INDIANAPOLIS POWER & LIGHT COMPANY

2019 Integrated Resource Plan

Volume 2 of 3

December 16, 2019

Attachment 1.1

ipl an AES company

2019 Integrated Resource Plan (IRP) Non Technical Summary

BACKGROUND

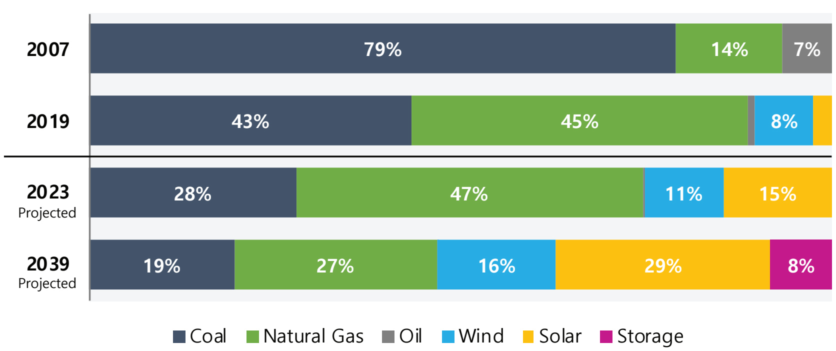
Indianapolis Power & Light Company ("IPL") is engaged primarily in generating, transmitting, distributing and selling electric energy to more than 500,000 retail customers in Indianapolis and neighboring areas; the most distant point being about 40 miles from Indianapolis. IPL's service area covers about 528 square miles. IPL is subject to the regulatory authority of the Indiana Utility Regulatory Commission ("IURC") and the Federal Energy Regulatory Commission ("FERC"). IPL fully participates in the electricity markets managed by the Midcontinent Independent System Operator ("MISO"). IPL is a transmission company member of Reliability First ("RF"). RF is one of eight Regional Reliability Councils under the North American Electric Reliability Corporation ("NERC"), which has been designated as the Electric Reliability Organization under the Energy Policy Act ("EPAct"). IPL is part of the AES Corporation, a Fortune 500 global power company, with a mission to improve lives by accelerating a safer and greener energy future.

The Integrated Resource Plan ("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, will require regulatory approval.

IPL's 2019 IRP continues to move the Company towards cleaner energy resources. Figure 1 shows how IPL's resource mix has changed over time. For a map of IPLs' service territory and location of current resources, see Figure 2.

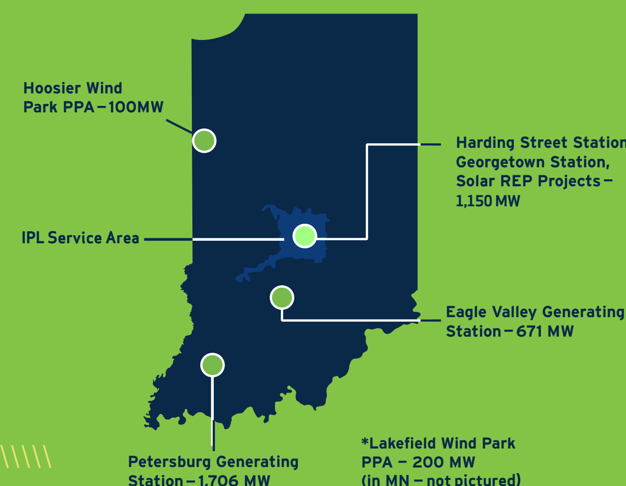
Figure 1 - ***IPL RESOURCE MIX***

IPL has been a leader in moving toward cleaner energy resources.



Resources based on maximum summer rated capacity for thermal units and nameplate capacity for wind and solar. Includes both owned assets and those under long-term power purchase agreements. The 2039 projections are based on IPL's most recent Integrated Resource Plan and are subject to change.

Figure 2 - ***IPL SERVICE TERRITORY AND EXISTING RESOURCES***



IRP OBJECTIVE

The objective of IPL's Integrated Resource Plan ("IRP") is to identify a portfolio to provide safe, reliable, sustainable, reasonable, least-cost energy service to IPL customers throughout the study period giving due consideration to potential risks and stakeholder input.

IRP Process

Every three years, IPL submits an IRP to the IURC in accordance with Indiana Administrative Code (IAC 170 4-7) to describe expected electrical load requirements, a discussion of potential risks, possible future scenarios and 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 input from stakeholders known as a "Public Advisory" process.

Public Advisory Process

IPL hosted five (5) public advisory meetings to discuss the IRP process with interested parties and solicit feedback from stakeholders. The meeting agendas from each meeting are highlighted here. For all meeting notes, presentations and other materials, see IPL's IRP webpage at IPLpower.com/irp.

IPL incorporated feedback from stakeholders to shape the scenarios, develop metrics, and clarify the data presented.

Public Advisory Meeting #1
January 29, 2019

Topics covered: 2016 IRP review, introduction to the 2019 IRP (timeline, mission, objectives), capacity discussion, 2019 IRP starting point, modeling replacement resources, DSM/EE modeling and load forecast update

Public Advisory Meeting #2
March 26, 2019

Topics covered: stakeholder presentations, detailed load forecast, IPL DSM market potential study and end use results, commodity prices and modeling, assumptions for replacement resources, scenario analysis framework and proposed scenarios

Public Advisory Meeting #3
May 14, 2019

Topics covered: electric vehicle and distributed solar forecast, stakeholder presentation, detailed load forecast, DSM bundles in IRP modeling, modeling and scenario recap

Public Advisory Meeting #4
September 30, 2019

Topics covered: modeling and scenario recap, preliminary model results, optimized portfolios, portfolio metrics

Public Advisory Meeting #5
December 9, 2019

Topics covered: summary of IPL 2019 short term action plan, 2019 IRP modeling insights, analysis of alternatives and preferred resource portfolio

IRP MODELING

The electric utility continues to evolve through technology advancements, fluctuations in customer consumption, changes in state and federal energy policies, uncertainty of long-term fuel supply and prices, and a multitude of other factors. Since the impacts these factors will have on the future utility industry landscape remains largely uncertain, IPL models multiple possible scenarios to evaluate various futures.

The key drivers (Figure 3) that differ between each scenario are natural gas prices, carbon tax, coal prices, IPL load and the capital cost assumptions for wind, solar, and storage. In this IRP, IPL evaluated a set of fifteen (15) candidate resource portfolios (Figure 4) created from a modeling process that incorporated an evaluation of coal retirement dates, DSM targets and new resource economics in a probabilistic optimization framework. The candidate resource portfolios were stressed across a wide range of scenarios, which allowed IPL to identify the portfolio that mitigates risk and performs the best across multiple futures.

Figure 3 - ***IRP SCENARIO DRIVERS***

	Reference Case	Scenario A: Carbon Tax	Scenario B: Carbon Tax + High Gas	Scenario C: Carbon Tax + Low Gas	Scenario D: No Carbon Tax + High Gas
Natural Gas Prices	Base	Base	HIGH	LOW	HIGH
Carbon Tax	No Carbon Price	Carbon Tax (2028+)	Carbon Tax (2028+)	Carbon Tax (2028+)	No Carbon Price
Coal Prices	Base	Base	Base	Base	Base
IPL Load	Base	Base	Base	LOW	HIGH
Capital Costs for Wind, Solar, and Storage	Base	Base	Base	Base	Base

Figure 4 - ***IPL CANDIDATE RESOURCE PORTFOLIOS***

Portfolio	Description	DSM Decrements 1-3	DSM Decrements 1-4	DSM Decrements 1-5
Portfolio 1	No Early Retirements	1a	1b	1c
Portfolio 2	Pete Unit 1 Retire 2021; Pete Units 2-4 Operational	2a	2b	2c
Portfolio 3	Pete Unit 1 Retire 2021; Pete 2 Retire 2023; Pete Units 3-4 Operational	3a	3b	3c
Portfolio 4	Pete Unit 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	4a	4b	4c
Portfolio 5	Pete Unit 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	5a	5b	5c

PREFERRED RESOURCE PORTFOLIO

The candidate resource portfolios produced by the capacity expansion model are summarized in Figure 5.

The "Preferred Resource Portfolio" represents what IPL believes to be the most likely scenario based on factors known at the time of the IRP submission. Portfolio 3b, depicted in Figure 5, is the Preferred Resource Portfolio. Each candidate resource portfolio was run through stochastic production cost modeling runs for each scenario which provides insight into the risk, benefits and overall robustness of portfolios across time and a range of market conditions. IPL analyzed three primary categories of metrics: cost, risk and environmental, as shown in Figure 6. The results of these metrics show that the largest key driver of changes in the Present Value Revenue Requirement ("PVRR") of the candidate resource portfolios is carbon tax legislation. There is also strong benefit to having a diverse portfolio. The diverse Preferred Resource Portfolio is the lowest cost across a range of futures.

Figure 5 – ***CUMULATIVE INSTALLED CAPACITY CHANGES THROUGH 2039*** *(ICAP MW)*

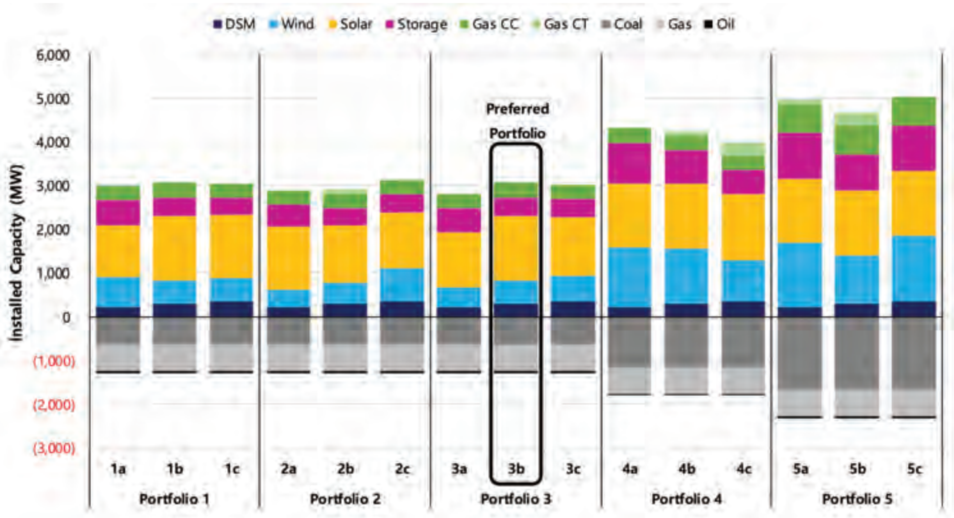
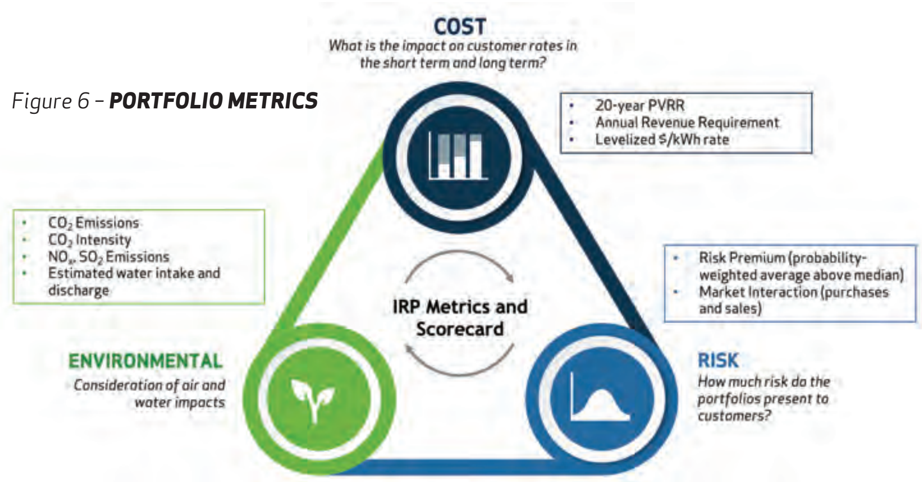


Figure 6 – ***PORTFOLIO METRICS***



SHORT TERM ACTION PLAN

RETIRE	REPLACE	SAVE	MONITOR
Retire 630 MW of coal generation by 2023: • Pete 1: 2021 • Pete 2: 2023	Competitively bid for approximately 200 MW of firm capacity with all-source RFP	Target ~130,000 MWh per year of new DSM as part of the 2021-2023 DSM Plan	Maintain cost-effective units at Petersburg to retain flexibility and continue to monitor market conditions leading to our 2022 IRP

Retirement of 630 MW of coal by 2023

Based on extensive modeling, IPL has determined that the cost of operating Petersburg Units 1 and 2 exceeds the value customers receive compared to alternative resources. Retirement of these units allows the company to cost-effectively diversify the portfolio and transition to cleaner, more affordable resources while maintaining a reliable system.

Competitively bid for 200 MW of replacement capacity

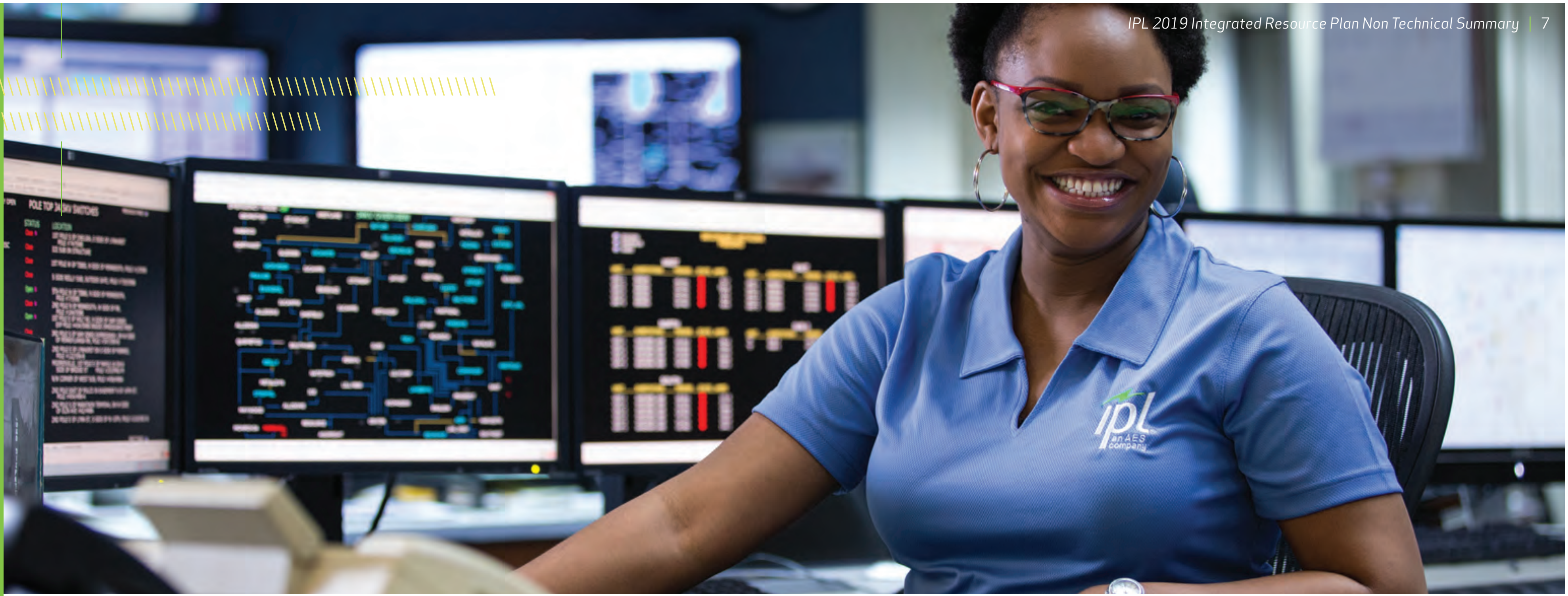
IPL intends to issue an all-source Request for Proposal ("RFP") to competitively procure replacement capacity by June 1, 2023, which is the first year IPL is expected to have a capacity shortfall. IRP modeling indicates that a combination of wind, solar and storage resources would be the lowest cost options for the replacement capacity, but IPL will assess the type, size and location of resources after bids are received.

Target ~130,000 MWh per year of DSM and energy efficient programs

IPL plans to continue to be a state leader in Demand-Side Management (DSM) implementation and through an extensive valuation of DSM bundles, compared to supply-side alternatives, will target 130,000 MWh of DSM in the 2021-2023 plan.

Maintain safe, reliable, cost effective generation at Petersburg

IPL conducted a holistic evaluation of the economics of each coal unit in our fleet. While several systematic changes in wholesale power markets are impacting the viability of coal in MISO, Petersburg Units 3 and 4 provide firm, dispatchable capacity. Maintaining those units preserves optionality in the face of great uncertainty over the next five years. Examples of this uncertainty preceding the next IRP include a federal election, the Indiana 21st Century Energy Task Force publishing its recommendations to Indiana lawmakers, and IPL being on the path to execute plans for replacement capacity as part of the RFP process.



CONCLUSION

As part of the 2019 IRP, IPL is focused on

- Customer Centricity
- Least Cost
- Flexibility & Balance
- Greener Energy Future

As a result, IPL hired a 3rd party to manage an all-source RFP. For more information, visit IPLpower.com/RFP

2019 Integrated Resource Plan (IRP)
Non Technical Summary

IPL 2019 IRP: PUBLIC ADVISORY MEETING #1

January 29, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

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MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

Topic	Time (EST)	Presenter
Welcome & Opening Remarks	9:30 - 9:40	Lisa Krueger, President, AES US SBU
Meeting Agenda & Guidelines	9:40 - 9:50	Stewart Ramsay, Meeting Facilitator
2016 IRP Review	9:50 - 10:10	Patrick Maguire, Director of Resource Planning
2019 IRP: Timeline, Mission, Objectives	10:10 - 10:30	
BREAK	10:30 - 10:45	
Capacity Discussion: ICAP, UCAP, Capacity Factor, Economic Min/Max	10:45 - 11:30	Patrick Maguire, Director of Resource Planning
2019 IRP Starting Point: IPL Load and Resources	11:30 - 12:00	
LUNCH	12:00 - 12:45	
Ascend Analytics PowerSimm Model	12:45 - 1:30	David Millar, Ascend Analytics
Modeling Replacement Resources	1:30 - 2:15	Patrick Maguire, Director of Resource Planning
BREAK	2:15 - 2:30	
DSM/EE Modeling and Load Forecast Update	2:30 - 3:00	Erik Miller, Senior Research Analyst
Concluding Remarks & Next Steps	3:00 - 3:15	Patrick Maguire, Director of Resource Planning

2016 IRP RECAP

Patrick Maguire

Director of Resource Planning

2016 IRP SUMMARY

Meeting 1 (April)	Meeting 2 (June)	Meeting 3 (August)	Meeting 4 (September)
• Supply Side and Distributed Resources • Demand Side Resources • DSM Modeling • Risk Discussion • Scenario Workshop	• Metrics Exercise • Resource Adequacy • IPL T&D • Load Forecast • Environmental Risks • Portfolio Exercise	• IRP Modeling Update • Sensitivity Analysis and Stochastic Setup	• Final Model Results • Metrics & Sensitivity Analysis Results • Analysis Observations • Short Term Action Plan

Report Filed on November 1, 2016

All presentations, materials, and reports can be found on IPL's website.

Joint Utilities Integrated Resource Plan (IRP): Stakeholder Education Session

Indiana IOUs jointly presented an educational session to discuss the IRP process. All materials can be found here.

2016 IRP: COMMENTS AND IMPROVEMENTS TARGETED

Topic	Comments Summary (not exhaustive)	2019 IRP Improvements
Commodity Forecasts	• Not enough narrative and underlying fundamental support data to support commodity price forecasts • Base forecast inconsistent with changing market fundamentals and trends • Changing resource mix and other fundamentals could materially change	• Scenarios will be built around varying commodity assumptions, with all supporting data clearly outlined • Narrative and thorough set of supporting data will be provided well in advance of Nov. 1st filing date • Data will be made available with signed NDA and public whenever possible
Scenarios and Portfolios	• Unclear modeling framework with regards to scenarios, portfolios, and stochastics • All portfolios weighed against base case assumptions • Preferred plan not optimized in capacity expansion	• March 13th Meeting will outline comprehensive scenario modeling framework to address concerns in 2016 IRP • Modeling types will be clearly identified and discussed (i.e. portfolios vs scenarios, optimized vs fixed portfolios, capacity expansion vs production cost model)

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2016 IRP: COMMENTS AND IMPROVEMENTS TARGETED (CONT'D)

Topic	Comments Summary (not exhaustive)	2019 IRP Improvements
Metrics	• Stochastic results not fully integrated with metrics scorecard and used in a limited manner • No specific metrics related to portfolio diversity • Environmental metrics should also include land and water impacts	• IPL's move to Ascend Analytics' PowerSimm will enable IPL to more fully incorporate stochastic results into the metrics process • Metrics and risk analysis will be conducted using the same set of underlying data from PowerSimm • IPL will consider additional environmental metrics
DSM/EE Modeling	• Inconsistent avoided cost values • Only two DSM/EE decision points considered • Assumptions on future DSM costs need to be reviewed	• New model will allow for more DSM bundles and decision points • IPL considering alternative approaches to accounting for changes in future DSM costs • Avoided costs will be consistent and presented clearly in meetings and/or provided data files

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INTRODUCTION TO THE 2019 IRP

Patrick Maguire

Director of Resource Planning

IPL 2019 IRP

INTEGRATED RESOURCE PLAN (IRP):

IPL's plan to provide safe, reliable, and sustainable energy solutions for the communities we serve

- IRP submitted every three years
- Plan created with stakeholder input
- 20-year look at how IPL will serve load
- Modeling and analysis culminates in a preferred resource portfolio

What is a preferred resource portfolio?

" 'Preferred resource portfolio' means the utility's selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration."

IURC RM #15-06, LSA Document #18-127

Link (PDF): https://www.in.gov/iurc/files/RM_ord_20181024141710007.pdf

2019 IRP STAKEHOLDER PROCESS

Dates to follow for meetings #3-5

January 29th	March 13th	May	August	October
•2016 IRP Recap •2019 IRP Timeline, Objectives, Stakeholder Process •Capacity Discussion •IPL Existing Resources and Preliminary Load Forecast •Introduction to Ascend Analytics •Supply-Side Resource Types •DSM/Load Forecast Schedule	•Stakeholder Presentations •Commodity Assumptions •Capital Cost Assumptions •IPL-Proposed Scenario Framework •Scenario Workshop •MPS Update and Plan	•Stakeholder Presentations •Summary of Stakeholder Feedback •Present Final Scenarios •Modeling Update •Assumptions Review and Updates	•Stakeholder Presentations •Summary of Stakeholder Feedback •Preliminary Model Results •Scenario Descriptions and Results •Preliminary Look at Risk Analysis and Stochastics	•Stakeholder Presentations •Final Model Results •Scenario Updates •Updates on Stakeholder Scenarios •Preferred Plan

IPL is committed to conducting a robust and collaborative stakeholder process. Multiple communication avenues will be provided to ensure that all stakeholders have the opportunity to be a part of the 2019 IRP process.

IRP PROCESS OVERVIEW

Load Forecast → Resource Options → Identify Risks/Drivers → Create Scenarios → Model Portfolios → Evaluate + Measure → Identify Preferred Plan

Final Report filed on November 1, 2019

2019 IRP PARTNERS AND RESOURCES

Key Partners

Ascend Analytics — Better models. Better decisions.

Itron

GDS Associates, Inc. — Engineers & Consultants

Concentric Energy Advisors

Vanry Associates

Resources

IHS Markit

Wood Mackenzie — Power & Renewables

ABB

S&P Global Market Intelligence — Energy

NREL — National Renewable Energy Laboratory

Bloomberg New Energy Finance

eia — U.S. Energy Information Administration

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BREAK

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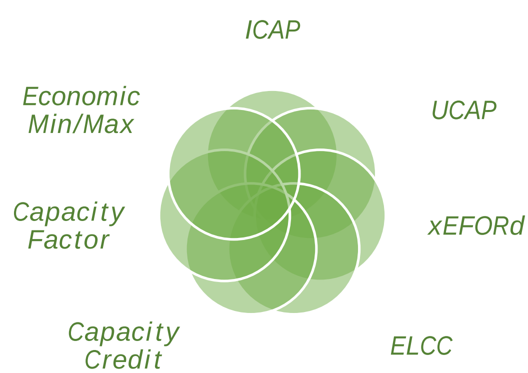
CAPACITY: DEFINING COMMON IRP MODELING TERMS

Patrick Maguire

Director of Resource Planning

CAPACITY DEFINITIONS

Goal: Define capacity terms in IRP modeling to provide transparency and clarity in presentations, analysis, and reporting



ICAP

ICAP = INSTALLED CAPACITY

Installed Capacity, or ICAP, refers to the generating capacity after ambient weather adjustments and before forced outage adjustments

Examples:

- "The county will be the home of a new 100 MW wind farm…"
- "Deal signed for 200 MW solar farm…"
- "1,000 MW of natural gas-fired capacity…"

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XEFORD

xEFORd = Equivalent Demand Forced Outage Rate excluding some outages

Per MISO BPM-011, Section 3.5.4*:

Equivalent demand Forced Outage Rate (EFORd): A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

XEFORd: Same meaning as EFORd, but calculated by excluding causes of outages that are Outside Management Control (OMC). For example, losses of transmission outlet lines are considered as OMC relative to a unit's operation.

* BPM-011 - Resource Adequacy can be found at https://www.misoenergy.org/planning/resource-adequacy

Planning Year 2018-2019 Pooled EFORd Class	Pooled EFORd (%)	Data Source
Combined Cycle	5.37	MISO
Combustion Turbine (50+ MW)	5.18	MISO
Diesel Engines	10.26	MISO
Steam - Coal (200-400 MW)	9.82	MISO
Steam - Coal (400-600 MW)	9.28	MISO*
Steam - Coal (600-800 MW)	8.22	MISO
Steam - Coal (800-1000 MW)	9.28	MISO*
Steam - Gas	11.56	MISO

For new units with less than 12 months of operational data, a pooled class-average xEFORd% is provided by MISO.

Link: MISO PY 19/20 Resource Adequacy Documents

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ELCC

ELCC = Effective Load Carrying Capability = Capacity Credit

Per MISO Wind & Solar Capacity Credit Report, Section 2.1*:

> *Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while also considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served.*

Translation: what percent of a wind resource's total capacity (ICAP) is actually being produced at the time of the summer peak load?

* MISO Wind & Solar Capacity Credit Report, December 2018 (PDF):
https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf

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UCAP

UCAP = UNFORCED CAPACITY = FIRM CAPACITY = PLANNING CAPACITY

Unforced capacity, or UCAP, is a unit's generating capacity adjusted down for forced outage rates (thermal resources) or expected output during the peak load (intermittent resources).

