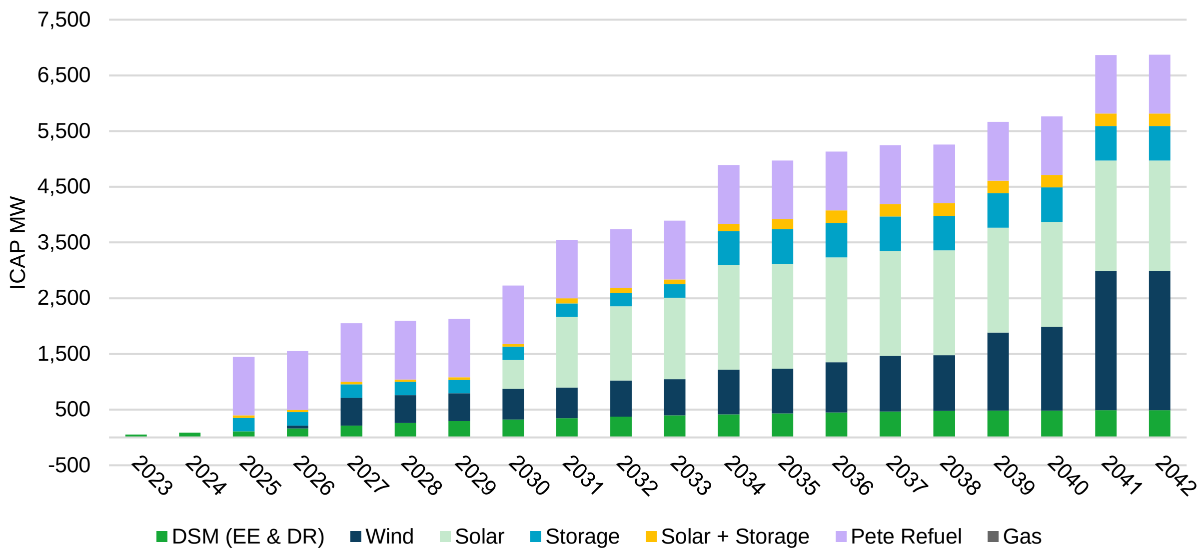


Figure 9-15 shows the incremental capacity additions over the planning period for the Petersburg Conversion strategy. Along with converting the units, the strategy adds 240 MW of battery energy storage resources in 2025 for its winter capacity value and a large amount of solar and storage in the 2030s to replace the age-based retirements of Harding Street ST5, ST6, and ST7.

Figure 9-15: Petersburg Conversion Strategy Installed Capacity Cumulative Additions (MW) [67]



Resource Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
DSM (EE & DR)	52	84	111	162	215	256	292	322	348	372	396	416	434	448	463	475	482	484	488	490
Wind	0	0	0	50	500	500	500	550	550	650	650	800	800	900	1,000	1,000	1,400	1,500	2,500	2,500
Solar	0	0	0	0	0	0	0	520	1,268	1,333	1,463	1,885	1,885	1,885	1,885	1,885	1,885	1,885	1,983	1,983
Storage	0	0	240	240	240	240	240	240	240	240	240	600	620	620	620	620	620	620	620	620
Solar + Storage	0	0	45	45	45	45	45	45	90	90	90	135	180	225	225	225	225	225	225	225
Petersburg Conversion	0	0	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 9-16 below provides the Petersburg Conversion strategy near-term incremental installed capacity additions. Like the No Early Retirement strategy, the portfolio adds a 240 MW battery energy storage project in 2025 along with a small (45 MW) solar plus storage project. The portfolio also adds 500 MW of wind resources in 2026 and 2027 for its capacity and energy value.

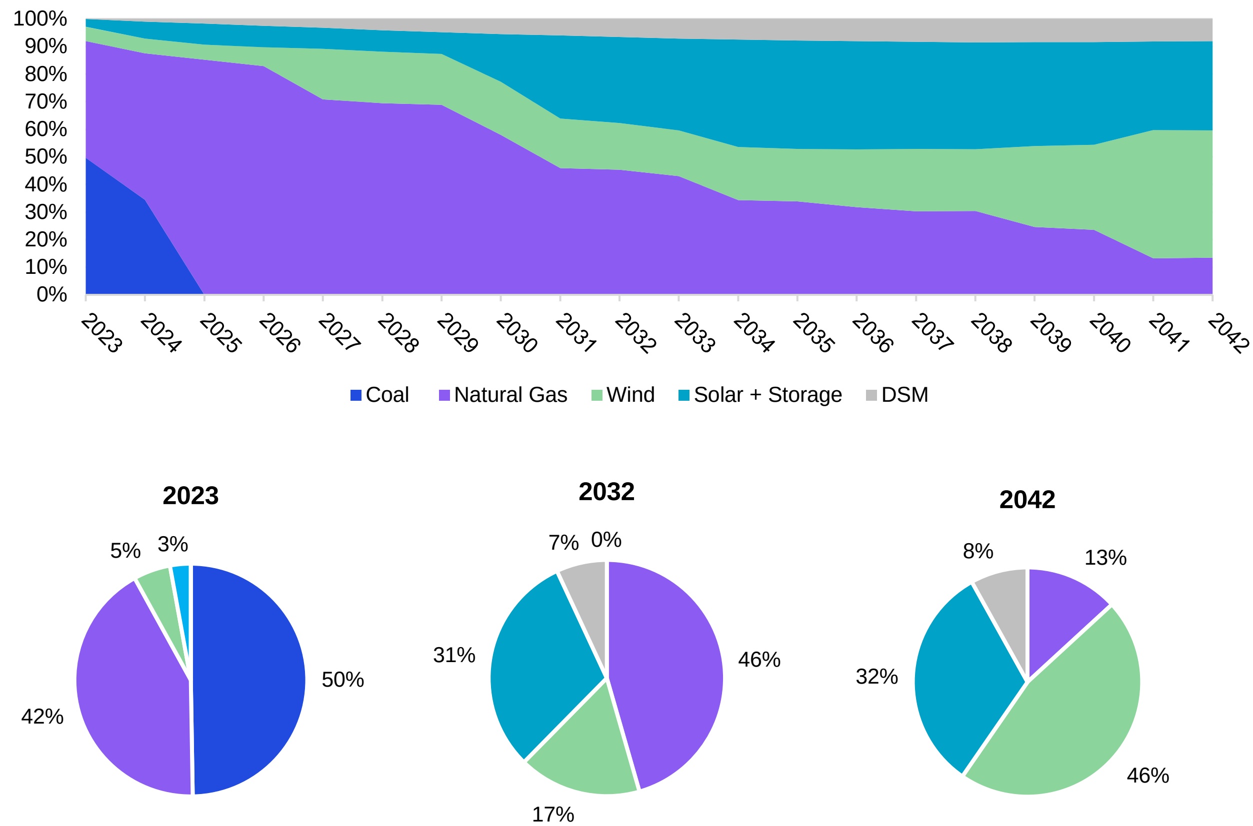
[67] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-16: Petersburg Conversion Strategy Near-term Incremental Installed Capacity Additions (MW)

	2023	2024	2025	2026	2027	2028
Petersburg Conversion	0	0	**1,052**	0	0	0
Wind	0	0	0	**50**	**450**	0
Solar[68]	0	0	0	0	0	0
Storage	0	0	**240**	0	0	0
Solar + Storage	0	0	**45**	0	0	0
Natural Gas	0	0	0	0	0	0

Figure 9-17 and Figure 9-18 show the Petersburg Conversion strategy energy mix and position over the planning period. Focusing on renewable generation results in 2032, which is one of the sustainability metrics on the IRP Scorecard, it is estimated that the Petersburg Conversion strategy will provide 55% of its energy generation from renewables by this year.

Figure 9-17: Petersburg Conversion Strategy Percentage of Energy Mix by Resource Type



Thermal MWh %	92%	Thermal MWh %	54%	Thermal MWh %	13%
Renewable/DSM MWh %	8%	Renewable/DSM MWh %	45%	Renewable/DSM MWh %	87%

[68] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-18: Petersburg Conversion Energy Position by Resource Type (GWh)

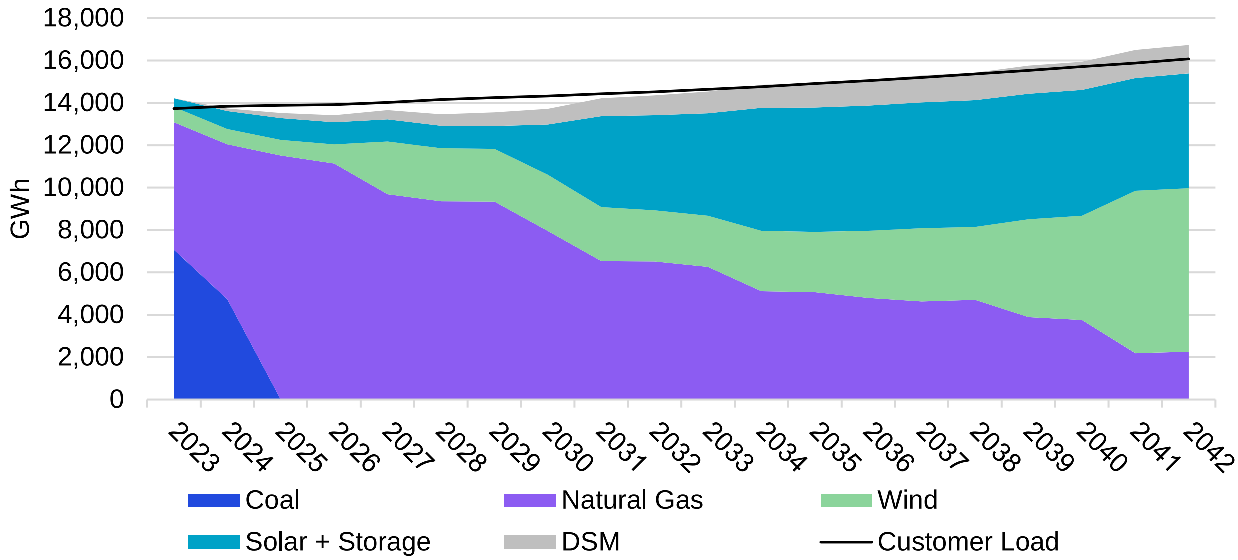


Figure 9-19 provides a summary of the DSM selected in the Petersburg Conversion strategy. All but the Efficient Products – Higher Cost and Appliance Recycling bundles are selected from Vintage 1. Implementing the selected programs in Vintage 1, results in 131,578 MWh of annual DSM on average over the three-year period. For Vintage 2 (2027 – 2029) & 3 (2030 – 2042), the Lower Cost Residential bundle and all C&I energy efficiency were selected. IQW was predefined in the model and not treated as selectable because the Company intends to maintain offerings for this segment of customers regardless of cost effectiveness. For demand response, the model selected the Residential and C&I rates programs which would result in a cumulative summer peak impact of 75 MW.

Figure 9-19: Petersburg Conversion Strategy DSM Selections

Energy Efficiency:

	Vintage 1	Vintage 2	Vintage 3
	2024 - 2026	**2027 - 2029**	**2030 - 2042**
Residential	Efficient Products - Lower Cost	Lower Cost Residential (excluding IQW)	Lower Cost Residential (excluding IQW)
	Efficient Products - Higher Cost		
	Behavioral		
	School Education	Higher Cost Residential (excluding IQW)	Higher Cost Residential (excluding IQW)
	Appliance Recycling		
	Multifamily		
	IQW	IQW	IQW
C&I	Prescriptive	C&I	C&I
	Custom		
	Custom RCx		
	Custom SEM		
Impacts	Avg Annual MWh	Avg Annual MWh	Avg Annual MWh
	131,578	141,526	146,428
	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out
	1.0%	1.1%	1.2%
	Cumulative Summer MW	Cumulative Summer MW	Cumulative Summer MW
	87 MW	92 MW	303 MW

Demand Response:

	2026 - 2042
Residential	Direct Load Control
	Residential Rates
C&I	Direct Load Control
	C&I Rates
	Cumulative Summer MW
	75 MW

Note: Boxes highlighted in purple denote DSM bundles that were selected by EnCompass

One Petersburg Unit Retires Strategy Results

The One Petersburg Unit Retires strategy retires Petersburg Unit 3 in 2026 and leaves Petersburg Unit 4 on coal through the remainder of planning period. Thus, the EnCompass Model made retirement and replacement decisions for the approximately 520 MW of capacity associated with the retirement of Petersburg Unit 3 in 2026. The Harding Street steam Units 5 and 6 retire in 2031 and steam Unit 7 retires in 2034. These are age-based retirements that occur in every strategy analyzed in this IRP. A summary of the total change in retirements and replacements over the planning period resulting from the One Petersburg Unit Retires strategy is provided below.

Retirements

Petersburg:

→ Petersburg 3 Coal: 2026

- **Total Coal Retired MW: 520 MW**

Harding Street:

→ HS ST5 Nat Gas: 2030

→ HS ST6 Nat Gas: 2030

→ HS ST7 Nat Gas: 2033

- **Total Nat Gas Retired MW: 618 MW**

Replacement Additions by 2042[69]

→ DSM: 490 MW

→ Wind: 2,500 MW

→ Solar: 2,340 MW

→ Storage: 1,240 MW

→ Solar + Storage: 45 MW

→ Thermal: 0 MW

Figure 9-20 below provides the PVRR results for the One Petersburg Unit Retires strategy compared to the other Candidate Portfolios. This strategy performs the worst from an affordability perspective because, after reducing the capacity at Petersburg by retiring one unit, the fixed cost of coal operations, such as coal handling, emissions reduction equipment, are needed to operate the remaining unit. Petersburg operation basically becomes very costly to operate on a dollar per MWh basis.

[69] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC ratio is treated as being equal to 1.

Figure 9-20: PVRR Overview of the Candidate Portfolios Current Trends PVRR Summary[70]

Strategy	PVRR
No Early Retirement	$9,572
Petersburg Conversion to Natural Gas (est. 2025)	$9,330
One Petersburg Unit Retires (2026)	$9,773
Both Petersburg Units Retire (2026 and 2028)	$9,618
Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)	$9,711
EnCompass Optimization without Predefined Strategy – Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027	$9,262

Figure 9-21and Figure 9-22 below provides the summer and winter unforced capacity position for the One Petersburg Unit Retires strategy. In 2026, Peterburg Unit 3 retires and is replaced with battery energy storage and wind. The One Petersburg Unit Retires strategy adds a significant amount of solar and storage as replacement for the age-based Harding Street ST5, ST6, and ST7 retirements in the 2030s. Note that solar resources do not contribute winter capacity under MISO's seasonal resource adequacy construct; therefore, solar resources do not appear in the winter position chart.

[70] 20-year PVRR (2023 dollars in millions from 2023-2042).

Figure 9-21: One Petersburg Unit Retires Strategy Firm Unforced Capacity Position – Summer

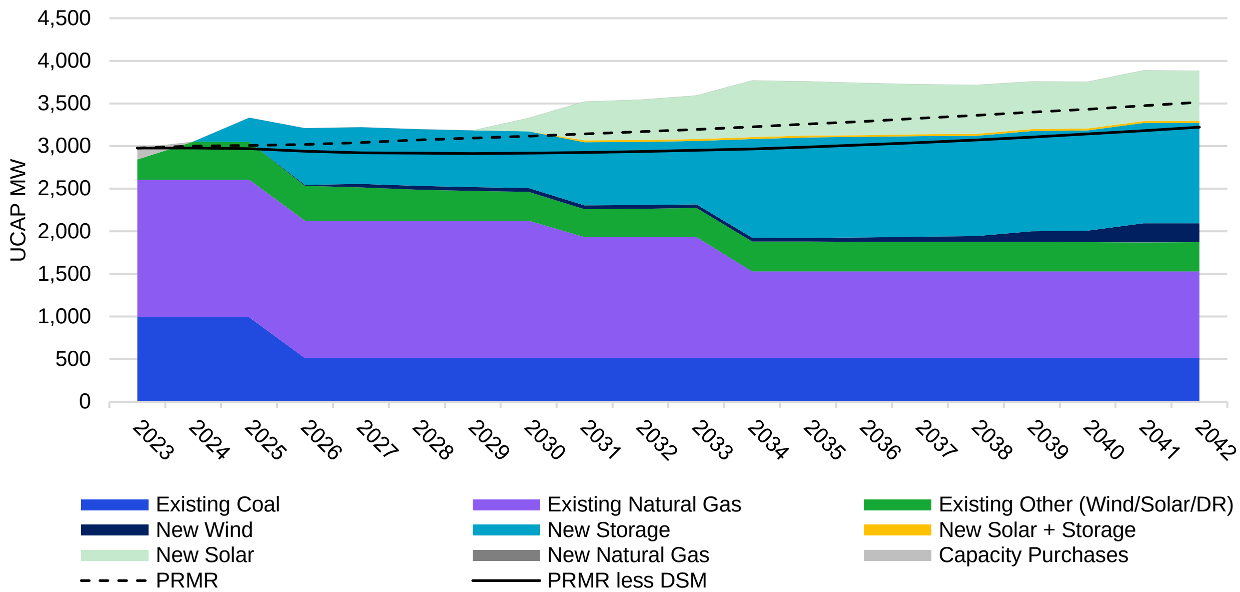


Figure 9-22: One Petersburg Unit Retires Strategy Firm Unforced Capacity Position – Winter

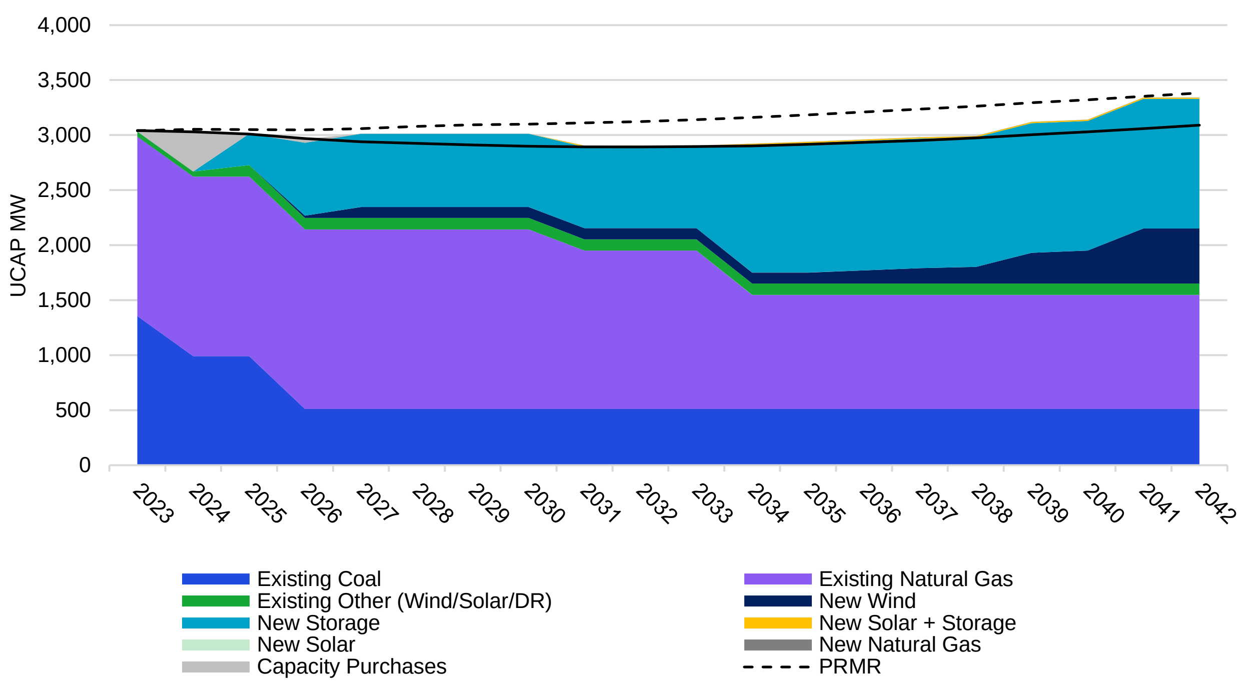
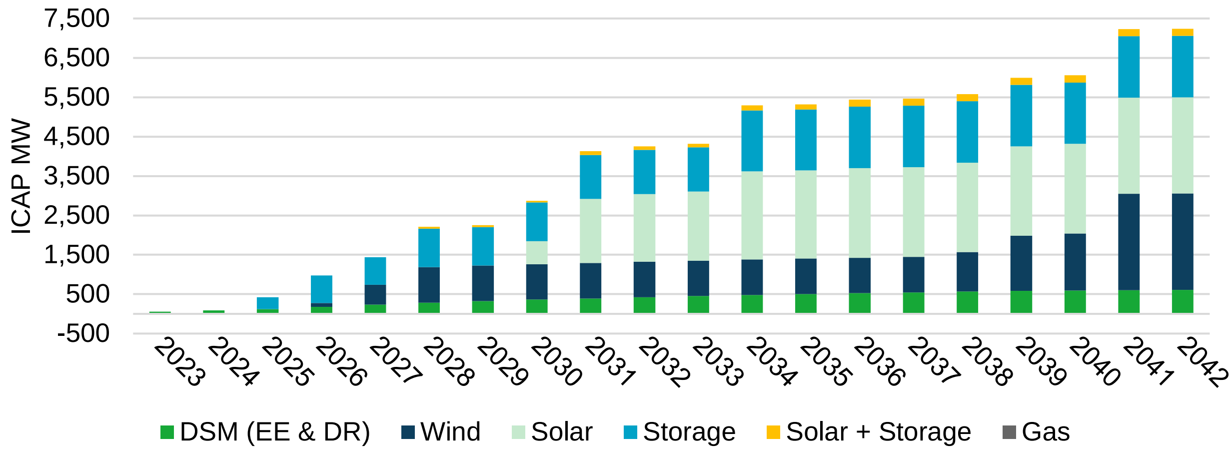


Figure 9-23 shows the incremental capacity additions over the planning period for the One Petersburg Unit Retires strategy. To replace Petersburg Unit 3, which retires in 2026, the strategy adds storage and wind. Also, the strategy adds large amount of solar and storage in the 2030s to replace the age-based Harding Street ST5, ST6, and ST7 retirements.

Figure 9-23: One Petersburg Unit Retires Strategy Installed Capacity Cumulative Additions (MW) [71]



Resource Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
DSM (EE & DR)	52	84	111	162	215	256	292	322	348	372	396	416	434	448	463	475	482	484	488	490
Wind	0	0	0	100	500	500	500	500	500	500	500	500	500	600	700	750	1,400	1,500	2,500	2,500
Solar	0	0	0	0	0	0	0	455	1,398	1,463	1,593	2,080	2,080	2,080	2,080	2,080	2,080	2,080	2,340	2,340
Storage	0	0	300	700	700	700	700	700	780	780	780	1,220	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240
Solar + Storage	0	0	0	0	0	0	0	0	45	45	45	45	45	45	45	45	45	45	45	45
Petersburg Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 9-24 below provides the One Petersburg Unit Retires strategy's near-term incremental installed capacity additions. The portfolio adds 700 MW of battery energy storage resources to fill the capacity from retiring Petersburg Unit 3 in 2026 and to fill 240 MW of needed capacity in the winter. Additionally, the portfolio builds 500 MW of wind resources in 2026 and 2027 as energy and capacity replacement for the retired Petersburg unit.