THERMAL RESOURCE EXAMPLE

ICAP = 100 MW
xEFORd = 10%
*UCAP = ICAP * (1 – xEFORd)*
UCAP = 100 * (1- .1) = 90 MW

For Solar:
Capacity Credit = ELCC%
until MISO conducts a formal ELCC study

WIND AND SOLAR EXAMPLES

Wind
ICAP = 100 MW
ELCC % = 7%
*UCAP = ICAP * ELCC*
UCAP = 100 * .07 = 7 MW

Solar
ICAP = 100 MW
Capacity Credit = 50%
*UCAP = ICAP * Capacity Credit*
UCAP = 100 * .5 = 50 MW

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ICAP VS UCAP: EXAMPLES

ICAP = Installed Capacity UCAP = Unforced Capacity

		ICAP MW	UCAP MW
Thermal Unit (e.g. Coal, Gas)	10% xEFORd	100	90
Wind	7.8% Zone 6 ELCC	100	7.8
Solar	50% credit	100	50
4-Hour Storage *100 MW, 400 MWh*	5% xEFORd	100	95
1-Hour Storage *100 MW, 100 MWh*	5% xEFORd	100	23.8

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ICAP VS UCAP: EXAMPLES

ICAP = Installed Capacity UCAP = Unforced Capacity

To Cover a 1,000 MW UCAP Shortfall:

	ICAP MW	UCAP MW	ICAP MW Required
Thermal	100	90	1,111
Wind	100	7.8	12,821
Solar	100	50	2,000
4-Hour Storage	100	95	1,053
1-Hour Storage	100	23.8	4,202

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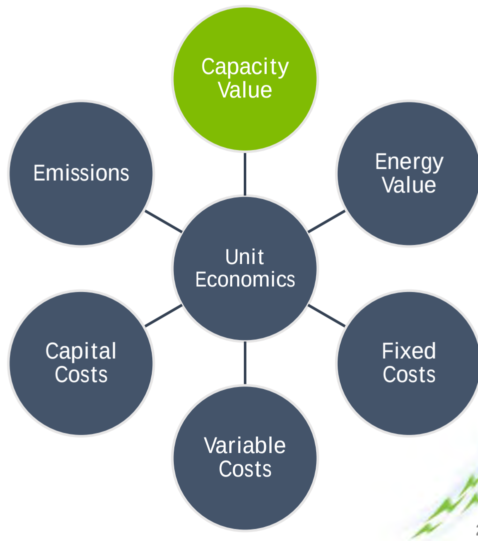
CAPACITY: ONLY ONE PIECE OF RESOURCE VALUATION PUZZLE

Important to note that the UCAP contribution of a resource type is only one part of the valuation process.



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ECONOMIC DISPATCH CAPACITY

Economic Minimum

Minimum amount of MW available for economic dispatch in the market

Economic Maximum

Maximum amount of MW available for economic dispatch in the market

Economic Min/Max: for thermal units, the MW limits used for dispatch modeling in the IRP

- Can be different than ICAP and UCAP
- Closely aligned with IPL Commercial Group that offers the units in MISO
- Can change daily due to ambient weather conditions, operational constraints at the plant, and other factors

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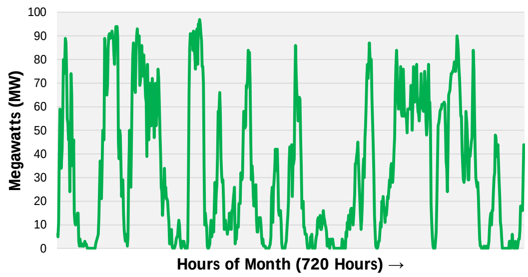
CAPACITY FACTOR: INPUT OR OUTPUT?

Definition via EIA:
The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

- **Wind and Solar**: Input to the model via monthly energy targets and profiles
- **Thermal units**: Output from the model via hourly economic dispatch

Example: 100 MW Wind Farm
November Hourly Profile



Wind Farm Capacity (ICAP) = 100 MW

Monthly Total Energy = 23,500 MWh

Maximum Energy = 720 hours x 100 MW = 72,000 MWh

Capacity Factor = Actual MWh / Max Potential MWh

Monthly Capacity Factor = 23,500 / 72,000 = 32.6%

2019 IRP STARTING POINT: IPL LOAD AND RESOURCES

Patrick Maguire
Director of Resource Planning

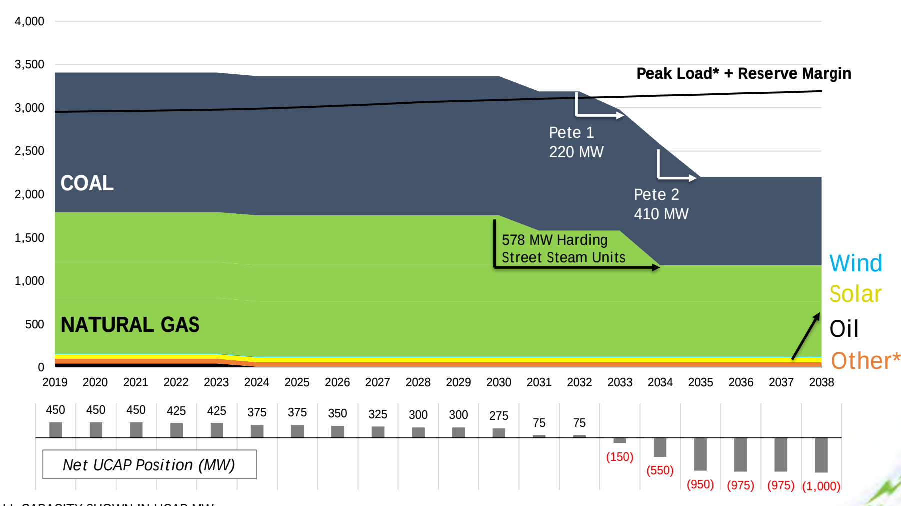
IPL'S CHANGING RESOURCE MIX

2009 - 2018

2009	2011	2013-2015	2016	2016	2018
Signed 100 MW PPA at Hoosier Wind Park in NW Indiana	Signed 200 MW PPA at Lakefield Wind Farm in Minnesota	Signed 96 MW PPA for solar in Indianapolis through Rate REP	Retired 260 MW of coal at Eagle Valley	Finalized conversion of 630 MW of coal-fired generation at Harding Street to natural gas	Eagle Valley 671 MW Gas-Fired Combined Cycle Plant Completed

IRP STARTING POINT

IPL NET LONG CAPACITY THROUGH 2032 WITH AGE-BASED RETIREMENT SCHEDULES



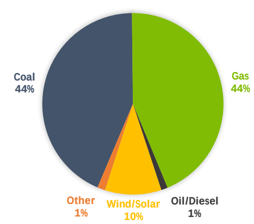
ALL CAPACITY SHOWN IN UCAP MW
* Other: ACLM (37 MW), CVR (17 MW), Rider 17 (1 MW)

** Preliminary peak load forecast*

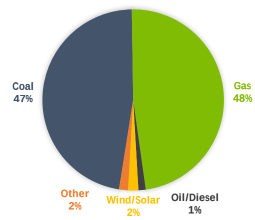
IPL RESOURCES: SUMMARY

	ICAP	UCAP
Coal	1,706	1,608
Gas	1,725	1,634
Oil/Diesel	47	44
Wind/Solar	396	62
Other	54	54
Total	3,929	3,402

% of ICAP



% of UCAP



ICAP = Installed Capacity **UCAP = Unforced Capacity**

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IPL RESOURCES: NATURAL GAS

Unit	Name	Type	ICAP MW	UCAP MW	Avg HR @ Max (MMBtu/MWh)	In-Service Year	Estimated Last Year In-Service
Eagle Valley							
EV CCGT	Eagle Valley	CCGT	671	640	6.7	2018	2068
Harding Street							
HS 5G	Harding Street 5	Gas ST	95	90	10.5	1958	2030
HS 6G	Harding Street 6	Gas ST	95	90	10.5	1961	2030
HS 7G	Harding Street 7	Gas ST	422	400	9.7	1973	2033
HS GT4	Harding Street GT4	Gas CT	71	67	12.4	1994	2044
HS GT5	Harding Street GT5	Gas CT	72	68	12.4	1995	2045
HS GT6	Harding Street GT6	Gas CT	145	134	10.0	2002	2052
Georgetown							
GTOWN GT1	Georgetown 1	Gas CT	76	71	12.4	2000	2050
GTOWN GT4	Georgetown 4	Gas CT	78	75	12.4	2001	2052

Unit Type	UCAP
Combined Cycle (CCGT)	640 MW
Steam Turbine (ST)	578 MW
Combustion Turbine (CT)	415 MW

Total Natural Gas UCAP:
1,634 MW

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IPL RESOURCES: WIND AND SOLAR

Name	Type	ICAP MW	UCAP MW	PPA Start	PPA Expiration
Hoosier Wind Park (IN)	PPA	100	7.8	Nov-09	Nov-29
Lakefield Wind (MN)	PPA	200	0	Oct-11	Oct-31
Solar (Rate REP)	PPA	96	54	*varies*	*varies*

- **Wind PPA Modeling Assumption:** assuming that projects continue to be in the IPL Portfolio past PPA term
- **Lakefield Wind:** no firm transmission
- **IPL Solar Capacity Credit:** credit if greater than 50% because it is netted against peak load forecast rather than registered as a separate resource in MISO

Total Renewable ICAP: 396 MW

Total Renewable UCAP: 62 MW

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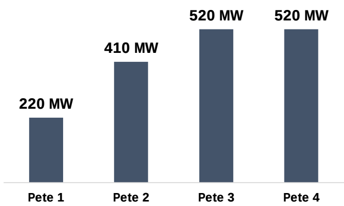
IPL RESOURCES: COAL

Unit	Name	Type	ICAP MW	UCAP MW	Avg HR @ Max (MMBtu/MWh)	In-Service Year	Estimated Last Year In-Service
Petersburg							
PETE ST1	Pete 1	Coal	220	210	10.36	1967	2032
PETE ST2	Pete 2	Coal	417	376	10.36	1969	2034
PETE ST3	Pete 3	Coal	532	497	10.43	1977	2042
PETE ST4	Pete 4	Coal	537	524	10.55	1986	2042

Total Coal ICAP: 1,706 MW

Total Coal UCAP: 1,608 MW



Framework for scenario analysis will be presented at the March 13th meeting

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INTRODUCTION TO ASCEND ANALYTICS

Patrick Maguire

Director of Resource Planning

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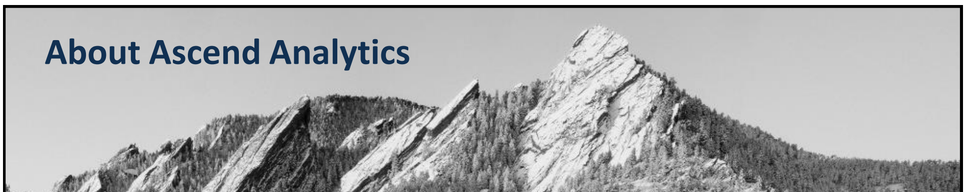
AGENDA

- Introduction to Ascend
- PowerSimm Product Suite
- What makes Ascend and PowerSimm different?
- Deterministic vs Stochastic
- Q&A

About Ascend Analytics



- Founded in 2002 with over 50 employees in Boulder, Oakland, and Bozeman
- Seven integrated software products for operations, portfolio analytics, and planning
- Custom analytical solutions and consulting

Proven and Broadly Adopted

AEP American Electric Power; Austin Energy; LA DWP Los Angeles Department of Water & Power; Duke Energy; PNM; NorthWestern Energy; Hawaiian Electric Company; New York Power Authority

Differentiated Value

PowerSimm OPS
OPERATIONAL STRATEGY

1 to 10 days

- Forecast short-term loads and market prices with uncertainty
- Determine operating strategies from position and financial exposure
- Track realized customer revenue and costs to settled day ahead and real time price
- Optimize financial exposure between day ahead and real time prices

PowerSimm Portfolio Manager
PORTFOLIO MANAGEMENT

1 month to ≈ 5 years

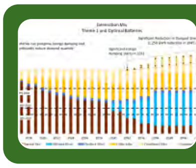
- Budgeted cash flows equal realized cash flows
- Management of retail load risk with volumetric and market price uncertainty
- Impact of hedges on reducing cash flow uncertainty
- Retail management & pricing
- Portfolio management with analytics insight to manage risk (CFaR, GMaR, EaR)
- Track portfolio performance of retail contracts and hedges with settled prices

PowerSimm Planner
LONG-TERM PLANNING

5 to 30 years

- Resource Planning
- Optimal expansion planning
- Renewable integration
- Reliability Analysis
- Renewable Integration
- Cost versus risk tradeoff resource analysis
- Battery storage optimization
- Financial Analysis

Ascend Analytics expertise in long-term planning



Integrated Resource planning
- Resource selection
- Reliability analysis
- Renewable integration
- Energy storage

Regulatory and stakeholder support
- Testimony and interrogatory
- Expert witness

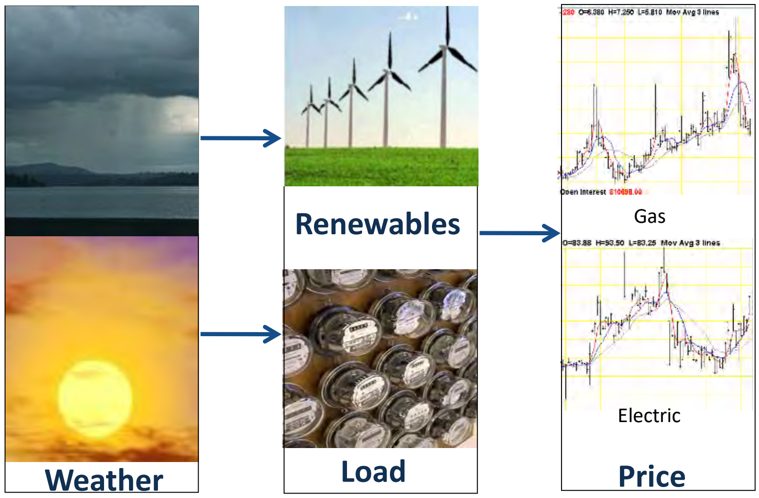
Fundamental and Market Analysis
- Changing market dynamics
- Long-term forward curves
- Day-ahead and real-time

PowerSimm Suite: Short-, Intermediate, Long-term

A full, end-to-end solution

PowerSimm OPS OPERATIONAL STRATEGY	PowerSimm Portfolio Manager PORTFOLIO MANAGEMENT	PowerSimm Planner LONG-TERM PLANNING
1 to 10 days	1 month to ≈ 5 years	5 to 30 years
• Forecast short-term loads and market prices • Optimize financial exposure between DA and RT prices • Provide continuous bid optimization • Track realized customer revenue and costs to settled DA and RT price	• Budgeted cash flows equal realized cash flows • Management of retail load risk with volumetric and market price uncertainty • Impact of hedges on reducing cash flow uncertainty • Retail management & pricing • Portfolio management with analytics insight to manage risk (CFaR, GMaR, EaR) • Track portfolio performance of retail contracts and hedges with settled prices	• Resource planning • Optimal expansion planning • Renewable integration • Reliability analysis • Renewable integration • Cost vs. risk tradeoff resource analysis • Battery storage optimization • Financial analysis

Weather → Renewables/Load → Price Simulations



Weather – Load – Delivery – Price Paradigm

Weather

- Weather is the underlying covariate input
- Key benefit is the most appropriate range of future states will be simulated based on historical observations.

Load

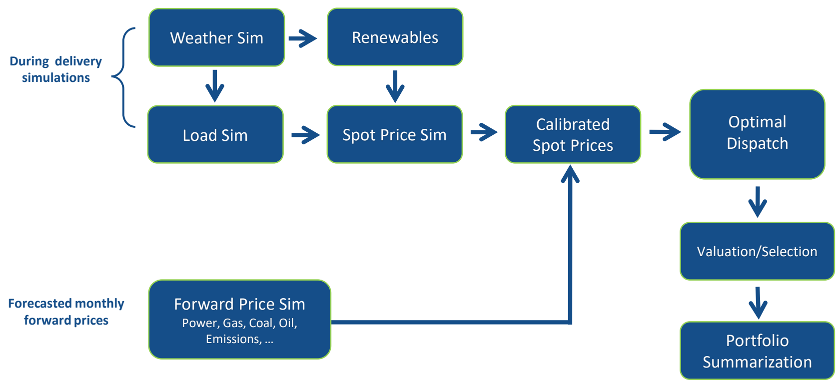
- Load is driven primarily by weather
- Key benefit is analysis of high and low temperatures produce more accurate energy expectations, and hourly demand

Delivery

- Electricity price is predominantly driven by load
- Key benefit of utilizing multiple variables is they better reflect the factors of economic risks (fuel price, transmission, regulations, etc.).

PowerSimm Modeling Framework

Unified simulation framework reflecting joint financial and physical uncertainty
- Rigorous validation
- Capture of critical causal effects



PowerSimm Modeling Framework

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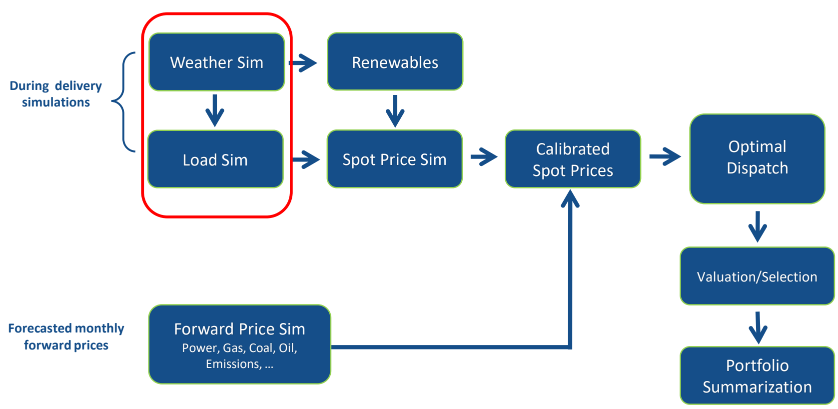
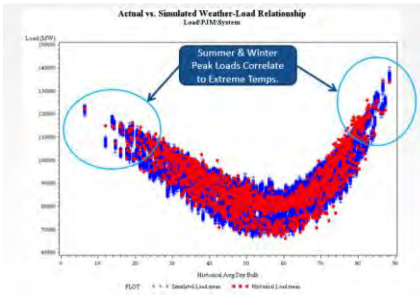
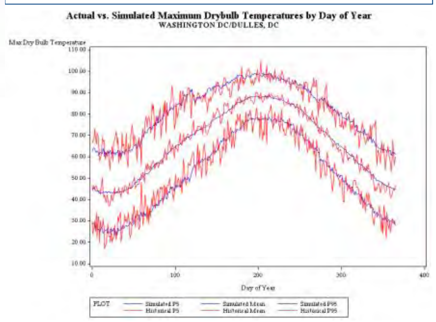


Preserving Relationship and Dependency



Maintaining Relationships
- Incorporating weather into the load model maintains integrity in the weather – load relationship
- Simulations nicely smooth out "bumps" of historical weather record
- Simulations provide for new extreme values to exceed historic record



Validating Relationship
- Validate by capturing the weather – load relationship in the historical period and simulated back-cast
- The structural state space modeling captures the changes in shape with changes in load

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PowerSimm Modeling Framework

Unified simulation framework reflecting joint financial and physical uncertainty
- Rigorous validation
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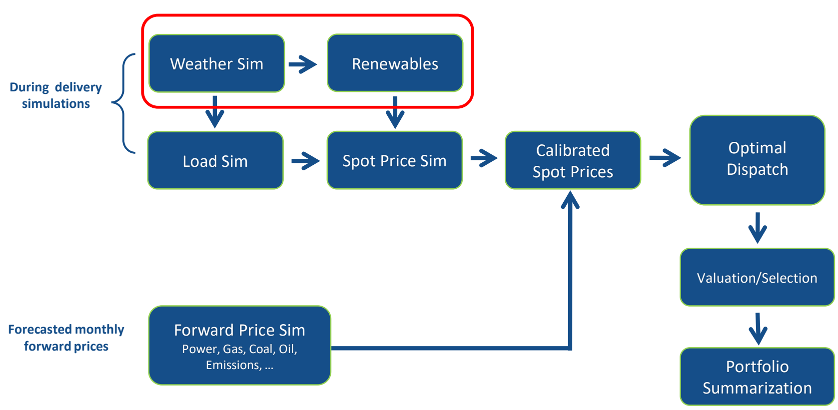

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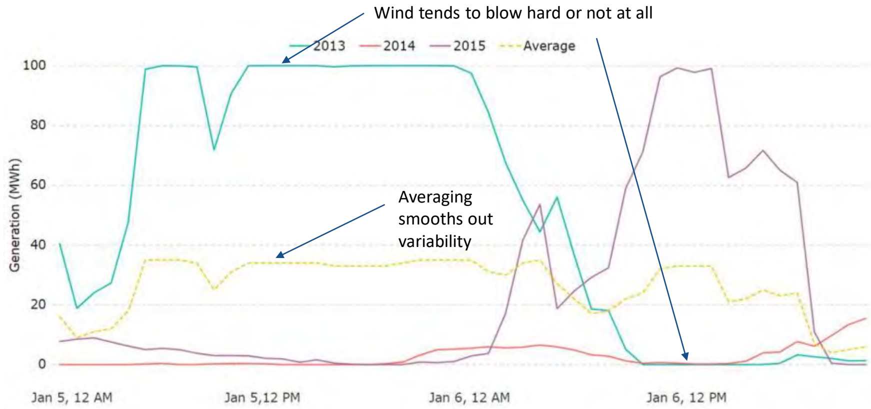
Why You Can't Just Average Renewables: Wind in January



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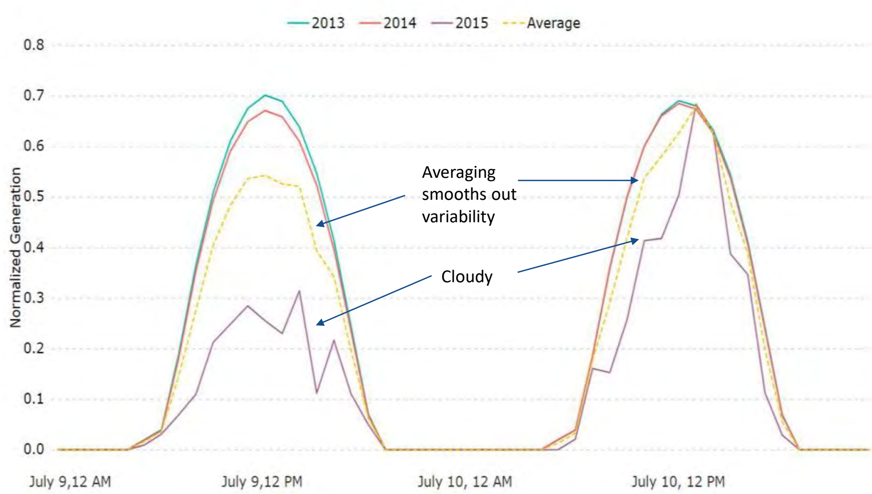
Why You Can't Just Average Renewables: Solar in July



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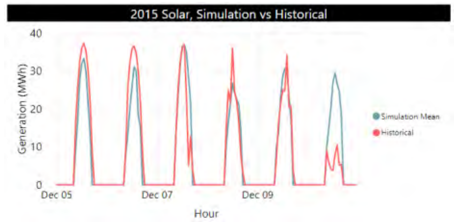
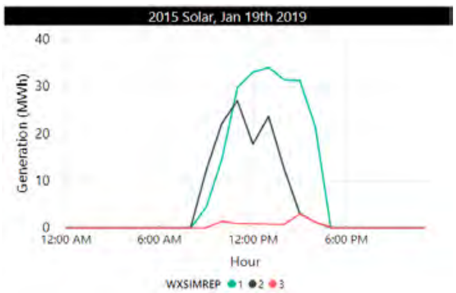
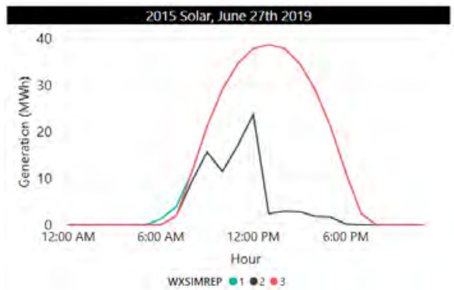
Renewables - Solar

Simulated vs Historical :

- Accurately capturing solar's behavior in summer and winter months by modeling expected peaks in conjugation with nameplate capacities
- Capturing volatility in generation with periods of no generation in winter months and lower maximum generation in winters compared to higher generation in summers



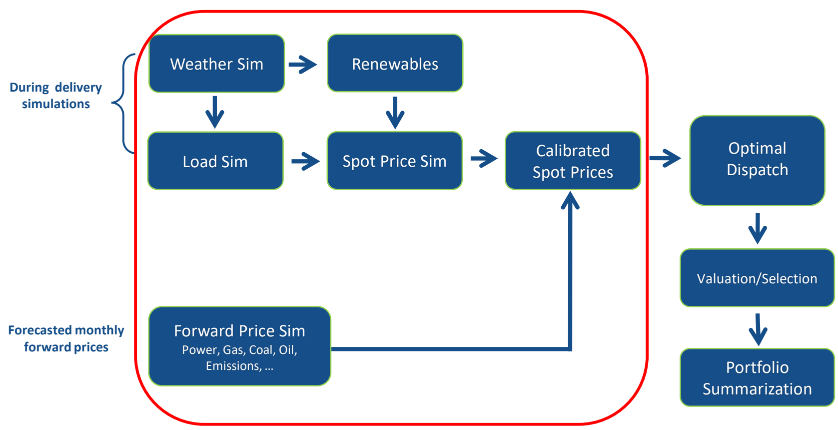




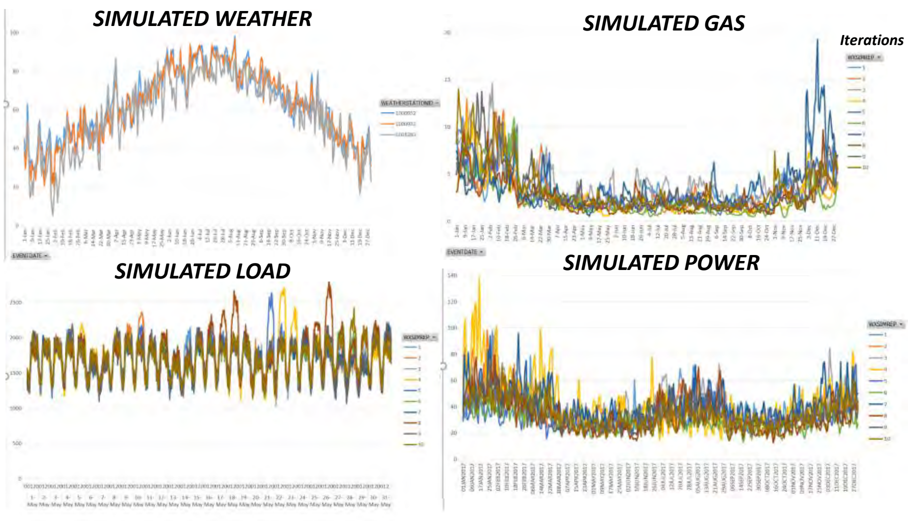
PowerSimm Modeling Framework

Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Capture of critical causal effects



Example: Simulated Temperature, Load, Gas and Power Prices



PowerSimm Modeling Framework

Unified simulation framework reflecting joint financial and physical uncertainty
- Rigorous validation
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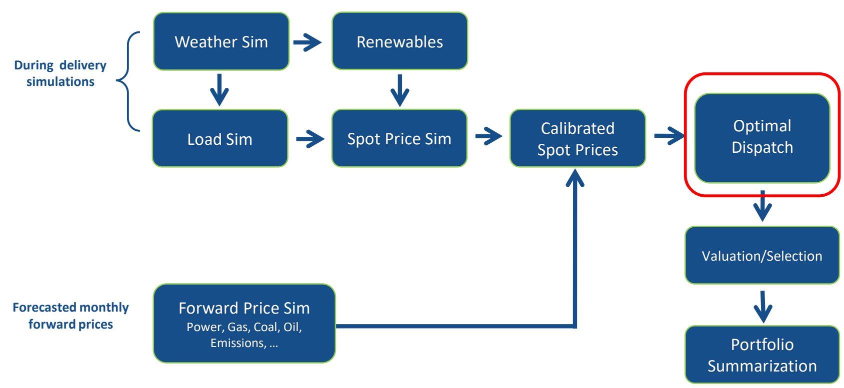
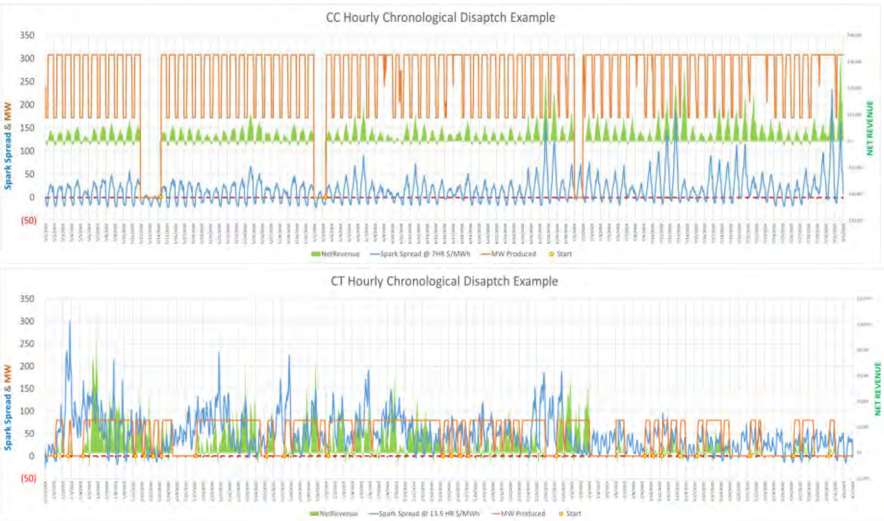
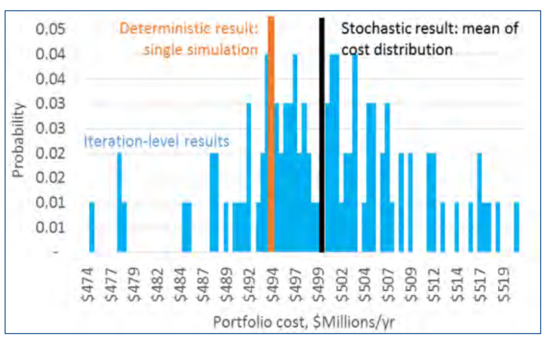


Thermal Asset Modeling



Need for New Tools to Incorporate Uncertainty: Deterministic vs. Stochastic Models

- Deterministic models can bias results with their limited pathways into the future.
  - Deterministic modeling misses critical scenarios, producing inconsistent values.
  - The likelihood of deterministic results actually occurring are not understood.
  - Simulated weather captures actual operations of renewables and load, relative to normalized weather utilized in deterministic models
- What's the impact of unused information
  - Inaccurate forecasting
  - Assessing risk becomes difficult



Planning for future resources, PowerSimm finds the "Best Triathlete"

PowerSimm finds the best plan across hundreds of possible future conditions

The triathlete is not the best, swimmer, biker, or runner, but the best when combining all three. Likewise, we want to pick a resource plan that performs well in any future condition. This is critical in a highly uncertain future.

Dave Scott

Best Triathlete

Katie Ledecky **Ryan Hall** **Megan Guanier**

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REPLACEMENT RESOURCES IN THE 2019 IRP

Patrick Maguire

Director of Resource Planning

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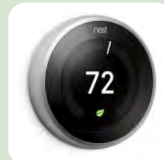
REPLACEMENT RESOURCES MODELED







NATURAL GAS
- CCGT
- CT
- Reciprocating Engine/ICE

WIND
- Land-Based Wind

SOLAR
- Utility-Scale
- C&I
- Residential

STORAGE
- Standalone Front-of-meter

DSM/EE
- Measures bundled into tranches by cost and shape

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NATURAL GAS

- Combined Cycle (CCGT)
  - F-Class
  - H-Class
- CT
- Reciprocating Engine/ICE
  - Quick start generator sets
  - Higher capital cost
  - More flexible ramp offerings (e.g. off to full load in ~10 minutes)

NATURAL GAS
Mature technologies with more certainty around operational parameters and capital costs

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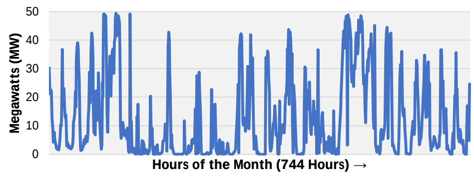
WIND

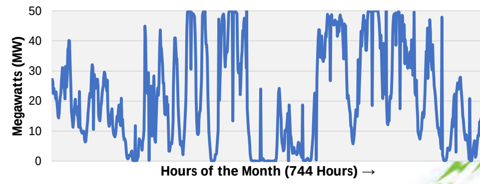
Building Profiles and Capacity Factors

- Wind profiles sourced from a combination of internal data sources (IPL contracted wind projects) and external resources
- NREL Wind Toolkit* provides access to simulated wind profiles at different locations
- Simulated profiles from NREL scaled to IPL's generic wind project size in the PowerSimm model
- Historical hourly simulated production entered in PowerSimm along with monthly forecasted energy

Hypothetical 50 MW Wind Farm in Indiana
JULY Hourly Profile



Hypothetical 50 MW Wind Farm in Indiana
JANUARY Hourly Profile



* NREL Wind Toolkit: https://www.nrel.gov/grid/wind-toolkit.html

WIND (CONT'D)

Wind Capacity Credit

Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

2019										
Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	18,210	5,080	734	9,488	763	282	1,863	0	0	0
UCAP (MW)	2,855	891	114	1,438	92	22	298	0	0	0
ELCC %	15.7%	17.5%	15.6%	15.2%	12.1%	7.8%	16.0%	0.0%	0.0%	0.0%
Wind CPNode Count	215	74	11	91	9	4	26	0	0	0

Figure 1-1: MISO Local Resource Zones (LRZs) and Distribution of Wind Capacity

Capacity credit for new Indiana wind will be modeled at 7.8% and held constant through study period

Sourced from MISO's December 2018 Wind & Solar Capacity Credit Report*

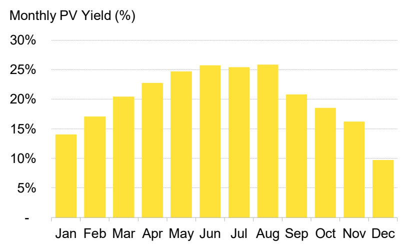
* MISO Wind & Solar Capacity Credit Report, December 2018 (PDF): https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf

SOLAR

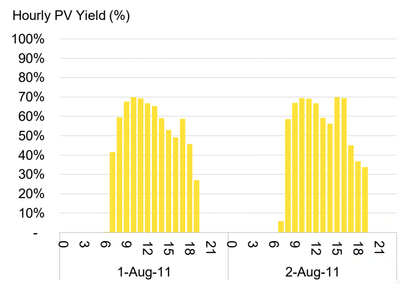
Building Profiles and Capacity Factors

- IPL's 96 MW of solar provides a robust source of hourly profile data
- Profiles also sourced from Bloomberg New Energy Finance (BNEF) Solar Capacity Factor Tool (SCFT 1.0.5)

*Hypothetical Single-**Axis Tracking Solar Project in IPL's Service Territory***



Source: BloombergNEF & PVGIS.



Source: BloombergNEF & PVGIS.

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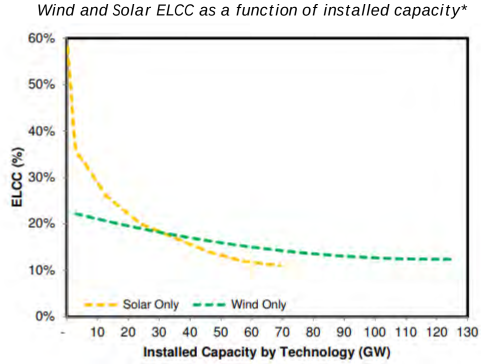
SOLAR (CONT'D)

Solar Capacity Credit

- Currently new solar projects in MISO receive 50% capacity credit
- Capacity credit expected to decline as more solar added to the system due to shift in net peak load
- IPL will align supply fundamentals from commodity forecast with information from MISO to calculate annual solar ELCC %
- **Capacity credit will start at 50% and decline over time**
- Annual capacity percentages to be provided and discussed at the March 13th meeting

*Wind and Solar ELCC as a function of installed capacity**



* Source: MISO Renewable Integration Impact Assessment (RIIA) Assumptions Document, Version 6 https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v6301579.pdf

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STORAGE

- 4-Hour battery storage considered for modeling
- MISO requires a 4-hour test for capacity accreditation
- Modeled as energy arbitrage and capacity resources
  - No sub-hourly, DA/RT, or ancillary services modeled this IRP
  - Battery modeling still evolving along with ISO market rules

4-Hour Storage
Example: • 20 MW, 80 MWh battery • Can discharge 20 MW for 4 hours • UCAP = 20 MW * (1 - xEFORd%)

BREAK

DSM/EE AND LOAD FORECAST OVERVIEW

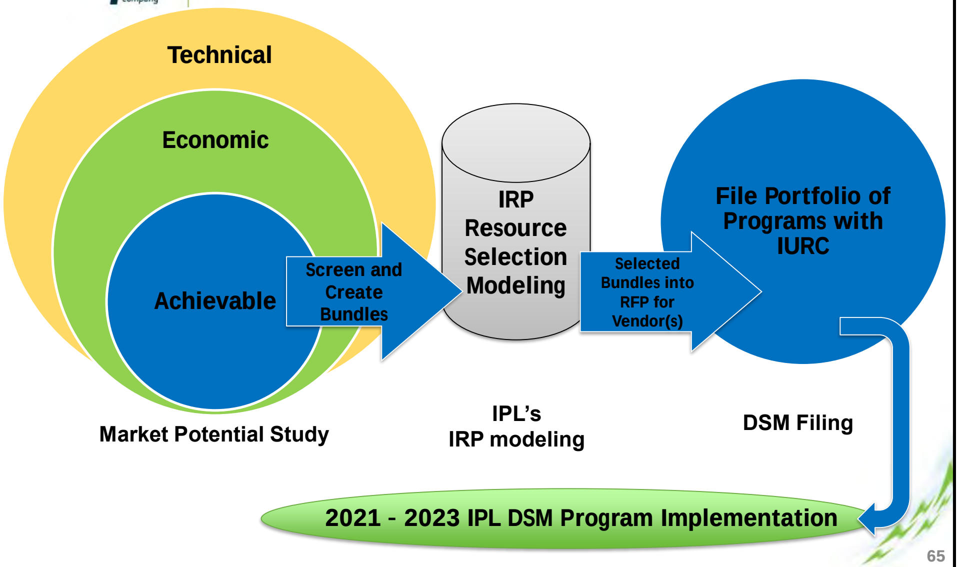
Erik Miller

Senior Research Analyst

DSM UPDATE

- Market Potential Study (MPS)
  - DSM & the IRP
  - DSM Bundles
  - MPS Overview
  - End-use Analysis

DSM PROCESS & THE IRP



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DSM BUNDLES

Example of Bundles from the IPL 2016 IRP:

Near-term DSM "blocks" developed for 2018 - 2020 (Base Case Selections)

	Levelized Utility Cost per MWh		
Sector and Technology	**(up to $30/MWh)**	**($30-60/MWh)**	**($60+ /MWh)**
EE Residential HVAC	Selected	Not Selected	Not Selected
EE Residential Lighting	Selected	N/A	N/A
EE Residential Other	Selected	Not Selected	Not Selected
EE C&I HVAC	Selected	Not Selected	Not Selected
EE C&I Lighting	Selected	Not Selected	Not Selected
EE C&I Other	Selected	Not Selected	Not Selected
EE C&I Process	Not Selected	Not Selected	N/A
EE Residential Behavioral	Not Selected		
DR Water Heating DLC	Not Selected		
DR Smart Thermostats	Not Selected		
DR Emerging Tech	Not Selected		
DR Curtail Agreements	Not Selected		
DR Battery Storage	Not Selected		
DR Air Conditioning Load Mgmt	Not Selected		

*N/A indicates that a bundle was not needed; all measures fell within lower cost bundles.

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MARKET POTENTIAL STUDY OVERVIEW

- IPL working with GDS Associates to complete the Market Potential Study
- MPS will cover IRP years: 2020 – 2039
- Per the Settlement Agreement in IPL's 2018 – 2020 DSM Order (44945) – MPS will also include a market refresh for 2020
  - Results of the refresh will be considered for adoption in 2020; not be modeled as a resource in the IRP

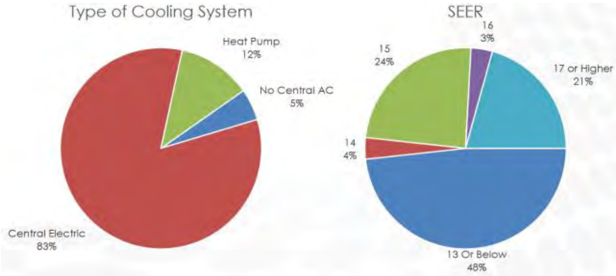
MARKET POTENTIAL STUDY PROCESS

- Step 1: End Use Analysis & Market Characterization by sector; Current snapshot of IPL's Market
- Step 2: Load Forecast - Baseline projection of energy consumption absent future programs by sector and by end use; estimate saturations and efficiencies of technologies
- Step 3: Define energy efficiency and demand response measures to consider
- Step 4: Define Technical & Economic Potentials
- Step 5: Develop and apply adoption rates; Determine Achievable Potential
- Step 6: Develop inputs for the IRP model

END USE ANALYSIS OVERVIEW

- The End Use Analysis establishes the market baseline which informs the load forecast used in the MPS
  - Characterizes the end uses within each sector
  - Establishes the saturation and efficiencies of the end uses
  - Provides a snapshot and starting point for the MPS
- Analysis is performed through surveys and site visits that were completed during the fall of 2018
- In previous MPS, IPL relied on regional EIA data for the end use characterization as opposed to surveys and site visits

End Use Example: Residential Cooling



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LOAD FORECASTING UPDATE

- Load Forecast
  - Methodology & Approach
  - Model Framework
- MPS & Load Forecast Schedule

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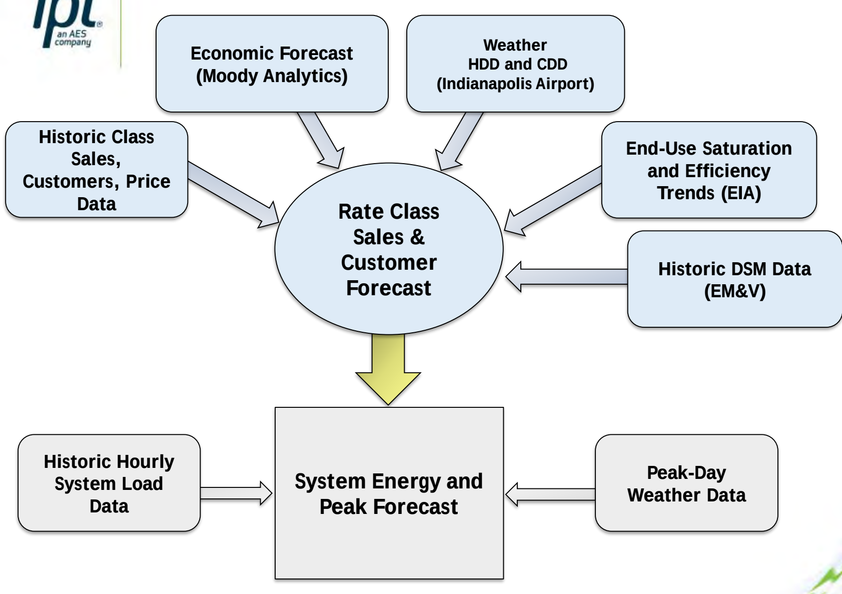
METHODS FOR LOAD FORECASTING

- Top-Down
  - Trend analysis
  - Time Series
- Bottom-Up
  - Survey-based
  - End-use
- **IPL Methodology: Hybrid**
  - Itron's Statistically-adjusted end-use (SAE) model

FORECAST MODELING FRAMEWORK



FORECAST MODELS

- Forecasts are based on monthly regression models using historical sales and customer data
- Sales Models
  - Residential and commercial models estimated using a blended end-use/econometric modeling framework
  - Industrial sales estimated with a generalized econometric model
  - Small rate classes such as process heating, security lighting, and street lighting are estimated using simple trend and seasonal models
- Demand Model
  - Monthly system peak model based on heating, cooling, and base-use energy requirements derived from the sales forecast models

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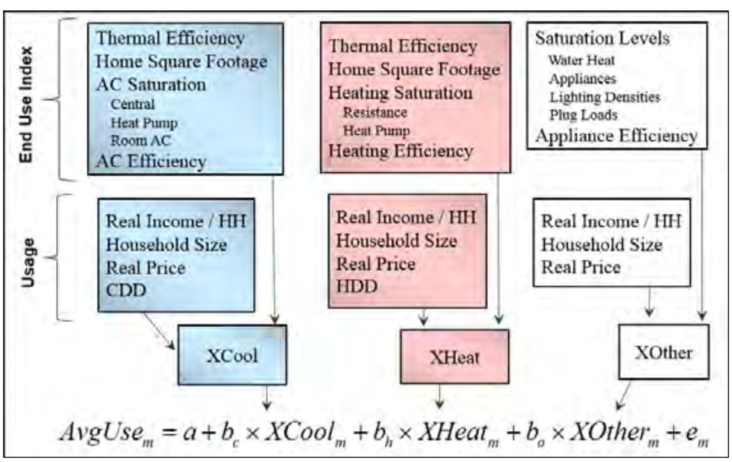
RESIDENTIAL MODEL FRAMEWORK



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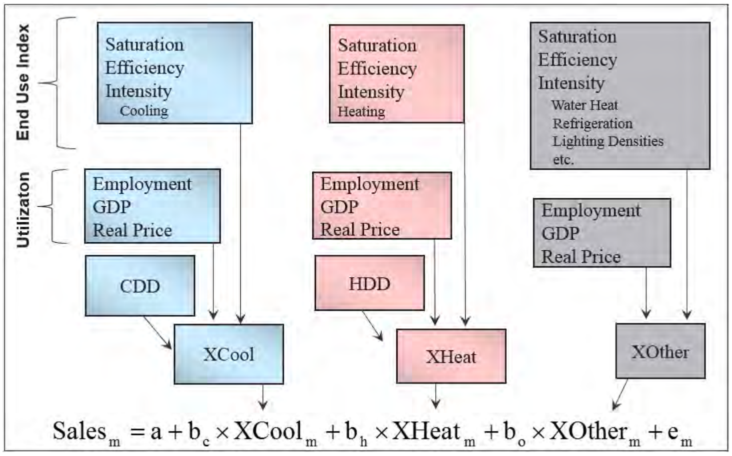
COMMERCIAL MODEL FRAMEWORK



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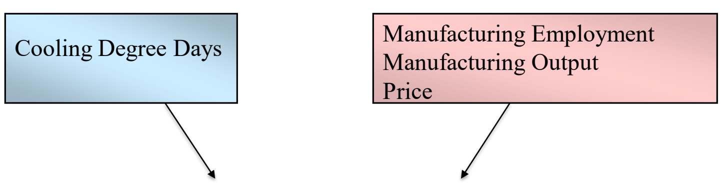
INDUSTRIAL MODEL FRAMEWORK

Industrial sales are estimated with a generalized econometric model



$$Sales_m = a + b_{cdd} \times CDD_m + b_{Econ} \times EconVariable_m + e_m$$

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DSM AND LOAD FORECAST SUMMARY

- DSM
  - o MPS Results will be presented at the March 13th meeting
    - ➢ Introduction to bundles
- Load Forecast
  - o Base forecast and high/low scenarios will be presented at the March 13th meeting

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FINAL Q&A AND NEXT STEPS

Patrick Maguire

Director of Resource Planning

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NEXT STEPS

- **Next Meeting: March 13, 2019**
  - IPL Electric Building
  - Register at http://iplpower.com/irp
- Meeting #2 Material:
  - Commodity Forecast Assumptions
  - Capital Cost Assumptions
  - Proposed Scenario and Modeling Framework
  - Detailed Load Forecast (Peak and Energy)
  - Market Potential Study Update

Email questions, comments, or other feedback to ipl.irp@aes.com

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IPL 2019 IRP: PUBLIC ADVISORY MEETING #2

March 26, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

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MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

Topic	Time (EST)	Presenter
Registration	9:00 – 9:30	-
Welcome & Opening Remarks	9:30 – 9:35	Lisa Krueger, President AES US SBU
Meeting Objectives & Agenda	9:35 – 9:45	Stewart Ramsay, Meeting Facilitator
Meeting 1 Recap	9:45 – 9:55	Patrick Maguire, Director of Resource Planning
Stakeholder Presentation: Sierra Club, Beyond Coal Campaign	9:55 – 10:10	Matt Skuya-Boss, Lead Organizer, Sierra Club
Detailed Load Forecast – Base, High & Low Peaks and Energy	10:10 – 11:00	Erik Miller, Senior Research Analyst
BREAK	11:00 – 11:15	
IPL DSM MPS and End Use Results	11:15 – 12:00	Jeffrey Huber, GDS Associates
LUNCH	12:00 – 12:45	
Commodity Prices and Modeling	12:45 – 1:15	Patrick Maguire, Director of Resource Planning
Assumptions for Replacement Resources	1:15 – 1:45	
BREAK	1:45 – 2:00	
Scenario Analysis Framework & Proposed Scenarios	2:00 – 2:30	Patrick Maguire, Director of Resource Planning
Final Q&A, Concluding Remarks & Next Steps	2:30 – 3:00	Stewart Ramsay, Meeting Facilitator

MEETING 1 RECAP

Patrick Maguire

Director of Resource Planning

2019 IRP STAKEHOLDER PROCESS

January 29th	March 26th	May	August	October
•2016 IRP Recap •2019 IRP Timeline, Objectives, Stakeholder Process •Capacity Discussion •IPL Existing Resources and Preliminary Load Forecast •Introduction to Ascend Analytics •Supply-Side Resource Types •DSM/Load Forecast Schedule	•Stakeholder Presentations •Commodity Assumptions •Capital Cost Assumptions •IPL-Proposed Scenario Framework •MPS Update and Plan	•Stakeholder Presentations •Summary of Stakeholder Feedback •Present Final Scenarios •Modeling Update •Assumptions Review and Updates	•Stakeholder Presentations •Summary of Stakeholder Feedback •Preliminary Model Results •Scenario Descriptions and Results •Preliminary Look at Risk Analysis and Stochastics	•Stakeholder Presentations •Final Model Results •Scenario Updates •Updates on Stakeholder Scenarios •Preferred Plan

STAKEHOLDER PRESENTATION: SIERRA CLUB, BEYOND COAL CAMPAIGN

Matt Skuya-Boss

Lead Organizer, Sierra Club

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DETAILED LOAD FORECAST - PEAKS & ENERGY

Erik Miller

Senior Research Analyst

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AGENDA

- Load Forecast Data Inputs
- Residential
- Small C&I
- Large C&I
- System Energy & Peaks

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MODEL INPUTS

- Historic Sales & Customers
- End Use: EIA Regional End Use Saturations and Efficiency Trends
- Economics: Moody's Q4 2018 Forecast
- IPL Price Forecast
- Weather: 20-Yr Trended
- Future utility DSM will be selected in IRP

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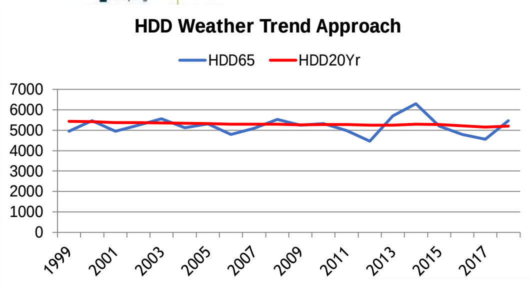
WEATHER 20-YR TRENDED



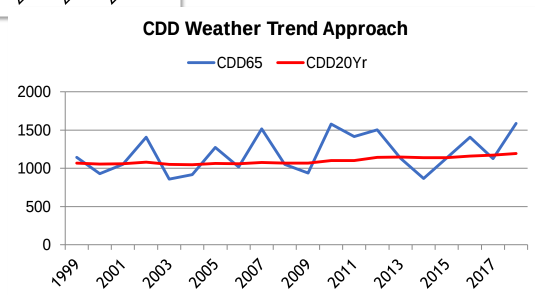
Trend line (red) developed for the 20-yr rolling average HDDs

-0.3% decline in 20-yr rolling average HDDs; Rate of decline applied to original forecast HDDs

Trend line (red) developed for the 20-yr rolling average CDDs

0.6% increase in 20-yr rolling average CDDs; Rate of growth applied to original forecast CDDs

HDD = Heating Degree Day
CDD = Cooling Degree Day



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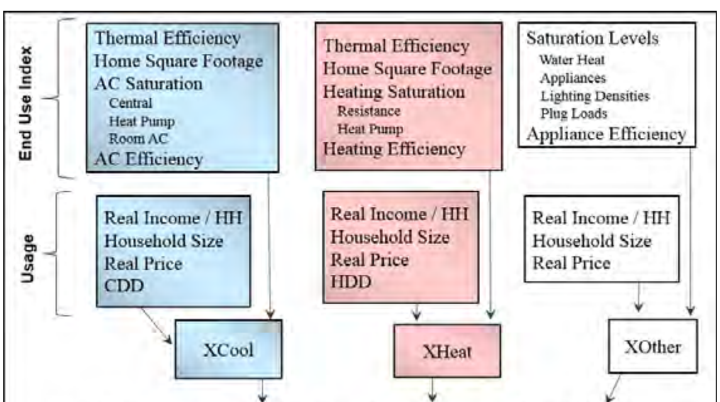
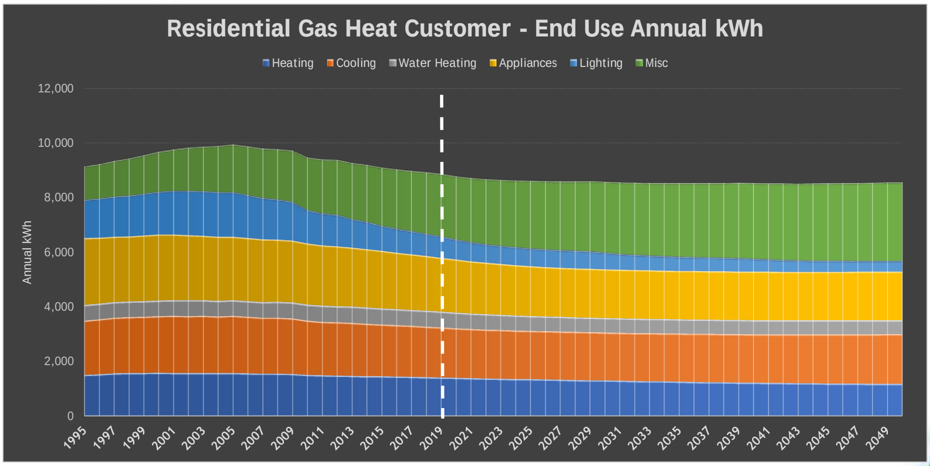
RESIDENTIAL MODEL