Figure 9-24: One Petersburg Unit Retires Strategy Near-term Incremental Installed Capacity Additions (MW)

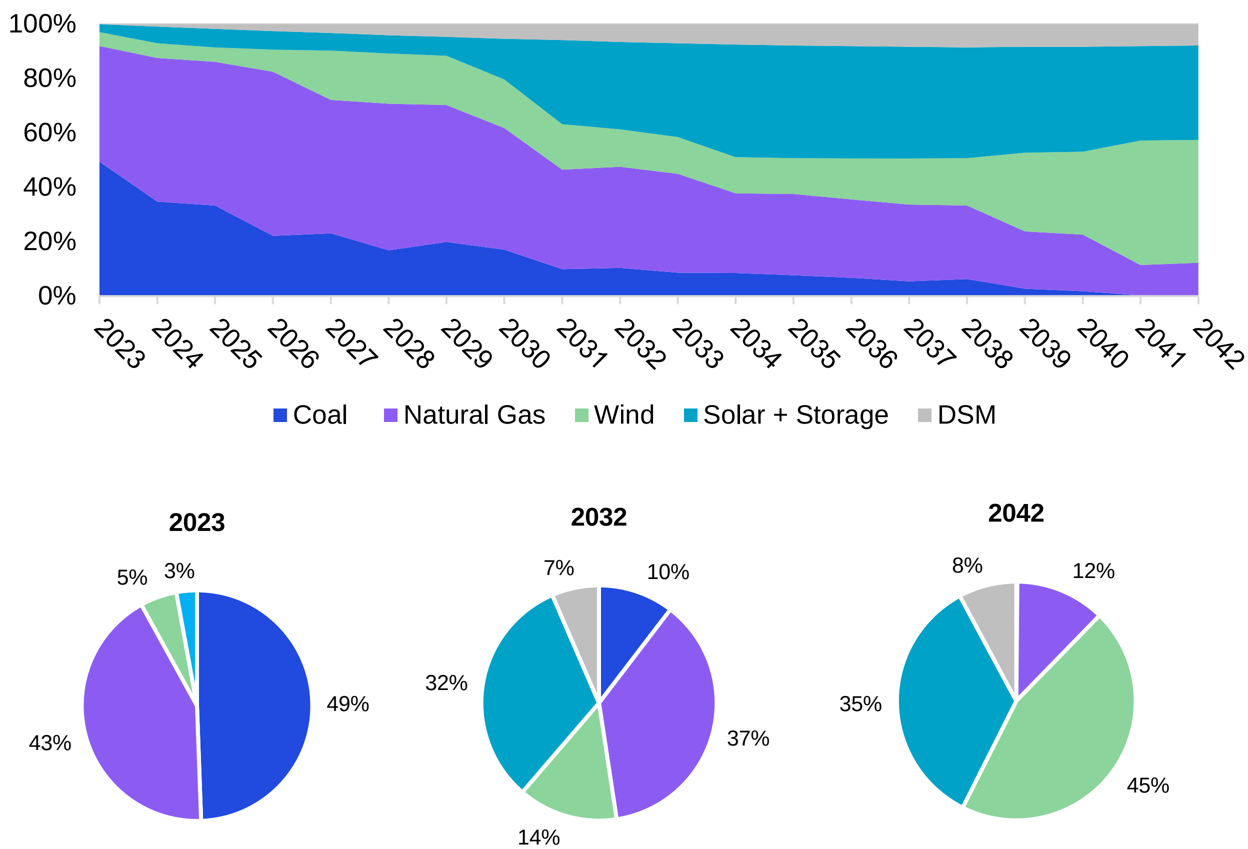
	2023	2024	2025	2026	2027	2028
Wind	0	0	0	**100**	**400**	0
Solar[72]	0	0	0	0	0	0
Storage	0	0	**300**	**400**	0	0
Solar + Storage	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0

[71] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

[72] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-25 and Figure 9-26 show the One Petersburg Unit Retires energy mix and position over the IRP planning period. Focusing on renewable generation results in 2032, which is one of the sustainability metrics on the IRP Scorecard, it is estimated that the One Petersburg Unit Retires strategy will provide 52% of its energy generation from renewable resources by this year

Figure 9-25: One Petersburg Unit Retires Strategy Percentage of Energy Mix by Resource Type



Thermal MWh %	92%	Thermal MWh %	48%	Thermal MWh %	12%
Renewable/DSM MWh %	8%	Renewable/DSM MWh %	52%	Renewable/DSM MWh %	88%

Figure 9-26: One Petersburg Unit Retires Strategy Energy Position by Resource Type (GWh)

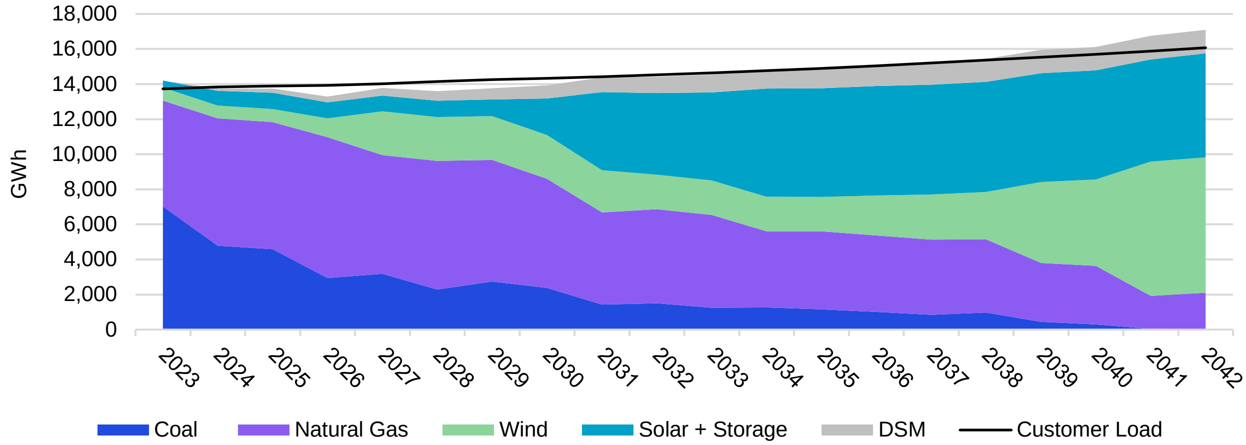


Figure 9-27 provides a summary of the DSM selected in the One Petersburg Unit Retires strategy. All but the Efficient Products – Higher Cost and Appliance Recycling bundles get selected from Vintage 1. Implementing the selected programs in Vintage 1 results in 131,578 MWh of annual DSM on average over the three-year period. For Vintage 2 (2027 – 2029) and Vintage 3 (2030 – 2042), the Lower Cost Residential bundle and all C&I energy efficiency were selected. IQW was predefined in the model and not treated as selectable because the Company intends to maintain offerings for this segment of customers regardless of cost effectiveness. For demand response, the model selected the Residential and C&I rates programs, which would result in a cumulative summer peak impact of 75 MW in 2042.

Figure 9-27: One Petersburg Unit Retires Strategy DSM Selections

Energy Efficiency:

	Vintage 1	Vintage 2	Vintage 3
	2024 - 2026	**2027 - 2029**	**2030 - 2042**
Residential	Efficient Products - Lower Cost	Lower Cost Residential (excluding IQW)	Lower Cost Residential (excluding IQW)
	Efficient Products - Higher Cost		
	Behavioral		
	School Education	Higher Cost Residential (excluding IQW)	Higher Cost Residential (excluding IQW)
	Appliance Recycling		
	Multifamily		
	IQW	IQW	IQW
C&I	Prescriptive	C&I	C&I
	Custom		
	Custom RCx		
	Custom SEM		
Impacts	Avg Annual MWh	Avg Annual MWh	Avg Annual MWh
	131,578	141,526	146,428
	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out
	1.0%	1.1%	1.2%
	Cumulative Summer MW	Cumulative Summer MW	Cumulative Summer MW
	87 MW	92 MW	303 MW

Demand Response:

	2026 - 2042
Residential	Direct Load Control
	Residential Rates
C&I	Direct Load Control
	C&I Rates
	Cumulative Summer MW
	75 MW

Note: Boxes highlighted in purple denote DSM bundles that were selected by EnCompass

Both Petersburg Units 3 and 4 Retire Strategy Results

The Both Petersburg Units Retire strategy retires Petersburg Unit 3 in 2026 and Petersburg Unit 4 in 2028. Therefore, the EnCompass Model made retirement and replacement decisions for approximately 1,000 MW of capacity associated with the retirement of both Petersburg units. The Harding Street Steam Units 5 and 6 retire in 2031 and steam Unit 7 retires in 2034. These are age-based retirements that occur in every strategy analyzed in this IRP. A summary of the total change in retirements and replacements over the planning period resulting from the Both Petersburg Units Retire strategy is provided below.

Retirements

Petersburg:

→ Petersburg 3 Coal: 2026

→ Petersburg 4 Coal: 2028

- **Total Coal Retired MW: 1,040 MW**

Harding Street:

→ HS ST5 Nat Gas: 2030

→ HS ST6 Nat Gas: 2030

→ HS ST7 Nat Gas: 2033

- **Total Nat Gas Retired MW: 618 MW**

Replacement Additions by 2042

→ DSM: 610 MW

→ Wind: 2,450 MW

→ Solar: 2,308 MW[73]

→ Storage: 1,280 MW

→ Solar + Storage: 225 MW

→ Thermal: 325 MW

Figure 9-28 below provides the PVRR results for the Both Petersburg Units Retire strategy compared to the other Candidate Portfolios. This strategy is one of the costlier portfolios for customers because it requires a significant amount of investment to replace the approximately 1,000 MW of retired Petersburg coal-fired capacity.

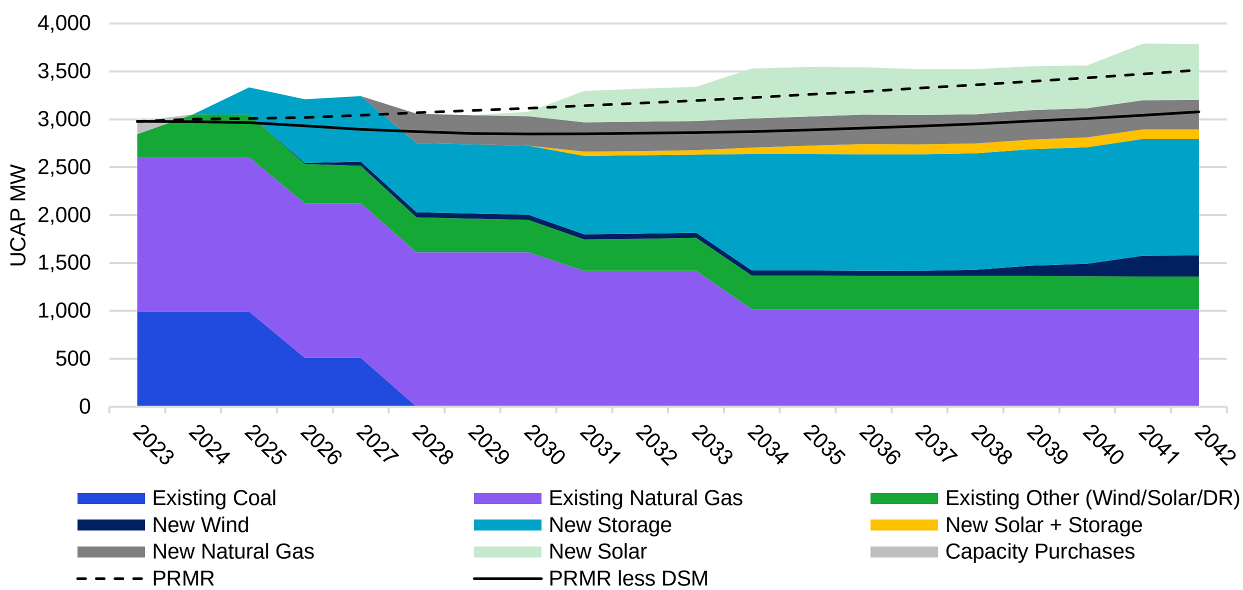
[73] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC ratio is treated as being equal to 1.

Figure 9-28: PVRR overview of the Candidate Portfolios Current Trends PVRR Summary[74]

Strategy	PVRR
No Early Retirement	$9,572
Petersburg Conversion to Natural Gas (est. 2025)	$9,330
One Petersburg Unit Retires (2026)	$9,773
Both Petersburg Units Retire (2026 and 2028)	$9,618
Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage Resources (2026 and 2028)	$9,711
EnCompass Optimization without Predefined Strategy – Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027	$9,262

Figure 9-29 and Figure 9-30 below provides the summer and winter unforced capacity position for the Both Petersburg Units Retire strategy. In 2026 and 2028, Peterburg Units 3 and 4 retire, respectively. The units are replaced with a significant amount of wind and battery energy storage and a 325 MW CCGT. The strategy also adds a significant amount of solar and storage as replacement for the age-based Harding Street Units ST5, ST6, and ST7 retirements in the 2030s. Note that solar resources do not contribute winter capacity under MISO's seasonal resource adequacy construct; therefore, solar resources do not appear in the winter position chart.

Figure 9-29: Both Petersburg Units Retire Strategy Firm Unforced Capacity Position – Summer



[74] 20-year PVRR (2023 dollars in millions from 2023-2042).

Figure 9-30: Both Petersburg Units Retire Strategy Firm Unforced Capacity Position – Winter

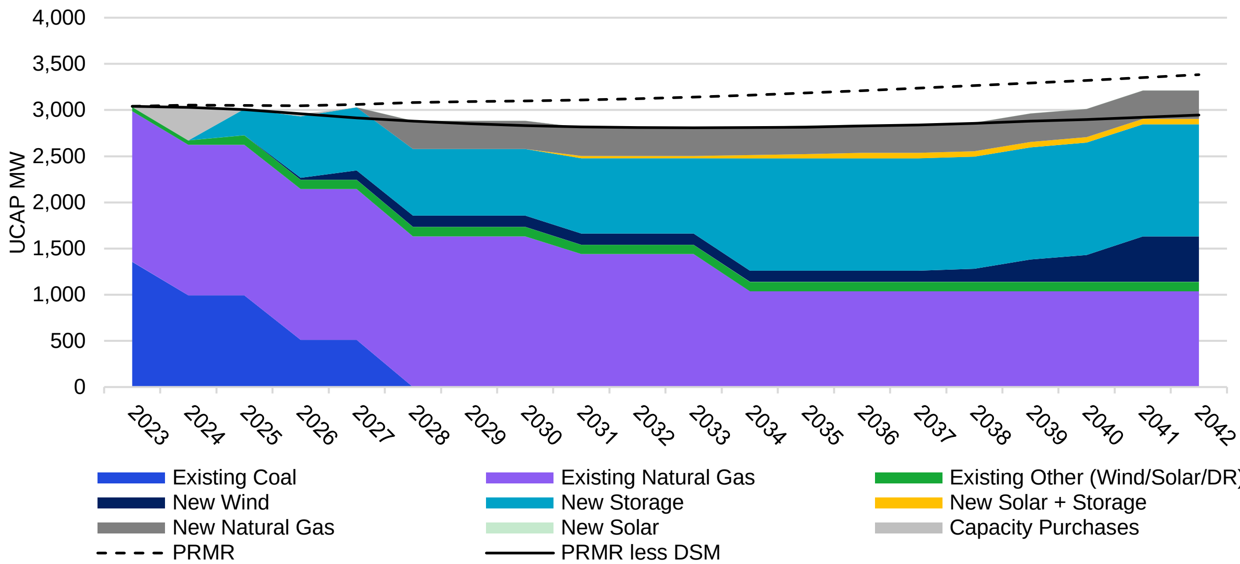
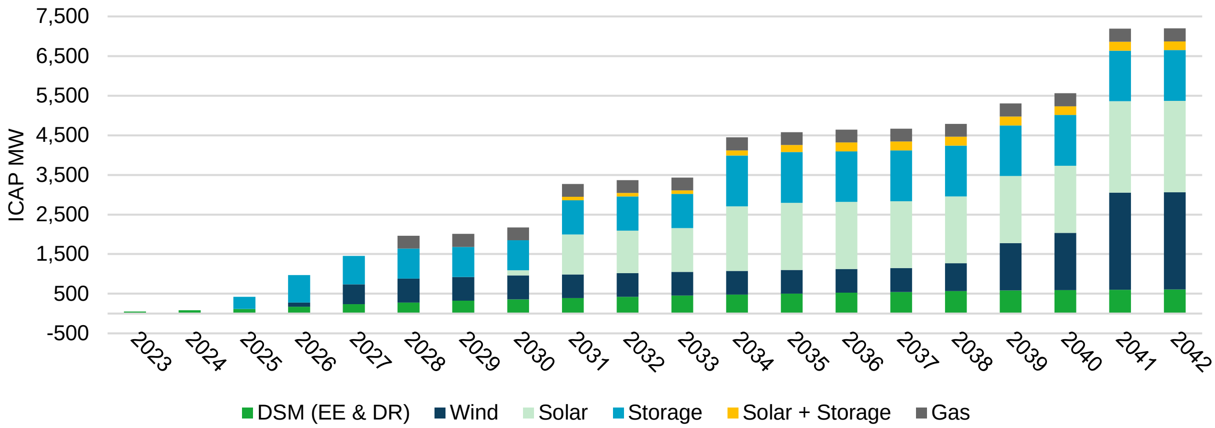


Figure 9-31 shows the incremental capacity additions over the planning period for the Both Petersburg Units Retire strategy. To replace Petersburg Unit 3 and 4, the strategy adds battery energy storage resources, wind resources, and a 325 MW CCGT. The strategy also adds large amount of solar and storage resources in the 2030s to replace Harding Street ST5, ST6, and ST7 due to their age-based retirements.

Figure 9-31: Both Petersburg Units Retire Strategy Installed Capacity Cumulative Additions (MW)[75]



Resource Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
DSM (EE & DR)	52	87	119	174	233	281	323	360	391	422	453	480	504	525	547	567	581	590	601	610
Wind	0	0	0	100	500	600	600	600	600	600	600	600	600	600	600	700	1,200	1,450	2,450	2,450
Solar	0	0	0	0	0	0	0	130	1,008	1,073	1,105	1,625	1,690	1,690	1,690	1,690	1,690	1,690	2,308	2,308
Storage	0	0	300	700	720	760	760	760	860	860	860	1,280	1,280	1,280	1,280	1,280	1,280	1,280	1,280	1,280
Solar + Storage	0	0	0	0	0	0	0	0	90	90	90	135	180	225	225	225	225	225	225	225
Petersburg Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325

Figure 9-32 provides the incremental installed capacity additions through 2028. The Both Petersburg Units Retire strategy replaces the retired units with 760 MW of battery energy storage resources, 600 MW of wind resources, and a 325 MW CCGT in 2028. Of the Candidate Portfolios, this is the only portfolio that selects a natural gas resource as a replacement resource.

Figure 9-32: Both Petersburg Units Retire Strategy Near-term Incremental Installed Capacity Additions (MW)

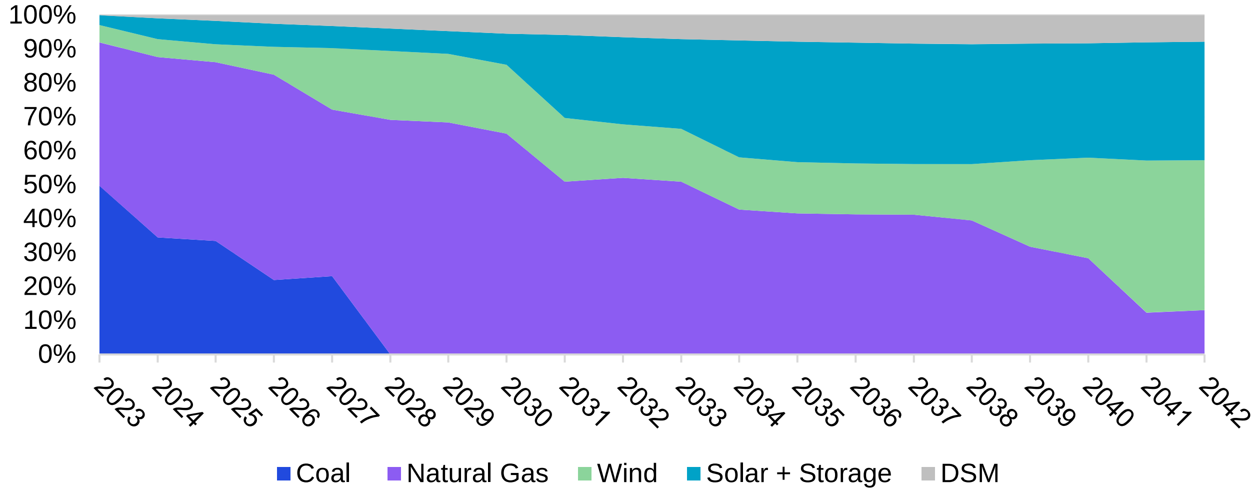
	2023	2024	2025	2026	2027	2028
Wind	0	0	0	**100**	**400**	**100**
Solar[76]	0	0	0	0	0	0
Storage	0	0	**300**	**400**	**20**	**40**
Solar + Storage	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	**325**

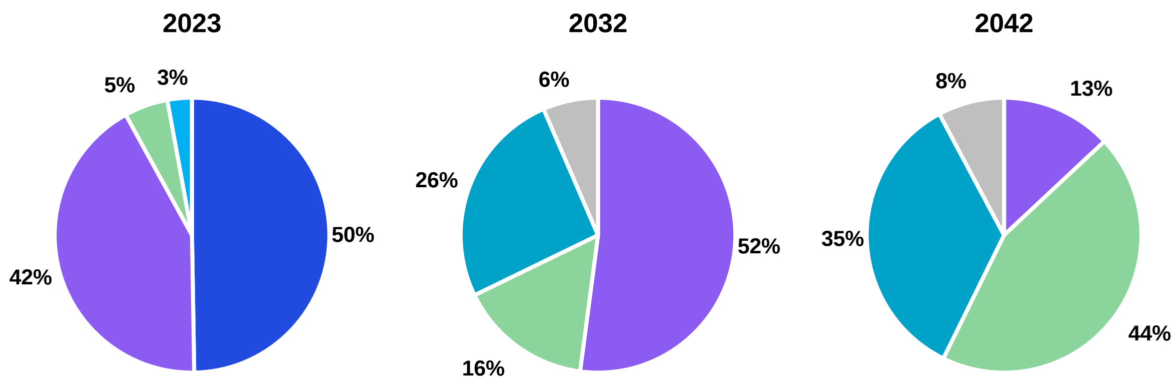
Figure 9-33 and Figure 9-34 show the Both Petersburg Units Retires strategy energy mix and position over the planning period. Focusing on renewable generation results in 2032, which is one of the sustainability metrics on the IRP Scorecard – it is estimated that the Both Petersburg Units Retire strategy will provide 48% of energy generation from renewables by this year. The addition

[75] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.
[76] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

of an efficient 325 MW CCGT in 2028 is a key contributor to keeping the majority of energy generated from thermal resources in 2032.

Figure 9-33: Both Petersburg Units Retire Strategy Energy Mix Percentages by Resource Type





Thermal MWh %	92%	Thermal MWh %	52%	Thermal MWh %	15%
Renewable/DSM MWh %	8%	Renewable/DSM MWh %	48%	Renewable/DSM MWh %	87%

Figure 9-34: Both Petersburg Units Retire Strategy Energy Position by Resource Type (GWh)

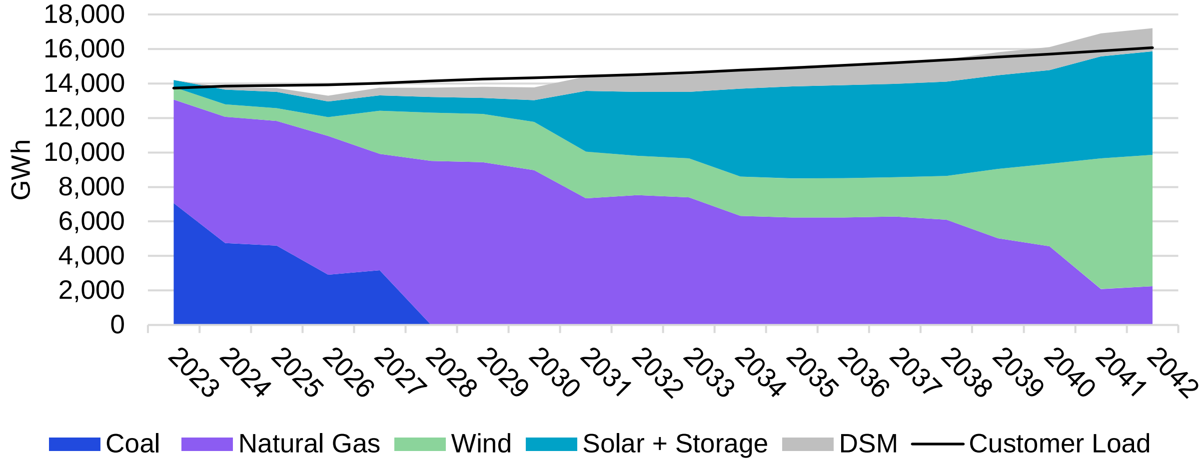


Figure 9-35 provides a summary of the DSM selected in the Both Petersburg Units Retire strategy. All but the Efficient Products – Higher Cost and Appliance Recycling bundles get selected from Vintage 1. Implementing the selected programs in Vintage 1, would results in 131,578 MWh of annual DSM on average over the three-year period. For Vintage 2 (2027 – 2029) and Vintage 3 (2030 – 2042), the Lower Cost Residential bundle and all C&I energy efficiency were selected. IQW was predefined in the model and not treated as selectable because the Company intends to maintain offerings for this segment of customers regardless of cost effectiveness. For Demand Response, the model selected the Residential Load Control and Rates program for the C&I Rates programs, which would result in a cumulative summer peak impact of 195 MW in 2042.

Figure 9-35: Both Petersburg Units Retire Strategy DSM Selections

Energy Efficiency:

	Vintage 1	Vintage 2	Vintage 3
	2024 - 2026	**2027 - 2029**	**2030 - 2042**
Residential	Efficient Products - Lower Cost	Lower Cost Residential (excluding IQW)	Lower Cost Residential (excluding IQW)
	Efficient Products - Higher Cost		
	Behavioral		
	School Education	Higher Cost Residential (excluding IQW)	Higher Cost Residential (excluding IQW)
	Appliance Recycling		
	Multifamily		
	IQW	IQW	IQW
C&I	Prescriptive	C&I	C&I
	Custom		
	Custom RCx		
	Custom SEM		
Impacts	Avg Annual MWh	Avg Annual MWh	Avg Annual MWh
	134,263	141,526	146,428
	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out
	1.1%	1.1%	1.2%
	Cumulative Summer MW	Cumulative Summer MW	Cumulative Summer MW
	89 MW	92 MW	303 MW

Demand Response:

	2026 - 2042
Residential	Direct Load Control
	Residential Rates
C&I	Direct Load Control
	C&I Rates
	Cumulative Summer MW
	195 MW

Note: Boxes highlighted in purple denote DSM bundles that were selected by EnCompass

Clean Energy Strategy – Petersburg Unit 3 Retires in 2026 and Petersburg Unit 4 Retires in 2028 and Replaced with Wind, Solar and Storage Results

The Clean Energy Strategy retires Petersburg Unit 3 in 2026 and Petersburg Unit 4 in 2028 and replaces this retired generation with only wind, solar, and storage resources. This strategy was modeled at the request of stakeholders to guarantee AES Indiana modeled a clean energy replacement strategy for Petersburg for comparison to the other strategies. In this strategy, the EnCompass Model made retirement and replacement decisions for approximately 1,000 MW of capacity associated with the retirement of both Petersburg units. Harding Street steam Units 5 and 6 retire in 2031 and steam Unit 7 retires in 2034. These are age-based retirements that occur in every strategy analyzed in AES Indiana's 2022 IRP. A summary of the total change in retirements and replacements over the planning period resulting from the Clean Energy Strategy is provided below.