$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + e_m$$

12

RESIDENTIAL END USE TRENDS



Cool AAGR 2019 - 2039: 0.13%
Heat AAGR 2019 - 2039: -0.39%

AAGR = Average Annual Growth Rate

Source: 2018 EIA Annual Energy Outlook

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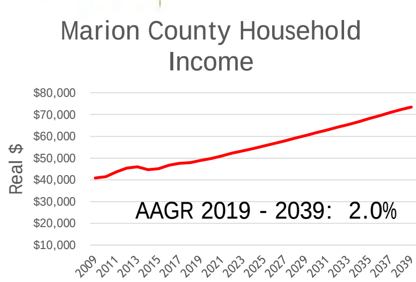
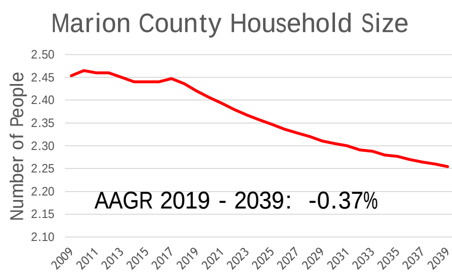
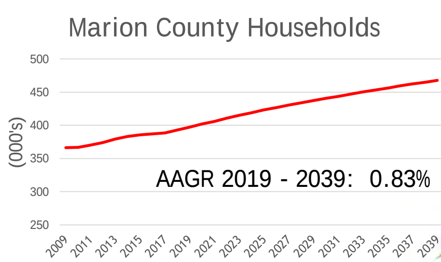
RESIDENTIAL ECONOMIC DRIVERS





- Moody's Analytics Marion County Economic Forecast
- Multifamily Growth:
  - Increasing # of households
  - Decreasing persons / household



AAGR = Average Annual Growth Rate

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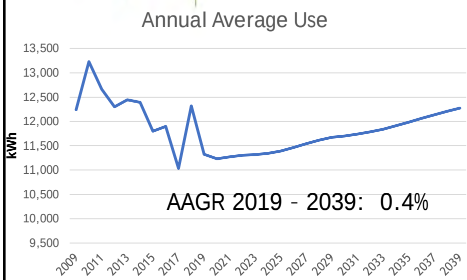
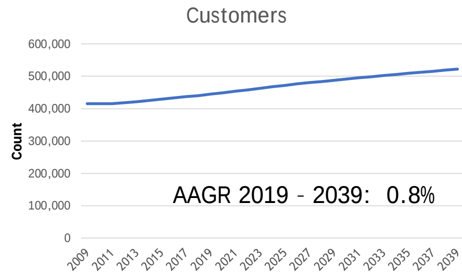
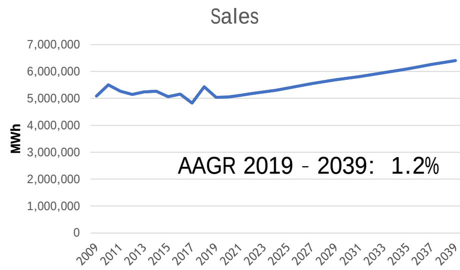
RESIDENTIAL FORECAST







AAGR = Average Annual Growth Rate

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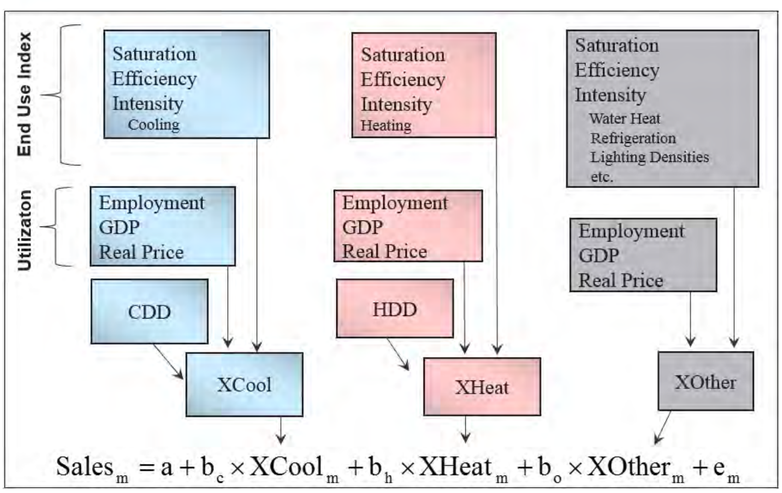
COMMERCIAL MODEL



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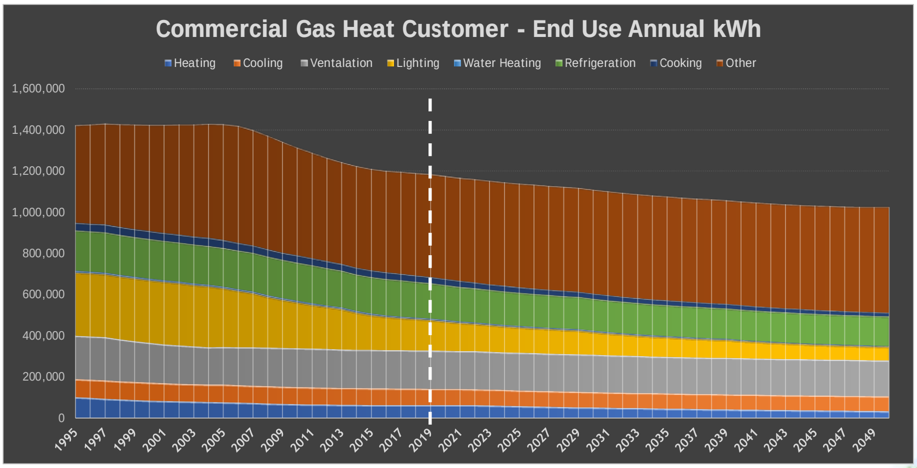
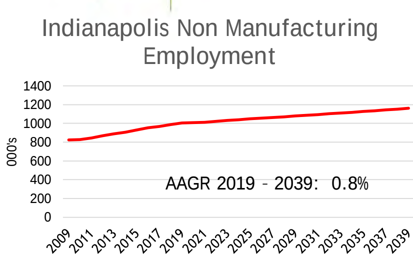
COMMERCIAL END USE TRENDS

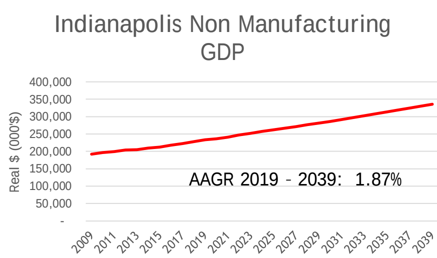


Cool AAGR 2019 - 2039: -0.45%
Heat AAGR 2019 - 2039: -1.9%
AAGR = Average Annual Growth Rate

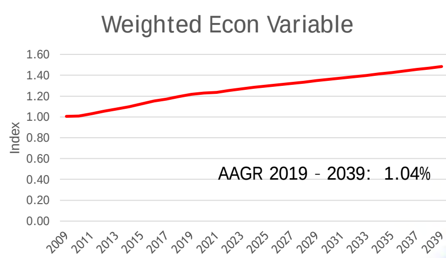
Source: 2018 EIA Annual Energy Outlook

COMMERCIAL ECONOMIC DRIVERS





- Moody's Analytics Indianapolis Metropolitan Statistical Area (MSA)
- Weighted Economic Variable: 80% Employment / 20% GDP



AAGR = Average Annual Growth Rate

INDUSTRIAL MODEL

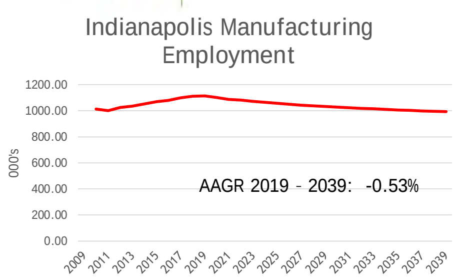
Industrial sales are estimated with a generalized econometric model

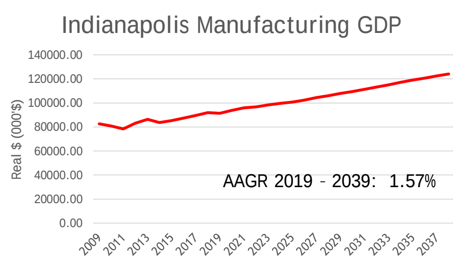
Cooling Degree Days

Manufacturing Employment
Manufacturing Output
Price

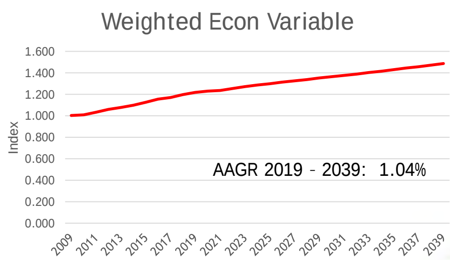
$$Sales_m = a + b_{cdd} \times CDD_m + b_{Econ} \times EconVariable_m + e_m$$

INDUSTRIAL ECONOMIC DRIVERS





- Moody's Analytics Indianapolis MSA
- Weighted Economic Variable: 90% Employment / 10% GDP

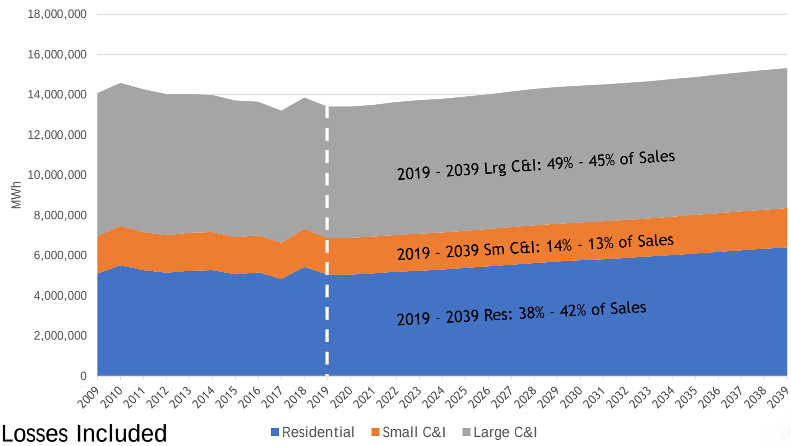


AAGR = Average Annual Growth Rate

CLASS SALES FORECAST

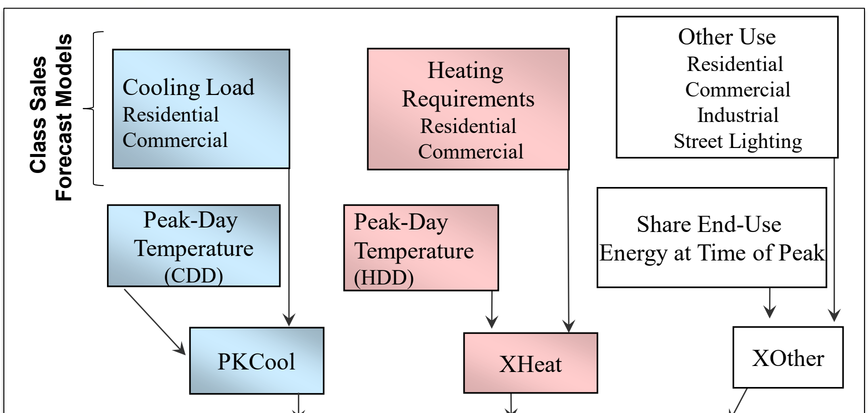
INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP

	Residential	Small C&I	Large C&I
Average Annual Growth Rate 2019 - 2039:	1.2%	0.2%	0.3%



No Losses Included

PEAK MODEL

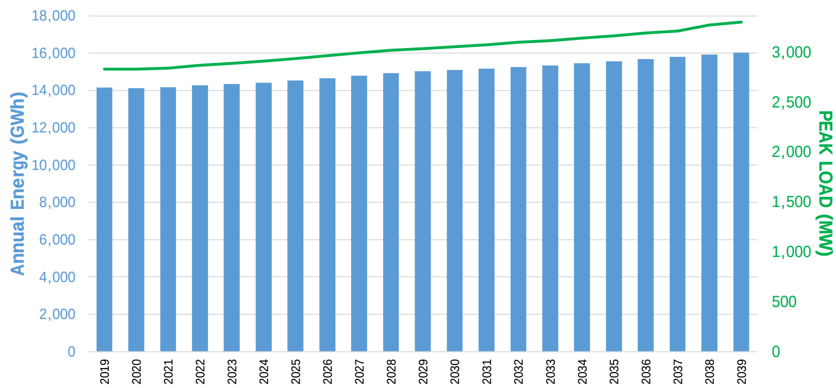


$$Peak_m = a + b_c \times PkCool_m + b_h \times PkHeat_m + b_o \times PKOther_m + e_m$$

IRP ENERGY & PEAK FORECAST

INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP

	Energy	Peaks
Average Annual Growth Rate 2019 - 2039:	0.4%	0.8%



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ADDITIONAL LOAD FORECAST ITEMS

- High and low load forecasts still being developed
  - Alternate Moody's economic scenarios
  - Standard deviation in Itron models
  - Verified with PowerSimm
- EV & PV Forecast by MCR Consultants
  - Close to final
  - MCR will present forecast at next Stakeholder meeting
- Above items will be developed & incorporated and presented at the next Stakeholder Meeting

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BREAK

IPL DEMAND SIDE MANAGEMENT (DSM) MARKET POTENTIAL STUDY (MPS) AND END USE RESULTS

GDS ASSOCIATES

END-USE ANALYSIS AND DRAFT RESULTS FOR 2020-2039 DSM MARKET POTENTIAL STUDY

MARCH 26, 2019 – IRP Public Advisory Meeting #2

Presented by **THE GDS TEAM**

2018 IPL END USE ANALYSIS RESULTS

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END USE ANALYSIS OBJECTIVES

RESEARCH TO IMPROVE UPON INPUTS TYPICALLY USED IN LOAD FORECAST

- *Primary & Secondary Research*
  - Surveys & onsite visits
  - Building energy simulation models
  - CBECS*
- *Residential*
  - End Use Market Share
  - Unit Energy Consumption
- *Small Commercial & Industrial*
  - End-use intensity
  - Distribution of customers by building type
  - End-use saturation

UNDERSTANDING ENERGY EFFICIENCY BEHAVIOR

- *Large Commercial & Industrial*
- *Onsite Visits*
- *Interview Questions to Assess Attitudes Toward Energy Efficiency*

commercial building energy consumption survey

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RESEARCH DESIGN-RESIDENTIAL END USE ANALYSIS

SELF-REPORT SURVEY

Online/Mail

384 responses (95/5)

Sample stratified by average usage

Data elements

End-use saturation

Miscellaneous end-uses

Hours of use

Willingness to participate in a site visit

Demographics

the research goal was to recruit site visits from the survey respondents

SITE VISITS

Sub-sample of survey respondents (n=68)

Verify accurate reporting on survey

Catalogue of misc. end-uses

Evaluate willingness to participate in programs

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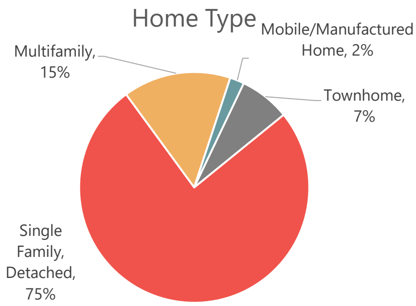
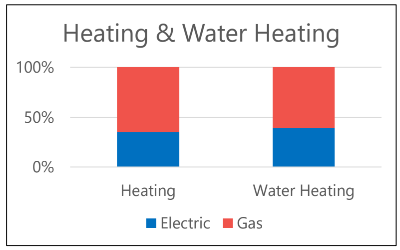
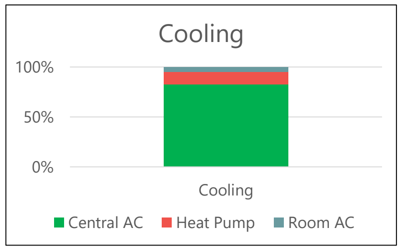
Market Segmentation







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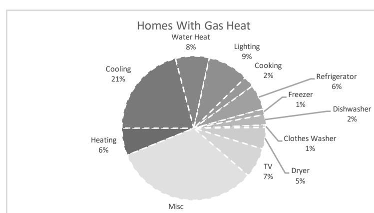
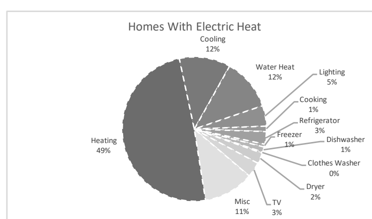
End Use Profiles

average annual kWh per home

Gas Heat		*Electric Heat*
6%	*heating intensity*	49%
21%	*cooling intensity*	12%
8%	*water heating intensity*	12%





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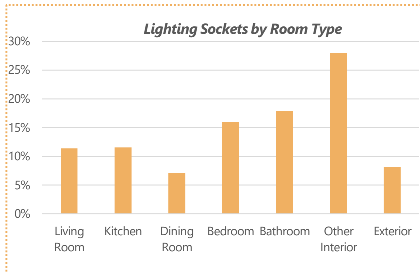
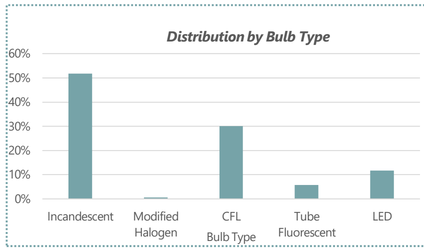
LIGHTING *averages per home*

40.5 *sockets*

5.5 *bulbs in storage*

61% *of storage are incandescent*





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LIGHTING

01 **Self-responders tend to understate the number of lighting sockets in the home**

02 **They reported an average of 20 bulbs per home, whereas site visits indicated an average of 41 per home**

03 **The site visits are considered the accurate representation, since technicians perform a detailed count and inventory of all bulbs**

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RESEARCH DESIGN-SMALL C&I END USE ANALYSIS

ENERGY INTENSITY

- CBECS
- Basic assumption for energy intensity by end-use per sq. ft.
- Regional data
- Update to 2012 version
  - *Decline in lighting intensity*
  - *Increase in computer intensity*

END-USE SATURATION

- 70 site visits
- Building type representation
- Compare end-use saturation with CBECS assumptions

BUILDING TYPES

- Use *InfoUSA* SIC codes to classify accounts to industry codes
- Map industry codes to CBECS building types
- Summarize energy sales by building type
- Update % of energy sales by building type assumption in forecast

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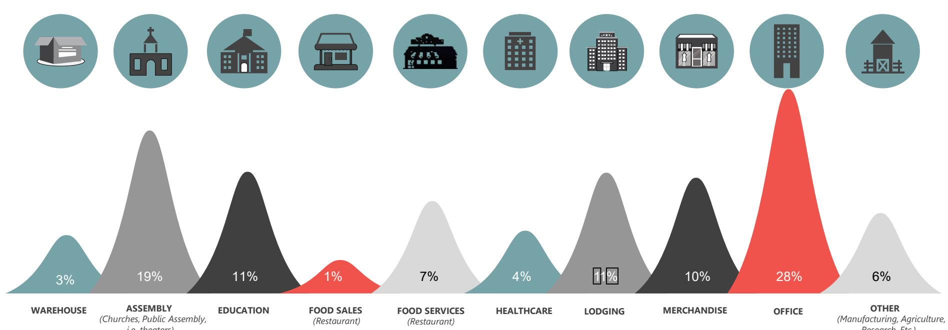
SEGMENTATION *by Electric Consumption*

Commercial Segmentation by Commercial Building Type



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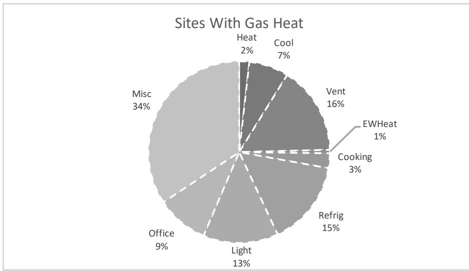
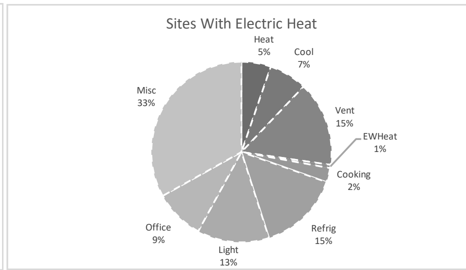
End Use Profiles

average annual kWh per commercial site





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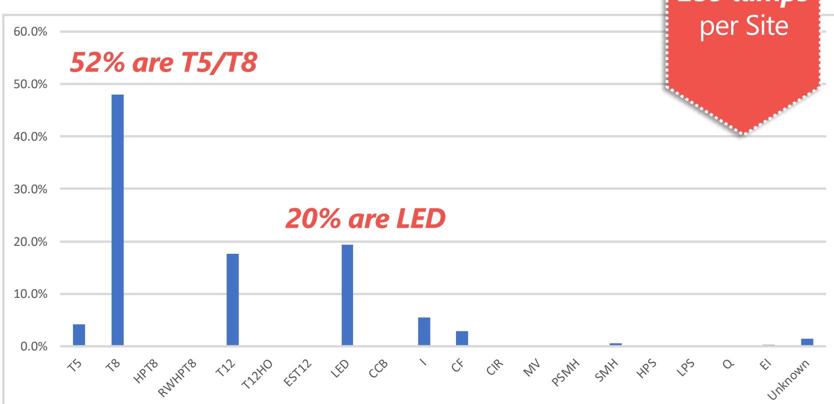
LIGHTING

average
259 lamps
per Site



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RESEARCH DESIGN LARGE C&I END-USE ANALYSIS

IDENTIFY POPULATION FRAME

Work with IPL staff, want to include opt-out accounts

RECRUIT PARTICIPANTS *(45 accounts)*

Attempt to get representative sample
- by industry type
- by usage amount

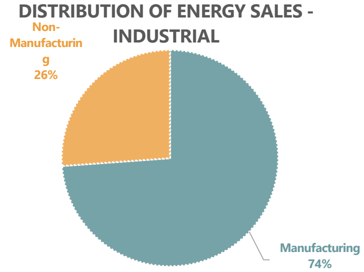
CONDUCT ON-SITE SURVEYS

Collect equipment characteristics
Willingness to participate

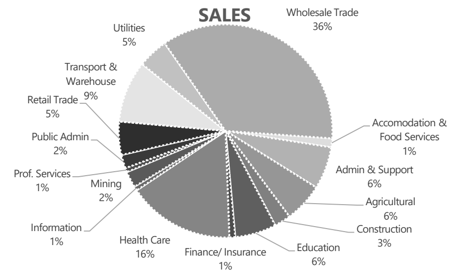
COLLECT INFORMATION ON EFFICIENCY ACTIVITY

INDUSTRY SEGMENTATION

DISTRIBUTION OF ENERGY SALES - INDUSTRIAL

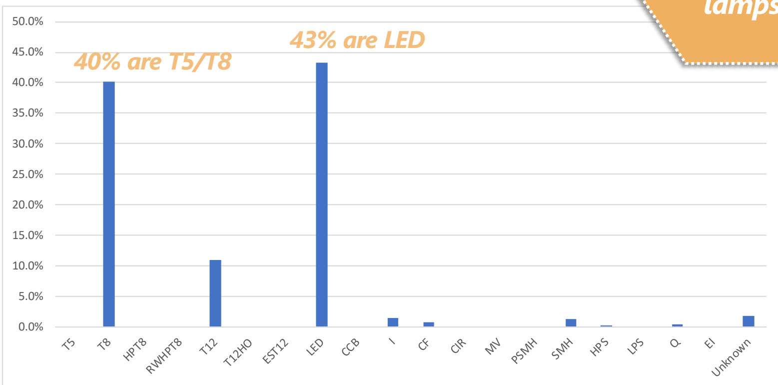


DISTRIBUTION OF NON-MANUFACTURING SALES



LIGHTING

average **347** ***lamps*** per site



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IPL DSM MARKET POTENTIAL STUDY (MPS) PRELIMINARY RESULTS

- Please note that the following information represents the preliminary results of the Market Potential Study (MPS) completed by GDS.
- This information does not necessarily represent either the amount of DSM:
  a) that will ultimately be selected by the IRP modeling, or
  b) the amount of DSM IPL will seek approval to deliver during the 2021-2023 period or subsequent years beyond 2023
- This information will serve as the starting point for IPL to develop the DSM inputs (DSM as a resource) for the IRP modeling.
- The eventual DSM plan that will be proposed for the 2021-2023 period will be the product of the IRP modeling and proposals by implementation vendors.

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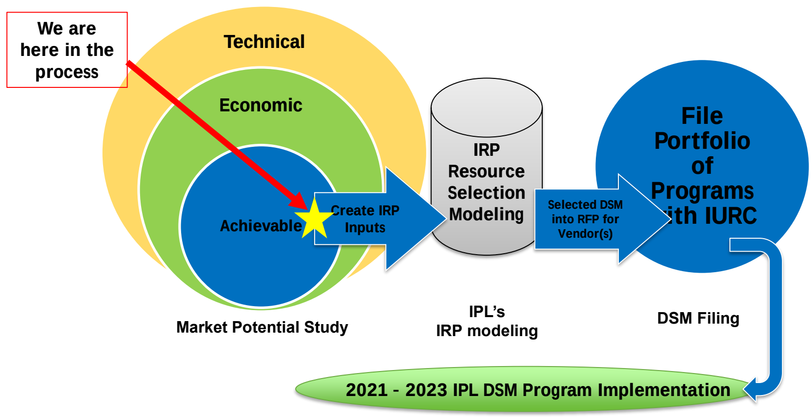
DSM PROCESS & THE IRP



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POTENTIAL STUDY METHODOLOGY

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METHODOLOGY-MEASURE CHARACTERIZATION

Draft Results

01 INCLUDES…

- Savings
- Incremental/full costs
- Measure interaction
- Measure life
- Measure applicability

02 DATA SOURCES…

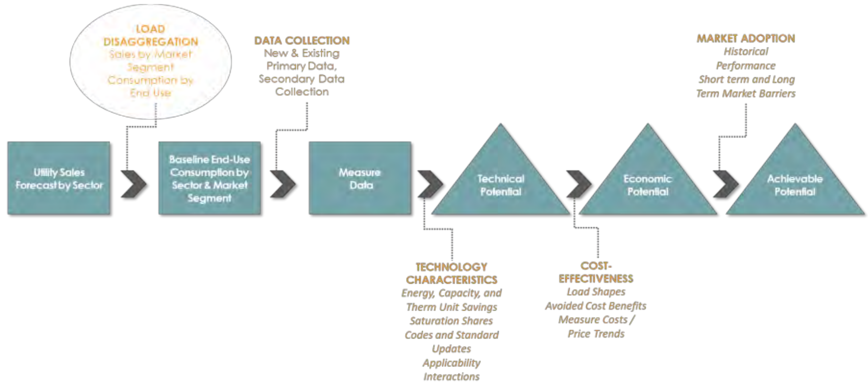
- Current catalog of IPL Measures
- Indiana TRM, Illinois TRM, Michigan Energy Measures Database
- Regional and national costs databases
- Building energy modeling
- IPL market data and survey data

03 ASSUMPTIONS…

Assumptions were collected and sourced in a spreadsheet that was shared for review and comment by OSB

METHODOLOGY-STUDY APPROACH

Draft Results



METHODOLOGY-TECHNICAL POTENTIAL

Draft Results

Residential Example *(electric)*

TECHNICAL POTENTIAL OF EFFICIENT MEASURE = total number of households X base case end use intensity (kWh/unit) X saturation share X remaining factor X feasibility factor X savings factor

analysis covers a 20-year timeframe

TECHNICAL POTENTIAL
Theoretical maximum, only constrained by technical feasibility & applicability of measures

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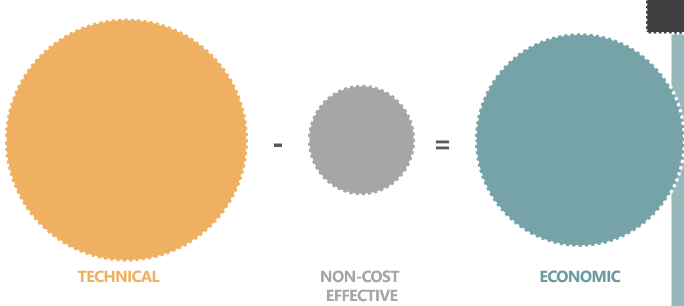
METHODOLOGY-ECONOMIC POTENTIAL

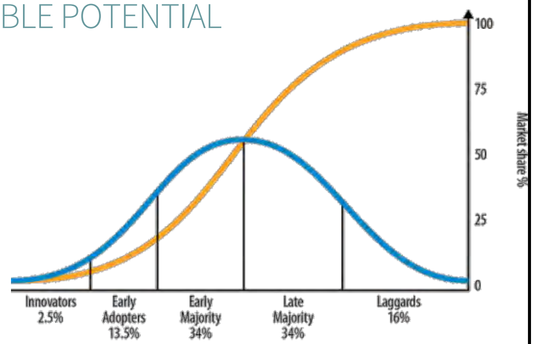
Draft Results

ECONOMIC POTENTIAL
Subset of the Technical Potential that is economically cost effective (based on screening with the Utility Cost Test)



METHODOLOGY-ACHIEVABLE POTENTIAL

Draft Results



ADOPTION RATES

– **short term adoption rate** (a)
– **long term adoption rate** (b)
– **adoption curve**
  - *i.e. how you get from (a) to (b)*

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METHODOLOGY-ACHIEVABLE POTENTIAL

Draft Results

SHORT TERM ADOPTION RATE

historical performance & current saturation of EE equipment is a key indicator

LONG TERM ADOPTION RATE

incentive and payback are two primary variables; others considered

IPL willingness to participate research

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RESIDENTIAL

ipl an AES company

RESIDENTIAL POTENTIAL RESULTS

Draft Results

01 **Nearly 3,000,000 MWh of Technical Potential**
(cumulative, 2021-2039)
- HVAC Equipment, Water Heating and HVAC Shell are leading end uses

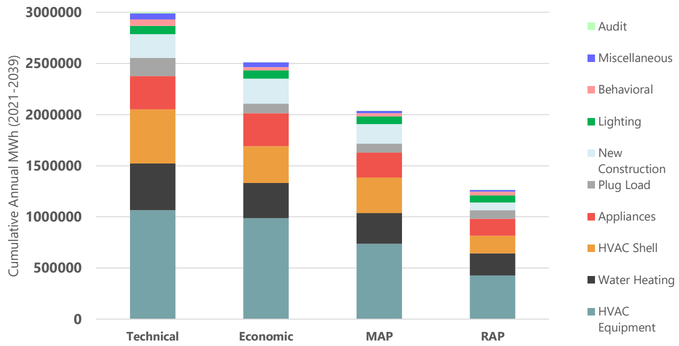
02 **Economic Potential is about 85% of Technical Potential**
- Utility Cost Test used for benefit-cost screening
- Low-income measures retained in Economic Potential, regardless of UCT ratio

03 **Realistic Achievable Potential is approximately 1,250,000 MWh**
(cumulative, 2021-2039)

RESIDENTIAL POTENTIAL RESULTS

Draft Results

2021-2039 Cumulative (gross MWh)



current cost effectiveness screening is based on gross savings and excludes delivery (non-incentive) costs

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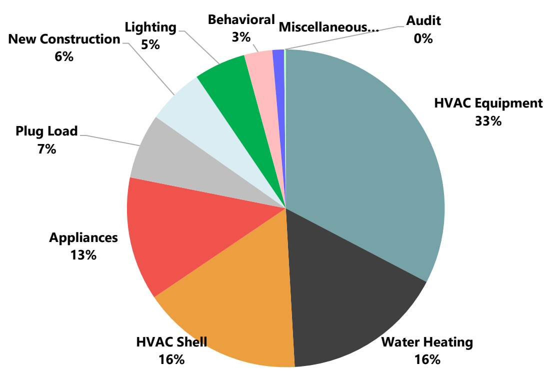
RESIDENTIAL POTENTIAL RESULTS

Draft Results

2021-2039 Cumulative RAP (percent savings by end use)



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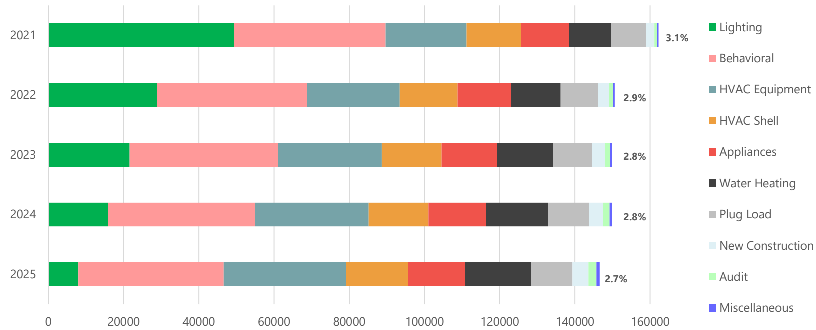
RESIDENTIAL POTENTIAL RESULTS

Draft Results

Annual Incremental RAP 2021-2025 (gross MWh)



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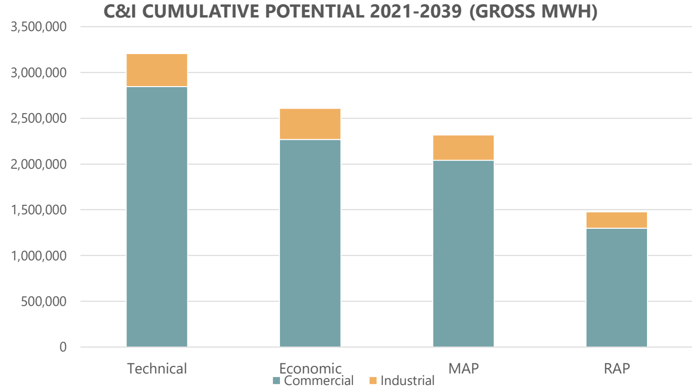
COMMERCIAL & INDUSTRIAL

ipl an AES company

C&I POTENTIAL RESULTS

Draft Results



Current cost effectiveness screening is based on Gross savings and excludes delivery (non-incentive) costs

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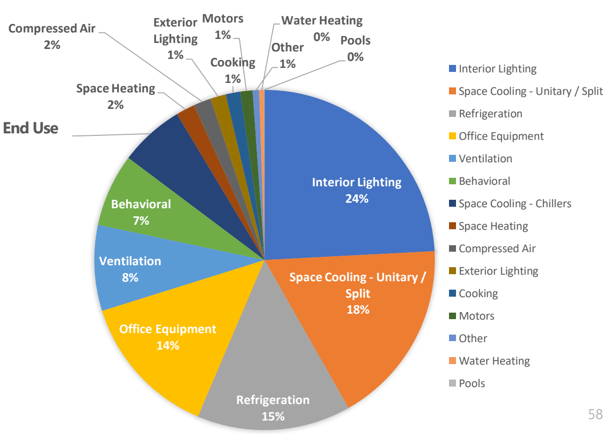
COMMERCIAL POTENTIAL RESULTS

Draft Results

2021-2039

Commercial Cumulative RAP by End Use



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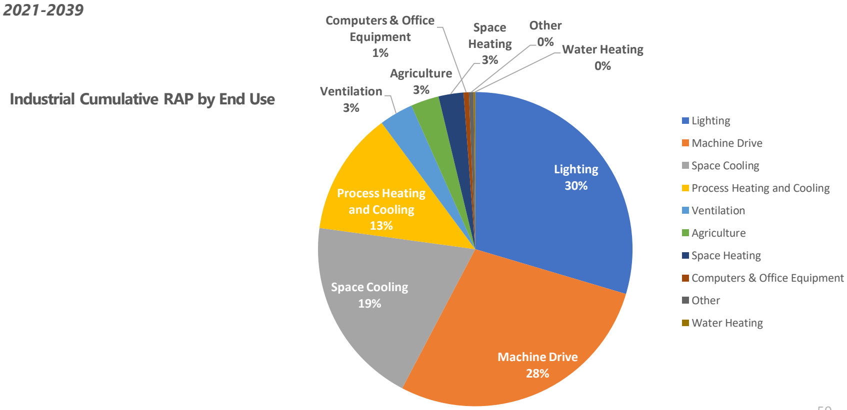
INDUSTRIAL POTENTIAL RESULTS

Draft Results

2021-2039



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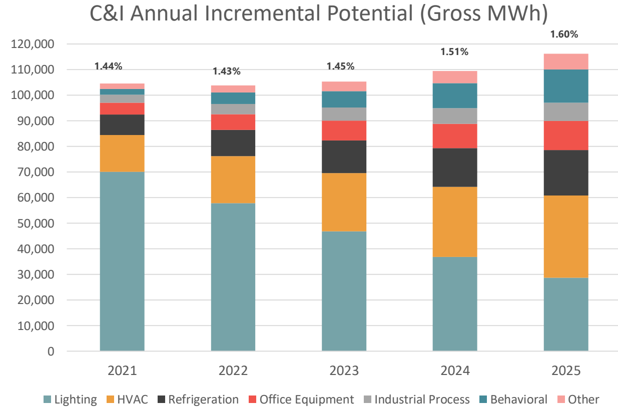
TOTAL C&I 2021-2025 POTENTIAL

Draft Results



Percent of adjusted C&I sales
(net of opt-out customers)

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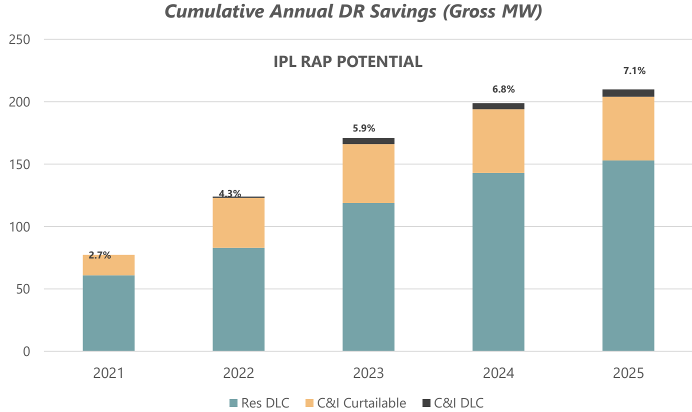
DEMAND RESPONSE

DEMAND RESPONSE
Draft Results

Cumulative Annual DR Savings (Gross MW)



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MPS PRELIMINARY RESULTS NEXT STEPS

- April 2019: Review OSB comments, finalize MPS results and create IRP inputs from the MPS results
- Stakeholder Meeting #3: Present IRP/DSM modeling approach
- Stakeholder Meeting #4: Present DSM results; volume of DSM for 2021 - 2039 selected in Reference Case
- Fall/Winter 2019: Issue RFP for DSM implementation
- Spring 2020: Submit DSM filing for 2021 - 2023

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LUNCH

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COMMODITY PRICES AND MODELING

Patrick Maguire

Director of Resource Planning

FORWARD CURVES USED IN IRP MODELING

- Power Prices (Indiana Hub On/Off)
- Henry Hub Natural Gas
  - Gas basis for delivered prices
- IPL delivered coal
- Fuel oil
- Emissions (NO_x, SO_2, carbon)
- Capacity Prices
  - MISO Zone 6

FUNDAMENTAL FORECAST VENDOR

- **Wood Mackenzie H1 2018 Long Term Outlook**
- Provided Cases:
  1. Federal Carbon Case (Carbon tax starting 2028)
  2. Federal Carbon Case + High Gas Sensitivity
  3. No Carbon Case
  4. No Carbon + Low Gas Sensitivity

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FORWARD CURVE NOTES

	Deterministic Modeling	Stochastic Ranges	Notes
Power	✓	✓	On/Off peak monthly power prices from Wood Mackenzie. Hourly shapes created in PowerSimm.
Natural Gas	✓	✓	Wood Mackenzie monthly gas prices with delivery adders. Daily price shapes created in PowerSimm.
Coal	✓	✓	Internally sourced IPL coal curves.
Fuel Oil	✓	✓	Wood Mackenzie
Emissions	✓	✗	NOx and SO2 curves will be sourced from forward curves. Carbon prices from Wood Mackenzie.
Capacity	✓	✓	Capacity will be valued at the estimated bilateral price for MISO Zone 6.

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MISO CAPACITY PRICE FORECAST

- MISO Capacity Market is a residual market for balancing prompt year positions
- IPL price construction:
  - o "Most likely"/Mode capacity price: 25% of Cost of New Entry (CONE) for a new Combustion Turbine
  - o Bilateral Floor: 5% of CONE
  - o Bilateral Ceiling: 60% of CONE
- Deterministic Runs: "Most Likely" capacity price
- Stochastic Runs: triangular distribution based on floor, mode, and ceiling prices

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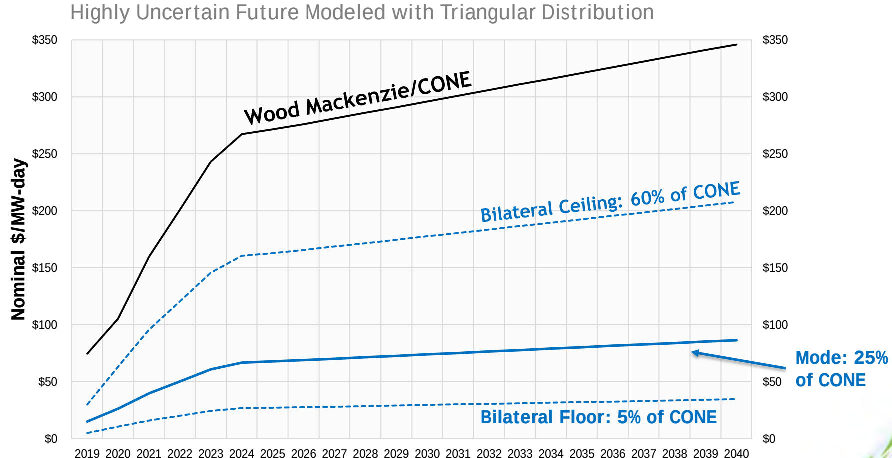
MISO CAPACITY PRICE FORECAST (CONT.)

MISO's Residual Capacity Market Results in Low Capacity Prices

Highly Uncertain Future Modeled with Triangular Distribution



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ASSUMPTIONS FOR REPLACEMENT RESOURCES

Patrick Maguire

Director of Resource Planning

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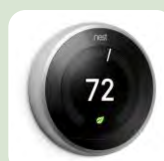
JAN 29TH MEETING: REPLACEMENT RESOURCES MODELED

NATURAL GAS
- CCGT
- CT
- Reciprocating Engine/ICE

WIND
- Land-Based Wind

SOLAR
- Utility-Scale
- C&I
- Residential

STORAGE
- Standalone Front-of-meter



DSM/EE
- Measures bundled into tranches by cost and shape

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KEY ASSUMPTIONS FOR NEW RESOURCES

Variable	Description
Capital Costs	Overnight costs to construct, typically represented in $/kW
Operating Costs	Fixed O&M Variable O&M
Operating Characteristics	Heat Rates (natural gas units) MW limits Ramp rates Capacity Factors/Profiles (wind/solar)

GENERIC RESOURCE COST

- Methodology:
  - Evaluated publicly available data and forecasts from third party vendors
  - Vetted for reasonableness and alignment with market intelligence
- **Capital Costs: average of NREL "Mid" case and three other vendors:**
  - IHS Markit
  - Wood Mackenzie
  - Bloomberg New Energy Finance
- Averages benchmarked against Lazard LCOE report and NIPSCO's average bid responses from 2018 RFP

RESOURCE COST DATA SOURCES

PUBLIC DATA SOURCES

National Renewable Energy Laboratory (NREL)
- 2018 Annual Technology Baseline (ATB)
- https://atb.nrel.gov/electricity/2018/

Lazard
- Levelized Cost of Energy Analysis, Version 12.0
- Levelized Cost of Storage Analysis, Version 4.0
- https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/

NIPSCO RFP Average Bid Prices
- NIPSCO 2018 Integrated Resource Plan
- 7-24-2018 Public Advisory Presentation
- https://www.nipsco.com/about-us/integrated-resource-plan

Lazard's Levelized Cost of Energy (LCOE) reports and NIPSCO's public RFP data provide useful cost benchmarks but are not used directly

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RESOURCE COST DATA SOURCES (CONT.)

CONFIDENTIAL DATA SOURCES AVAILABLE WITH SIGNED NDA

IHS Markit
- US wind capital cost and required price outlook: 2018
- US solar PV capital cost and required price outlook: 2018
- US battery energy storage system capital cost outlook (August 2018)
- 2018 Update of Rivalry Scenario
- Subscription Required: https://ihsmarkit.com/products/energy-outlooks-2040-power-gas-coal-renewables.html

Bloomberg New Energy Finance (BNEF)
- Energy Project Asset Valuation Model (EPVAL 8.8.4)
- 2H 2018 LCOE: Data Viewer
- Subscription Required: https://www.bnef.com

Wood Mackenzie
- North America Power & Renewables
- H1 2018 Long Term Outlook
- Subscription Required: https://www.woodmac.com/research/products/power-and-renewables/north-america-power-and-renewables-service/

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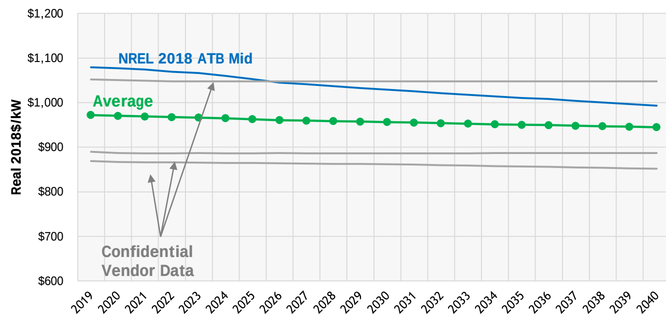
NATURAL GAS TECHNOLOGIES

Type	Capital Cost (2018$/kW)	Fixed O&M (2018$/kW-year)	Variable O&M (2018$/MWh)
1x1 CCGT	$967	$14.22	$3.04
Frame CT	$754	$10.96	$6.94

EXAMPLE: Gas Combined Cycle Capital Costs (Real 2018 $/kW)



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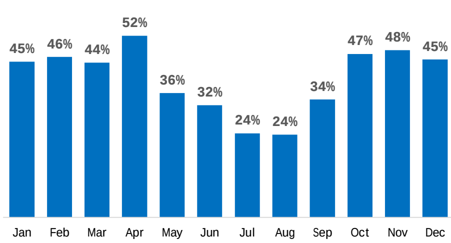
WIND: OPERATIONAL PARAMETERS

- **Location:** Northwestern Indiana
- **Annual Capacity Factor:** 42%
- **Profile Source:** NREL Wind Toolkit, 2009-2012 simulated wind data
- **Generic Project Size:** 50 MW ICAP
- **Capacity Credit:** 7.8% (3.9 MW per 50 MW project)

Generic Wind: Monthly Capacity Factors



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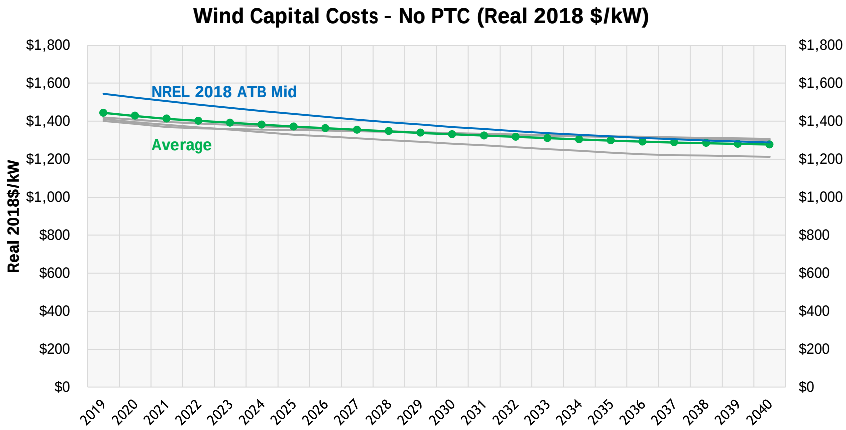
WIND: CAPITAL COSTS



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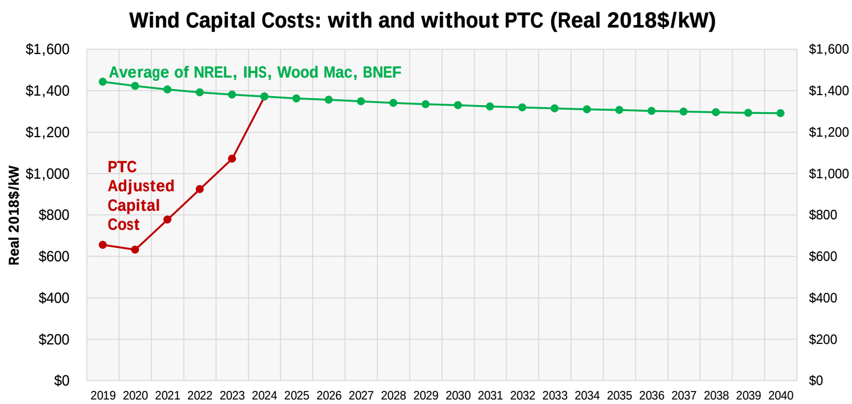
WIND: CAPITAL COSTS (CONT.)

	2020	2021	2022	2023	2024+
PTC Safe Harbor	100%	80%	60%	40%	0%



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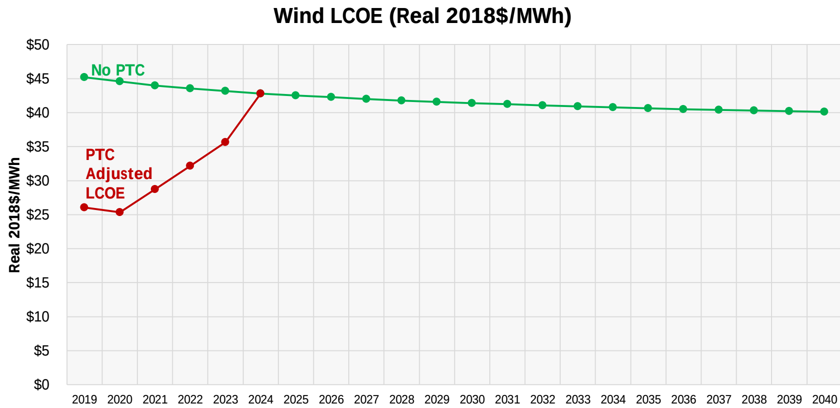
WIND LCOE

	2020	2021	2022	2023	2024+
PTC Safe Harbor	100%	80%	60%	40%	0%



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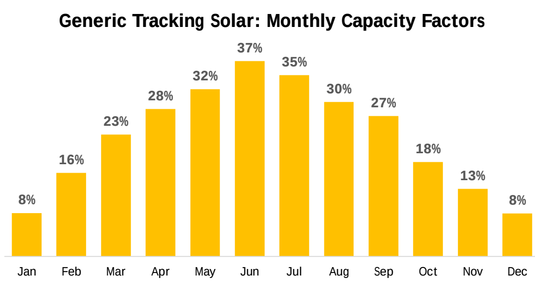
SOLAR: OPERATIONAL PARAMETERS

- **Location:** Central Indiana
- **Annual Capacity Factor:** 23% (single-axis tracking)
- **Profile Source:** IPL Rate REP Projects, hourly data 2016-2018
- **Generic Project Size:** 25 MW for utility-scale



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SOLAR: CAPACITY FACTORS

IPL Rate REP Solar: 2016-2018 Monthly Capacity Factors

	GROUND FIXED TILT			TRACKING			COMMERCIAL ROOFTOP		
	2016	2017	2018	2016	2017	2018	2016	2017	2018
Jan	9.8%	5.8%	7.0%	9.7%	6.1%	7.1%	6.7%	4.0%	4.7%
Feb	16.5%	15.7%	9.9%	17.3%	16.4%	10.4%	13.2%	12.6%	9.4%
Mar	19.5%	18.6%	15.7%	23.0%	21.6%	19.8%	16.4%	16.7%	15.2%
Apr	19.3%	21.3%	21.8%	27.1%	24.8%	26.2%	18.4%	19.0%	16.1%
May	21.9%	22.9%	24.4%	27.8%	30.1%	30.6%	19.0%	18.8%	17.3%
Jun	26.8%	25.2%	24.5%	36.2%	35.6%	31.6%	20.9%	14.8%	18.9%
Jul	22.9%	25.3%	24.4%	29.5%	35.3%	31.0%	19.8%	14.7%	21.8%
Aug	21.0%	23.5%	22.6%	25.5%	28.8%	27.4%	16.6%	9.8%	21.0%
Sep	22.0%	21.6%	18.5%	25.8%	25.7%	22.7%	17.3%	9.7%	16.7%
Oct	18.9%	12.6%	16.9%	20.1%	11.9%	17.9%	13.4%	9.3%	12.7%
Nov	15.0%	13.4%	9.5%	14.9%	10.9%	9.8%	10.5%	8.6%	7.4%
Dec	7.1%	9.6%	8.9%	7.3%	7.2%	8.4%	5.2%	6.3%	6.4%
Annual	**18.4%**	**17.9%**	**17.0%**	**22.0%**	**21.2%**	**20.3%**	**14.8%**	**12.0%**	**14.0%**

Avg: 17.8% **Avg: 21.2%** **Avg: 13.6%**

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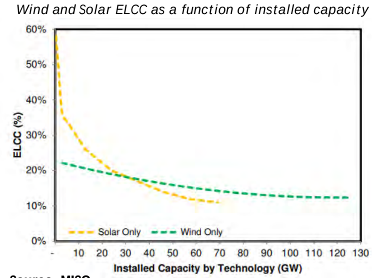
SOLAR CAPACITY CREDIT

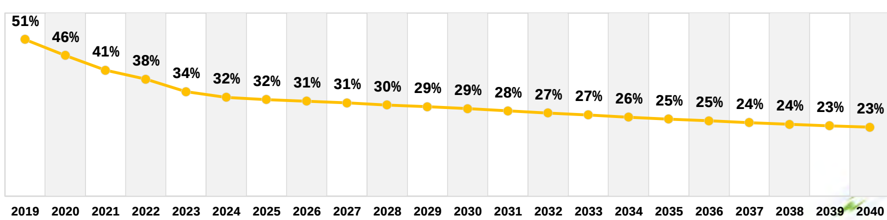
- Solar capacity credit changes as more solar is added to the MISO system
- "Duck curve" phenomenon of shifting net peak load
- Annual capacity credit calculated using forecasted annual installed GW of utility solar in MISO Central
- Installed solar forecast from Wood Mackenzie

Wind and Solar ELCC as a function of installed capacity



Source: MISO

Annual Solar Capacity Credit



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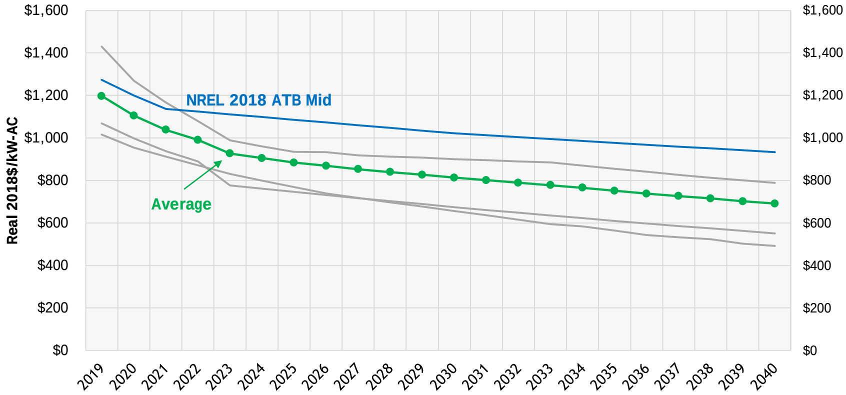
SOLAR: CAPITAL COSTS



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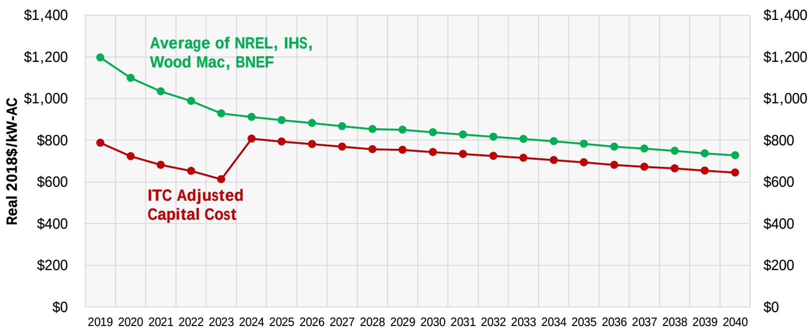
SOLAR: CAPITAL COSTS (CONT.)