Retirements

Petersburg:

→ Petersburg 3 Coal: 2026

→ Petersburg 4 Coal: 2028

- **Total Coal Retired MW: 1,040 MW**

Harding Street:

→ HS ST5 Nat Gas: 2030

→ HS ST6 Nat Gas: 2030

→ HS ST7 Nat Gas: 2033

- **Total Retired Nat Gas MW: 618 MW**

Replacements by 2042[77]

→ DSM: 610 MW

→ Wind: 2,450 MW

→ Solar: 2,438 MW

→ Storage: 1,560 MW

→ Solar + Storage: 180 MW

→ Thermal: 0 MW

Figure 9-36 below provides the PVRR results for the Clean Energy Strategy compared to the other Candidate Portfolios. This strategy is one of the costlier portfolios for customers because it requires a significant amount of investment to replace approximately 1,000 MW of retired Petersburg coal-fired capacity. It ends up being costlier than the Both Petersburg Units Retire strategy because the portfolio relies on renewable resources to replace Petersburg. Due to MISO's capacity accreditation for these resources, the Company would have to build significantly more wind and solar resources to meet its PRMR. For comparison, in the Both Petersburg Units Retire strategy, the model partly replaces the Petersburg coal units with a 325 MW CCGT, which receives better accreditation from MISO and helps keep the portfolio PVRR lower.

[77] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC ratio is treated as being equal to 1.

Figure 9-36: PVRR Overview of the Candidate Portfolios Current Trends PVRR Summary[78]

Strategy	PVRR
No Early Retirement	$9,572
Petersburg Conversion to Natural Gas (est. 2025)	$9,330
One Petersburg Unit Retires (2026)	$9,773
Both Petersburg Units Retire (2026 and 2028)	$9,618
Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)	$9,711
EnCompass Optimization without predefined Strategy – Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027	$9,262

Figure 9-37 and Figure 9-38 below provides the summer and winter unforced capacity position for the Clean Energy Strategy. In 2026 and 2028, Peterburg Units 3 and 4 retire, respectively. The units are replaced entirely with wind and battery energy storage resources. The strategy also adds a significant amount of solar and storage resources as replacement for the age-based Harding Street ST5, ST6, and ST7 retirements in the 2030s. Note that solar resources do not contribute winter capacity under MISO's seasonal resource adequacy construct; therefore, solar resources do not appear in the winter position chart.

[78] 20-year PVRR (2023 dollars in millions from 2023-2042).

Figure 9-37: Clean Energy Strategy Firm Unforced Capacity Position – Summer

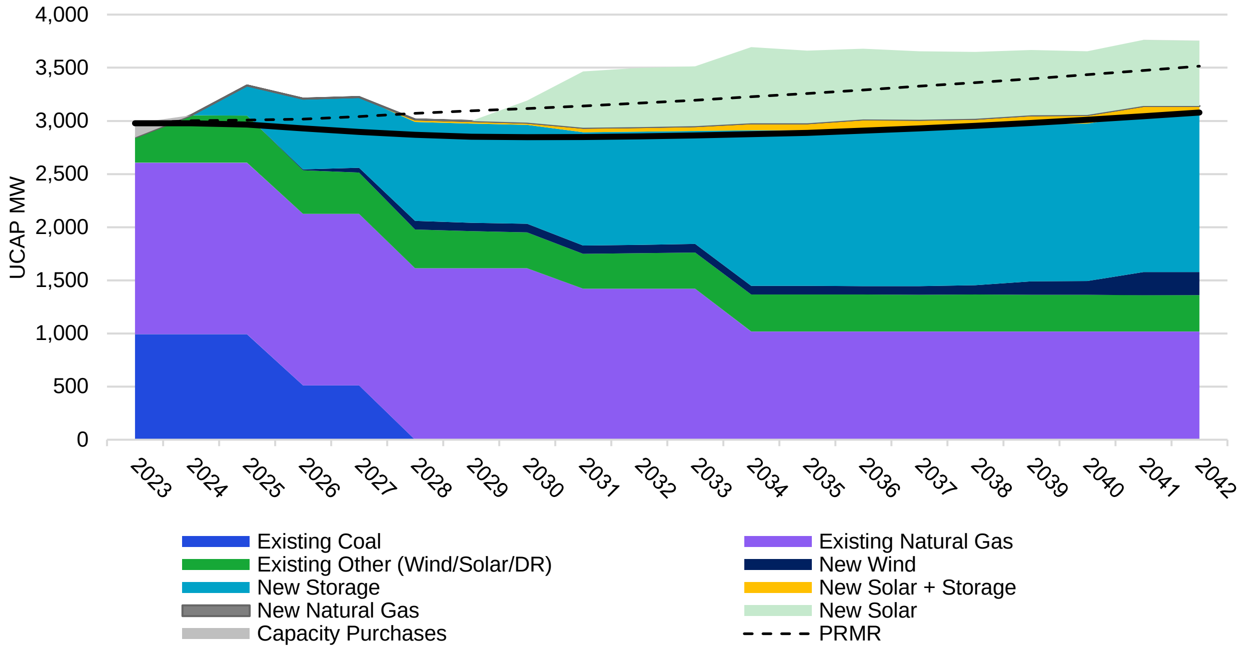


Figure 9-38: Clean Energy Strategy Firm Unforced Capacity Position – Winter

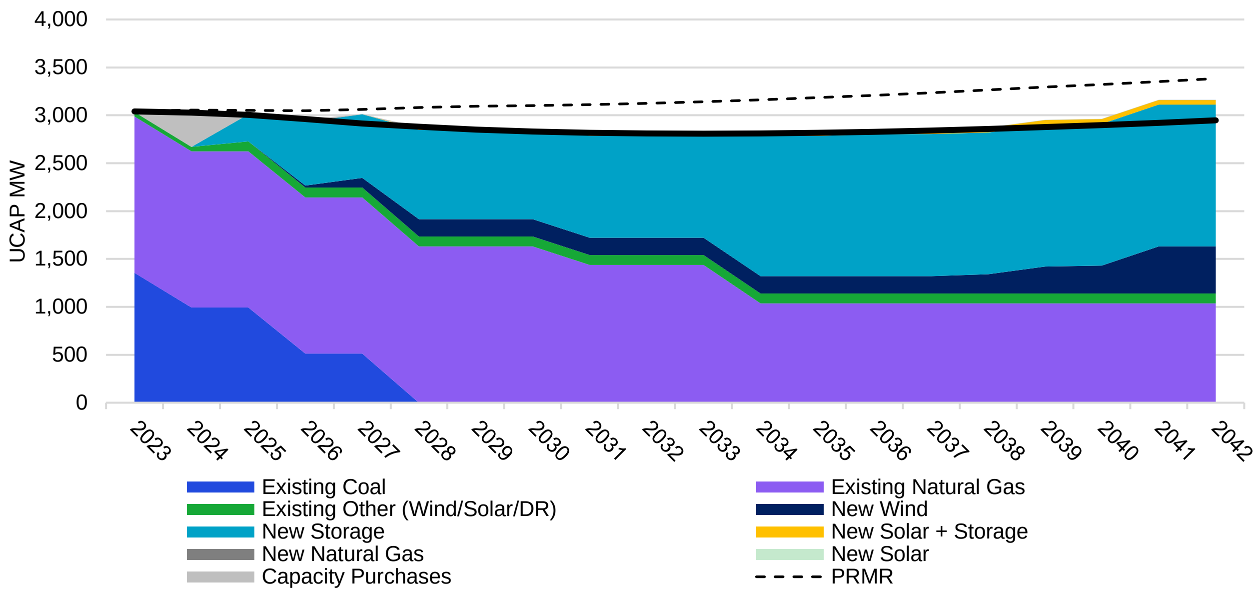
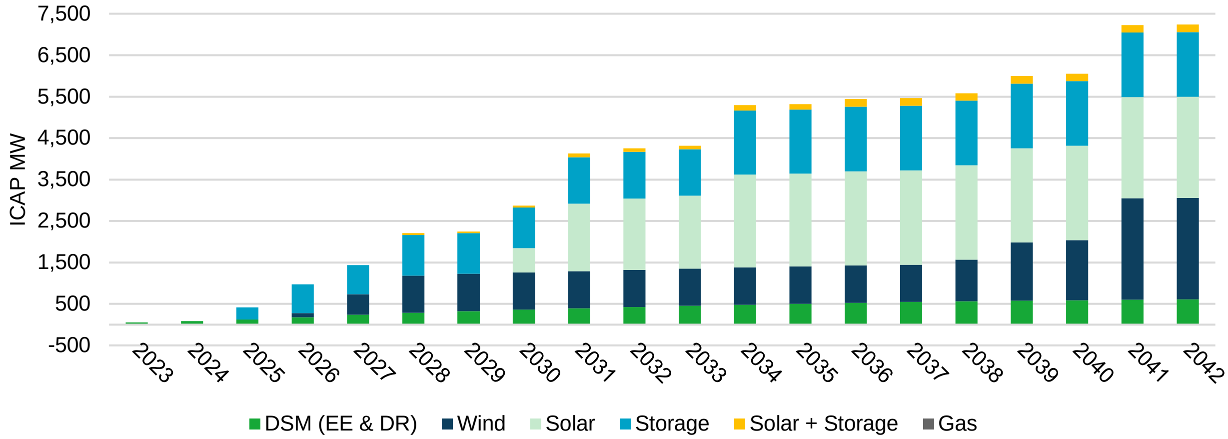


Figure 9-39 shows the incremental capacity additions over the planning period for the Clean Energy Strategy. To replace Petersburg Units 3 and 4, the strategy adds battery energy storage, solar, and wind resources. Also, the strategy adds large amounts of wind, solar, and storage resources in the 2030s for replacement of the age-based Harding Street ST5, ST6, and ST7 retirements.

Figure 9-39: Clean Energy Strategy Installed Capacity Cumulative Additions (MW) [79]



Resource Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
DSM (EE & DR)	52	88	120	177	236	283	325	361	392	423	453	480	504	525	547	567	581	590	601	610
Wind	0	0	0	100	500	900	900	900	900	900	900	900	900	900	900	1,000	1,400	1,450	2,450	2,450
Solar	0	0	0	0	0	0	0	585	1,625	1,723	1,755	2,243	2,243	2,275	2,275	2,275	2,275	2,275	2,438	2,438
Storage	0	0	300	700	700	980	980	980	1,120	1,120	1,120	1,540	1,540	1,560	1,560	1,560	1,560	1,560	1,560	1,560
Solar + Storage	0	0	0	0	0	45	45	45	90	90	90	135	135	180	180	180	180	180	180	180
Petersburg Conversion	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 9-40 provides the incremental installed capacity additions through 2028. The Clean Energy Strategy replaces the retired units with 980 MW of battery energy storage and 900 MW of wind by 2028. Additionally, the strategy adds a small solar plus battery energy storage project in 2028.

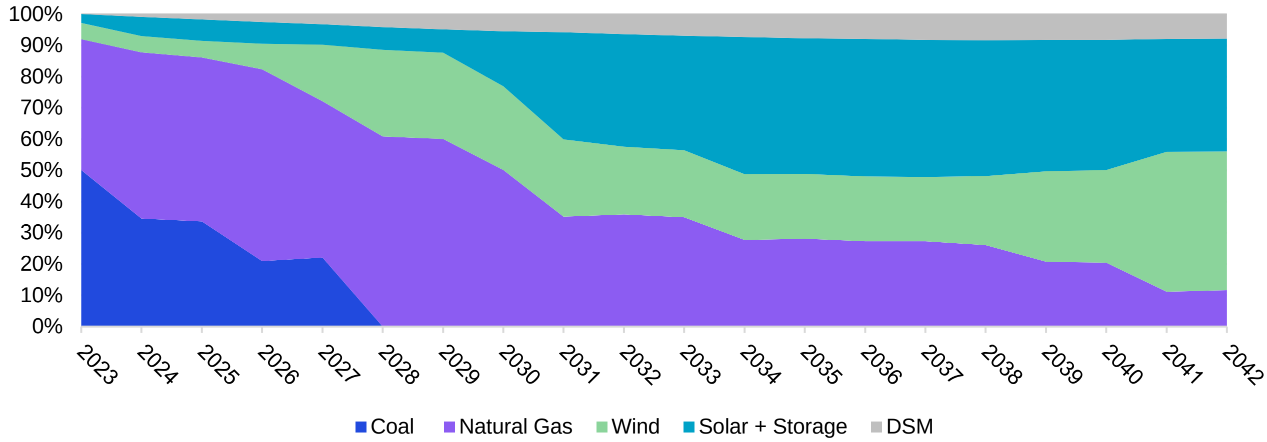
Figure 9-40: Clean Energy Strategy Near-Term Incremental Installed Capacity Additions (MW)

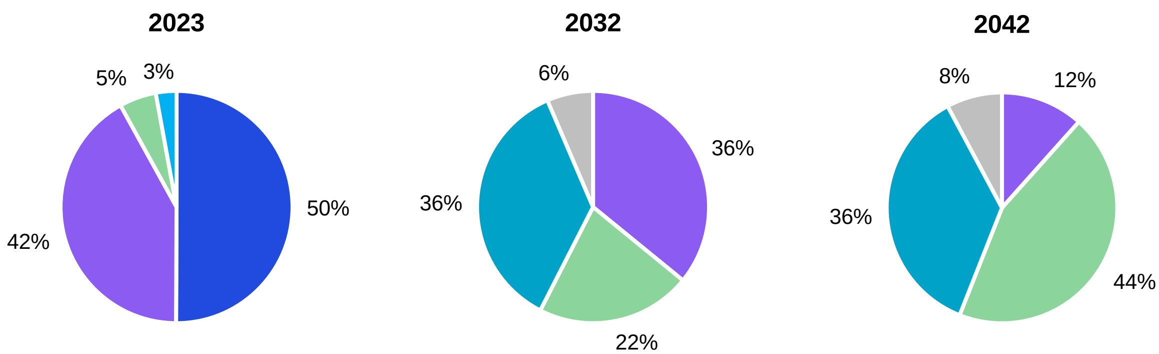
	2023	2024	2025	2026	2027	2028
Wind	0	0	0	**100**	**400**	**400**
Solar[79]	0	0	0	0	0	0
Storage	0	0	**300**	**400**	0	**280**
Solar + Storage	0	0	0	0	0	**45**
Natural Gas	0	0	0	0	0	0

Figure 9-41 and Figure 9-42 show the Clean Energy Strategy energy mix over the planning period. Focusing on renewable generation results in 2032 – which is one of the sustainability metrics on the IRP Scorecard – it is estimated the Clean Energy Strategy will provide 64% of energy generation from renewables by this year. This is the highest volume of renewable energy generation in 2032 of the Candidate Portfolios.

[79] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-41: Clean Energy Strategy Percent Energy Mix by Resource Type





Thermal MWh %	92%	Thermal MWh %	36%	Thermal MWh %	12%
Renewable/DSM MWh %	8%	Renewable/DSM MWh %	64%	Renewable/DSM MWh %	88%

Figure 9-42: Clean Energy Strategy Energy Position by Resource Type (GWh)

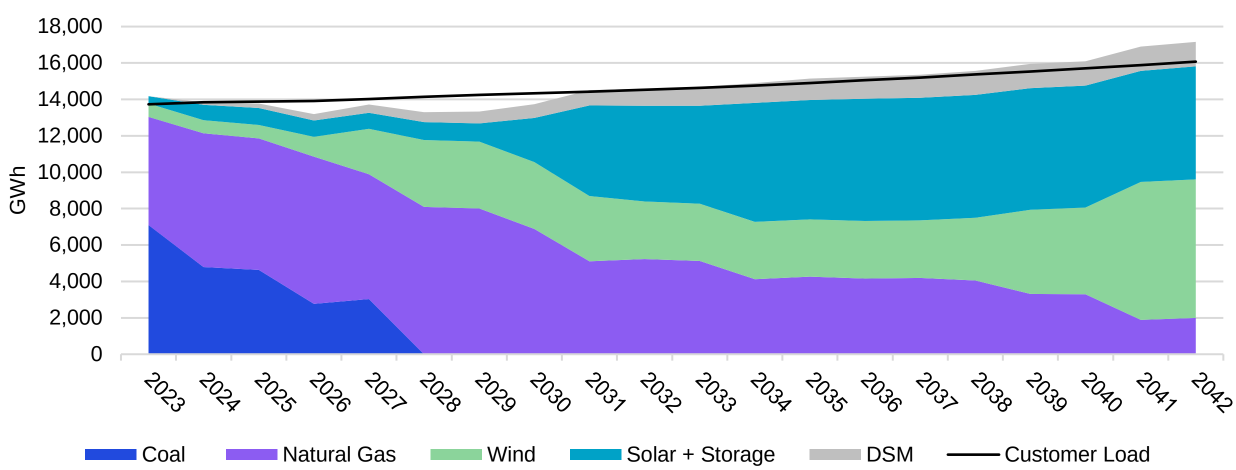


Figure 9-43 provides a summary of the DSM selected in the Clean Energy Strategy. All but the Efficient Products – Higher Cost bundles gets selected from Vintage 1. Implementing the selected programs in Vintage 1, would results in 134,263 MWh of annual DSM on average over the three-year period. For Vintage 2 (2027 – 2029) and 3 (2030 – 2042), the Lower Cost Residential bundle and all C&I energy efficiency were selected. IQW was predefined in the model and not treated as selectable because the Company intends to maintain offerings for this segment of customers regardless of cost effectiveness. For demand response, the model selected the Residential Load Control and Rates program for the C&I Rates programs, which would result in a cumulative summer peak impact of 195 MW in 2042.

Figure 9-43: Clean Energy Strategy DSM Selections

Energy Efficiency:

	Vintage 1	Vintage 2	Vintage 3
	2024 - 2026	**2027 - 2029**	**2030 - 2042**
Residential	Efficient Products - Lower Cost	Lower Cost Residential (excluding IQW)	Lower Cost Residential (excluding IQW)
	Efficient Products - Higher Cost		
	Behavioral		
	School Education	Higher Cost Residential (excluding IQW)	Higher Cost Residential (excluding IQW)
	Appliance Recycling		
	Multifamily		
	IQW	IQW	IQW
C&I	Prescriptive	C&I	C&I
	Custom		
	Custom RCx		
	Custom SEM		
Impacts	Avg Annual MWh	Avg Annual MWh	Avg Annual MWh
	134,263	141,526	146,428
	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out
	1.1%	1.1%	1.2%
	Cumulative Summer MW	Cumulative Summer MW	Cumulative Summer MW
	89 MW	92 MW	303 MW

Demand Response:

	2026 - 2042
Residential	Direct Load Control
	Residential Rates
C&I	Direct Load Control
	C&I Rates
	Cumulative Summer MW
	195 MW

Note: Boxes highlighted in purple denote DSM bundles that were selected by EnCompass

EnCompass Optimization without a Predefined Strategy: Converts Petersburg Unit 3 in 2025 and Petersburg Unit 4 in 2027 Results

The EnCompass Optimization analysis allows the EnCompass Model to select the most cost effective strategy for customers without a strategy predefined. In this analysis, the model has the option to keep Petersburg on coal, retire Petersburg (one or both units), or convert Petersburg to natural gas (one or both units). In executing this optimization, the model can select to split apart the conversion of Petersburg into different years; however, there are cost economies to converting both units at the same time (in the same year). These were difficult to accurately capture and, at the same time, have EnCompass dynamically select a portfolio in this optimization. Therefore, they were excluded from the analysis. With this caveat in mind, the results from this analysis give an approximate assessment of the portfolio cost to customers, which is useful in that it helps confirm which **predefined strategy** is the reasonable least cost option for customers.

Additionally, the Harding Street steam Units 5 and 6 retire in 2031 and steam Unit 7 retires in 2034. These are age-based retirements that occur in every strategy analyzed in AES Indiana's 2022 IRP. A summary of the total change in retirements and replacements over the planning period resulting from the EnCompass Optimization analysis is provided below.

Retirements and Conversions

Petersburg:

→ Petersburg 3 Coal: 2026

→ Petersburg 4 Coal: 2028

- **Total Converted MW: 1,040 MW**

Harding Street:

→ HS ST5 Nat Gas: 2030

→ HS ST6 Nat Gas: 2030

→ HS ST7 Nat Gas: 2033

- **Total Nat Gas Retired MW: 618 MW**

Replacement Additions by 2042[80]

- → DSM: 490 MW
- → Wind: 2,500 MW
- → Solar: 2,145 MW
- → Storage: 680 MW
- → Solar + Storage: 45 MW
- → Thermal: 0
- → Petersburg Units 3 and 4 Converted to Natural Gas: 1,052 MW

Figure 9-44 below provides the PVRR results for the EnCompass Optimization analysis compared to the other Candidate Portfolios. This analysis produced the lowest PVRR compared to the other strategies by converting Petersburg unit 3 in 2025 and unit 4 in 2027. However, the difference in PVRR compared to the Petersburg Conversion strategy that converts both units in 2025 is less than 1%. As previously noted, there are economies from converting both units in the same year that are excluded from the analysis. This result indicates that a strategy that converts Petersburg in the near term is the reasonable least cost for AES Indiana customers.

Figure 9-44: PVRR overview of the Candidate Portfolios Current Trends PVRR Summary[81]

Strategy	PVRR
No Early Retirement	$9,572
Petersburg Conversion to Natural Gas (est. 2025)	$9,330
One Petersburg Unit Retires (2026)	$9,773
Both Petersburg Units Retire (2026 and 2028)	$9,618
Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar & Storage (2026 and 2028)	$9,711
EnCompass Optimization without Predefined Strategy – Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027	$9,262

Figure 9-45 and Figure 9-46 below provides the summer and winter unforced capacity position for the EnCompass Optimization analysis. The optimization chooses the gas conversion of Petersburg Unit 3 in 2025 and Unit 4 in 2028. Converting the units provides an approximate one-for-one capacity replacement of the coal-fired Petersburg units. The optimization also adds a 240 MW battery energy storage resource in 2025 to fill a near-term winter capacity need prompted by MISO's seasonal resource adequacy construct. The EnCompass Optimization analysis also adds

[80] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC ratio is treated as being equal to 1.
[81] 20-year PVRR (2023 dollars in millions from 2023-2042).

a significant amount of solar and storage as replacement for the age-based Harding Street ST5, ST6, and ST7 retirements in the 2030s. Note that solar resources do not contribute winter capacity under MISO's seasonal resource adequacy construct; therefore, solar resources do not appear in the winter position chart.