	2020	2021	2022	2023	2024+
ITC Safe Harbor	30%	30%	30%	30%	10%



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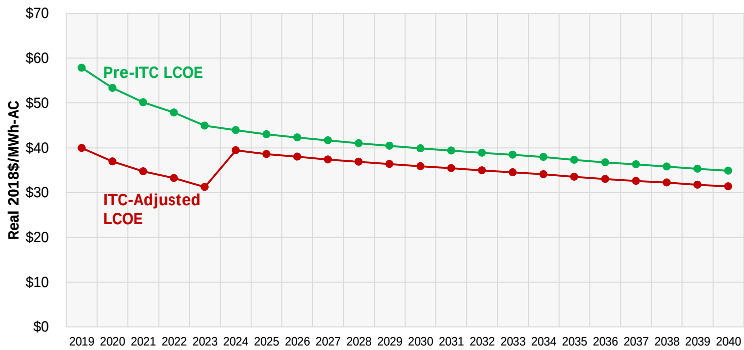
SOLAR: LCOE

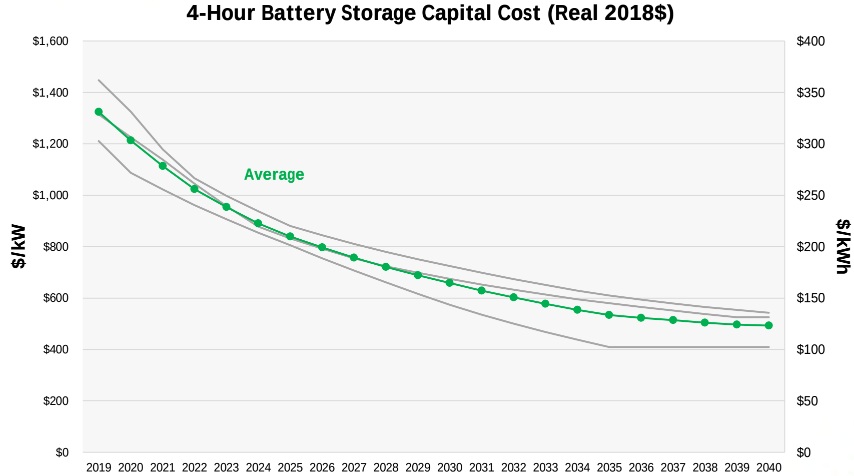
	2020	2021	2022	2023	2024+
ITC Safe Harbor	30%	30%	30%	30%	10%

Utility-Scale, Single-Axis Tracking LCOE (Real 2018$/MWh-AC)



STORAGE CAPITAL COST

4-Hour Battery Storage Capital Cost (Real 2018$)



SCENARIO ANALYSIS FRAMEWORK & PROPOSED SCENARIOS

Patrick Maguire

Director of Resource Planning

ROLE OF SCENARIOS IN IPL'S IRP

- Scenarios are used to generate a set of different optimized portfolios
- IPL is net long capacity with existing resources and planned, age-based retirements

Scenario modeling framework is designed to evaluate accelerated retirements in conjunction with portfolio optimization via capacity expansion

SCENARIO DRIVERS

	Reference Case	Scenario A: Carbon Tax	Scenario B: Carbon Tax + High Gas	Scenario C: Carbon Tax + Low Gas	Scenario D: No Carbon Tax + High Gas
Natural Gas Prices	Base	Base	**HIGH ↑**	**LOW ↓**	**HIGH ↑**
Carbon Tax	No Carbon Price	**Carbon Price (2028+)**	**Carbon Price (2028+)**	**Carbon Price (2028+)**	No Carbon Price
Coal Prices	Base	Base	Base	Base	Base
IPL Load	Base	Base	Base	**LOW ↓**	**HIGH ↑**
Capital Costs for Wind, Solar, and Storage	Base	Base	Base	Base	Base

PROPOSED SCENARIO FRAMEWORK

CURRENT PROPOSED FRAMEWORK EVALUATES STAGGERED RETIREMENTS WITH OPTIMIZED PORTFOLIOS FOR REPLACMENT CAPACITY

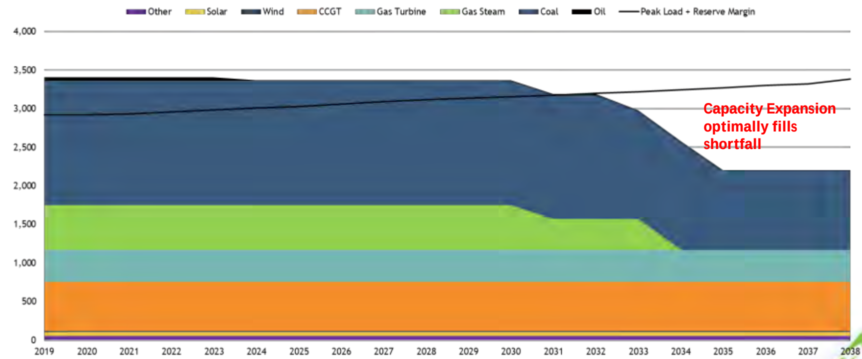
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
No Accelerated Retirements	**Portfolio 1**	1a	1b	1c	1d
Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	**Portfolio 2**	2a	2b	2c	2d
Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	**Portfolio 3**	3a	3b	3c	3d
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	**Portfolio 4**	4a	4b	4c	4d
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	**Portfolio 5**	5a	5b	5c	5d

Retirement dates fixed for base set of scenarios. Other sensitivities and flexible retirement date optimization will be conducted.

IPL STARTING POSITION

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
No Accelerated Retirements	Portfolio 1	1a	1b	1c	1d

BASE CASE: NO ACCELERATED RETIREMENTS



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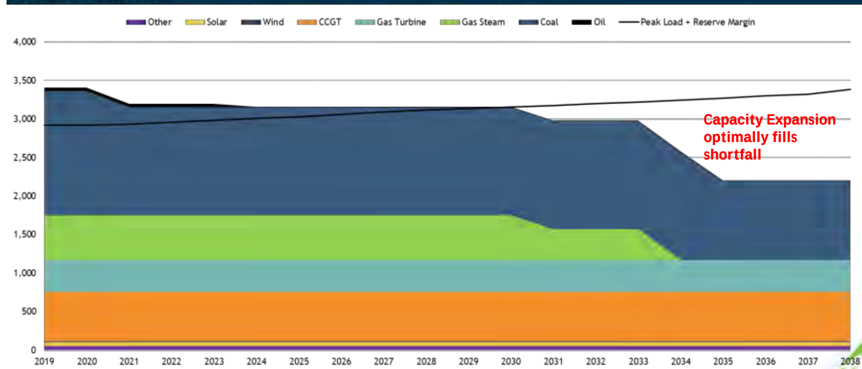
RETIREMENT PORTFOLIOS (1 OF 4)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Pete Unit 1 Retire **2021** Pete Units 2-4 Operational	Portfolio 2	2a	2b	2c	2d

PETE 1 EARLY RETIRE



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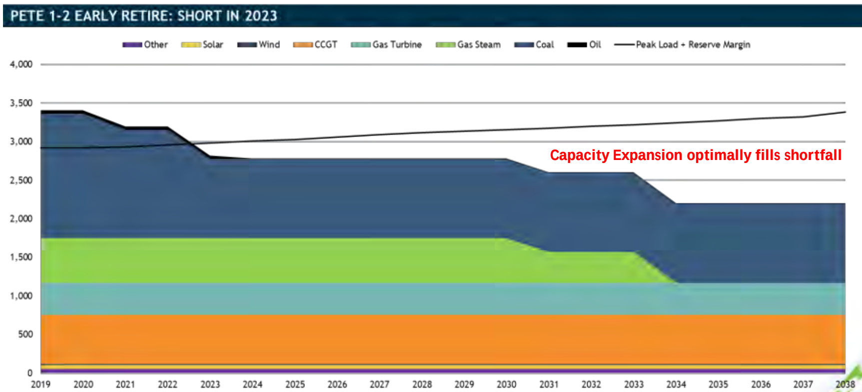
RETIREMENT PORTFOLIOS (2 OF 4)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	Portfolio 3	3a	3b	3c	3d



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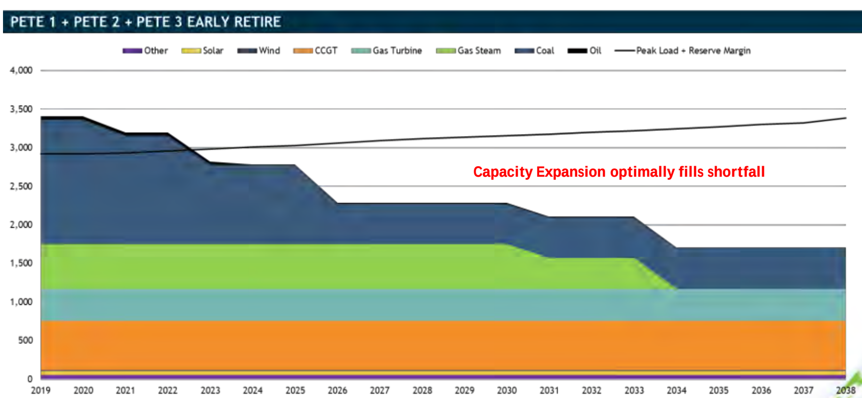
RETIREMENT PORTFOLIOS (3 OF 4)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	Portfolio 4	4a	4b	4c	4d



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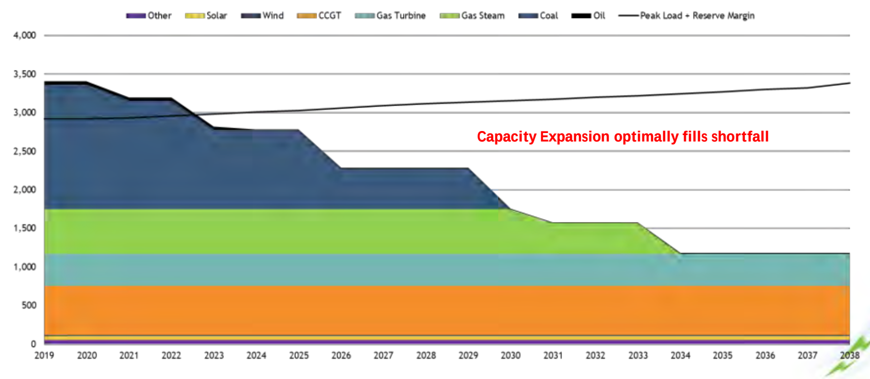
RETIREMENT PORTFOLIOS (4 OF 4)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	Portfolio 5	5a	5b	5c	5d

PETE 1 + PETE 2 + PETE 3 + PETE 4 RETIRE BY END OF 2030



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PORTFOLIO COMPARISON

PORTFOLIO COST WILL BE COMPARED ACROSS SCENARIOS TO DETERMINE OPTIMIAL PATH FORWARD

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
No Accelerated Retirements	Portfolio 1	1a	1b	1c	1d
Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	Portfolio 2	2a	2b	2c	2d
Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	Portfolio 3	3a	3b	3c	3d
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	Portfolio 4	4a	4b	4c	4d
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	Portfolio 5	5a	5b	5c	5d

Each portfolio will be compared on cost (PVRR) and other metrics

Scenarios inform optimal decision: which resource types are consistently selected in scenarios and retirement portfolios?

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ROLE OF STOCHASTICS

- Phase 1: Deterministic scenario analysis and portfolio construction
- Phase 2: Stochastic capacity expansion
- Goal: stochastic ranges envelope high/low scenario drivers, allowing us to capture full range of uncertainty
- **Result: broad range of scenarios and resource portfolios that are the foundation of a robust and flexible preferred portfolio**

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FINAL Q&A AND NEXT STEPS

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NEXT STEPS

- **Next Meeting: May 14, 2019**
  - IPL Morris Street Operations Center
  - Register at http://iplpower.com/irp
- Meeting #3 Material:
  - Modeling Update
  - Final Scenarios
  - Updated Load Forecast
  - Stochastic distributions from PowerSimm

Email questions, comments, or other feedback to ipl.irp@aes.com

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IPL 2019 IRP: PUBLIC ADVISORY MEETING #3

May 14, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

Topic	Time (Eastern)	Presenter
Registration	9:00 – 9:30	-
Welcome & Opening Remarks	9:30 – 9:35	Lisa Krueger, President AES US SBU
Meeting Objectives & Agenda	9:35 – 9:40	Stewart Ramsay, Meeting Facilitator
Meeting 2 Recap	9:40 – 9:50	Patrick Maguire, Director of Resource Planning
Stakeholder Presentation: Indiana Chapter of the National Association for the Advancement of Colored People (NAACP)	9:50 – 10:05	Denise Abdul-Rahman, NAACP
Stakeholder Presentation: Advanced Energy Management Alliance (AEMA)	10:05 – 10:20	Ingrid Bjorklund, AEMA Consultant
Electric Vehicle (EV) & Distributed Solar Forecast	10:20 – 11:10	Ed Schmidt, MCR
BREAK	11:10 – 11:25	
Load Forecast – High & Low Presentation Recap Customer Class Breakout	11:25 – 11:40	Erik Miller, Senior Research Analyst
DSM Bundles for IRP Modeling	11:40 – 12:00	Erik Miller, Senior Research Analyst
LUNCH	12:00 – 12:45	
Modeling and Scenario Recap	12:45 – 1:45	Patrick Maguire, Director of Resource Planning
Final Q&A, Concluding Remarks & Next Steps	1:45 – 2:00	Stewart Ramsay, Meeting Facilitator

MEETING 2 RECAP

Patrick Maguire

Director of Resource Planning

IPL 2019 IRP

INTEGRATED RESOURCE PLAN (IRP):
IPL's plan to provide safe, reliable, and sustainable energy solutions for the communities we serve

- IRP submitted every three years
- Plan created with stakeholder input
- 20-year look at how IPL will serve load
- Modeling and analysis culminates in a preferred resource portfolio

What is a preferred resource portfolio?

" 'Preferred resource portfolio' means the utility's selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration."

IURC RM #15-06, LSA Document #18-127
Link (PDF): https://www.in.gov/iurc/files/RM_ord_20181024141710007.pdf

2019 IRP STAKEHOLDER PROCESS

Dates to follow for Meeting #4 & Meeting #5

January 29th	March 13th	May 14th	August	October
•2016 IRP Recap •2019 IRP Timeline, Objectives, Stakeholder Process •Capacity Discussion •IPL Existing Resources and Preliminary Load Forecast •Introduction to Ascend Analytics •Supply-Side Resource Types •DSM/Load Forecast Schedule	•Stakeholder Presentations •Commodity Assumptions •Capital Cost Assumptions •IPL-Proposed Scenario Framework •Scenario Workshop •MPS Update and Plan	•Stakeholder Presentations •Summary of Stakeholder Feedback •Present Final Scenarios •Modeling Update •Assumptions Review and Updates	•Stakeholder Presentations •Summary of Stakeholder Feedback •Preliminary Model Results •Scenario Descriptions and Results •Preliminary Look at Risk Analysis and Stochastics	•Stakeholder Presentations •Final Model Results •Scenario Updates •Updates on Stakeholder Scenarios •Preferred Plan

IPL is committed to conducting a robust and collaborative stakeholder process. Multiple communication avenues will be provided to ensure that all stakeholders have the opportunity to be a part of the 2019 IRP process.

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STAKEHOLDER PRESENTATION

Denise Abdul-Rahman

NAACP

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STAKEHOLDER PRESENTATION

Ingrid Bjorklund

Advanced Energy Management Alliance (AEMA)

ELECTRIC VEHICLE (EV) & DISTRIBUTED SOLAR FORECAST

Ed Schmidt

MCR Performance Solutions

Electric Vehicle and Distributed Solar Forecasts: 2020-2040

5/14/19

MCR Performance Solutions: Management Consulting to the Utility Industry

Regulatory Services
- Strategic Analysis
- Rate Design & Cost Analysis
- Regulatory Filings
- Process Improvement

Energy Efficiency
- Strategy and Program Design
- Process and Data Management
- Program Implementation
- Program Management & Administration
- Program Tracking & Reporting

Utility Transformation
- New Technology Strategy & Product Development: Electric Vehicles and C&I
- Customer Onsite Product Development
- Enhanced Customer Experience: Strategies, Roadmaps and Product Financing Strategy

Financial Advisory
- Financial Forecasting
- Enterprise Risk Management
- Strategic Planning
- Capital Allocation
- Financial Processes & Systems

Transmission Strategy
- Formula Rate and Cost Analysis
- FERC Filings
- Strategic Analysis

Asset Management
- Zero-Base Budgeting
- Capital Project Evaluation
- Life Cycle Management Planning
- Long Range Planning
- Management Reporting
- Capitalization Policies and Procedures

Table of Acronyms

BNEF	Bloomberg New Energy Finance
BRT	IndyGo bus rapid transit routes
BYD	IndyGo-selected bus manufacturer
CAGR	Compound annual growth rate
C&I	Commercial and industrial
EEI	Edison Electric Institute
EIA	US Energy Information Administration
EV	Electric vehicle

GTM	GreenTech Media
ICE	Internal combustion engine
IHS	IHS Markit Company
IU	Indiana University
LDEV	Light duty electric vehicle
NEM	Net metered
PV	Photovoltaic, or distributed, solar
PVWatts	US National Renewable Energy Laboratory PV calculation tool

Agenda

- EV Forecast
  - 2018 baseline data
  - Methodology
  - Input data
  - Forecast
- Distributed solar (PV) Forecast
  - 2018 baseline data
  - Methodology
  - Input data
  - Forecast
- Summary: EV and Distributed Solar Forecast

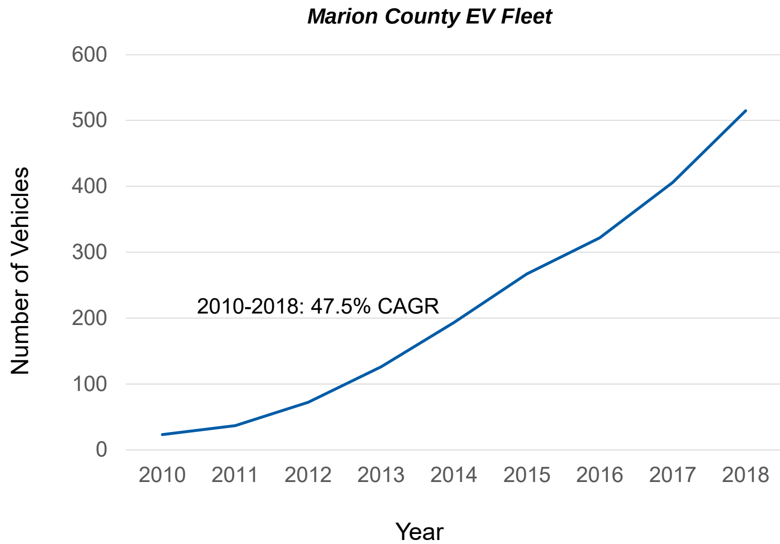
EV Forecast

Light Duty EV (LDEV)

Attribute	Value	Source
Count	515	IPL-provided IHS/Polk
kWh/100 miles	31	www.fueleconomy.gov
Annual miles	11,655	www.carinsurance.com
Annual kWh	3,613	= 31 * (11,655/100)

Notes: 1. 31 kWh/100 miles takes the weighted average for Bolt, Leaf, Tesla S, Tesla 3, Tesla X
2. Annual kWh = 11,655 miles / 100 * 31

Historical Light Duty EV Fleet Growth



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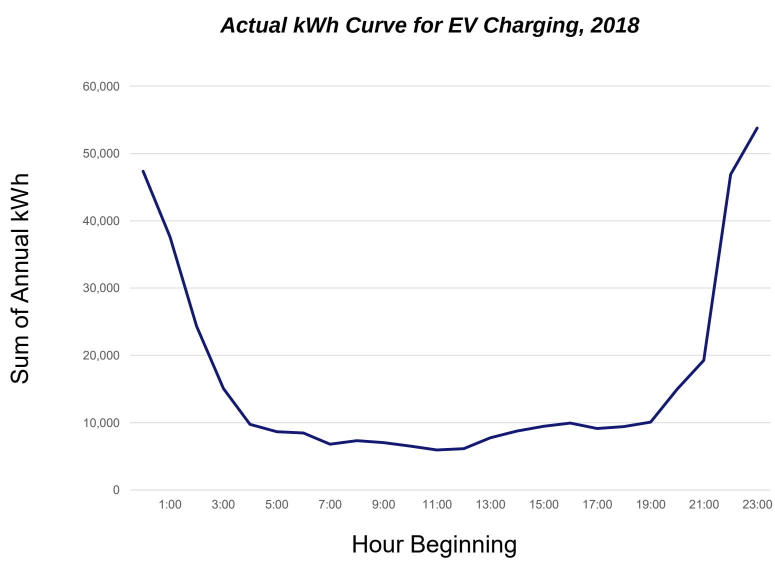
EV Charging Curve – IPL Electric Vehicle Rates



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IndyGO Electric Buses

Attribute	60' BYD BRT	40' Fleet
Current quantity	2	21
2032 quantity	56	144
Range	275	250
Miles/year	45,600	45,600
Charger	40 kW x 2	40 kW x 2
Battery kWh	652	489
Charge time hours	6	4.5

Notes:
1. 2032 quantities are per IndyGO capital plan
2. Ranges are current per manufacturers
3. BYD charger, battery kWh and charge time are per BYD, fleet buses are estimated

LDEV Unit Forecasting Methodology

Data Sources
- BNEF Forecast (2040)
- EEI Forecast (2030)
- US Census Population Projection and Facts
- IU Marion County Population Projection
- Polk Vehicle Registrations

National Forecasts
- Examination of both BNEF and EEI forecasts
- Review of relationship between forecasts to extend EEI from 2030 to 2040

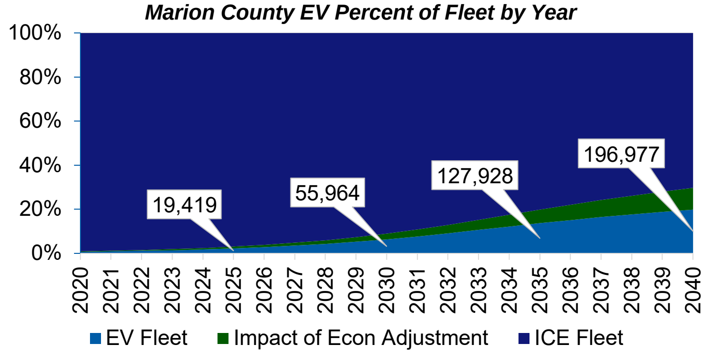
EV Fleet Estimate
- National EV % of vehicle fleet
- Project Marion County fleet size based on population growth
- % of fleet values applied to Marion County fleet

Economic Adjustment
- Ratio of Marion County to National median household income used to scale down EV fleet

LDEV Unit Forecast

Year	Total Fleet	EV Fleet	ICE Fleet	EV % Fleet
2020	833,269	5,573	827,696	0.7%
2025	850,552	19,419	831,133	2.3%
2030	865,691	55,964	809,727	6.5%
2035	879,523	127,928	751,595	14.6%
2040	893,781	196,977	696,804	22.0%

Marion County EV Percent of Fleet by Year



EV MWh Forecasting Methodology

LDEV Unit Energy → **IPL Peak / Off-Peak Hours** → **IndyGo Buses** → **Energy Forecast**

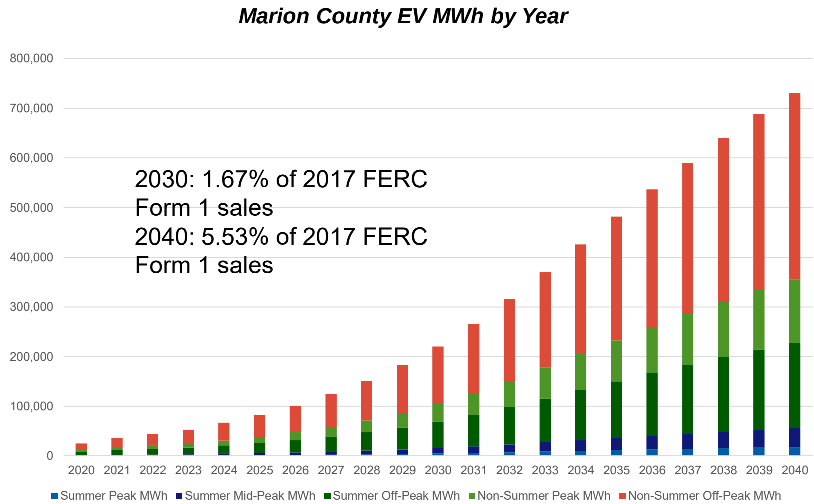
LDEV Unit Energy
- 3,613 kWh/year used, as discussed above

IPL Peak / Off-Peak Hours
- Rate EVX pricing periods used
- 2.5% of charging occurs in the Summer peak period

IndyGo Buses
- Annual energy usage based on vehicle specs and operations

Energy Forecast
- Annual energy and impacts driven by fleet size and unit kWh

Electric Vehicle MWh Impacts through 2040



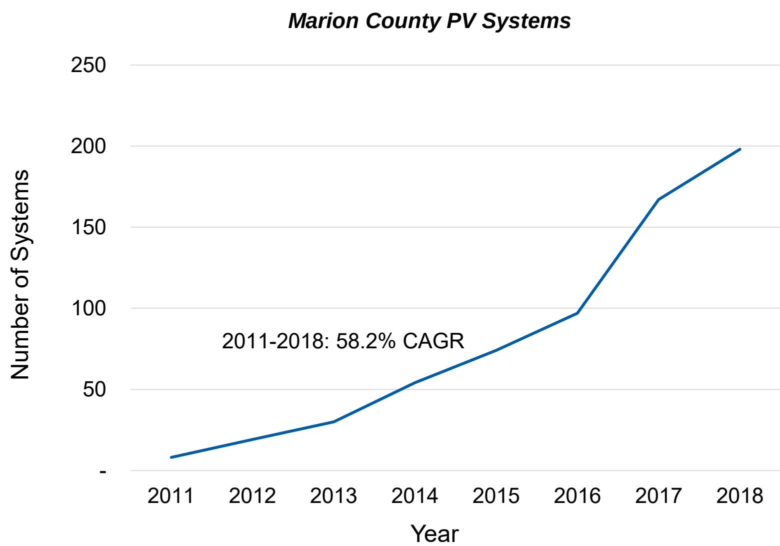
Distributed Solar Forecast

2018 Residential and Commercial Distributed Solar Baseline

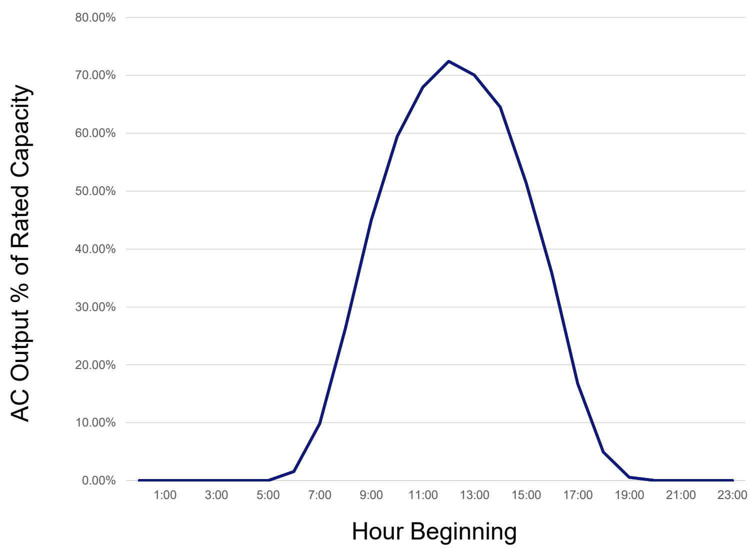
Attribute	Residential	C&I
IPL NEM count (Adjusted EIA counts from IPL 2018 NEM file)	177	21
Size (kW - DC)	8	125
Panel type	Anti-reflective crystalline silicon	Anti-reflective crystalline silicon
Array type	Fixed	Fixed
Capacity factor (AC)	15.8%	15.8%
Production basis	PVWatts – 46241	PVWatts – 46241

Notes: 1. Panel type is PVWatts "premium"
2. Zip code 46241 shows relatively high solar penetration

Historical Distributed Solar System Growth



Distributed Solar Production Curve



Distributed Solar Unit Forecasting Methodology

IPL 2018 NEM Baseline

- Cleaned input 2018 IPL NEM census dataset
- Retained all NEM records showing non-null system size and installation date

GTM 4Q18 Solar Outlook

- Compiled annual installed MWdc national actual and forecasts for 2013-2023 separately for residential and non-residential customers
- Examined impact of high-volume states, relative intensity of activity in Indiana, etc.