Figure 9-45: EnCompass Optimization without a Predefined Strategy Firm Unforced Capacity Position – Summer

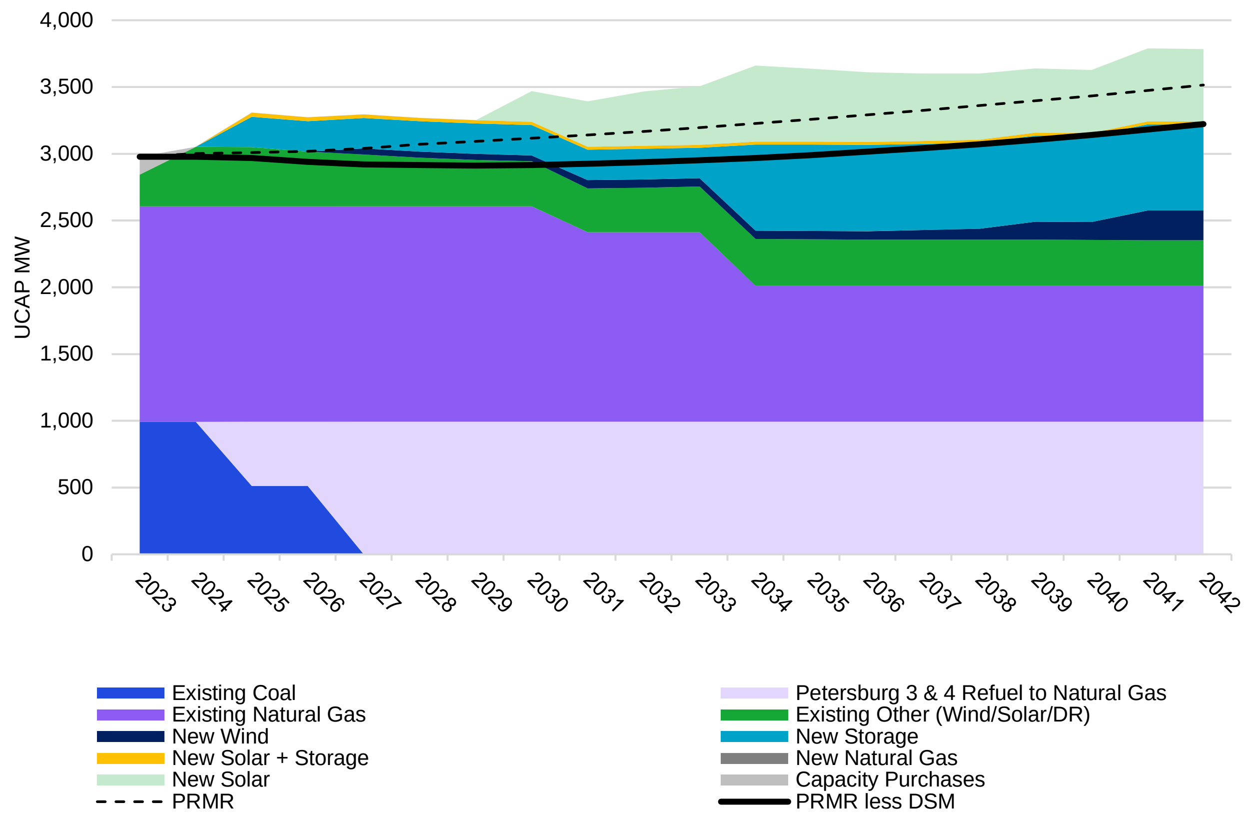


Figure 9-46: EnCompass Optimization without a Predefined Strategy Firm Unforced Capacity Position – Winter

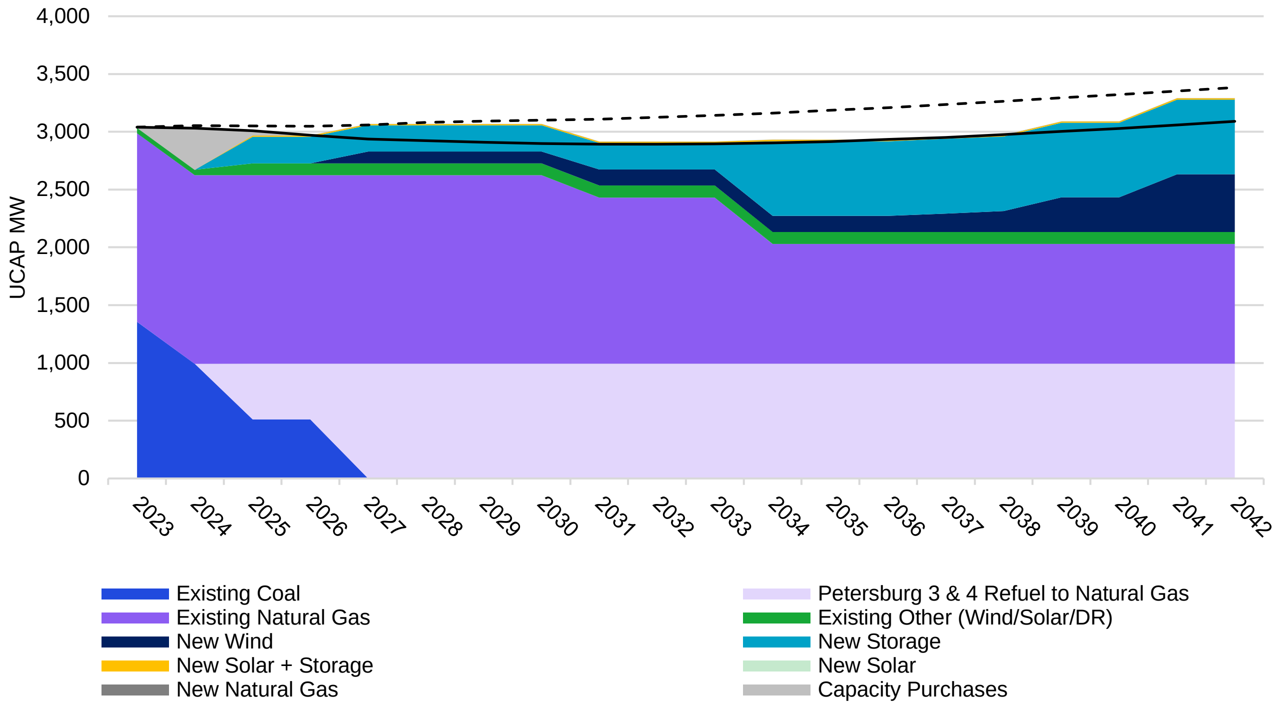
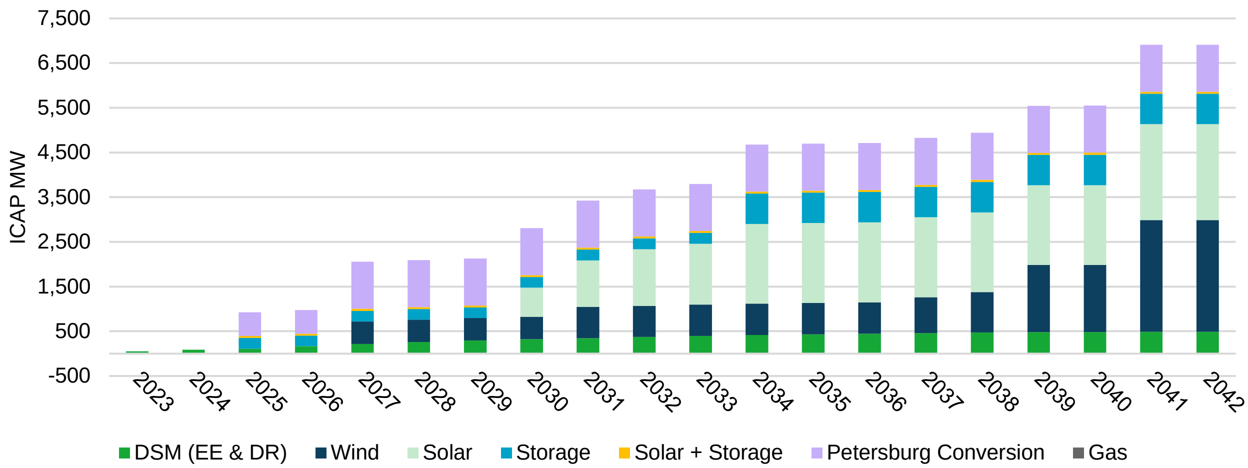


Figure 9-47 shows the incremental capacity additions over the planning period for the EnCompass Optimization analysis. To replace Petersburg Unit 3 and 4, the strategy adds battery energy storage, solar and wind. Also, the strategy adds large amounts of wind, solar, and storage resources in the 2030s as replacement of the age-based Harding Street ST5, ST6, and ST7 retirements.

Figure 9-47: EnCompass Optimization without a Predefined Strategy Installed Capacity Cumulative Additions (MW) [82]



Resource Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
DSM (EE & DR)	52	85	113	164	218	259	294	324	349	372	396	416	434	448	463	475	482	484	488	490
Wind	0	0	0	0	500	500	500	500	700	700	700	700	700	700	800	900	1,500	1,500	2,500	2,500
Solar	0	0	0	0	0	0	0	650	1,040	1,268	1,365	1,788	1,788	1,788	1,788	1,788	1,788	1,788	2,145	2,145
Storage	0	0	240	240	240	240	240	240	240	240	240	680	680	680	680	680	680	680	680	680
Solar + Storage	0	0	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Petersburg Conversion	0	0	526	526	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 9-48 provides the incremental installed capacity additions through 2028 under the EnCompass Optimization analysis. The EnCompass Optimization analysis converts Petersburg Unit 3 to natural gas in 2025 and Unit 4 to natural gas in 2027. Additionally, the model selects battery energy storage to fill a 240 MW winter capacity shortfall brought about by MISO's seasonal resource adequacy construct and adds 500 MW of wind resources in 2028 for capacity and energy.

Figure 9-48: EnCompass Optimization without a Predefined Strategy Near-Term Incremental Installed Capacity Additions (MW)

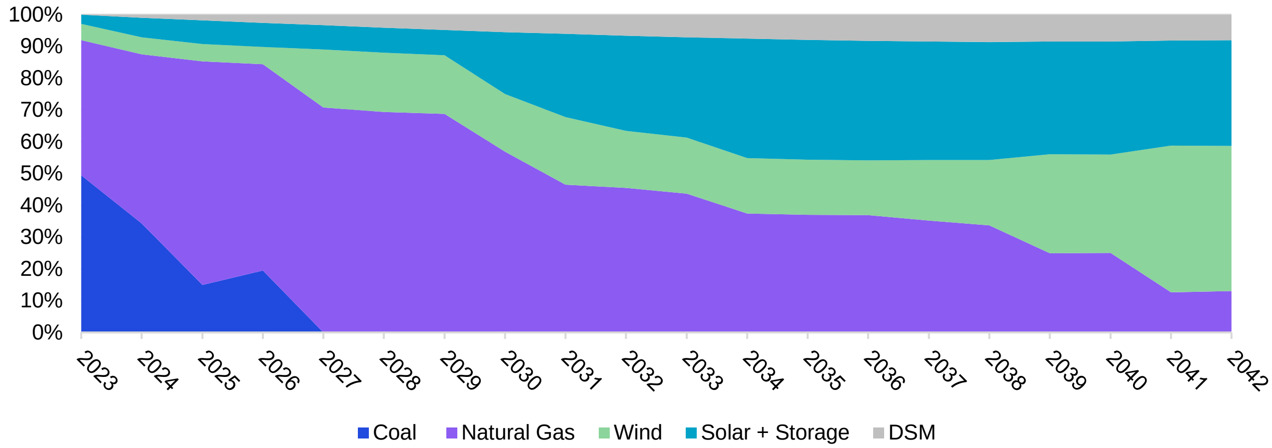
	2023	2024	2025	2026	2027	2028
Petersburg Conversion	0	0	**526**	0	**526**	0
Wind	0	0	0	0	**500**	0
Solar[83]	0	0	0	0	0	0
Storage	0	0	**240**	0	0	0
Solar + Storage	0	0	**45**	0	0	0

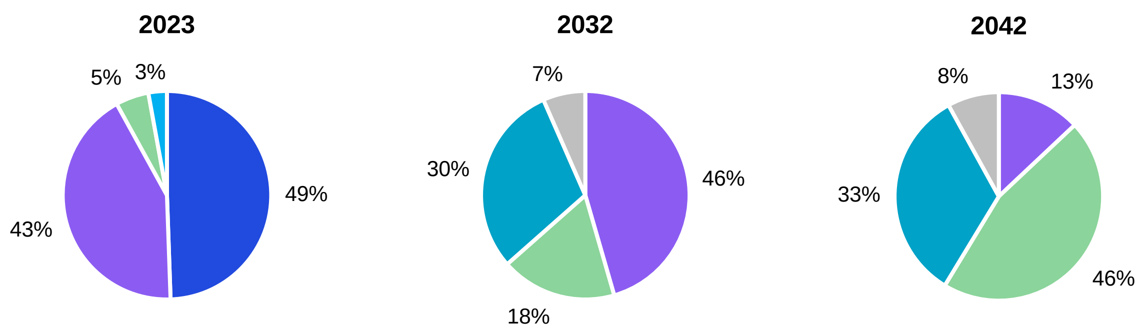
[82] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

[83] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-49 and Figure 9-50 show the EnCompass Optimization energy mix and position over the planning period. Focusing on renewable generation results in 2032, which is one of the sustainability metrics on the IRP Scorecard, it is estimated that the EnCompass Optimization analysis will provide 54% of its energy generation from renewable resources by this year.

Figure 9-49: EnCompass Optimization without a Predefined Strategy Percentage of Energy Mix by Resource Type





Thermal MWh %	92%	Thermal MWh %	46%	Thermal MWh %	13%
Renewable/DSM MWh %	8%	Renewable/DSM MWh %	54%	Renewable/DSM MWh %	87%

Figure 9-50: EnCompass Optimization without a Predefined Strategy Energy Position by Resource Type (GWh)

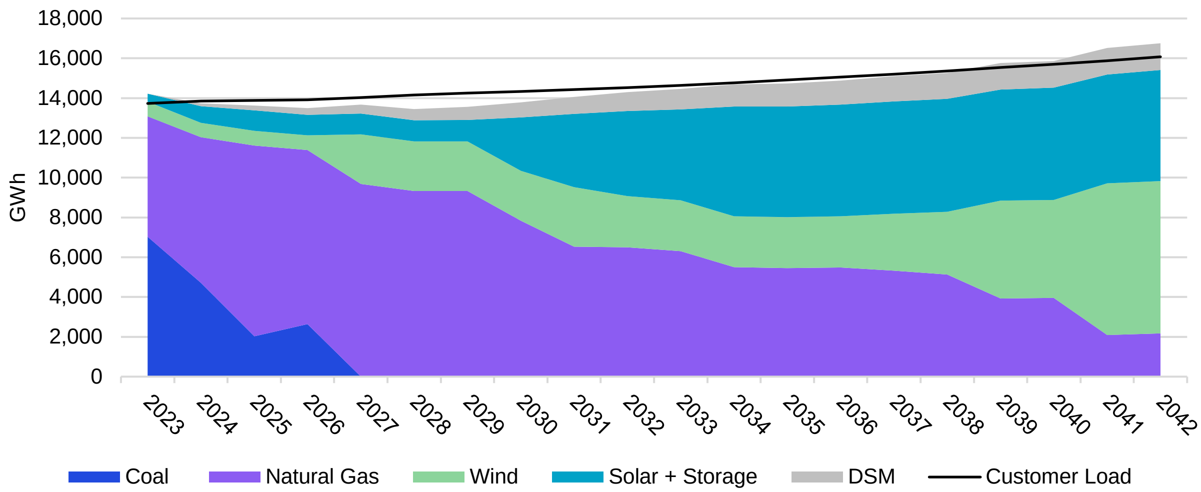


Figure 9-51 provides a summary of the DSM selected in the EnCompass Optimization analysis. All but the Efficient Products – Higher Cost bundles gets selected from Vintage 1. Implementing the selected programs in Vintage 1, would results in 134,263 MWh of annual DSM on average over the three-year period. For Vintage 2 (2027 – 2029) and Vintage 3 (2030 – 2042), the Lower Cost Residential bundle, and all C&I energy efficiency were selected. IQW was predefined in the model and not treated as selectable because the Company intends to maintain offerings for this segment of customers regardless of cost effectiveness. For demand response, the model selected the Residential and C&I Rates programs, which would result in a cumulative summer peak impact of 75 MW in 2042.

Figure 9-51: EnCompass Optimization without a Predefined Strategy DSM Selections

Energy Efficiency:

	Vintage 1	Vintage 2	Vintage 3
	2024 - 2026	2027 - 2029	2030 - 2042
Residential	Efficient Products - Lower Cost	Lower Cost Residential (excluding IQW)	Lower Cost Residential (excluding IQW)
	Efficient Products - Higher Cost		
	Behavioral		
	School Education	Higher Cost Residential (excluding IQW)	Higher Cost Residential (excluding IQW)
	Appliance Recycling		
	Multifamily		
	IQW	IQW	IQW
C&I	Prescriptive	C&I	C&I
	Custom		
	Custom RCx		
	Custom SEM		
Impacts	Avg Annual MWh	Avg Annual MWh	Avg Annual MWh
	134,263	141,526	146,428
	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out	% of 2021 Sales ex. Opt-Out
	1.1%	1.1%	1.2%
	Cumulative Summer MW	Cumulative Summer MW	Cumulative Summer MW
	89 MW	92 MW	303 MW

Demand Response:

	2026 - 2042
Residential	Direct Load Control
	Residential Rates
C&I	Direct Load Control
	C&I Rates
	Cumulative Summer MW
	75 MW

Note: Boxes highlighted in purple denote DSM bundles that were selected by EnCompass

9.2.4 Retirement and Replacement Analysis – Final Takeaways

Upon review of the five predetermined strategies and one EnCompass Optimization, it is worth noting two resource selections that were consistent across all the Candidate Portfolios:

- Every portfolio has a 240 MW winter capacity need starting in 2025 due to MISO's new seasonal resource adequacy construct and seasonal reserve margin requirements. EnCompass selects 240 MW of battery energy storage to replace this capacity in every portfolio.
- **At least** 500 MW of wind is selected in every portfolio to be delivered by 2027 to also help fill capacity under the new MISO seasonal resource adequacy construct.

Since these selections occur across the Candidate Portfolios, they are guaranteed to make it into the Preferred Resource Portfolio and Short Term Action Plan as firm capacity.

9.3 Replacement Resource Capital Cost Sensitivity Analysis

170 IAC 4-7-8(c)(10)

9.3.1 Replacement Resource Capital Cost Sensitivity Analysis Overview

As detailed in Section 8.4, AES Indiana conducted a sensitivity analysis on the capital costs for replacement resources. The analysis was conducted in response to the current volatility of replacement resource capital cost caused by supply constraints and potential solar tariffs.

For the Analysis, the Company ran a Retirement & Replacement Analysis on the Candidate Portfolios using the low and high capital cost forecasts for replacement resources. Note that the base capital cost forecasts were included in the base Portfolio Matrix runs that were reviewed in Section 8.3.

As fully detailed in Section 8.4.1, the capital cost tiers were generally forecasted as follows:

→ *Low* – low replacement resource costs are based on the average of Wood Mackenzie's North American Long Term Outlook 2021 Base Case Update, NREL's 2021 ATB, and BNEF's 2H 2021 LCOE Report, and benchmarked against the responses from AES Indiana's 2020 RFP.

→ *Base* – base costs were based on the lower half (below and including the median) of the 2022 RFP responses.

→ *High* – high costs were based on the upper half (above the median) of the 2022 RFP responses.

Ultimately, this analysis provides an estimate of how the portfolio mixes and affordability (PVRR) to customers changes as the capital cost of replacement resources change. The results of this analysis helped inform the Preferred Resource Portfolio and Short Term Action Plan discussed in Section 9.5 and Section 10.

9.3.2 Replacement Resource Capital Cost Sensitivity Analysis Results

Figure 9-52 through Figure 9-57 provide a comparison of the total retirements and replacements of installed capacity over the planning period for each of the strategies and the Candidate Portfolios using the three different cost tiers. Generally, the results demonstrate that less wind and storage is built as replacement resource capital costs increase. Instead, the EnCompass Model selects natural gas resources (i.e., CCGT) as a more economic replacement resource. The reason for this result is that there is more volatility in the cost for renewable resources compared to the cost of thermal based on the 2022 all-source RFP results. For example, compared to the base cost tier, the cost for wind increases 22% in the high cost tier, whereas, the cost for CCGT only increases 8% in the high cost tier.

Figure 9-52: No Early Retirements Strategy Portfolio ICAP Retirements and Replacements by 2042[84]

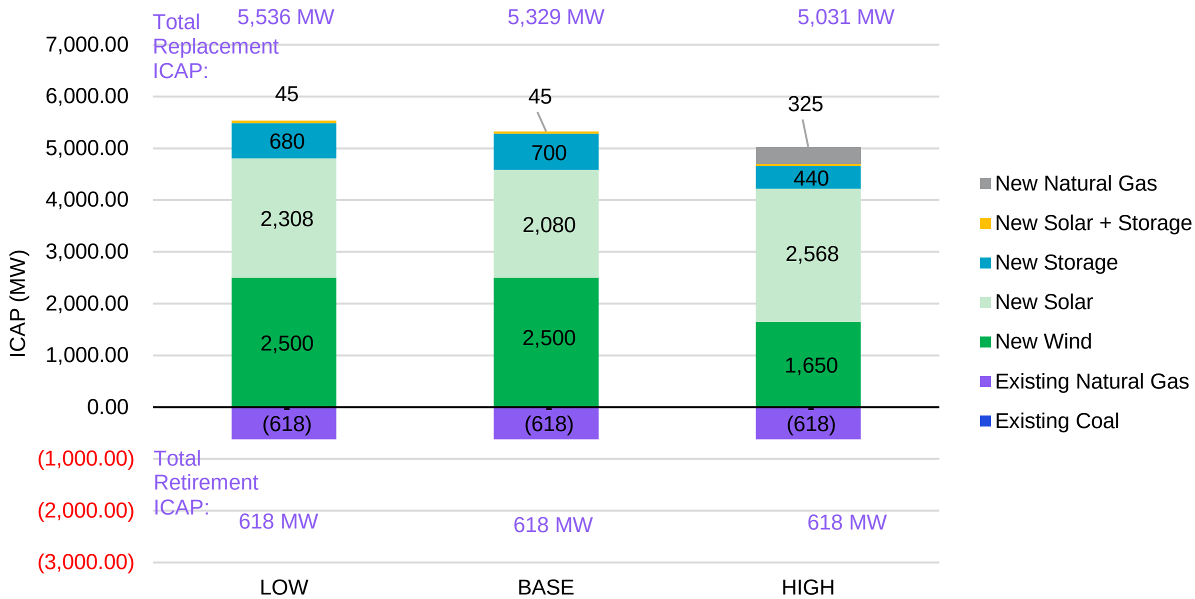
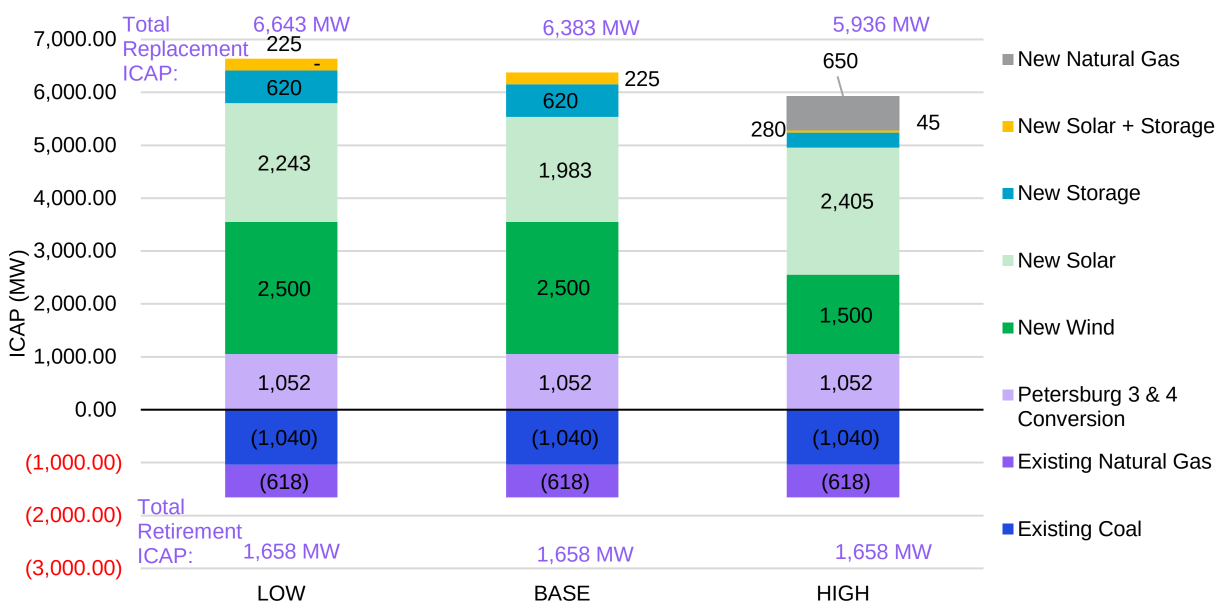


Figure 9-53: Petersburg Conversion Strategy Portfolio ICAP Retirements and Replacements by 2042



[84] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-54: One Petersburg Unit Retires Strategy Portfolio ICAP Retirements and Replacements by 2042[85]

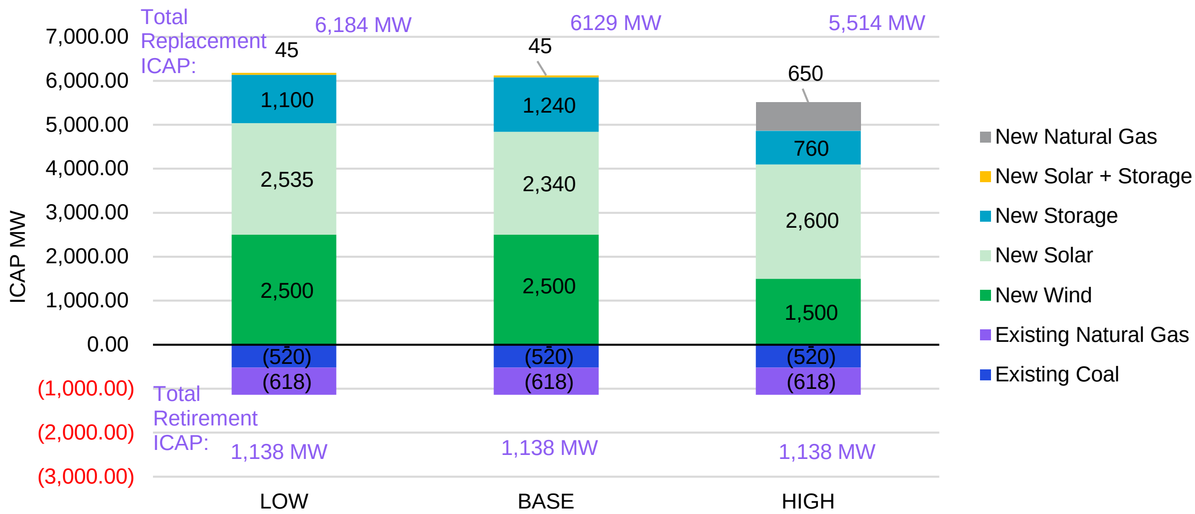
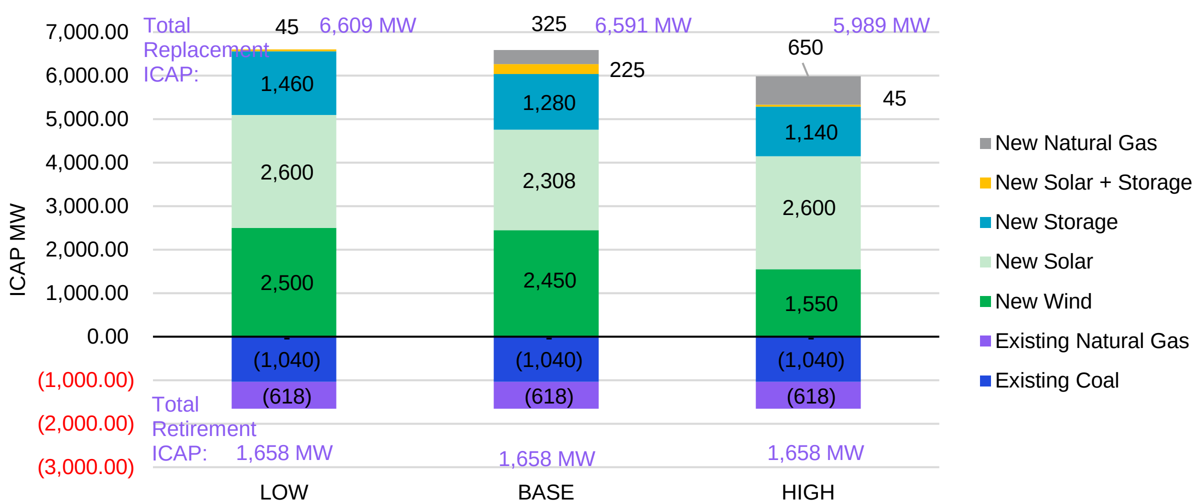


Figure 9-55: Both Petersburg Units Retires Strategy Portfolio ICAP Retirements and Replacements by 2042



85 Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-56: Clean Energy Strategy Portfolio ICAP Retirements and Replacements by 2042[86]

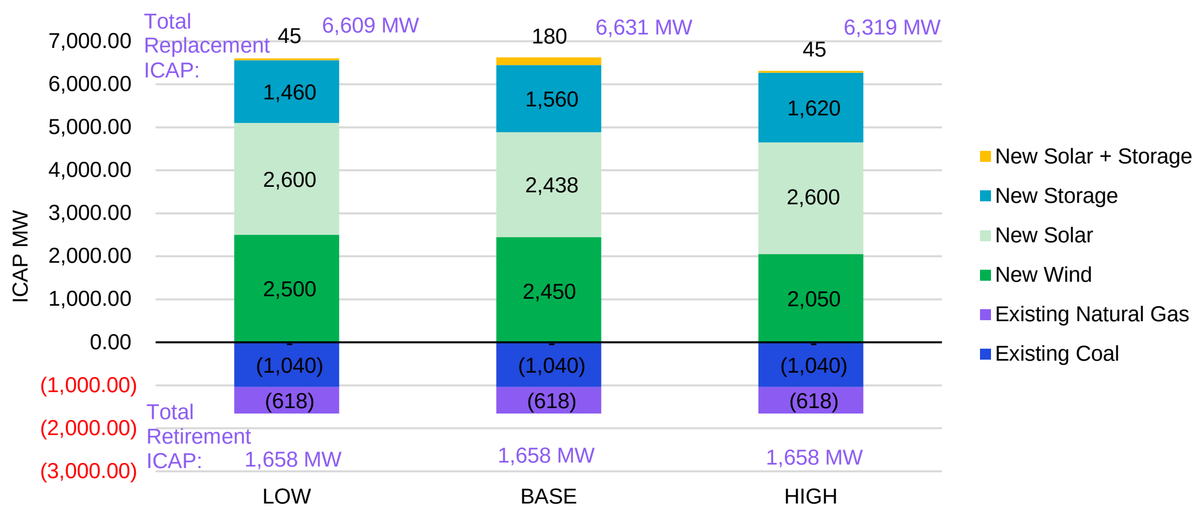


Figure 9-57: EnCompass Optimization Strategy Portfolio ICAP Retirements and Replacements by 2042

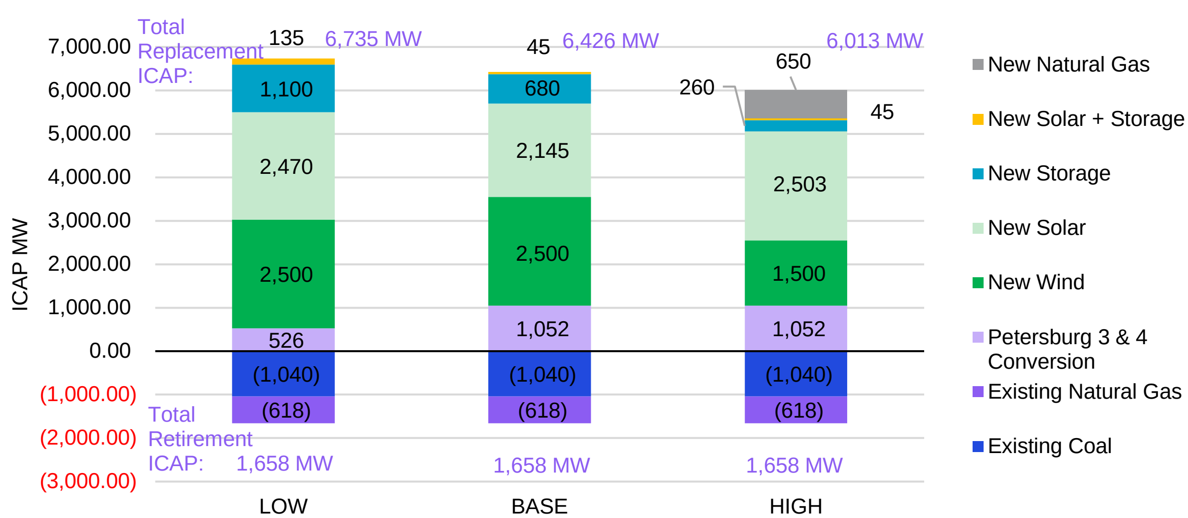


Figure 9-58 below provides a comparison of how the affordability to customers measured in the 20-year portfolio PVRR changes when the Retirement and Replacement Analysis is conducted using the different replacement resource capital cost tiers. The Portfolio Matrix demonstrates that the Petersburg Conversion strategy is not as sensitive to replacement resource capital cost volatility because, after converting Petersburg, the portfolio does not need as much replacement capacity as the other strategies that retire and replace the Petersburg units. Intuitively, these portfolios become less cost effective as the capital cost for the replacement capacity increase.

[86] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

Figure 9-58: PVRR results from the Replacement Resource Capital Cost Sensitivity Analysis[87]

	20-Year PVRR (2023$MM, 2023-2042)	Current Trends (Reference Case)		
		Low	Base	High
Generation Strategies	No Early Retirement	$9,054	$9,572	$9,876
	Petersburg Conversion to Natural Gas (est. 2025)	$8,698	$9,330	$9,661
	One Petersburg Unit Retires (2026)	$9,081	$9,773	$10,181
	Both Petersburg Units Retire (2026 and 2028)	$8,790	$9,618	$10,178
	Clean Energy Strategy Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)	$8,787	$9,711	$10,586
	EnCompass Optimization without Predefined Strategy	$8,670*	$9,262	$9,624

9.4 Scorecard Evaluation Results

9.4.1 Overview

This section provides the IRP Scorecard Evaluation results. The section begins by reviewing the results of each of the Scorecard metrics by category and then provides the results in aggregate on the completed Scorecard for comparison.

As detailed in Section 8.5, the IRP Scorecard is categorized into five key categories. They include: 1) Affordability, 2) Sustainability, 3) Reliability, Stability, and Resiliency, which are consistent with the "Five Pillars of Electric Service" as defined by the Indiana 21st Century Energy Policy Task Force, 4) Risk and Opportunity, and 5) Social and Economic Impact.

The Scorecard evaluates the Candidate Portfolios' performance in each of the five categories. The categories and metrics for scoring are as follows:

1) ***Affordability***
   a. 20-year PVRR
2) ***Sustainability***
   a. CO2 Emissions – total Portfolio CO2 emissions over 20 years.
   b. SO2 Emissions – total portfolio SO2 emissions over 20 years.
   c. NOx Emissions – total portfolio NOx emissions over 20 years.
   d. Water Use – total portfolio water usage over 20 years.
   e. Coal Combustion Products (CCP) – total portfolio coal combustion products over 20 years.
   f. Clean Energy Progress – percentage of energy from renewable resources in 2032.
3) ***Reliability, Stability, and Resiliency***

[87] 20-year PVRR (2023 dollars in millions from 2023-2042).

a. Composite Reliability Score – analysis performed by Quanta.

4) Risk and Opportunity

a. Environmental Policy Risk and Opportunity – sensitivity analysis that evaluates the Candidate Portfolios' performance under different policy and commodity futures.
b. General Cost Risk and Opportunity – stochastic analysis of the cost risk and opportunity associated with power prices, gas prices, coal prices, load, and renewable energy generation.
c. Market Exposure/Interaction – risk associated with general exposure to the power market through sales and purchases.
d. Renewable Capital Cost Sensitivity Analysis – sensitivity analysis that analyzes the risk and opportunity associated with high or low renewable capital costs.

5) Social and Economic Impact

a. Generation Employees – total change in the FTEs associated with generation over the planning period. This includes employment for a generation portfolio whether directly employed by AES Indiana or a third-party.
b. Property Taxes – total amount of property tax paid from AES IN generation assets.

For more details regarding the analysis performed for each of these metrics please see Section 8.5

9.4.2 Affordability

170 IAC 4-7-6(C)(4)(D)-(E)

As part of the Retirement and Replacement Analysis review in Section 8.1, AES Indiana compared the affordability of the Candidate Portfolios provided in Figure 9-59 below. The key takeaways from this review when comparing the 20-year PVRR values are:

1. The Petersburg Conversion strategy provides the lowest PVRR of the strategies analyzed and represents the reasonable least cost option for customers.
2. The No Early Retirement, which continues to operate Petersburg using coal, is more costly to customers than converting Petersburg to operate using natural gas because the conversion is an economic investment.
3. The One Petersburg Unit Retire strategy is particularly costly to customers because it reduces the capacity value of the plant by half by retiring one unit, while the fixed costs associated with essential coal operations, such as coal handling and coal pollution controls, continue to exist. The Petersburg plant becomes very expensive to operate on a dollar per MWh basis.
4. The Both Petersburg Units Retire strategy exhibits a higher PVRR compared to operating Petersburg using coal or economically converting Petersburg to operate using natural gas because retiring both units requires large investment costs in new additional replacement capacity.
5. The Clean Energy Strategy exhibits a higher PVRR compared to the other strategies because, like the Both Petersburg Units Retire strategy, it requires larger investment in

new additional capacity to replace the retired units. Compared to the Both Petersburg Units Retire strategy, the Clean Energy Strategy must make significant investments in renewable resources to meet capacity requirements (based on MISO accreditation for renewables), which results in a larger PVRR. Whereas the Both Petersburg Units Retire strategy builds a 325 MW CCGT to help fill the retired Petersburg capacity.

6. The EnCompass Optimization analysis that allows EnCompass to optimize without a predefined strategy converted Petersburg Unit 3 in 2025 and Unit 4 in 2027 to operate using natural gas. This analysis demonstrates the lowest PVRR compared to the other strategies; however, there are added costs of splitting the Petersburg conversion into different years that were not fully captured in this analysis. The most economic option to convert both units would be to convert both units at the same time. The results from this analysis indicate that the Petersburg conversion is the reasonable least cost strategy for AES Indiana customers.

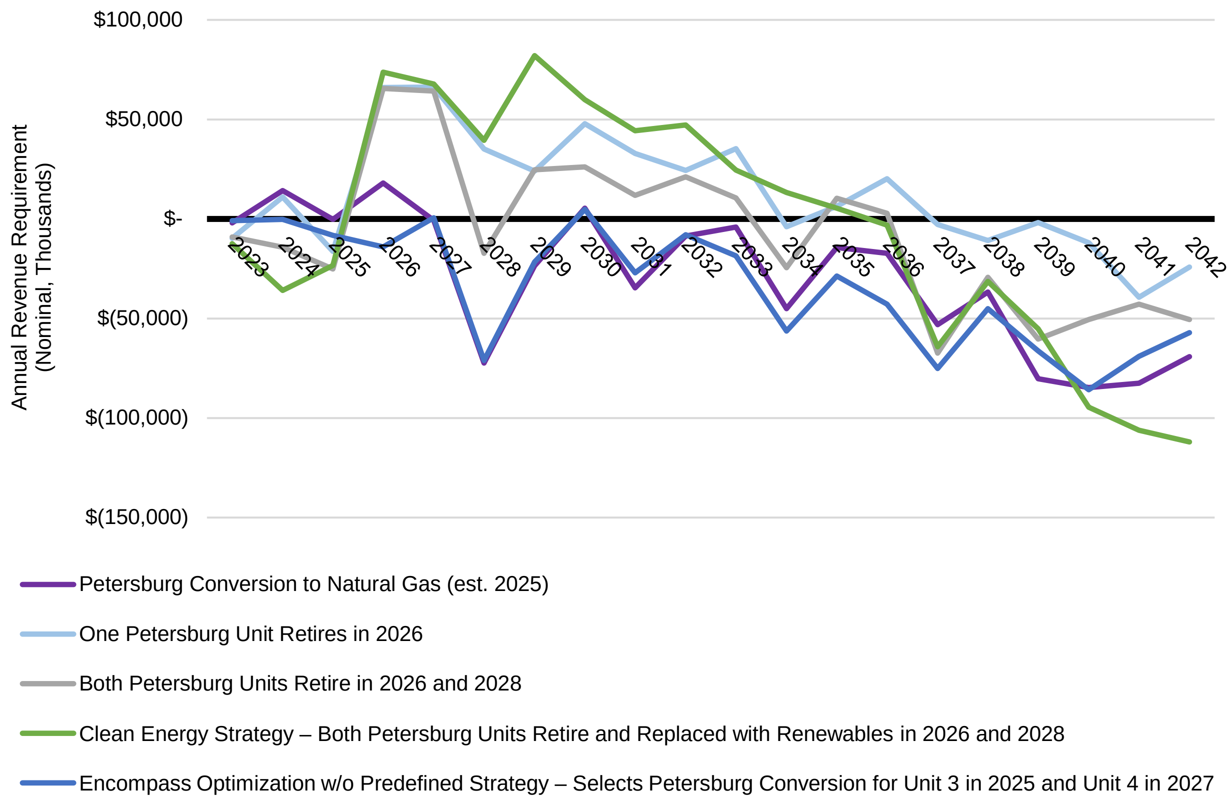
Figure 9-59: 20-Year PVRR results for the Candidate Portfolios[88]

Strategy	PVRR
No Early Retirement	$9,572
Petersburg Conversion to Natural Gas (est. 2025)	$9,330
One Petersburg Unit Retires (2026)	$9,773
Both Petersburg Units Retire (2026 and 2028)	$9,618
Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)	$9,711
EnCompass Optimization without Predefined Strategy – Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027	$9,262

Figure 9-60 below compares the annual revenue requirement impact of each strategy and the EnCompass Optimization analysis to the No Early Retirement strategy, which maintains the status quo operation of Petersburg. The analysis demonstrates that converting Petersburg to natural gas, displayed as the solid purple line in Figure 9-60, provides the lowest revenue requirement volatility and generally a lower annual revenue requirement over the period when compared to the other strategies. In strategies that retire both Petersburg units (i.e., Both Peterburg Units Retire and Clean Energy Strategy), the analysis shows large spikes in the annual revenue requirement in years where large investments in replacement Petersburg capacity is needed.

[88] 20-year PVRR (2023 dollars in millions from 2023-2042).

Figure 9-60: Annual Revenue Requirement for the IRP strategies and the EnCompass Optimization Analysis Compared to the No Early Retirement Strategy



9.4.3 Sustainability

170 IAC 4-7-6(b)(3)(C)

AES Indiana quantified pollution from CO2, SO2, NOx, and CCP as well as water usage to evaluate the sustainability of the Candidate Portfolios. Figure 9-61 provides the total estimated volumes for these categories for the Candidate Portfolios over the first 10 years of the study (2023 – 2032) and Figure 9-62 provides the total estimated volumes over the full study period (2023 – 2042).

In the 10-year comparison, the Petersburg Conversion strategy performs the best across all categories because the Petersburg Conversion strategy provides the soonest exit from coal-fired generation in 2025. This strategy even performs slightly better than the Clean Energy Strategy on CO2 emissions, which continues to burn coal through 2028. In the 20-year comparison, the Clean Energy Strategy performs slightly better than the Petersburg Conversion strategy because the Clean Energy Strategy ultimately provides more carbon free energy over the planning period.

Figure 9-61: Candidate Portfolio total emissions results over 10 Years (2023 – 2032)[89]

		Total Portfolio CO_2 Emissions (mmtons)	Total Portfolio SO2 Emissions (tons)	Total Portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)
Generation Strategies	No Early Retirement	73.2	49,944	34,755	28.4	5,126
	Petersburg Conversion	54.5	13,402	19,501	7.9	1,417
	One Petersburg Unit Retires	65.2	37,102	33,243	26.7	4,813
	Both Petersburg Units Retire	58.6	25,506	23,102	15.0	2,700
	Clean Energy Strategy	55.3	25,254	23,303	14.8	2,676
	EnCompass Optimization	56.6	18,503	22,559	10.9	1,970

Figure 9-62: Candidate Portfolio Total Emissions Results over 20 Years (2023 – 2042)

	Total portfolio Co_2 emissions (mmtons)	Total portfolio SO2 emissions (tons)	Total portfolio NOx emissions (tons)	Water use (mmgal)	CCP (tons)
No Early Retirement	101.9	64,991	45,605	36.7	6,611
Petersburg Conversion	72.5	13,513	22,146	7.9	1,417
One Petersburg Unit Retires	88.1	45,544	42,042	26.7	4,813
Both Petersburg Units Retire	79.5	25,649	24,932	15.0	2,700
Clean Energy Strategy	69.8	25,383	24,881	14.8	2,676
EnCompass Optimization	76.1	18,622	25,645	10.9	1,970

Figure 9-63 through Figure 9-65 below demonstrates the Petersburg Conversion strategy outperformed the Clean Energy Strategy on CO2, SO2, and NOx metrics over 10 years. As demonstrated in Figure 9-63 through Figure 9-65, a drop in emissions occurs when the Petersburg coal units are converted to operate using natural gas in 2025. These emissions do not drop until 2026 and 2028 in the Clean Energy Strategy when the units are retired and replaced with wind, solar and storage resources. The extra emissions in these two years contribute to the higher total period emissions in the Clean Energy Strategy.

[89] Millions of Metric Tons ("mmtons") and Millions of Gallons ("mmgal").

Figure 9-63: Comparison of Petersburg Conversion and Clean Energy Strategy CO2 Emissions (2023 to 2042)

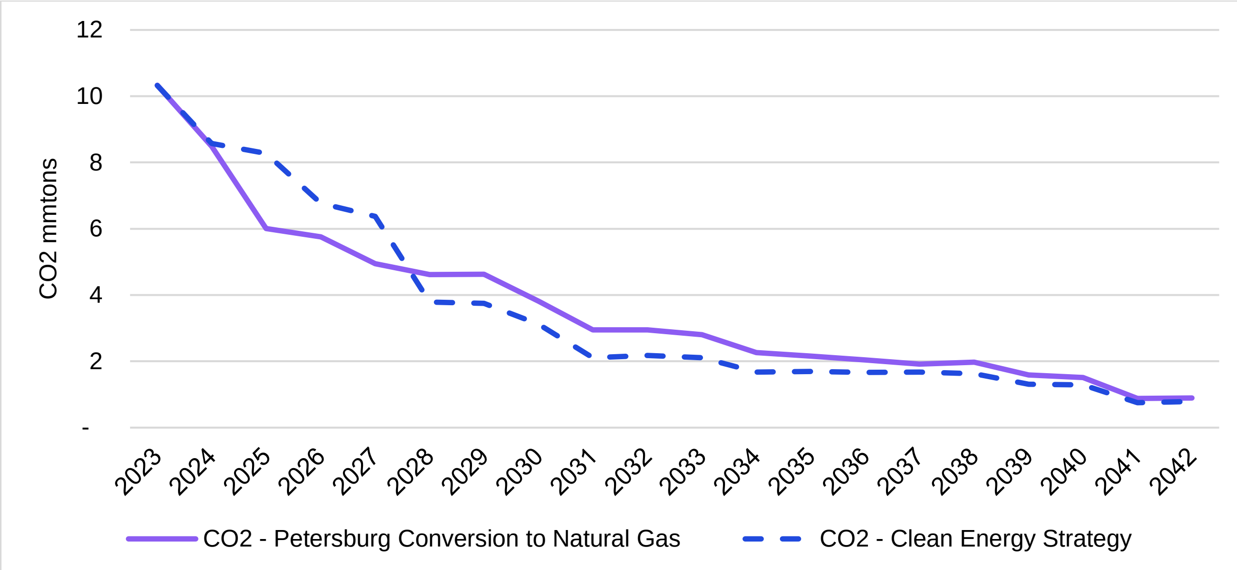


Figure 9-64: Comparison of Petersburg Conversion and Clean Energy Strategy SO2 Emissions (2023 to 2042)

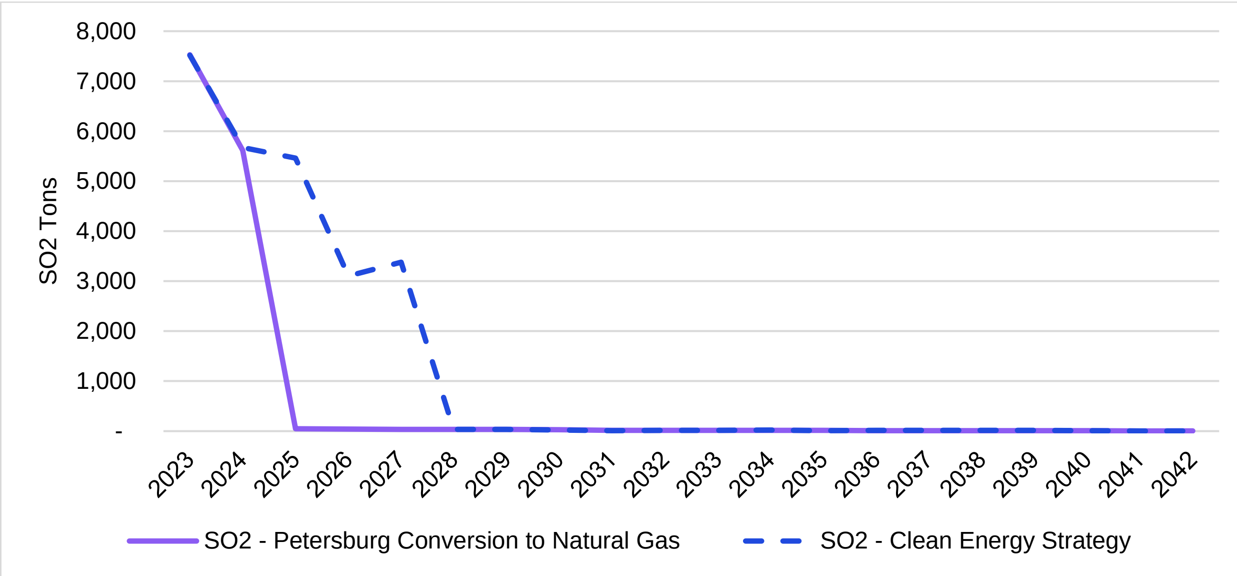
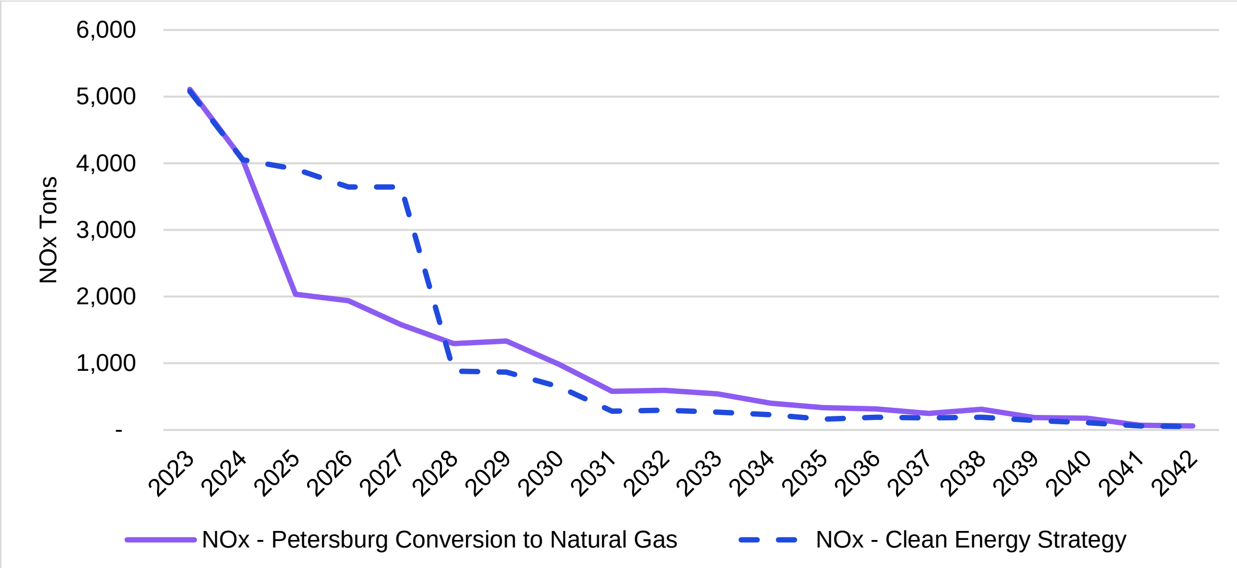


Figure 9-65: Comparison of Petersburg Conversion and Clean Energy Strategy NOx Emissions (2023 to 2042)



AES Indiana also compared the Clean Energy Progress, which measures the percentage of energy generated from renewable resources in 2032, for each of the Candidate Portfolios to measure its Sustainability metric. This metric was suggested by stakeholders during the IRP process and measured as the percent of energy generation from renewable energy in 2032. This information was reviewed in Section 9.2.3 as part of the Candidate Portfolio Summaries and is summarized below in Figure 9-66. The Clean Energy Strategy performs the best out of the Candidate Portfolios on this metric because this portfolio optimizes the most wind and solar as replacement generation.