2019-23 GTM-based CAGR

- Computed 2019-2023 compound annual growth rates for residential and non-residential MWdc installed nationally

Apply CAGR to IPL NEM Baseline

- Applied compound annual growth rates to 2018 IPL actual number of systems for 2019 and 2020-2040
- Applied baseline IPL system size in kW-DC and annual kWh-AC separated into Rate CGS peak/off-peak splits

Input Data: GTM-based CAGR

Year	Incremental Residential MWdc	Incremental Residential Growth Rate	Incremental C&I MWdc	Incremental C&I Growth Rate
2019	2,510	10.62%	1,761	-16.70%
2020	2,827	12.63%	1,853	5.22%
2021	3,302	16.80%	1,965	6.04%
2022	3,424	3.69%	1,944	-1.07%
2023	3,775	10.25%	2,144	10.29%
CAGR		10.74%		5.04%

Distributed Solar kW and MWh Forecasting Methodology

PVWatts Output

- 8 kW-DC residential and 125 kW-DC C&I systems
- 46241 zip code
- Fixed, open rack coated crystalline silicone panels

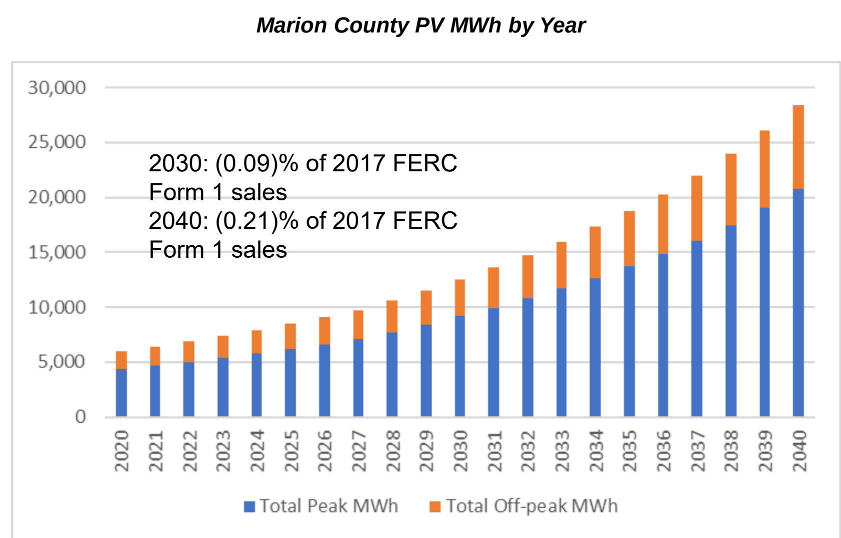
IPL Peak/Off-Peak Hours

- Rate CGS hours 8-23 are peak
- Rate CGS assigns all weekends to off-peak

Derived kWh per kW

- PVWatts sum of peak kWh-AC output divided by system kW-DC
- PVWatts sum of off-peak kWh-AC divided by system kW

Distributed Solar MWh Impacts through 2040



MCR Performance Solutions, LLC

Summary: EV and Distributed Solar Forecast

MCR Performance Solutions, LLC

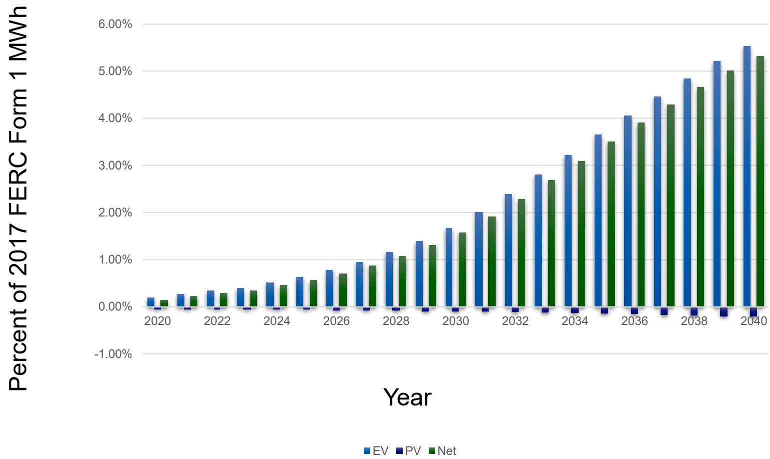
EV and Distributed Solar Forecast Summary: MWh

Year	EV Summer Peak MWh	EV Summer Mid-Peak MWh	EV Summer Off-Peak MWh	EV Non-Summer Peak MWh	EV Non-Summer Off-Peak MWh	EV Annual MWh	PV Peak MWh	PV Off-Peak MWh	PV Annual MWh
2020	500	1,076	6,273	3,610	13,506	24,965	4,388	1,619	6,007
2021	697	1,500	9,129	5,031	19,595	35,952	4,701	1,734	6,435
2022	887	1,908	11,277	6,399	24,255	44,726	5,035	1,858	6,893
2023	1,063	2,287	13,296	7,668	28,631	52,944	5,399	1,992	7,391
2024	1,378	2,966	16,620	9,947	35,883	66,795	5,783	2,134	7,917
2025	1,743	3,751	20,399	12,578	44,140	82,611	6,197	2,286	8,483
2026	2,175	4,680	24,803	15,693	53,776	101,126	6,632	2,447	9,079
2027	2,730	5,875	30,362	19,702	65,961	124,630	7,114	2,626	9,740
2028	3,374	7,259	36,738	24,343	79,945	151,657	7,754	2,861	10,615
2029	4,138	8,903	44,241	29,856	96,417	183,555	8,432	3,111	11,543
2030	5,023	10,809	52,878	36,248	115,389	220,348	9,170	3,383	12,553

EV and Distributed Solar Forecast Summary: MWh (continued)

Year	EV Summer Peak MWh	EV Summer Mid-Peak MWh	EV Summer Off-Peak MWh	EV Non-Summer Peak MWh	EV Non-Summer Off-Peak MWh	EV Annual MWh	PV Peak MWh	PV Off-Peak MWh	PV Annual MWh
2031	6,117	13,163	63,456	44,142	138,644	265,523	9,948	3,670	13,618
2032	7,358	15,833	75,151	53,094	164,413	315,848	10,777	3,976	14,753
2033	8,706	18,734	87,718	62,822	192,132	370,112	11,677	4,308	15,985
2034	10,095	21,723	100,667	72,845	220,694	426,023	12,648	4,666	17,314
2035	11,483	24,709	113,604	82,859	249,229	481,884	13,689	5,050	18,739
2036	12,843	27,636	126,285	92,675	277,200	536,639	14,811	5,464	20,275
2037	14,156	30,462	138,525	102,150	304,200	589,493	16,034	5,916	21,950
2038	15,414	33,168	150,251	111,227	330,063	640,122	17,490	6,453	23,943
2039	16,615	35,751	161,440	119,888	354,744	688,439	19,057	7,031	26,088
2040	17,681	38,045	171,380	127,583	376,669	731,358	20,756	7,658	28,414

EV and Distributed Solar as a Percent of 2017 Sales



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MCR Performance Solutions, LLC

ipl an AES company

BREAK

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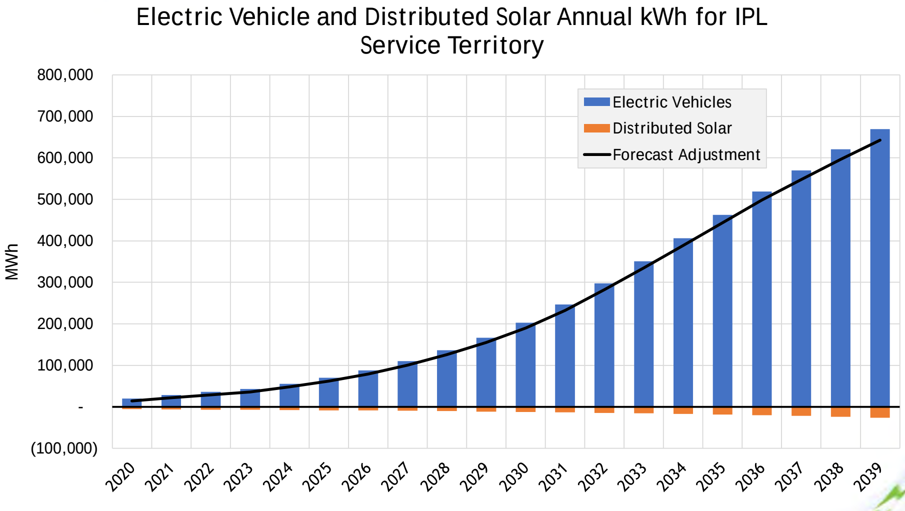
LOAD FORECAST - HIGH & LOW
RECAP OF CUSTOMER CLASS BREAKOUT

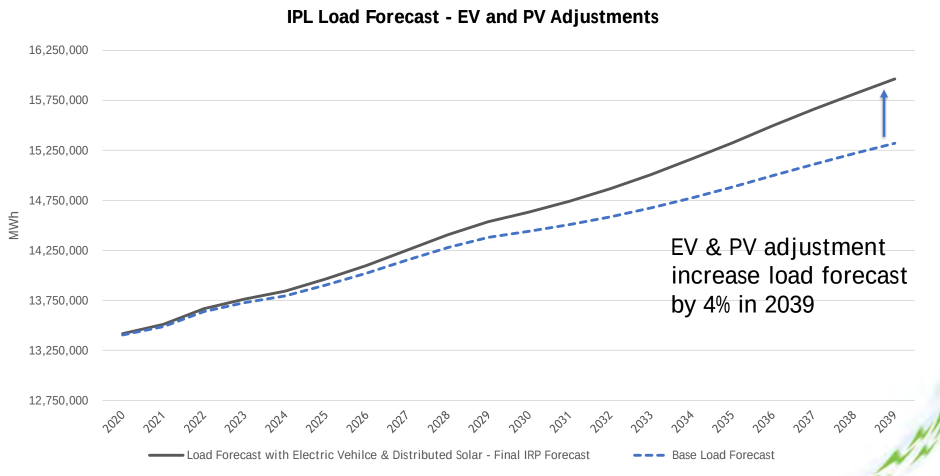
Erik Miller

Senior Research Analyst

EV & PV ADJUSTMENT



IPL LOAD FORECAST EV & PV ADJUSTMENT



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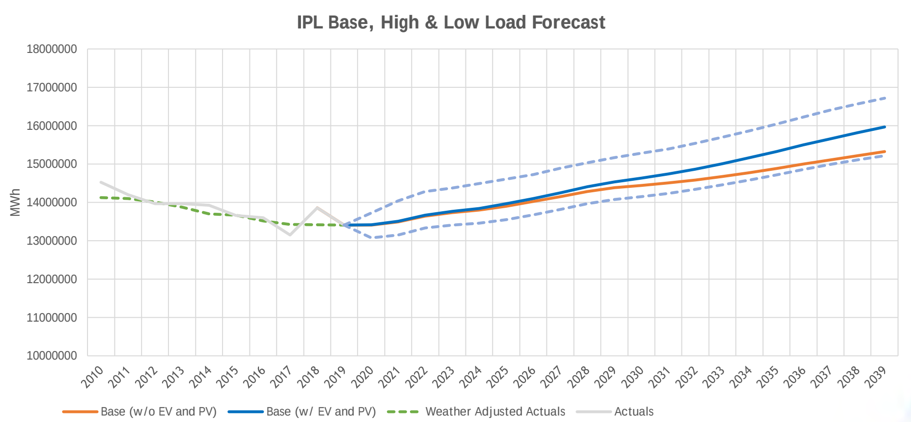
IPL BASE, HIGH & LOW LOAD FORECAST

INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP



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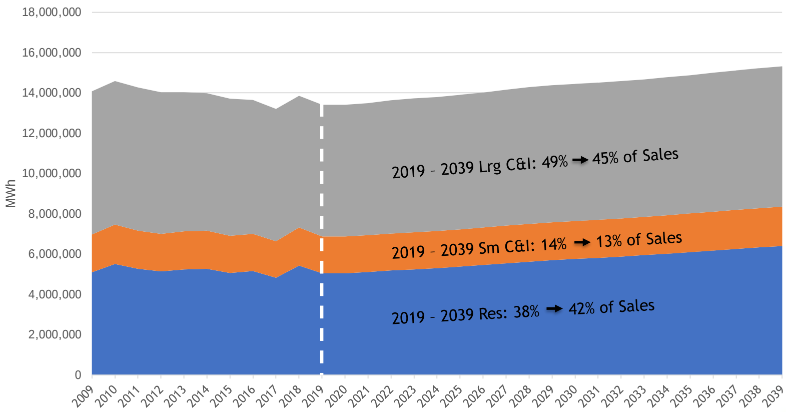
CLASS SALES FORECAST

INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP

	Residential	Small C&I	Large C&I
Average Annual Growth Rate 2020 - 2039:	1.2%	0.2%	0.3%



No Losses Included

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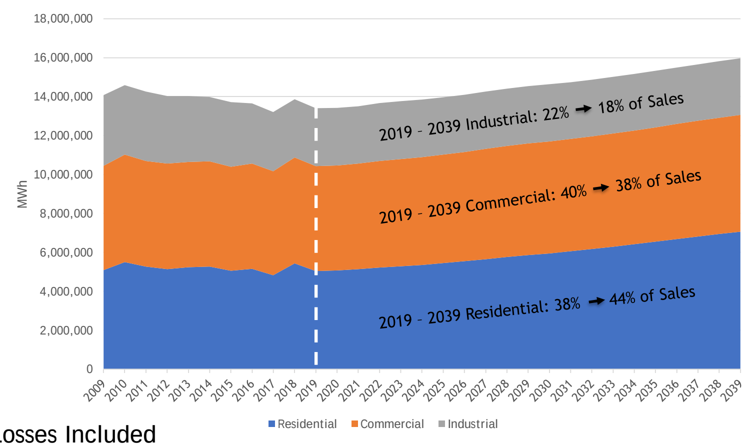
CLASS SALES FORECAST

INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP;
INCLUDES EV & PV

	Residential	Commercial	Industrial
Average Annual Growth Rate 2020 - 2039:	1.7%	0.5%	-0.1%



No Losses Included

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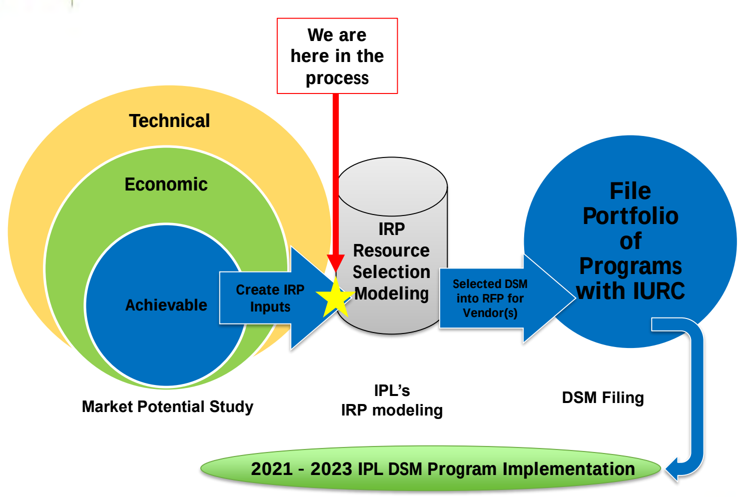
DSM BUNDLES IN IRP MODELING

Erik Miller

Senior Research Analyst

DSM PROCESS & THE IRP



IRP DSM BUNDLING APPROACH

- DSM Bundles are 0.25% "decrements" of annual load excluding Opt Out customers
- Bundles are created from the Market Potential Study's Realistic Achievable Potential
- Each "decrement" bundle has an associated loadshape and cost/MWh that serves as inputs into the IRP model
- GDS uses loadshapes specific to measure-types to create 8760s for the IRP model
- Residential and C&I are combined in bundles
- Ten bundles will be included as selectable resources in the IRP model
  - 8 - Energy Efficiency Bundles
  - 2 - Demand Response Bundles

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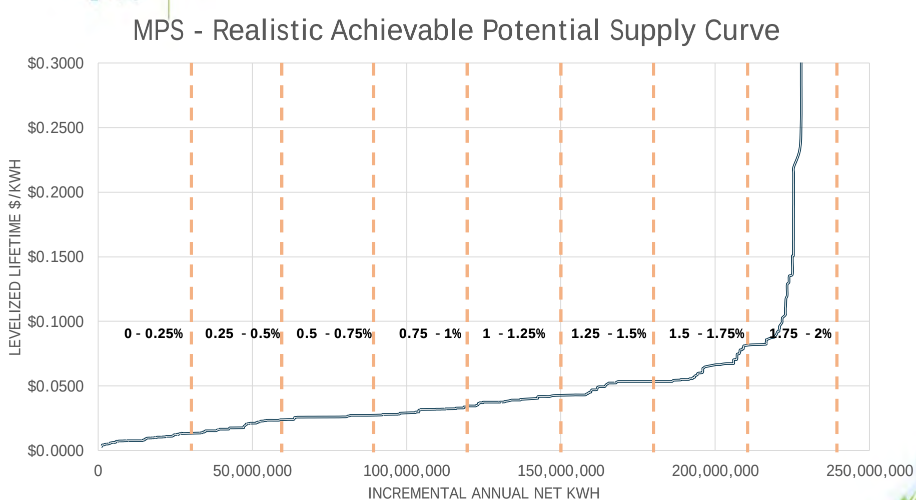
DSM DECREMENT BUNDLES



Data from IRP/MPS Planning Year: 2026

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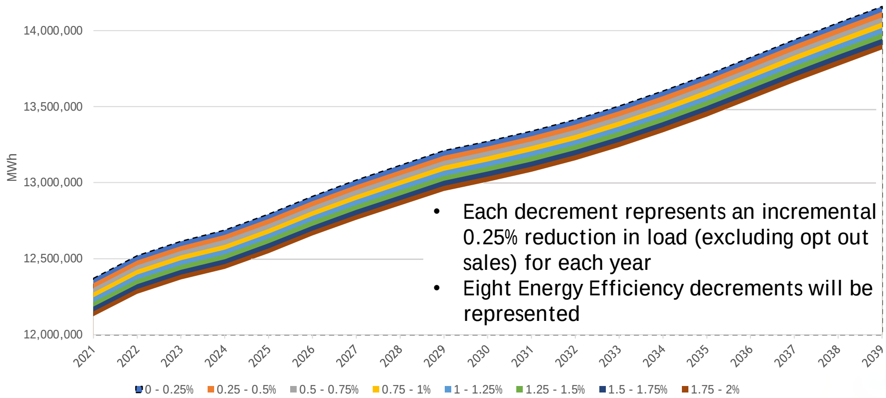
DSM DECREMENT BUNDLES - PERCENT OF OPT OUT SALES



- Each decrement represents an incremental 0.25% reduction in load (excluding opt out sales) for each year
- Eight Energy Efficiency decrements will be represented

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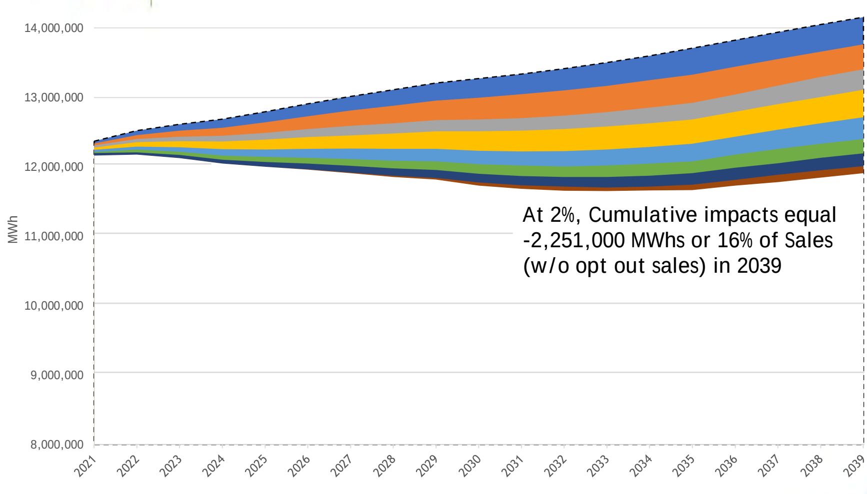
DSM DECREMENT BUNDLES - CUMULATIVE IMPACTS



At 2%, Cumulative impacts equal -2,251,000 MWhs or 16% of Sales (w/o opt out sales) in 2039

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DSM NEXT STEPS

Next Steps:

- Evaluate DSM in the IRP Model in May and June
- Present results at Public Advisory Meeting #4

LUNCH BREAK

MODELING AND SCENARIO RECAP

Patrick Maguire

Director of Resource Planning

RECAP: SCENARIO DRIVERS

	Reference Case	Scenario A: Carbon Tax	Scenario B: Carbon Tax + High Gas	Scenario C: Carbon Tax + Low Gas	Scenario D: No Carbon Tax + High Gas
Natural Gas Prices	Base	Base	**HIGH ↑**	**LOW ↓**	**HIGH ↑**
Carbon Tax	No Carbon Price	**Carbon Price (2028+)**	**Carbon Price (2028+)**	**Carbon Price (2028+)**	No Carbon Price
Coal Prices	Base	Base	Base	Base	Base
IPL Load	Base	Base	Base	**LOW ↓**	**HIGH ↑**
Capital Costs for Wind, Solar, and Storage	Base	Base	Base	Base	Base

FUNDAMENTAL FORECAST VENDOR

- **Wood Mackenzie H1 2018 Long Term Outlook**
- Provided Cases:
  1. Federal Carbon Case (Carbon tax starting 2028)
  2. Federal Carbon Case + High Gas Sensitivity
  3. No Carbon Case
  4. No Carbon + Low Gas Sensitivity
  5. No Carbon Case + High Gas Sensitivity
  6. Federal Carbon Case + Low Gas Sensitivity

Custom sensitivities completed for IPL - provided to NDA stakeholders

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RECAP: FORWARD CURVES

	Deterministic Modeling	Stochastic Ranges	Notes
Power	✓	✓	On/Off peak monthly power prices from Wood Mackenzie. Hourly shapes created in PowerSimm.
Natural Gas	✓	✓	Wood Mackenzie monthly gas prices with delivery adders. Daily price shapes created in PowerSimm.
Coal	✓	✓	Internally sourced IPL coal curves.
Fuel Oil	✓	✓	Wood Mackenzie
Emissions	✓	✗	NOx and SO2 curves will be sourced from forward curves. Carbon prices from Wood Mackenzie.
Capacity	✓	✓	Capacity will be valued at the estimated bilateral price for MISO Zone 6.

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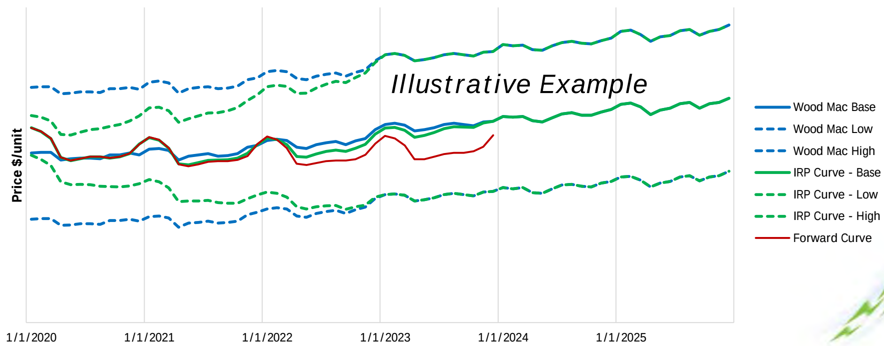
POWER AND NATURAL GAS: BLENDED CURVES FOR YEARS 1-3

- Forward curves utilized through 2023
- Blended into fundamental curves starting in 2021 for Base Case, 2020 for High and Low Gas Sensitivities



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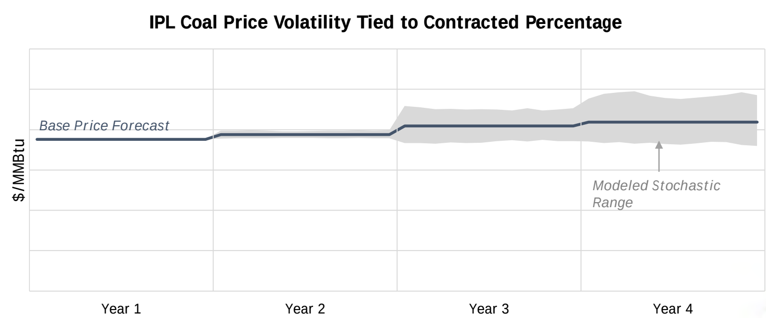
COAL PRICE MODELING

- IPL Coal Curve based on RFP prices and market intelligence on southern Indiana inland coal market
- Stochastic volatility applied only to open/unhedged portion



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SCENARIO FRAMEWORK

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
No Accelerated Retirements	**Portfolio 1**	1a	1b	1c	1d
Pete Unit 1 Retire **2021** Pete Units 2-4 Operational	**Portfolio 2**	2a	2b	2c	2d
Pete 1 Retire **2021**; Pete 2 Retire **2023** Pete Units 3-4 Operational	**Portfolio 3**	3a	3b	3c	3d
Pete 1 Retire **2021**; Pete 2 Retire **2023**; Pete 3 Retire **2026**; Pete Unit 4 Operational	**Portfolio 4**	4a	4b	4c	4d
Pete 1 Retire **2021**; Pete 2 Retire **2023**; Pete 3 Retire **2026**; Pete 4 Retire **2030**	**Portfolio 5**	5a	5b	5c	5d

Wide range of scenarios and portfolios will inform resource decisions. Modeling underway and will be ongoing over the next two months.