Figure 9-66: Comparison of the Percentage of Energy from Renewable Resources in 2032 Across the Candidate Portfolios

	Percentage of Renewable Energy in 2032
No Early Retirement	45%
Petersburg Conversion	55%
One Petersburg Unit Retires	52%
Both Petersburg Units Retire	48%
Clean Energy Strategy	64%
EnCompass Optimization	54%

9.4.4 Reliability, Resiliency, and Stability

IAC 4-7-8(c)(2) and 170 IAC 4-7-8(c)(4)(B)

To measure Reliability, Resiliency, and Stability of the Candidate Portfolios, AES Indiana consulted with Quanta Technology to perform an analysis that quantified each portfolio's performance in nine key reliability, resiliency, and stability categories. These categories included energy adequacy, Operational Flexibility and Frequency Support, Short Circuit Strength, Power Quality, Blackstart, Dynamic VAR Support, Dispatchability and Automatic Frequency Control, Predictability and Firmness, and Location. Quanta measured the performance of each portfolio across these categories in the year 2031. Figure 9-67 provides the results, including the composite score that is used as the Reliability, Resiliency, and Stability Metric on the Scorecard. The analysis found that, in the year 2031, each of the portfolios had reliability concerns, especially under emergency and islanded conditions. Portfolios with the most Inverter Based Resources ("IBR") generally performed the worst partly due to issues with Short Circuit Strength. The analysis demonstrates that portfolios with higher amounts of dispatchable generation score higher. The No Early Retirement and Petersburg Conversion strategies as well as the EnCompass Optimization analysis (analogous to Petersburg Conversion) scored the highest at 7.95 out of 9.

Figure 9-67: Results from Quanta's System Reliability Assessment of AES Indiana's 2022 IRP Candidate Portfolios

			Current Trends					
			No Early Retirement	Petersburg Conversion	One Petersburg Unit Retires	Both Petersburg Units Retire	Clean Energy Strategy	EnCompass Optimization
	Year 2031		**T7**	**T8**	**T9**	**T10**	**T11**	**T12**
1	**Energy Adequacy**	Loss of Load Hours - normal system, 50/50 forecast	1	1	0	0	0	1
		Expected Energy not Served (GWh) - normal system 50/50 forecast	1	1	1	1	1	1
		max MW Short (MW) - normal system 50/50 forecast	1	1	1	1	1	1
		max MW Short - loss of 50% of tieline capacity, 50/50 forecast	1	1	1	1/2	0	1
		max MW Short (islanded, 50/50 forecast)	1	1	1	1	1	1
		max MW Short (normal system, 90/10 forecast)	1/2	1/2	0	0	0	1/2
2	**Operational Flexibility and Frequency Support**	Inertia Megavolt-Amperes ("MVA")-s	1/2	1/2	1/2	1/2	1/2	1/2
		Inertial Gap Fast Frequency Response ("FFR") MW (% Capacity)	1/2	1/2	1/2	1/2	1/2	1/2
		Primary Gap Primary Frequency Response ("PFR") MW (% Capacity)	0	0	1	1	1	0
3	**Short Circuit Strength**	Inverter MWs passing Effective Short Circuit Ratio ("ESCR") limits (%) - Connected System	1	1	1	1	1	1
		Inverter MWs passing ESCR limits (%) - Islanded System	1	1	0	1/2	0	1
		Required Additional Synch Condensers MVA (when Connected)	1	1	1	1	1	1
		Required Additional Synch Condensers MVA (when Islanded)	1	1	1/2	1/2	0	1
4	**Power Quality**	Compliance with Flicker limits when Connected (General Electric Flicker Curve or International Electrotechnical Commission ("IEC") Flicker Meter)	1	1	1	1	1	1
		Compliance with Flicker limits when Islanded	1	1	1	1	1	1
		Required Synchronous Condensers MVA to mitigate Flicker	1	1	1	1	1	1
5	**Blackstart**	Qualitative Assessment of Ability to Blackstart the system	1	1	1	1	1	1
6	**Dynamic VAR Support**	Dynamic Volt-Amps Reactive ("VAR") to load Center Capability (% of Peak Load)	1	1	1	1	1	1
7	**Dispatchability and Automatic Generation Control**	Dispatchable (% Capacity)	1	1	1	1	1	1
		Unavoidable Variable Energy Resource ("VER") Penetration %	1	1	1	1	1	1
		Increased Freq Regulation Requirements (% Peak Load)	1	1	1	1	1	1
		1-min Ramp Capability (MW)	1/2	1/2	1	1	1	1/2
		10-min Ramp Capability (MW)	0	0	1/2	1/2	1/2	0
8	**Predictability and Firmness**	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	1	1	1	1	1	1
9	**Location**	Average Number of Evacuation Paths	1	1	1	1	1	1
		Cumulative Score (out of possible 9)	**7.95**	**7.95**	**7.86**	**7.90**	**7.57**	**7.95**

Quanta also proposed mitigation measures that could be taken to fill the reliability gaps in the portfolios. The mitigations take the form of grid-forming inverter technology, additional fast power resources such as battery storage, super capacitors, or combustion turbines, and additional synchronous condensers. Figure 9-68 provides a summary of the proposed mitigations for each of the Candidate Portfolios along with the mitigation cost. These costs were not included in the Scorecard Affordability calculations (i.e., PVRRs) due to their uncertainty, as they are far enough out into the future where grid and technology improvements could potentially lower these costs. They do, however, provide a general cost estimate to help quantify the differences in the composite reliability scores. While these differences appear small when observing the composite score, when put in terms of cost to mitigate the difference becomes more pronounced.

Quanta's key observations from the analysis were as follows:

1. Reliability concerns were identified for each portfolio, especially under emergency and islanded conditions, and mitigation measures were identified as follows:
    a. Stand-alone energy storage resources should have Grid-Forming Inverters ("GFM") with additional capabilities including blackstart and Fast Frequency response ("FFR"). GFM inverters are not widely used today in the US market, but the technology is available and is recommended for portfolios with high penetration of IBRs.
    b. The provision of additional fast power resources is required in each portfolio. These have been quantified for energy storage technology. However, super capacitors or combustion turbines can also provide the same function, but the size should be determined for these technologies.
    c. Specifications of equivalent short circuit ratio ("ESCR") of inverters not to exceed 3.5.
    d. Provision of additional synchronous condensers to increase the grid's short circuit strength ranging from 0 to 1500 MVAr.
2. This study covered several areas of reliability assessment. However, it is not exhaustive. Areas that have not been covered include the following:
    a. The study assumed that any required grid upgrades will be implemented as part of MISO interconnection process, and thus excluded the analysis of portfolio deliverability.
    b. The study assumed the IRP process produced portfolios with sufficient capacity to assure meeting the LOLE target of 0.1 days/year, and thus excluded the analysis of resource adequacy.
    c. All reliability assessments in this study applied screening level indicative analyses. Detailed system studies are essential and should be conducted to properly assess system reliability of the short-listed Portfolios.

Figure 9-68: Summary of the proposed mitigations for the Candidate Portfolios

	Candidate Portfolios					
	No Early Retirement	Petersburg Conversion	One Petersburg Unit Retires	Both Petersburg Units Retire	Clean Energy Strategy	EnCompass Optimization
	T7	T8	T9	T10	T11	T12
Equip Stand-alone ESS with GFM inverters (MW)	**129**	**99**	**183**	**49**	**128**	**98**
Additional Synchronous Condensers (MVA)	**0**	**0**	**350**	**300**	**1500**	**0**
Additional Power Mitigations (MW)[90]	**298**	**326**	**183**	**49**	**128**	**325**
Increased Freq Regulation	39	48	49	45	66	47
Address Inertial Response Gaps	129	99	183	49	128	98
Address Primary Response Gaps	298	326	0	0	0	325
Firm up Intermittent Renewable Forecast	0	0	0	0	0	0
GFM Inverter Premium ($M)	$6	$5	$9	$2	$6	$5
Additional BESS ($M)	$120	$131	$74	$20	$52	$131
Additional Synchronous Condensers ($M)	$0	$0	$158	$135	$871	$0
Estimated Cost of Mitigations ($M)	**$127**	**$136**	**$241**	**$157**	**$929**	**$136**

Please see Quanta's Report, "System Reliability Assessment of AES Indiana 2022 IRP Portfolios," which is attached to this Report as Attachment 9-1, for a complete review of Quanta's Reliability Analysis.

9.4.5 Risk and Opportunities

170 IAC 4-7-8(c)(4)(C)

For the Scorecard evaluation, AES Indiana measured the Risk and Opportunity of the Candidate Portfolios using four metrics. The four metrics were Environmental Policy Risk and Opportunity, General Cost Risk and Opportunity, Market Exposure/Interaction, and Renewable Capital Cost Sensitivity Analysis. The results for each of these metrics is detailed below.

[90] Requires fast frequency response within 100 milliseconds. It can be in the form of battery storage, super capacitors, or appropriately upsized combustion engines or gas turbines.

Environmental Policy Risk and Opportunity

To evaluate risk and opportunity associated with potential Environmental Policy changes, AES Indiana conducted an analysis that tested how the Candidate Portfolios, as optimized in EnCompass using the Current Trends/Reference Case assumptions, would perform under different Environmental Policy assumptions. The analysis was intended to answer the question: if AES Indiana were to implement one of the Candidate Portfolio strategies and the future ended up being very different, how would the cost to customers change in terms of PVRR?

In this sensitivity analysis, the Candidate Portfolios were dispatched using EnCompass across each of the other scenarios using the environmental policy, commodity, and load assumptions of those scenarios. See Section 8.5.4 for a more thorough discussion of how this analysis was performed.

Figure 9-69 provides the results from this analysis. The highest PVRRs identified by the analysis serve as the Environmental Policy Risk Metric on the Scorecard. As shown in the table, these are the PVRRs that resulted from utilizing the Aggressive Environmental assumptions. The lowest PVRRs identified by the analysis serve as the Environmental Policy Opportunity Metric on the Scorecard. As shown in the table, these are the PVRRs that resulted from utilizing the No Environmental Action assumptions.

The key takeaways from the analysis are as follows:

- → The Petersburg Conversion strategy maintains the lowest PVRR when modeled with the No Environmental Action scenario assumptions because these assumptions include low gas prices and no carbon price which are generally favorable to the cost of operating an asset on gas.
- → The No Early Retirement strategy is competitive compared to the other strategies when modeled with the Aggressive Environmental assumptions. This seems counterintuitive considering that the Aggressive Environmental scenario contains a carbon price starting at $19.47 per ton in 2028 and escalating at approximately 4.6% through the remainder of the period. Upon further evaluation, the Petersburg units in the No Early Retirement strategy are economic with a positive spark spread up until 2028 when the carbon price starts. After the carbon price takes effect, the portfolio still builds significant volume of renewables particularly to replace the retiring Harding Street Units ST5, ST6, and ST7 in the 2030s. These renewable resources are more economic later in the planning period, while the capacity factor of Petersburg on coal drops to less than 15%.
- → The Petersburg Conversion strategy exhibits a less favorable PVRR when modeled using the Aggressive Environmental assumptions because these assumptions include high gas prices which increase the cost for operating a gas asset.
- → The Petersburg Conversion performs the best of the Candidate Portfolios when modeled using the Decarbonized Economy assumptions because this scenario includes the base gas prices, which are more favorable for natural gas operation. Additionally, this portfolio selected considerable volumes of renewables over time, especially as part of the Harding

Street steam unit replacements, such that there were limited penalties associated with not meeting the scenario's RPS target and it even exceeded the target in some years resulting in grants.

→ The Clean Energy Strategy performs most competitively in the scenarios with stronger environmental policy assumptions.

Figure 9-69: Results for the Environmental Policy Rick & Opportunity Analysis[91]

		Current Trends – Reference Case	No Environmental Action	Aggressive Environmental	Decarbonized Economy
Generation Strategies	No Early Retirement	$9,572	$8,860	$11,259	$9,953
	Petersburg Conversion to Natural Gas (est. 2025)	$9,330	$8,564	$11,329	$9,699
	One Petersburg Unit Retires (2026)	$9,773	$9,288	$11,462	$10,084
	Both Petersburg Units Retire (2026 and 2028)	$9,618	$9,135	$11,392	$10,334
	Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)	$9,711	$9,590	$11,275	$9,776
	EnCompass Optimization (Conversion in 2025 and 2027)	$9,262	$8,517	$11,226	$9,721

Lowest PVRR (Opportunity Potential) **Highest PVRR (Risk Potential)**

General Cost Risk and Opportunity Stochastic Analysis

As discussed in Section 8.5.4, AES Indiana performed a stochastic analysis on the Candidate Portfolios to understand the Risk and Opportunity Metrics for each strategy related to energy price volatility, gas price volatility, coal price volatility and renewable generation volatility. The analysis consisted of varying these five variables over 100 simulations for each of the Candidate Portfolios. This resulted in a PVRR probability distribution for each strategy where the P95 (i.e., the 95th percentile or the value in which 95% of the outcomes are lower) serves as the risk metric and the P5 (i.e., 5th percentile or the value in which 95% of the outcomes are greater) serves as the opportunity metric.

In performing this analysis, AES Indiana recognized the importance of capturing recent trends in gas and power price volatility. Accordingly, the Company included recent history through September of 2022 in the estimation periods for each of the commodity variables. Figure 9-70 shows the 100 stochastic simulations for natural gas used in the analysis. Note that over the planning period some simulations see spikes in monthly gas prices well over $15.

91 20-year PVRR (2023 dollars in millions from 2023-2042).

Figure 9-70: Henry Hub Gas Prices for 100 Stochastic Simulations Included in the Analysis

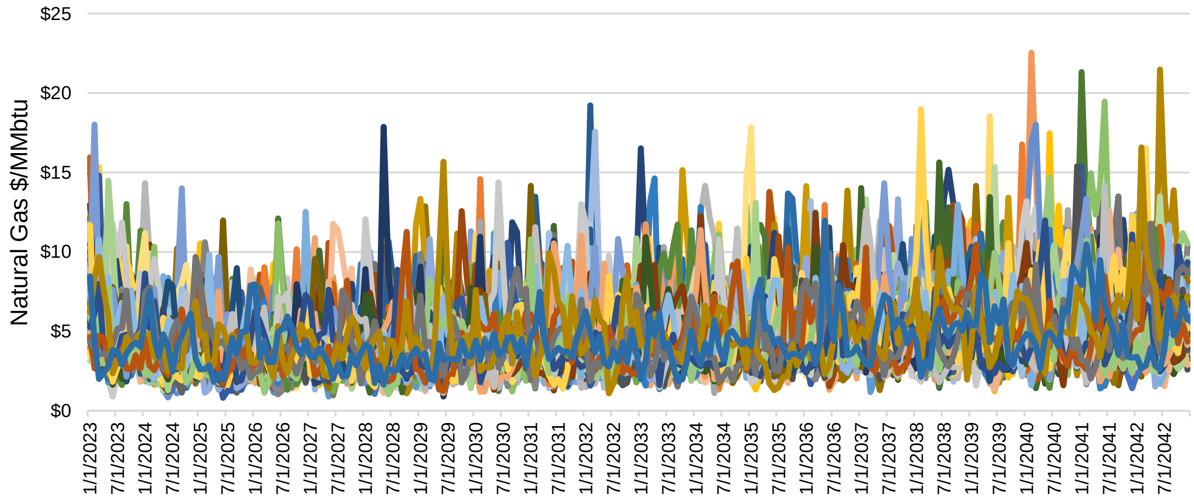


Figure 9-71 provides the mean, P5, and P95 results from the stochastic analysis. Additionally, Figure 9-71 includes the Scorecard PVRR for comparison to the stochastic mean. Note that there are slight differences when comparing these two values. This is because when the Scorecard PVRRs were calculated, AES Indiana included energy constraints that prevented the model from selling or purchasing more than 10% of annual load into or from the market. This constraint was included in the Retirement and Replacement (i.e., EnCompass Model) analysis to ensure reasonable optimization results by preventing the model from over investing in capacity or over relying on the market for energy purchases. In the stochastic analysis, AES Indiana lifted this constraint to fully evaluate the risk to the portfolios. These constraints would only constrain the dispatch and in turn reduce risk which is inconsistent with how AES Indiana would actually interact in the market. The difference between the stochastic mean and the Scorecard PVRR is insignificant; however, the Company thought that it was important to point out this adjustment was made to fully capture risk in the stochastic analysis.

The P5 and P95 results in Figure 9-71 demonstrate that the Petersburg Conversion strategy maintains the lowest PVRR both as an opportunity at the P5 and as a risk at the P95.

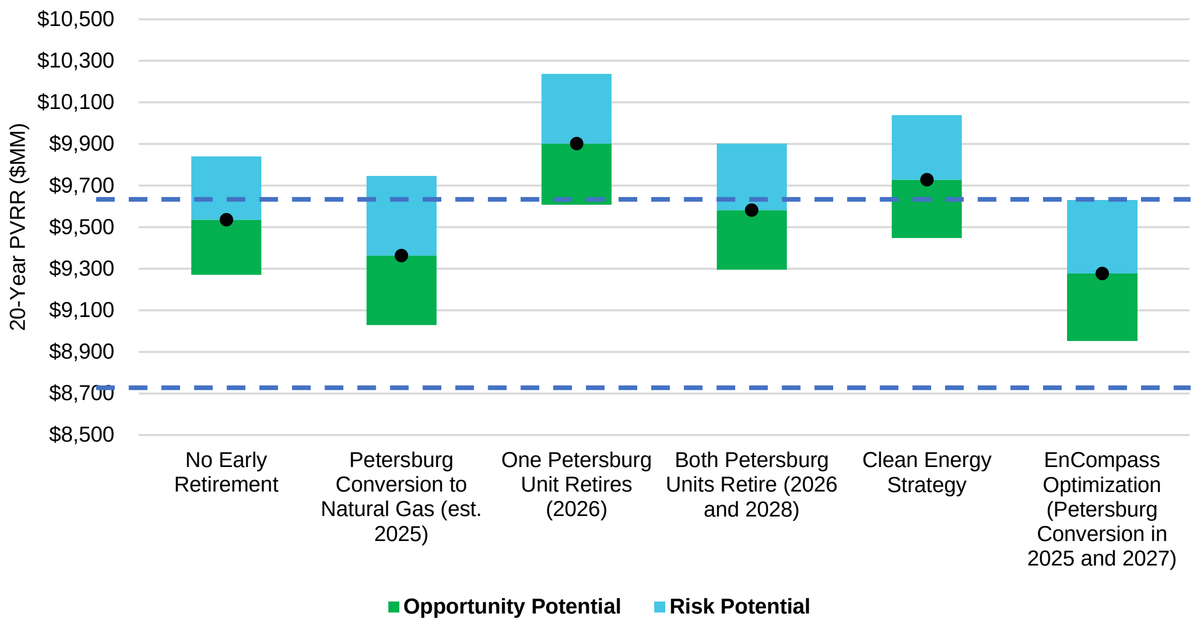
Figure 9-71: Candidate Portfolios Mean, P5, and P95 Stochastic Analysis Results

Portfolio	Scorecard PVRR Affordability Metric	Mean ↓	Opportunity: P5 [Mean - P5]	Risk: P95 [P95 - Mean]
No Early Retirement	$9,572	$9,535	$9,271 [-$264]	$9,840 [$305]
Petersburg Conversion to Natural Gas (est. 2025)	$9,330	$9,364	$9,030 [-$334]	$9,746 [$382]
One Petersburg Unit Retires (2026)	$9,773	$9,902	$9,608 [-$294]	$10,237 [$336]
Both Petersburg Units Retire (2026 and 2028)	$9,618	$9,582	$9,295 [-$287]	$9,903 [$321]
Clean Energy Strategy	$9,711	$9,727	$9,447 [-$280]	$10,039 [$312]
EnCompass Optimization (Petersburg Conversion 2025 and 2027)	$9,262	$9,277	$8,952 [-$324]	$9,629 [$352]

Figure 9-72 below provides the box plot distributions for each of the Candidate Portfolios that resulted from the stochastic analysis. The center line in each box represents the mean of the distribution, the top of the blue box represents the P95 and the bottom of the green box represents the P5. Note that this chart visually demonstrates that the Petersburg Conversion provides the lowest P95/risk and lowest P5/opportunity compared to the other portfolios.

Additionally, this chart allows one to compare the width of the distributions of each portfolio. Note that the Petersburg Conversion exhibits the widest distribution because this strategy relies the most on gas resources, which exhibits high volatility when including recent history. The No Early Retirement strategy exhibits the narrowest distribution because this strategy continues to burn coal, which tends to have less volatility. The volatility metrics are represented in Figure 9-71 above as differences between the mean and P95 [P95 – mean] and the mean and the P5 [mean – P5].

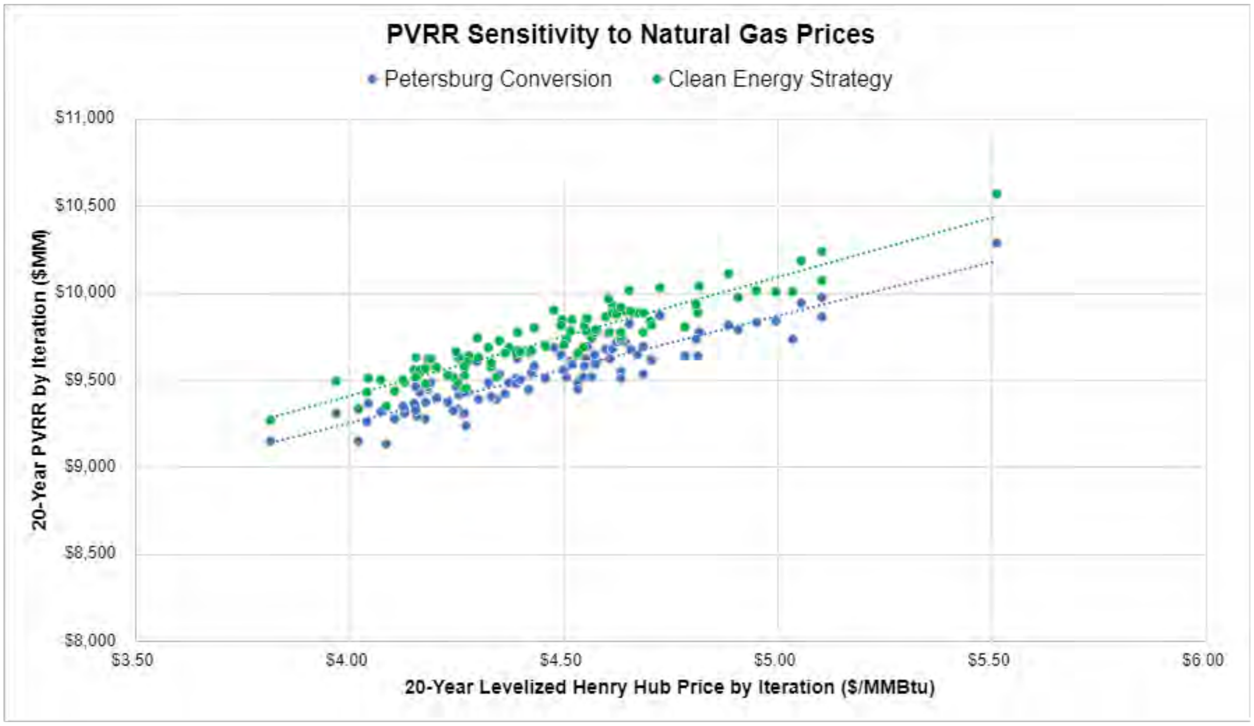
Figure 9-72: Box Plot Distribution Results from the Stochastic Analysis of the Candidate Portfolios



One final observation from the stochastic analysis, Figure 9-73 compares all 100 simulations of gas prices from the Petersburg Conversion to the same 100 simulations of gas prices from the Clean Energy Strategy. The analysis demonstrates that even the Clean Energy Strategy, which contains the least amount of gas generation, is sensitive to natural gas prices, which means as gas prices go up, so does the Clean Energy Strategy portfolio's PVRR. This is because both portfolios contain Eagle Valley acting as baseload generation at least for the near- and mid-term. Additionally, even though the Petersburg Conversion increases the amount of capacity from natural gas resources in the portfolio, the conversion is forecasted to have a low capacity factor over the planning period.

Finally, the analysis also demonstrates that in every simulation the Petersburg Conversion results in a lower PVRR than the Clean Energy Strategy.

Figure 9-73: Portfolio PVRR Sensitivity to Natural Gas Prices of Petersburg Conversion Strategy Compared to the Clean Energy Strategy[92]



Market Exposure/Interaction

AES Indiana also measured the risk associated with market interaction or exposure. This was measured by calculating the average of the absolute value of the annual sales and purchases and summing those over the 20-year period. For additional detail regarding the Market Exposure/Interaction metric see Section 8.5.4.

Figure 9-74 provides the results for this metric. The Petersburg Conversion is projected to have the lowest market interaction of the Candidate Portfolios. Generally, portfolios with higher non-dispatchable generation exhibit higher market interaction/exposure mainly in the form of sales. This is because these portfolios contain higher volumes of wind and solar that cannot be controlled, which often results in higher sales into the market. This poses a risk to customers because if these forecasted energy revenues ultimately get curtailed or sold at lower than assumed prices, it would ultimately cost customers.

[92] PVRR results are 20-year PVRR values (2023 dollars in millions from 2023-2042) from 100 simulations of natural gas prices. 20-year levelized Henry Hub values are measured in 2023 levelized dollars per Millions of British Thermal Units ("MMBtu").

Figure 9-74: Comparison of the 20-Year Average Annual Market Sales, Purchases, and Overall Market Interaction of the Candidate Portfolios

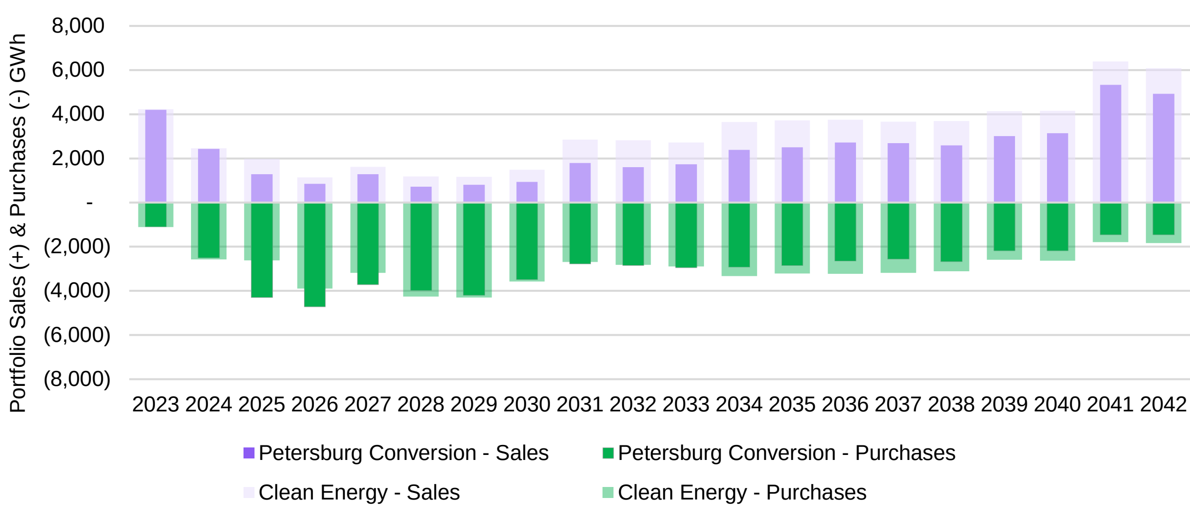
Candidate Portfolios (Strategies in Current Trends Scenario)	20-yr Annual Avg Market Sales (GWh)	20-yr Annual Avg Market Purchases (GWh)	Market Interaction/Exposure (GWh)
No Early Retirement	2,935	2,356	5,291
Petersburg Conversion to Natural Gas (2025)	2,346	2,877	5,222
One Petersburg Unit Retires in 2026	2,916	2,821	5,737
Both Petersburg Units Retire in 2026 and 2028	2,921	2,591	5,512
Clean Energy Strategy*	3,146	2,942	6,088
EnCompass Optimization**	2,285	2,851	5,136

**Both Petersburg Units Retire and replaced with Renewables in 2026 and 2028.*

***Selects Petersburg Unit 3 Conversion in 2025 and Petersburg Unit 4 Conversion in 2027.*

To demonstrate how portfolios with higher non-dispatchable generation result in higher market interaction by way of sales, Figure 9-75 below compares the annual market interaction of the Petersburg Conversion to the Clean Energy Strategy. Note how in the first few years of the study the sales in the two portfolios are the same because no portfolio changes have occurred. Then in 2025, the Clean Energy Strategy begins building renewables to replace Petersburg Units 3 and 4, while the Petersburg Conversion converts Petersburg Units 3 and 4 to operate using natural gas. The Clean Energy Strategy, which relies on non-dispatchable generation to replace Petersburg, exhibits a higher volume of market sales from the non-dispatchable replacements. Also, note that the Petersburg Conversion relies more on the market for purchases until wind resources are developed in 2027. By the 2030s, both portfolios are adding similar amounts of non-dispatchable generation, and sales appear to be increasing proportionally between the two portfolios.

Figure 9-75: Market Interaction Comparison of the Petersburg Conversion Strategy and the Clean Energy Strategy



Renewable Resource Capital Cost Sensitivity Analysis

AES Indiana conducted a Renewable Capital Cost Sensitivity Analysis to understand the impact to the Candidate Portfolio PVRRs if the capital costs for renewables end up being higher or lower than those included in the base set of capital cost assumptions. See Section 8.5.4 for more details on this analysis.

Figure 9-76 displays the results from this analysis. The Petersburg Conversion provides the lowest PVRR in each of the cost tiers because this portfolio has a moderate volume of renewable additions compared to the other strategies. As would be expected, portfolios that rely more on renewable resources as replacement capacity are more sensitive to capital cost fluctuations.

Figure 9-76: Comparison of the 20-Year PVRR results from Renewable Resource Capital Costs Sensitivity Analysis[93]

	Current Trends *(Reference Case)*		
	Low	**Base**	**High**
No Early Retirement	$9,080	$9,572	$10,157
Petersburg Conversion to Natural Gas (est. 2025)	$8,763	$9,330	$9,999
One Petersburg Unit Retires (2026)	$9,244	$9,773	$10,406
Both Petersburg Units Retire (2026 and 2028)	$9,104	$9,618	$10,249
Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)	$9,017	$9,711	$10,442
EnCompass Optimization without Predefined Strategy (Conversion 2025 and 2027)	$8,730	$9,262	$9,909

Opportunity Metric: Candidate Portfolios using low costs for renewables

Risk Metric: Candidate Portfolios using high costs for renewables

9.4.6 Social and Economic Impact

To evaluate the social and economic impacts from the generation changes made in the Candidate Portfolios, AES Indiana analyzed two metrics:

→ *Generation Employees* – this was calculated as the total change in the number of full-time generation employees over the 20-year planning period. The metric accounts for a reduction in the number of FTEs when resources are retired; however, when resources are added, the metric accounts for an increase in the number of FTEs. The metric is simply the change in the number of FTEs from the current state, which is calculated by summing the increases and decreases in employees associated with retirements and replacements over the planning period. The metric is not exclusive to employee count changes at the Petersburg Generating Station; it accounts for both AES Indiana-owned generation and any contracted (e.g., PPA) generation.

93 20-year PVRR (2023 dollars in millions from 2023-2042).

- → *Property Taxes* – this was calculated as the total amount of property taxes paid from AES Indiana assets over the planning period.

Figure 9-77 provides the results for the Social and Economic Impact Metrics. The No Early Retirement strategy results in the highest number of generation employees added over the planning period, whereas the Clean Energy Strategy results in the lowest. This is because strategies that retire the Petersburg units result in the highest reduction of employees. Additionally, the head count to support renewable resources is lower than that of thermal on a per MW basis. Since the Clean Energy Strategy retires both of the Petersburg coal units and replaces them with renewable and storage resources, this strategy exhibits the lowest score/FTE count in the comparison.

For the Property Tax metric, portfolios that include the highest investment in replacement capacity include the most property taxes. The analysis demonstrates that the Both Petersburg Units Retire strategy and Clean Energy Strategy score the highest on this metric because they require the highest investment in replacement capacity.

Figure 9-77: Candidate Portfolio Social and Economic Impact Metric Results

Strategy	Social and Economic Impact	
	Generation Employees (+/-)	*Property Taxes*
	Total change in FTEs associated with generation 2023 - 2042	Total amount of property tax paid from AES Indiana assets ($ Millions)
No Early Retirement	222	$154
Petersburg Conversion to Natural Gas (est. 2025)	99	$193
One Petersburg Unit Retires (2026)	195	$204
Both Petersburg Units Retire (2026 and 2028)	74	$242
Clean Energy Strategy	55	$256
EnCompass Optimization without Predefined Strategy	88	$185

9.5 Preferred Resource Portfolio and Final Scorecard

170 IAC 4-7-4(9), 170 IAC 4-7-6(a)(2), IAC 4-7-8(b)(2), and 170 IAC 4-7-8(c)(1)-(3)

Figure 9-78 combines the metrics reviewed in Section 9.4 into a complete Scorecard for comparison and evaluation of the Candidate Portfolios. After reviewing and evaluating the Candidate Portfolios' performances across the metrics described in Section 9.3, Section 9.4, and the metrics in aggregate on the Scorecard in Figure 9-78, AES Indiana finds the Petersburg Conversion performs the best across categories indicating that it is a reasonable, least cost strategy for customers and the best choice for the Preferred Resource Portfolio. By category, the Petersburg Conversion results are described as follows:

1) *Affordability*

- → Saves AES Indiana customers over $240 million over the IRP planning period.
- → Provides the least cost to customers over the 20-year planning horizon through the economic conversion of the remaining Petersburg units from coal to natural gas.
- → Demonstrates lowest annual PVRR relative to other portfolios over the 20-year planning horizon.

2) Environmental Sustainability

- → Provides a 68% reduction in carbon intensity in 2030 compared to 2018 levels.
- → Provides the lowest 20-year AES Indiana generation portfolio emissions for SO2, NOx, water use and coal combustion products, and the second lowest emissions for CO2.

3) Reliability, Stability, and Resiliency

- → Offers a one-for-one replacement dispatchable capacity (UCAP) for Petersburg that economically and effectively delivers in meeting MISO’s seasonal resource adequacy construct.
- → Provides firm unforced capacity when needed which will allow AES Indiana to responsibly and gradually transition to renewable energy resources over the planning horizon.
- → Demonstrates the highest composite reliability score while delivering significant renewable generation investment.

4) Risk and Opportunity

- → Provides best general performance across risk and opportunity metrics.

5) Social and Economic Impact

- → Continues to contribute economically to the Petersburg community by leveraging existing infrastructure and maintaining operation of the Petersburg Generating Station as a gas resource and hub for renewable resources.

Figure 9-78: AES Indiana 2022 IRP Scorecard Results

	Affordability	Environmental Sustainability						Reliability, Stability & Resiliency	Risk & Opportunity							Economic Impact	
	20-yr PVRR	*CO_2 Emissions*	*SO_2 Emissions*	*NO_x Emissions*	*Water Use*	*Coal Combustion Products (CCP)*	*Clean Energy Progress*	*Reliability Score*	*Environmental Policy Opportunity*	*Environmental Policy Risk*	*General Cost Opportunity **Stochastic Analysis***	*General Cost Risk **Stochastic Analysis***	*Market Exposure*	*Renewable Capital Cost Opportunity (Low Cost)*	*Renewable Capital Cost Risk (High Cost)*	*Generation Employees (+/-)*	*Property Taxes*
	Present Value of Revenue Requirements ($000,000)	Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)	% Renewable Energy in 2032	Composite score from Reliability Analysis	Lowest PVRR across policy scenarios ($000,000)	Highest PVRR across policy scenarios ($000,000)	P5 [Mean - P5]	P95 [P95 – Mean]	20-year avg sales + purchases (GWh)	Portfolio PVRR w/ low renewable cost ($000,000)	Portfolio PVRR w/ high renewable cost ($000,000)	Total change in FTEs associated with generation 2023 - 2042	Total amount of property tax paid from AES IN assets ($000,000)
1	$ 9,572	101.9	64,991	45,605	36.7	6,611	45%	7.95	$ 8,860	$ 11,259	$ 9,271	$ 9,840	5,291	$ 9,080	$ 10,157	222	$ 154
2	$ 9,330	72.5	13,513	22,146	7.9	1,417	55%	7.95	$ 8,564	$ 11,329	$ 9,030	$ 9,746	5,222	$ 8,763	$ 9,999	99	$ 193
3	$ 9,773	88.1	45,544	42,042	26.7	4,813	52%	7.86	$ 9,288	$ 11,462	$ 9,608	$ 10,237	5,737	$ 9,244	$ 10,406	195	$ 204
4	$ 9,618	79.5	25,649	24,932	15.0	2,700	48%	7.90	$ 9,135	$ 11,392	$ 9,295	$ 9,903	5,512	$ 9,104	$ 10,249	74	$ 242
5	$ 9,711	69.8	25,383	24,881	14.8	2,676	64%	7.57	$ 9,590	$ 11,275	$ 9,447	$ 10,039	6,088	$ 9,017	$ 10,442	55	$ 256
6	$ 9,262	76.1	18,622	25,645	10.9	1,970	54%	7.95	$ 8,517	$ 11,226	$ 8,952	$ 9,629	5,136	$ 8,730	$ 9,909	88	$ 185

Strategies

1. No Early Retirement
2. Pete Conversion to Natural Gas (est. 2025)
3. One Pete Unit Retires in 2026
4. Both Pete Units Retire in 2026 and 2028
5. Clean Energy Strategy – Both Pete Units Retire and replaced with Renewables in 2026 and 2028
6. Encompass Optimization without Predefined Strategy

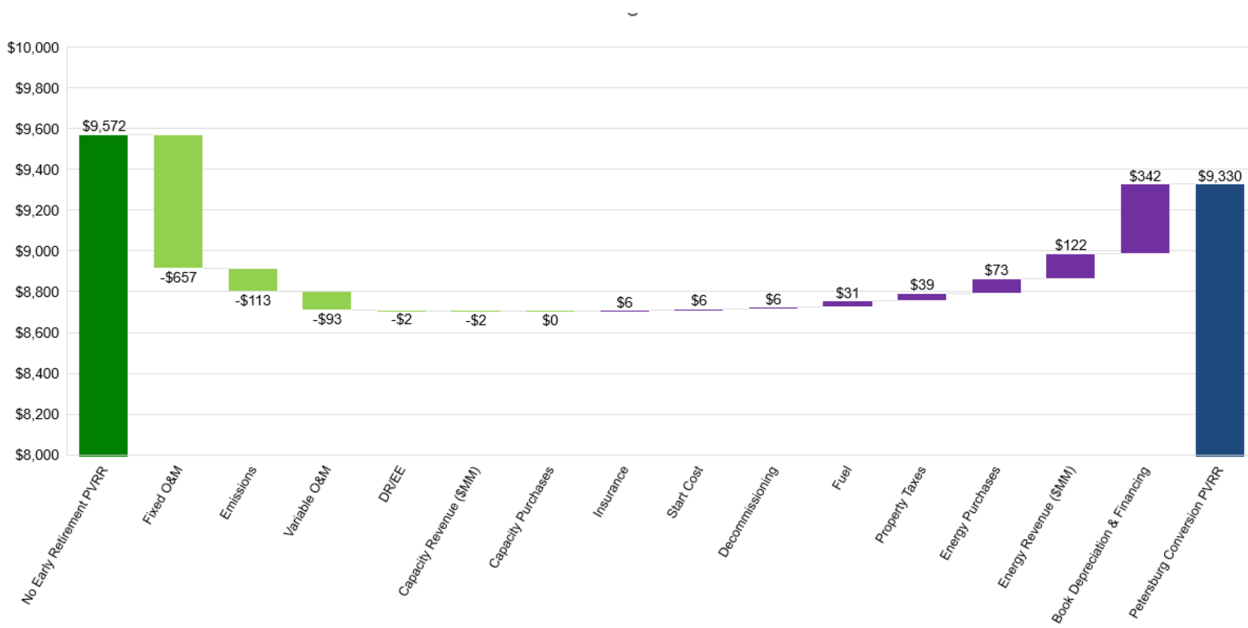
9.5.1 *Financial Impact of Preferred Resource Portfolio*

170 IAC 4-7-8(c)(7)

Figure 9-79 below provides a breakdown of the changes in the cost components of PVRR when comparing the entire No Early Retirement strategy portfolio, which represents the status quo, to the entire Petersburg Conversion strategy portfolio. The waterfall chart demonstrates that the largest savings to PVRR from converting Peterburg to natural gas comes from the reduction in -$657M of fixed costs over the period from the reduction of systems needed specifically for coal operation, e.g., coal handling and coal pollution controls. The conversion also results in reduction in -$113M in emissions costs and -$93M in variable O&M over the period. The Petersburg Conversion adds $342M in costs associated with book depreciation and financing to implement the Petersburg Conversion strategy, which includes additional renewable resources throughout the planning period and conversion of Petersburg Units 3 and 4.

Overall, the Petersburg Conversion provides an economic opportunity to continue utilizing the Petersburg infrastructure as a firm dispatchable capacity resource.

Figure 9-79: Costs Comparison of Petersburg Conversion Strategy Portfolio and the No Early Retirement Strategy Portfolio[94]



[94] 20-year PVRR (2023 dollars in millions from 2023-2042).

Section 10: Short Term Action Plan and Conclusion

170 IAC 4-7-4(24), 170 IAC 4-7-6(b)(4), 170 IAC 4-7-8(c)(10), and 170 IAC 4-7-9

10.1 2022 Short Term Action Plan

170 IAC 4-7-4(10)

Per IURC Rules (170 IAC § 4-7-9(a)), AES Indiana's Short Term Action Plan covers the next three years, 2023 through 2025, in this IRP. However, given the challenges and delays with procuring replacement capacity in the current and foreseeable market, the Company intends to pursue projects that the EnCompass Model has selected through 2027. This effort will be taken to sufficiently fill capacity requirements under the new MISO seasonal resource adequacy construct.

- → AES Indiana's Short Term Action Plan balances reliability, affordability, and sustainability by:
- → Having the highest composite reliability score amongst the Candidate Portfolios.
- → Saving customers more than $240M over the IRP planning period.
- → Providing a 68% reduction in carbon intensity in 2030 compared to 2018.
- → Adding up to 1,300 MW of renewable generation for capacity and energy, which includes:
    - 200 to 240 MW ICAP of battery energy storage at Petersburg to fill winter capacity position in 2025.
    - 550 to 1,065 MW ICAP of wind and solar as capacity and energy replacement for Petersburg based on results from the base and low Replacement Resource Capital Cost Sensitivity Analysis.
- → Ceasing coal-fired generation in 2025 after converting Petersburg Units 3 and 4 to natural gas.
- → Implementing three-year DSM action plan that targets an annual average of 130,000 – 134,000 MWh of energy efficiency (approximately 1.1% of 2021 sales) and three-year total of 53 MW summer peak impacts of demand response.

The Preferred Resource Portfolio also preserves optionality by providing a responsible and gradual transition to clean energy resources. Converting Petersburg Units 3 and 4 will maintain reliability by preserving 1,000 MW of firm dispatchable capacity and, at the same time, reduce carbon emissions by exiting coal in 2025. The Company will reevaluate its generation portfolio every three years through the IRP process to look for opportunities to transition its fleet to clean technologies both available and emerging.

Results from the Replacement Resource Capital Cost Sensitivity analysis indicate that, if replacement resources can be procured at a cost consistent with the lower cost tier, then the Company should procure more generation for its energy value. This is shown in Figure 10-1 and Figure 10-2. The results from the base sensitivity analysis indicate that 45 MW of solar plus storage resources in 2025 and 500 MW of wind resources in 2026 and 2027 should be procured; however, using the low replacement capital costs, the results indicate that 165 MW of solar plus storage in 2025 and 900 MW of wind in 2026 and 2027 should be procured. Based on these results, AES Indiana plans to procure up to 1,300 MW of solar, wind and storage resources, including 550 MW to 1,065 MW of solar and wind resources and 240 MW of BESS as capacity and energy replacement for Petersburg based on results from the Base and Low Replacement Resource Capital Cost Sensitivity Analysis. If solar, wind, and storage resources can be procured at a cost closer to the low-cost sensitivity, then AES Indiana will pursue a quantity consistent with the low sensitivity.

Figure 10-1: Short Term Action Plan Replacement Resource Results from the Base Replacement Resource Capital Cost Sensitivity Analysis

Petersburg Conversion Strategy using Base Replacement Resource Costs
(presented in MW ICAP)

Replacements	2023	2024	2025	2026	2027
Petersburg Conversion to Natural Gas	0	0	**1052**	0	0
Wind	0	0	0	**50**	**450**
Solar[95]	0	0	0	0	0
Storage	0	0	**240**	0	0
Solar+Storage	0	0	**45**	0	0

Figure 10-2: Short Term Action Plan Replacement Resource Results from the Low Replacement Resource Capital Cost Sensitivity Analysis

Petersburg Conversion Strategy using Low Replacement Resource Costs
(presented in MW ICAP)

Replacements	2023	2024	2025	2026	2027
Petersburg Conversion to Natural Gas	0	0	**1052**	0	0
Wind	0	0	0	**200**	**700**
Solar[95]	0	0	**75**	0	0
Storage	0	0	**240**	0	0
Solar+Storage	0	0	**90**	0	0

10.1.1 Supply Side (Generation) Short Term Action Plan

170 IAC 4-7-6(a)(2)

AES Indiana will file a CPCN in 2023 for the conversion of Petersburg Unit 3 and Unit 4 to natural gas. Pending IURC approval of the CPCN, the Company plans to complete the conversion of Petersburg Unit 3 in the spring of 2025 and Petersburg Unit 4 in the fall of 2025.

AES Indiana issued an all-source RFP in early 2022. The Company plans to use this RFP to procure capacity to fill the near-term 240 MW winter capacity need that has resulted from the new

[95] Solar capacities are shown in MWdc, as this is what EnCompass selects. Solar used a DC:AC ratio of 1.3. Other technologies' DC:AC is treated as being equal to 1.

MISO Seasonal Resource Adequacy construct. This will likely include a large battery energy storage project, which the Company seeks to locate at Petersburg to take advantage of the existing interconnection from retiring Petersburg Unit 2 (2023 retirement) and additional Energy Communities tax incentives. Upon completion of the RFP evaluation process, the Company plans to seek IURC approval as necessary or appropriate for a BESS resource and other projects deemed cost effective for customers and consistent with the result of this IRP. This filing will likely occur in 2023.

Additionally, the Company plans to issue another all-source RFP in early 2023 that will seek between 550 – 1065 MW of wind, solar and storage projects to fill capacity and energy needed in the near-term. Upon completion of the RFP evaluation process, the Company plans to seek IURC approval as necessary or appropriate for projects deemed cost effective for customers and consistent with the result of this IRP. This filing will likely occur in 2023 or 2024. The Company may also issue additional RFPs depending on the market conditions. Regulatory filings would follow these future procurements.

10.1.2 Demand Side Management Short Term Action Plan

170 IAC 4-7-6(b)(2)(F)

AES Indiana currently has approval to offer DSM programs for the 2021 through 2023 period under IURC Cause No. 43623 DSM 22. In 2023, the Company plans to seek Commission approval to deliver programs in 2024 through 2026 at a level consistent with those identified in the Preferred Resource Portfolio of this IRP. Figure 10-3 provides the estimated DSM targets for this filing.

Figure 10-3: Demand Side Management Short Term Action Plan Details

Energy Efficiency Targets

	2024	2025	2026
Incremental Net Savings (MWh)	133,505 – 136,106	129,303 – 131,995	131,926 – 134,688

Demand Response Targets

Cumulative Summer MW

	2024	2025	2026
Residential Rates	0	0	**3.7**
C&I Rates	0	0	**18.9**
Total DR	0	0	**22.6**

Energy efficiency was bundled by program for selection by the EnCompass Model in 2024 – 2026. In the Preferred Resource Portfolio, the model selected the following residential programs: Efficient Product Program – Lower Cost, Behavioral, School Education, Appliance Recycling, Multifamily, Income Qualified Weatherization; and selected the following commercial programs: Prescriptive, Custom, Retro-Commissioning, Strategic Energy Management.

Demand response was bundled by program categories for the entire planning period. In the Preferred Resource Portfolio, the model selected the Residential and C&I Rates program categories. These were modeled as pilot programs beginning in 2026.

The Company plans to work with its current vendors to refine the DSM plan based on the targets provided in Figure 10-3 and file this plan with the Commission in 2023.

10.1.3 Transmission Short Term Action Plan

170 IAC 4-7-6(b)(4)(C)

AES Indiana has submitted the following transmission system projects to MISO via the MTEP Portal and is inclusive of only Transmission Owner ("TO") projects or the TO portion of the project (with the exclusion of MTEP Number 23832, which includes Appendix D costs) that are submitted for MTEP 23 and prior MTEP cycles.

MTEP 23 and prior submissions are as follows:

→ MTEP Number: 23107

- J993 / Brickyard Solar – Brickyard Solar is a 217 MVA solar facility, this project consists of any necessary transmission adjustments to enable the solar facility to interconnect to the transmission system.
- Timing: 2023.
- Estimated Cost: $20,000,000.

→ MTEP Number: 23852

- R1011 / Petersburg Energy Center – Petersburg Energy Center is a 279.45 MVA solar facility, this project consists of any necessary transmission adjustments to enable the solar facility to interconnect to the transmission system.
- Timing: 2024.
- Estimated Cost: $4,000,000.

→ MTEP Number: 23831

- Gillette Substation – Gillette Substation is a new 138 kV, 80 MVA substation to serve new C&I customers near Indianapolis commercial business district. This project is also inclusive of any transmission adjustments necessary to allow the additional customer load to interconnection to the transmission system.
- Timing: 2024.
- Estimated Cost: $15,000,000.

→ MTEP Number: 23766

- Indiana University Health Substation – Indiana University Health Substation is a new 138 kV, 80 MVA substation to serve new C&I customers near Indianapolis commercial business district. This project is also inclusive of any transmission adjustments necessary to allow the additional customer load to interconnection to the transmission system.

- Timing: 2023.
- Estimated Cost: $15,000,000.

→ MTEP Number: 23825

- Rockville Substation Reconfiguration – Rockville Substation reconfiguration is a substation modification to allow for more operational flexibility during outage and contingent situations and future load growth along the west portion of Marion County, Indiana.
- Timing: 2024.
- Estimated Cost: $9,000,000.

→ MTEP Number: 23893

- Winding Ridge Substation – Winding Ridge Substation is a new 138 kV, 80 MVA substation to serve new RCI customers along the east side of Marion County. This project is a joint project with Wabash Valley Power Association.
- Timing: 2024.
- Estimated Cost: $15,000,000.

→ MTEP Number: 23834

- Valley Avenue Substation – Valley Avenue Substation is a new 138 kV, 80 MVA substation to serve existing RCI customers in the near east side of Indianapolis. This project is a joint project to retire 4 kV voltage service.
- Timing: 2023.
- Estimated Cost: $15,000,000.

→ MTEP Number: 23832

- Thompson Substation reconfiguration – Thompson Substation reconfiguration adds an additional 40 MVA transformer at Thompson substation to allow a direct service to an existing commercial customer.
- Timing: 2023.
- Estimated Cost: $16,000,000.

→ MTEP Number: 21836

- Replace Sunnyside Breakers – Age and condition breaker replacements at Sunnyside substation: three (3) 345 kV breakers, two (2) 138 kV breakers.
- Timing: 2024.

- Estimated Cost: $5,100,000.

→ MTEP Number: 21838

- Replace Southwest Breakers – Age and condition breakers replacements at Southwest substation: five (5) 138 kV breakers.
- Timing: 2024.
- Estimated Cost: $4,500,000.

→ MTEP Number: 21839

- Replacement West Breakers – Age and condition breaker replacements at West substation: three (3) 138 kV breakers.
- Timing: 2024.
- Estimated Cost: $2,400,000.

→ MTEP Number: 20137

- Guion substation reconfiguration to add an additional 345:138kV autotransformer at Guion substation. In addition, this project modifies the layout of Guion substation to allow for greater operational flexible during outage and contingent situations.
- Timing: 2023.
- Estimated Cost: $13,376,000.

→ MTEP Numbers: 17884, 17885, and 17886

- Replace Southeast Breakers to address reliability need from the annual short circuit analysis as required by NERC TPL-001-4 R2.3 & R2.8 results in breaker replacements at Southeast substation: three (3) 138 kV breakers.
- Timing: 2025.
- Estimated Cost: $2,700,000.

→ MTEP Number: 17887

- Replace Stout Breakers to address reliability need from the annual short circuit analysis as required by NERC TPL-001-4 R2.3 & R2.8 results in breaker replacements at Stout substation: one (1) 138 kV breaker.
- Timing: 2023.
- Estimated Cost: $900,000.

→ MTEP Number: 17888

- Replace Southport Breakers to address reliability need from the annual short circuit analysis as required by NERC TPL-001-4 R2.3 & R2.8 results in breaker replacements at Southport substation: one (1) 138 kV breaker.

- Timing: 2023.
- Estimated Cost: $900,000.

10.2 Long Term Action Plan (2025 and beyond)

Beyond the Short Term Action Plan timeframe, AES Indiana's modeling and analysis efforts in this IRP have highlighted several key areas to evaluate as AES Indiana moves forward into future IRPs.

→ **Harding Street** – Most notably, planning for the replacement of Harding Street Units ST5, ST6, and ST7, which total approximately 620 MW ICAP and are estimated to undergo age-based retirements by 2033, will be at the forefront of the next IRP rounds. With its location on the White River, AES Indiana sees an opportunity to develop innovative proposals for the future of the Harding Street location that meets AES Indiana's customers' needs and align with the City of Indianapolis's White River Vision Plan, which will redevelop the area along the White River.

→ **MISO Seasonal Resource Adequacy Construct** – Additionally, the MISO seasonal resource adequacy construct was just approved in August of 2022. As of the filing of this IRP, MISO load serving entities have yet to participate in the seasonal planning resource auction process; thus, there is much to learn about this new construct and process. As AES Indiana gains experience in the new market, the Company will modify planning, both in the interim and in future IRPs – to reflect the realities of a seasonal market and market accreditation.

→ **Cleaner Energy Future** – AES Indiana views the conversion of Petersburg Units 3 and 4 as a reliable bridge to a future carbon free portfolio as AES Indiana's conventional resources begin to play a smaller role in providing energy to customers. AES Indiana will primarily use the conversion as a firm capacity resource that is there when the system needs it. This allows the Company to invest in renewable resources for their energy value. AES Indiana will continue to evaluate renewable options that can provide reliable capacity to replace its conventional generation, particularly for the 2030s when the Harding Street Units retire, as AES Indiana progresses towards a Cleaner Energy Future.

10.3 Expectations for Future IRPs

170 IAC 4-7-4(16), 170 IAC 4-7-5(a)(9), and 170 IAC 4-7-8(c)(9)

AES Indiana plans to continue its effort to improve its IRP process and has identified the following items as potential improvements.

→ **Model alternative replacement resource options such as clean hydrogen or small modular reactors if commercially viable**: AES Indiana intends to monitor new and emerging technologies for feasibility as future replacement resources. If technologies like clean hydrogen or small modular reactors are deemed viable, then they may be included as replacement resources in future IRPs.

- → **Sub hourly modeling to capture additional PVRR benefits including ancillary services value of battery energy storage and reciprocating engines:** Some resources, such as batteries and reciprocating engines, offer nearly instantaneous ramp rates, which provides flexibility. This value may be more accurately captured through sub hourly modeling, though this currently pushes the limits of many available models and forecasts. AES Indiana will continue to assess whether the value of more granular modeling justifies the increase in complexity.
- → **Enhanced Distribution System Planning that captures circuit-level value of distributed generation and DSM**: AES Indiana is currently in the process of piloting Integral Analytics' LoadSEER; a distribution system, corporate planning, and DER integration platform. The intention of this pilot will be to test out a platform that will help plan for a future of electric vehicles, distributed generation, and non-wires alternatives. Additionally, LoadSEER may help quantify the avoided costs associated with the time and locational value of DSM. In future IRP's, the Company would like to integrate this planning and analysis into the IRP modeling.
- → **Include refinements made to non-dispatchable resource seasonal capacity credit such as seasonal ELCC**: Resource capacity credit will vary by season under MISO's new seasonal resource adequacy construct. AES Indiana will monitor MISO's capacity credit changes and their effect on future IRPs and on planning in the interim, between IRPs.

10.4 Response to the City of Indianapolis' Recommendations for AES Indiana's IRP

In early 2022, AES Indiana met with the City of Indianapolis to discuss the City's recommendations for AES Indiana's IRP. As a follow up, Mayor Joe Hogsett and Morgan Mickelson, Director, City of Indianapolis Office of Sustainability, sent the Company a letter summarizing their recommendations.

AES Indiana is pleased recognize that this IRP will meet the City's recommendations. Most notably, the Preferred Resource Portfolio is forecasted to achieve a 69% reduction in CO_2 emissions by 2030 compared to 2018 levels which surpasses the City's recommendation of 62.5%. AES Indiana and its Resource Planning team have enjoyed coordinating and collaborating with the City of Indianapolis during the IRP process and look forward to continued collaboration in the future.

Figure 10-4 provides a summary of the City's recommendations for this IRP and AES Indiana's responses.

Figure 10-4: City of Indianapolis Recommendations to AES Indiana's IRP

City of Indianapolis Recommendations	AES Indiana Response
The City of Indianapolis seeks a resource mix with renewable generation capacity that aligns with the goals of the City and community. *City recommends AES Indiana develop a model with multiple scenarios that achieve a 62.8% reduction over 2018 emissions levels, in order to align with the City's Science Based Target's for 2030.*	AES Indiana's Preferred Resource Portfolio achieves a 69% reduction in CO2 emissions in 2030 compared to 2018 levels. The portfolio provides affordable, reliable, and sustainable energy to Indianapolis residents.
The City of Indianapolis strongly supports AES Indiana's use of "all-source" procurement for future capacity additions to ensure cost effective, market-driven innovation.	AES Indiana will fill its need for replacement capacity identified in the Short Term Action Plan through all-source RFPs. The Company will pursue the most cost effective and viable wind, solar and storage projects through this process.
The City of Indianapolis encourages AES Indiana to expand offerings of and access to energy efficiency programs targeting those with the highest energy burden.	AES Indiana has identified energy efficiency as a cost effective energy resource and will work to develop a new energy efficiency program plan to start in 2024 - 2026. Based on current IRP inputs and modeling results, AES Indiana expects its new plan will continue to have an emphasis on programs that provide energy savings to all customers, with added emphasis on programs that benefit low- and moderate-income households.
The City of Indianapolis encourages AES Indiana to support a Just Transition for each Indiana community.	AES Indiana will continue to invest in new technologies and identify clean energy projects that deliver greener, smarter energy solutions. AES Indiana remains invested in its communities through commitments to the workforce, charitable organizations and economic development. Advanced modeling, additional economic impact metrics, greater transparency with stakeholders and increased accessibility to the IRP process allowed AES Indiana to paint a full picture of the potential impacts of each generation strategy and select a just and inclusive portfolio.
The City of Indianapolis requests that AES Indiana make energy performance and aggregated whole building data available to customers.	AES Indiana currently offers online tools that provide customers throughout its service territory with access to their energy usage data. These tools also provide recommendations to customers for managing their energy usage and costs through energy efficiency measures and programs. As AES Indiana expects the capabilities of its online tools will evolve to support additional customer friendly features that meet current and future data driven needs such as whole building data aggregation.

10.5 Conclusion

The IRP is the foundation for future regulatory requests based upon a holistic view of AES Indiana's resource needs and portfolio options. Through this process, AES Indiana determined that converting Petersburg Units 3 and 4 to operate using natural gas and investing in wind, solar, and battery energy storage resources is the reasonable, least cost option for customers, reliable, and sustainable option for customers. Converting Petersburg provides affordability to customers by reducing overall costs to customers and providing a reliable capacity foundation upon which the Company can invest in clean energy. AES Indiana looks forward to continued collaboration with stakeholders as the Company evaluates and seeks approval for supply and demand side projects identified in the Short Term Action Plan. The Company will continue to improve upon the IRP process from a modeling, evaluation, and stakeholder engagement perspective.

Section 11: Attachments and Rule Reference Table

Public attachments are available in Volumes 2 and 3 of AES Indiana's Public IRP Report. Confidential attachments and Information are available as part of AES Indiana's Confidential IRP Report.

11.1 List of Attachments

- Attachment 1-1 (AES Indiana's 2022 IRP Non-Technical Summary)
- Attachment 1-2 (Public Advisory Meeting Presentations) **170 IAC 4-7-4(30) and 170 IAC 4-7-8(c)(5)**
- Attachment 5-1 (Test Year July 2016 through June 2017 Hourly Loads (MW) - Rate Case) **170 IAC 4-7-4(12), 170 IAC 4-7-4(14), 170 IAC 4-7-5(a)(1), and 170 IAC 4-7-5(a)(2)**
- Attachment 5-2 (Itron Load Forecast Report) **170 IAC 4-7-4(12)**
- Confidential Attachments 5-3a-g (EIA End Use Data) **170 IAC 4-7-4(12)**
- Attachment 5-4 (AES Indiana's 2022 DER and Other Electrification MPS) **170 IAC 4-7-4(15), 170 IAC 4-7-6(b)(2)(B), 170 IAC 4-7-6(b)(2)(D), and 170 IAC 4-7-6(b)(2)(E)**
- Confidential Attachment 5-5a (Moody's Q3 2021 - Base) **170 IAC 4-7-4(12)**
- Confidential Attachment 5-5b (Moody's Q3 2021 - High) **170 IAC 4-7-4(12)**
- Confidential Attachment 5-5c (Moody's Q3 2021 - Low) **170 IAC 4-7-4(12)**
- Attachment 5-6 (AES Indiana's 10-Year Energy and Peak Forecast) **170 IAC 4-7-4(12) and 170 IAC 4-7-5(a)(6)**
- Attachment 5-7a (AES Indiana's 20-Year Base Load Forecast) **170 IAC § 4-7-4(1), 170 IAC 4-7-4(12), and 170 IAC 4-7-5(b)**
- Attachment 5-7b (AES Indiana's 20-Year High and Low Load Forecast) **170 IAC § 4-7-4(3), 170 IAC 4-7-4(12), and 170 IAC 4-7-5(b)**
- Attachment 5-8 (Energy Forecast Drivers) **170 IAC 4-7-4(12), 170 IAC 4-7-5(a)(3), and 170 IAC 4-7-5(a)(5)**
- Attachment 5-9 (Peak Forecast Drivers and Input Data) **170 IAC 4-7-4(12) and 170 IAC 4-7-5(a)(5)**
- Confidential Attachment 6-1 (Capital Costs)
- Attachment 6-2 (Decrement Load Shapes Summary) **170 IAC 4-7-6(b)(2)(D) and 170 IAC 4-7-6(b)(2)(E)**
- Attachment 6-3 (AES Indiana 2022 MPS) **170 IAC 4-7-4(15), 170 IAC 4-7-6(b)(2)(B), 170 IAC 4-7-6(b)(2)(D), and 170 IAC 4-7-6(b)(2)(E)**
- Confidential Attachment 6-4 (Avoided Costs) **170 IAC 4-7-4(29) and 170 IAC 4-7-8(c)(6)**
- Confidential Attachment 8-1 (Commodity Price Forecasts)

→ Confidential Attachment 8-2 (Annual Generator Fuel Prices) **170 IAC 4-7-6(a)(3)**

→ Attachment 8-3 (Executive Summary of Quanta Technology's System Reliability Assessment of AES Indiana's 2022 IRP Portfolios)

11.2 IURC Electric Utility Rule 7 Reference Table

170 IAC 4-7 (Readopted Filed Version April 11, 2019)

IAC Citation	Requirement	Location in AES Indiana 2022 IRP Report
170 IAC § 4-7-0.5	**Section 0.5: Purpose and applicability**	No Response Required
170 IAC § 4-7-1	**Section 1: Definitions**	No Response Required
170 IAC § 4-7-2	**Section 2: Integrated resource plan submission**	No Response Required
170 IAC § 4-7-2.1	**Section 2.1: Confidentiality**	No Response Required
170 IAC § 4-7-2.2	**Section 2.2: Public Comments and Director's Reports**	No Response Required
170 IAC § 4-7-2.3	**Section 2.3: Resource Adequacy Assessment Report**	No Response Required
170 IAC § 4-7-2.4	**Section 2.4: N/A**	No Response Required
170 IAC § 4-7-2.5	**Section 2.5: Effects of Integrated Resource Plans in Docketed Proceedings**	No Response Required
170 IAC § 4-7-2.6	**Section 2.6: Public Advisory Process**	Attachment 1-2 and Section 1-4
170 IAC § 4-7-2.7	**Section 2.7: Contemporary Issues Technical Conference**	No Response Required
170 IAC § 4-7-3	**Section 3: Waiver or Variance Requests**	No Response Required
	Section 4: Integrated Resource Plan Contents	
170 IAC § 4-7-4(1)	At least a twenty (20) year future period for predicted or forecasted analyses.	Section 5.3 and Attachment 5-7a
170 IAC § 4-7-4(2)	An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Section 5.5
170 IAC § 4-7-4(3)	At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	Section 5.3 and Attachments 5-7b
170 IAC § 4-7-4(4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	Section 6.1
170 IAC § 4-7-4(5)	A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Section 8
170 IAC § 4-7-4(6)	A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	Sections 6.2 and 6.3
170 IAC § 4-7-4(7)	The resource screening analysis and resource summary table required by section 7 of this rule.	Section 6.2
170 IAC § 4-7-4(8)	A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	Sections 8.1, 9.1, and 9.2.3
170 IAC § 4-7-4(9)	A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Section 9.5
170 IAC § 4-7-4(10)	A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Section 10.1
170 IAC § 4-7-4(11)	A discussion of the: (A) inputs; (B) methods; and (C) definitions;	Sections 5, 6, and 8

170 IAC § 4-7-4(12)	Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data.	Attachments 5-1 through 5-9
170 IAC § 4-7-4(13)	A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated.	Section 5.1
170 IAC § 4-7-4(14)	The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Attachment 5-1
170 IAC § 4-7-4(15)	A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	Section 6.4.3, Attachments 5-4 and 6-3
170 IAC § 4-7-4(16)	A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Sections 4.3, 4.6, 5.1, 6.5, and 10.3
170 IAC § 4-7-4(17)	A discussion of the designated contemporary issues designated, if required by section 2.7(e) of this rule.	Section 1.5
170 IAC § 4-7-4(18)	A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	Sections 4.2, 4.4, and 4.6
170 IAC § 4-7-4(19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Sections 8.1 and 8.2
170 IAC § 4-7-4(20)	A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	Section 2.4
170 IAC § 4-7-4(21)	A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	Section 7.2.1
170 IAC § 4-7-4(22)	A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 8
170 IAC § 4-7-4(23)	A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Sections 7 and 8.3
170 IAC § 4-7-4(24)	A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	Executive Summary, Sections 1.1, 9, and 10

170 IAC § 4-7-4(25)	A description and analysis of the utility's base case scenario, sometimes referred to as a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	Sections 8.4.2 and 9
170 IAC § 4-7-4(26)	A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Sections 8.4.2, 9.2.1, and 9.2.2
170 IAC § 4-7-4(27)	A brief description of the models, focusing on the utility's Indiana jurisdictional facilities, of the certain components of FERC Form 715.	Sections 3.2 and 3.3
170 IAC § 4-7-4(28)	A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	Sections 5.3, 8.2, and 8.3
170 IAC § 4-7-4(29)	An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.	Section 6.4.6 and Confidential Attachment 6-4
170 IAC § 4-7-4(30)	A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.	Section 1.4 and Attachment 1-2
170 IAC § 4-7-4(31)	A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 6
Section 5: Energy and Demand Forecasts		
170 IAC § 4-7-5(a)(1)	Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Attachment 5-1
170 IAC § 4-7-5(a)(2)	Disaggregation of historical data and forecasts by: (A) customer class;	Attachment 5-1

	(B) interruptible load; and (C) end-use; where information permits.	
170 IAC § 4-7-5(a)(3)	Actual and weather normalized energy and demand levels.	Attachment 5-8
170 IAC § 4-7-5(a)(4)	A discussion of methods and processes used to weather normalize.	Section 5.3
170 IAC § 4-7-5(a)(5)	A minimum twenty (20) year period for peak demand and energy usage forecasts.	Attachments 5-8 and 5-9
170 IAC § 4-7-5(a)(6)	An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or rate classes, or both. (C) Firm wholesale power sales.	Attachment 5-6
170 IAC § 4-7-5(a)(7)	A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 5.3
170 IAC § 4-7-5(a)(8)	Justification for the selected forecasting methodology.	Section 5.3
170 IAC § 4-7-5(a)(9)	A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	Section 10.3
170 IAC § 4-7-5(a)(10)	For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	Section 5.5
170 IAC § 4-7-5(b)	To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.	Attachments 5-7a and 5-7b
170 IAC § 4-7-5(c)	In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 5.3
Section 6: Description of Available Resources		
170 IAC § 4-7-6(a)(1)	The net and gross dependable generating capacity of the system and each generating unit.	Section 6.1.1
170 IAC § 4-7-6(a)(2)	The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Sections 6.1, 9.5, and 10.1.1
170 IAC § 4-7-6(a)(3)	A fuel price forecast by generating unit.	Confidential Attachment 8-2
170 IAC § 4-7-6(a)(4)	The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; (D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units.	Section 7
170 IAC § 4-7-6(a)(5)	An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	Section 3

170 IAC § 4-7-6(a)(6)	A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy.	Section 6.4
170 IAC § 4-7-6(b)(1)	Rate design as a resource in meeting future electric service requirements.	Section 6.5
170 IAC § 4-7-6(b)(2)(A)	A description of the potential demand-side resource, including its costs, characteristics, and parameters.	Section 6.4
170 IAC § 4-7-6(b)(2)(B)	The method by which the costs, characteristics, and other parameters of the demand-side resource are determined.	Section 6.4.4 and Attachments 5-4 and 6-3
170 IAC § 4-7-6(b)(2)(C)	The customer class or end-use, or both, affected by the demand-side resource.	Sections 6.4.2, 6.4.3, and 6.4.4
170 IAC § 4-7-6(b)(2)(D)	Estimated annual and lifetime energy (kWh) and demand (kW) savings.	Attachments 5-4, 6-2, and 6-3
170 IAC § 4-7-6(b)(2)(E)	The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements.	Attachments 5-4, 6-2, and 6-3
170 IAC § 4-7-6(b)(2)(F)	Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	Sections 6.4.1 and 10.1.2
170 IAC § 4-7-6(b)(3)(A)	Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of nondispatchable resources. (iv) Additional transmission facilities necessitated by the resource.	Sections 6.2 and 6.3
170 IAC § 4-7-6(b)(3)(B)	A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Sections 2 and 3
170 IAC § 4-7-6(b)(3)(C)	A description of significant environmental effects.	Section 9.4.3
170 IAC § 4-7-6(b)(4)(A)	The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology.	Section 3
170 IAC § 4-7-6(b)(4)(B)	A description of the timing, types of expansion, and alternative options considered.	Section 3
170 IAC § 4-7-6(b)(4)(C)	The approximate cost of expected expansion and alteration of the transmission network.	Section 10.1.3
170 IAC § 4-7-6(b)(4)(D)	A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 3
170 IAC § 4-7-6(b)(4)(E)	(E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Sections 2 and 3
Section 7: Selection of Resources		
170 IAC § 4-7-7	To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 6.2
Section 8: Resource Portfolios		
170 IAC § 4-7-8(a)	The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Sections 8 and 9
170 IAC § 4-7-8(b)(1)	An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(26) of this rule.	Section 9.2.2

170 IAC § 4-7-8(b)(2)	The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	Sections 9.2.3 and 9.5
170 IAC § 4-7-8(b)(3)	The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2.3
170 IAC § 4-7-8(c)(1)	A description of the utility's preferred resource portfolio.	Section 9.5
170 IAC § 4-7-8(c)(2)	Identification of the standards of reliability.	Sections 9.4.4 and 9.5
170 IAC § 4-7-8(c)(3)	A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.5
170 IAC § 4-7-8(c)(4)	An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Sections 8 and 9
170 IAC § 4-7-8(c)(5)	An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost-effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	Attachment 1-2 and Section 9.2.3
170 IAC § 4-7-8(c)(6)	An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	Confidential Attachment 6-4
170 IAC § 4-7-8(c)(7)	A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Section 9.5.1
170 IAC § 4-7-8(c)(8)	A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Section 9
170 IAC § 4-7-8(c)(9)	Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 10.3
170 IAC § 4-7-8(c)(10)	A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors that would cause the forecasted relationship between supply and demand for electric service to be in error.	Sections 9.3 and 10
Section 9: Short Term Action Plan		
170 IAC § 4-7-9(a)	A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	Section 10

170 IAC § 4-7-9(b)	The short term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(10) of this rule, where the utility must take action or incur expenses during the three (3) year period.	Section 10
170 IAC § 4-7-9(c)(1)	A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.	Section 10
170 IAC § 4-7-9(c)(2)	Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10 and 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	Section 10
170 IAC § 4-7-9(c)(3)	The implementation schedule for the preferred resource portfolio.	Section 10
170 IAC § 4-7-9(c)(4)	A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	Section 10
170 IAC § 4-7-9(c)(5)	A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	Section 10