IRP MODELING: PUTTING THE PIECES TOGETHER

Load Forecast
- Base, Low, and High
- Electric Vehicles
- Distributed Solar

Existing Resources
- Age, Type, Primary Fuel, Size

New Resources
- Supply-Side Options
- DSM

Commodity Prices
- Vendor, Key Variables

Scenarios
- Drivers defined
- Modeling Framework

DATA RELEASE SCHEDULE

IPL 2019 IRP Assumptions: Data Release Schedule

Dataset	Data Available
Commodity Price Forecasts [Complete]	Friday, April 12, 2019
MISO Solar Capacity Credit Calculation [Complete]	Friday, April 12, 2019
Capital Cost Assumptions for New Resources [Complete]	Friday, April 12, 2019
Updated Commodity Price Forecasts	Tuesday, May 14, 2019
IPL Load Forecast: Energy, Peak, Reserve Margin Target	Tuesday, May 14, 2019
Operating Characteristics for New Resources	Tuesday, June 11, 2019
Modeling Constraints for New Resources	Tuesday, June 11, 2019
Cost and Operating Characteristics for Existing IPL Resources	Tuesday, June 11, 2019
Stochastic Parameters and Distributions	Tuesday, June 11, 2019

Q&A, CONCLUDING REMARKS & NEXT STEPS

Stewart Ramsay
Meeting Facilitator

Patrick Maguire
Director of Resource Planning

NEXT STEPS

- **Next Meeting: TBD**
- Meeting #4 Material:
  - Scenario Descriptions and Results
  - Preliminary Model Results
  - Risk Analysis and Stochastics

Email questions, comments, or other feedback to ipl.irp@aes.com

ipl an AES company

IPL 2019 IRP: PUBLIC ADVISORY MEETING #4

September 30, 2019

ipl an AES company

WELCOME & OPENING REMARKS

Vince Parisi

IPL President and CEO

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MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

Topic	Time (Eastern)	Presenter(s)
Registration	12:30 – 1:00	-
Welcome & Opening Remarks	1:00 – 1:15	Vince Parisi, President and CEO, IPL
Meeting Objectives & Agenda	1:15 – 1:20	Stewart Ramsay, Meeting Facilitator
Modeling and Scenario Recap	1:20 – 1:40	Patrick Maguire, Director of Resource Planning
Preliminary Model Results – Optimized Portfolios	1:40 – 2:30	Patrick Maguire, Director of Resource Planning
BREAK	2:30 – 3:00	
Portfolio Metrics	3:00 – 3:45	Patrick Maguire, Director of Resource Planning
Final Q&A, Concluding Remarks & Next Steps	3:45 – 4:00	Stewart Ramsay, Meeting Facilitator Patrick Maguire, Director of Resource Planning

MODELING AND SCENARIO RECAP

Patrick Maguire

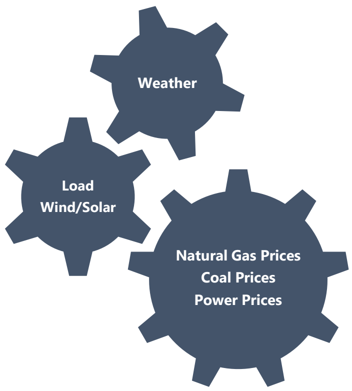
Director of Resource Planning

MODELING ASSUMPTIONS

- Solar Capacity Credit: re-calibrated capacity credit to reflect capacity contribution for tracking solar, which is higher than fixed tilt and rooftop. Capacity contribution validated by IPL tracking solar historical data
- Updated modeling constraints around new resources
- Releasing aero and recip capital costs, battery storage costs and operating characteristics
- Added 1x1 CCGT in 2034 in all portfolios: firm, dispatchable capacity on IPL's 138 kV system required with Harding Street Steam 5-7 retirements; final technology solution to be determined at a later date, but CCGT simply used as placeholder for now

CAPACITY EXPANSION

Stochastic Capacity Expansion



Portfolios optimized across a wide range of futures with dynamic commodity prices, load shapes, and renewable profiles through time and across iterations

KEY HIGHLIGHTS FROM CAPACITY EXPANSION RUNS

- Renewables being selected first, with storage and gas technology filling in remaining shortfall
- Small variations in capacity expansion between carbon tax and no carbon tax case because of model preference for renewables in both cases
- Results led IPL to determine fewer candidate portfolios stressed across range of scenarios better than assessment of more portfolios with slight variations

UNIT RETIREMENTS AND PORTFOLIOS

MODELED COAL RETIREMENTS

No Accelerated Retirements	**Portfolio 1**
Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	**Portfolio 2**
Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	**Portfolio 3**
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	**Portfolio 4**
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	**Portfolio 5**

RETIREMENTS IN ALL PORTFOLIOS

- 2024: Harding Street Oil 1-2 (37 MW)
- 2031: Harding Street ST 5-6 (189 MW)
- 2034: Harding Street ST 7 (394 MW)

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PRELIMINARY MODEL RESULTS: OPTIMIZED PORTFOLIOS

Patrick Maguire

Director of Resource Planning

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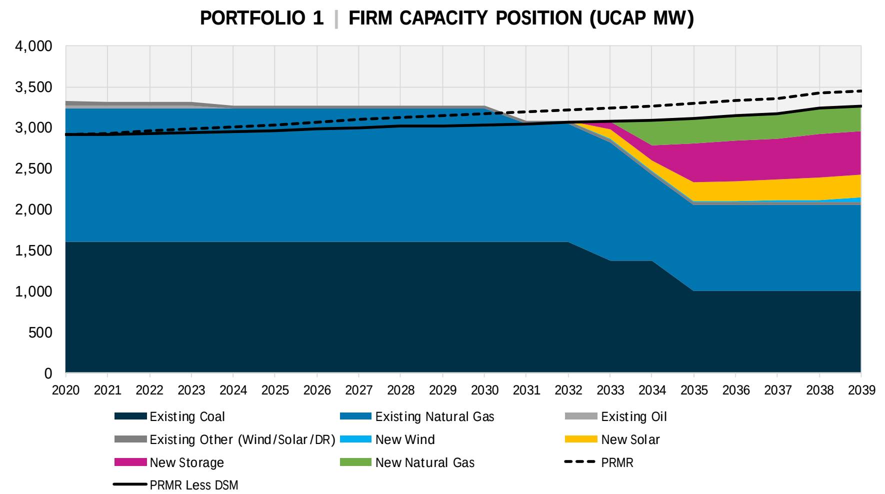
PORTFOLIO 1: FIRM UCAP POSITION



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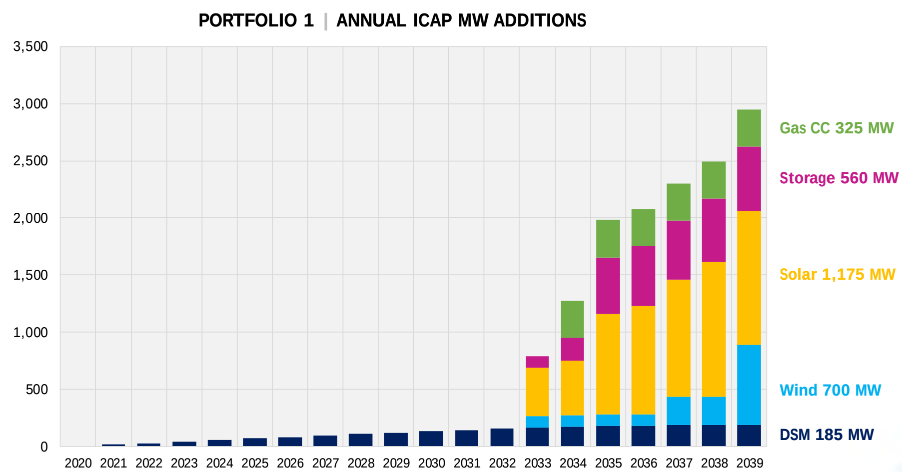
PORTFOLIO 1: ICAP MW ADDITIONS



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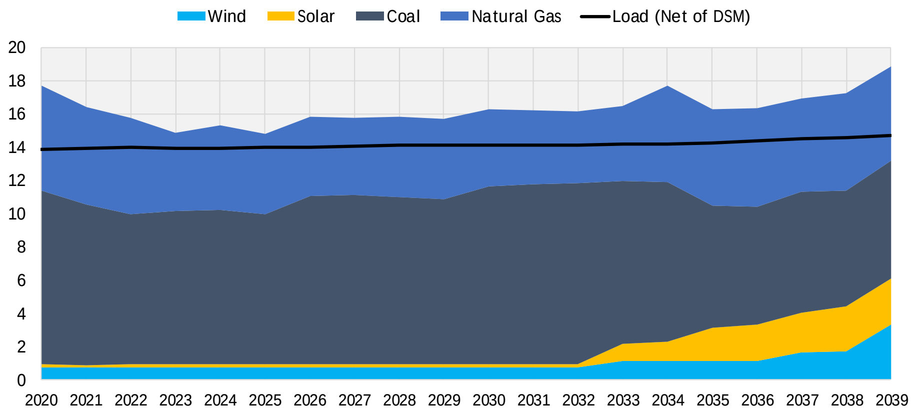
PORTFOLIO 1: REFERENCE CASE ENERGY MIX (1 OF 2)

PORTFOLIO 1 | Annual Energy Mix (TWh)



Energy mix for portfolios will vary across scenarios

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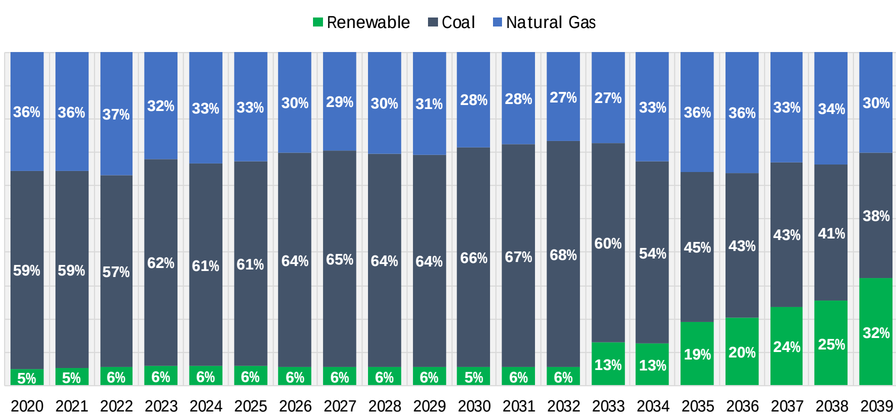
PORTFOLIO 1: REFERENCE CASE ENERGY MIX (2 OF 2)

PORTFOLIO 1 | Annual Produced Energy: Percent by Fuel Type



Energy mix for portfolios will vary across scenarios

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PORTFOLIO 1 RECAP

New Build by 2039

- First year short: 2033 (new DSM delays new build by 2 years)
- Wind: 700 MW
- Solar: 1,175 MW
- Storage: 560 MW
- Gas CCGT: 325 MW

Retirements

- Petersburg
  - Pete 1: 2033
  - Pete 2: 2035
  - Total UCAP: 591 MW
- Harding Street:
  - HS ST5: 2031
  - HS ST6: 2031
  - HS ST7: 2034
  - Total UCAP MW: 583

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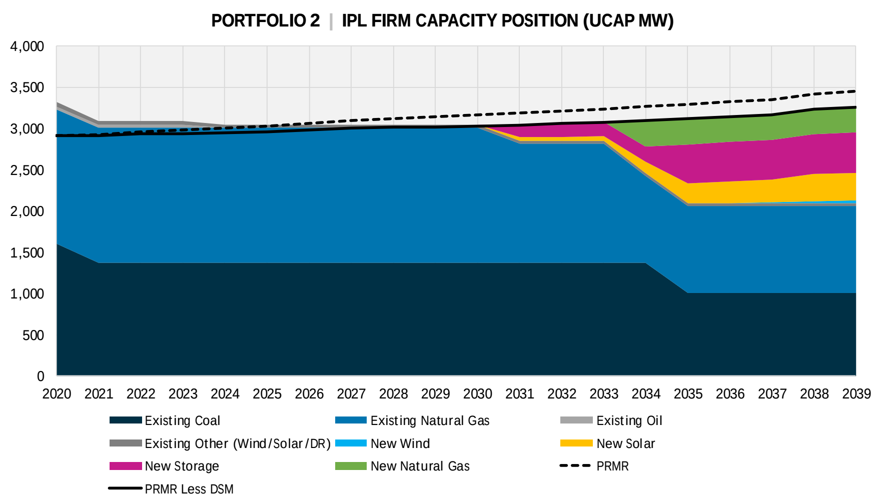
PORTFOLIO 2: FIRM UCAP CAPACITY



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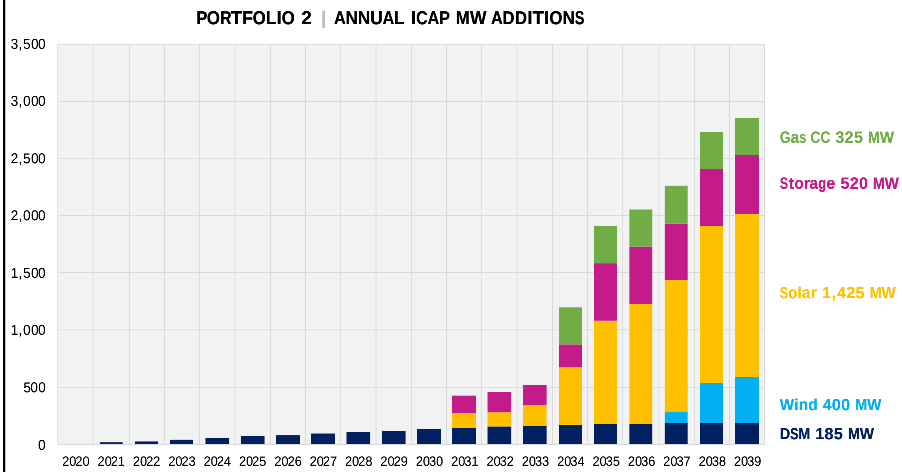
PORTFOLIO 2: ICAP MW ADDITIONS



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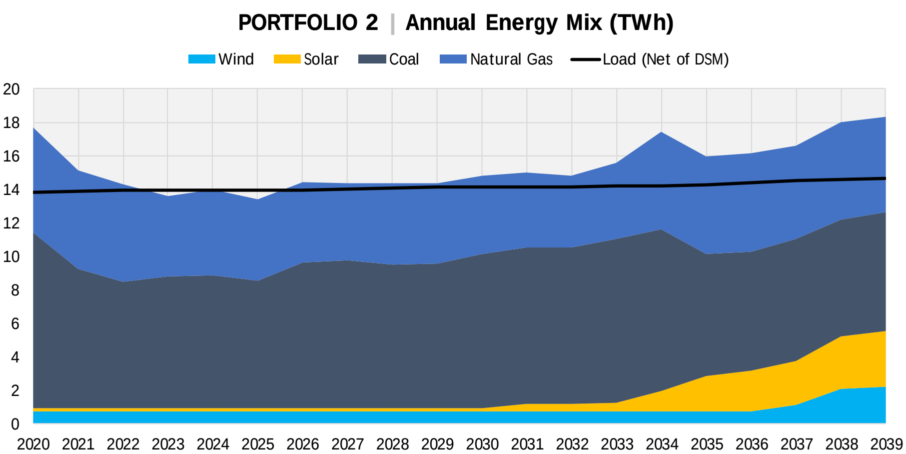
PORTFOLIO 2: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

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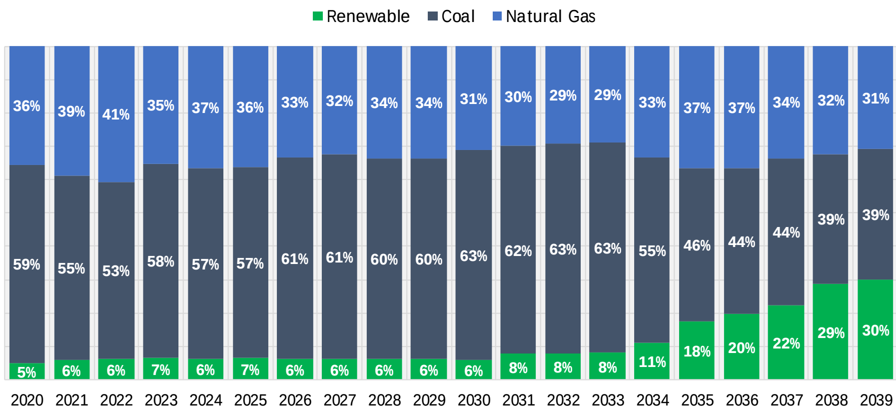
PORTFOLIO 2: REFERENCE CASE ENERGY MIX (2 OF 2)

PORTFOLIO 2 | Annual Produced Energy: Percent by Fuel Type



Energy mix for portfolios will vary across scenarios

19

PORTFOLIO 2 RECAP

New Build by 2039

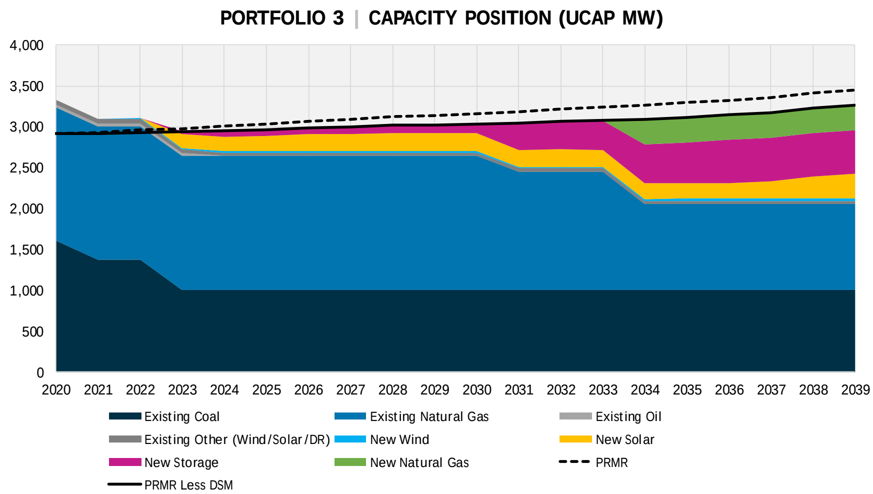
- First year short: 2031 (new DSM delays new build by 2 years)
- Wind: 400 MW
- Solar: 1,425 MW
- Storage: 520 MW
- Gas CCGT: 325 MW

Retirements

- Petersburg
  - Pete 1: 2021
  - Pete 2: 2035
  - Total UCAP: 591 MW
- Harding Street:
  - HS ST5: 2031
  - HS ST6: 2031
  - HS ST7: 2034
  - Total UCAP MW: 583

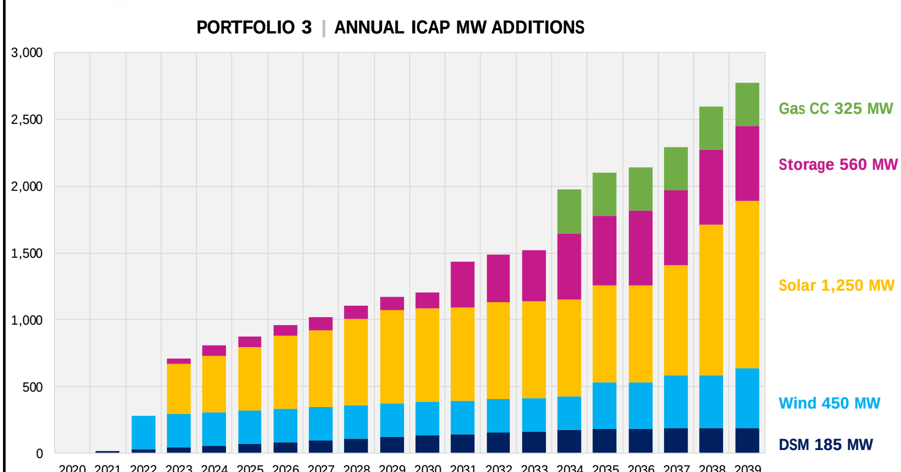
20

PORTFOLIO 3: FIRM UCAP CAPACITY



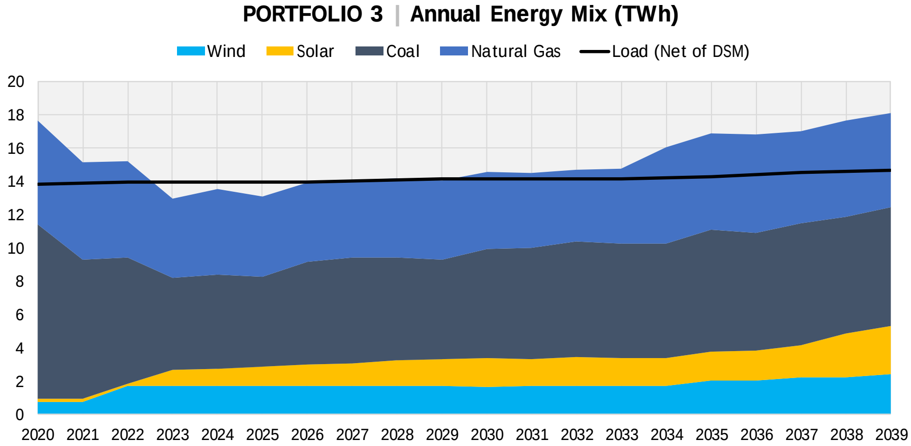
21

PORTFOLIO 3: ICAP MW ADDITIONS



22

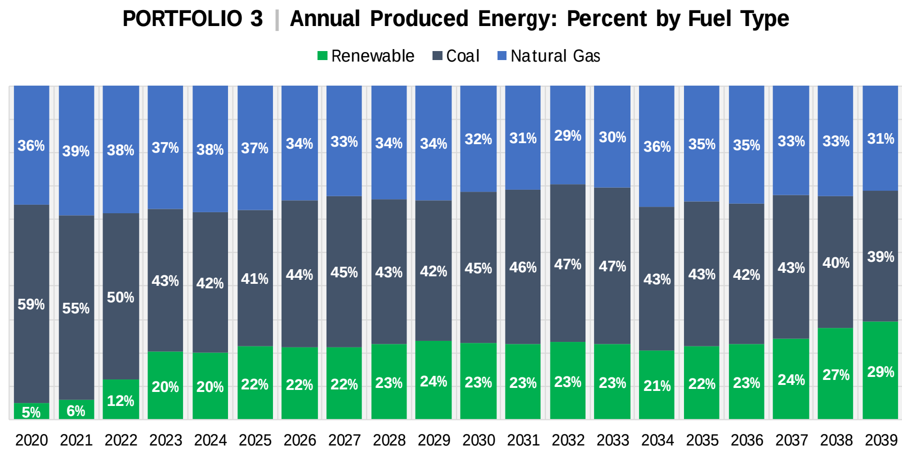
PORTFOLIO 3: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

23

PORTFOLIO 3: REFERENCE CASE ENERGY MIX (2 OF 2)



Energy mix for portfolios will vary across scenarios

24

PORTFOLIO 3 RECAP

New Build by 2039

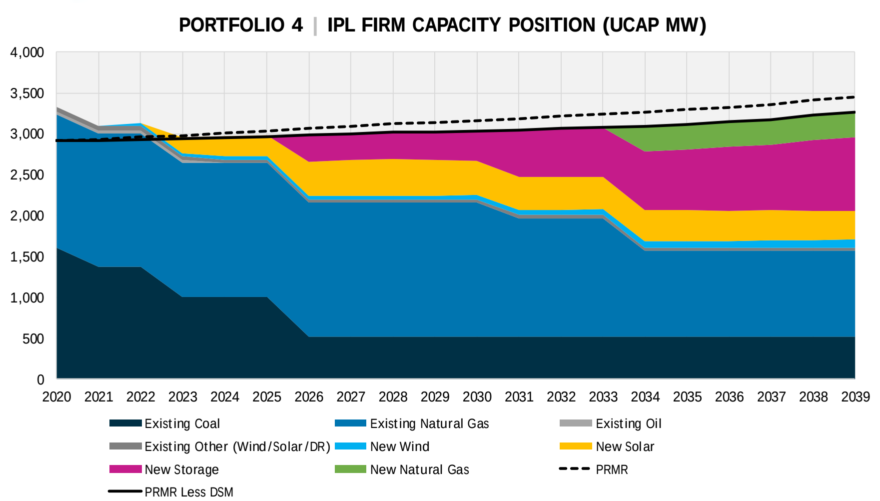
- First year short: 2023 (new DSM adds 40 MW UCAP in 2023)
- Wind: 450 MW
- Solar: 1,250 MW
- Storage: 560 MW
- Gas CCGT: 325 MW

Retirements

- Petersburg
  - Pete 1: 2021
  - Pete 2: 2023
  - Total UCAP: 591 MW
- Harding Street:
  - HS ST5: 2031
  - HS ST6: 2031
  - HS ST7: 2034
  - Total UCAP MW: 583

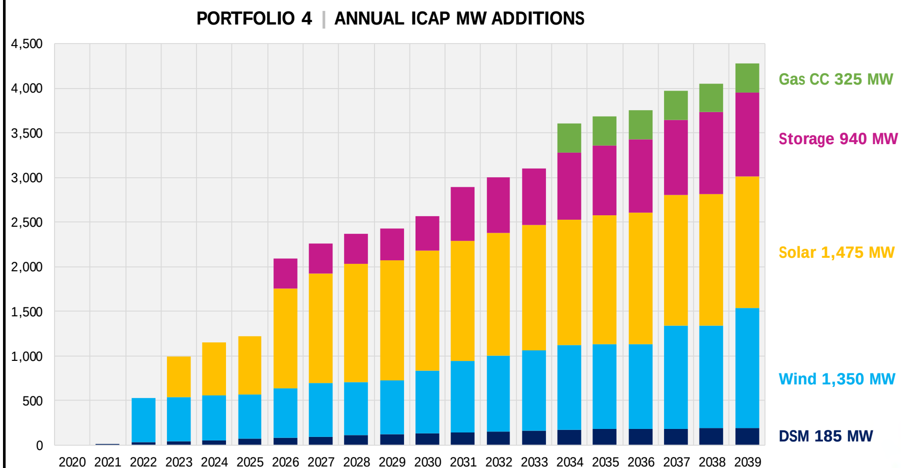
25

PORTFOLIO 4: FIRM UCAP CAPACITY



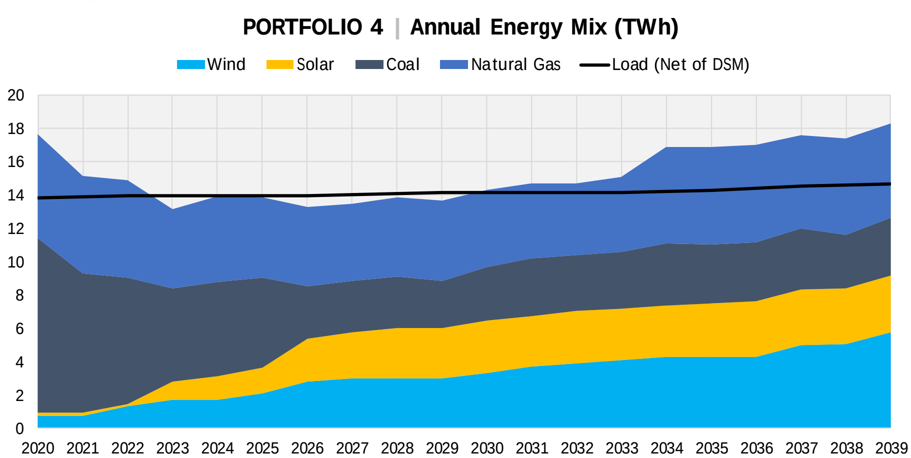
26

PORTFOLIO 4: ICAP MW ADDITIONS



27

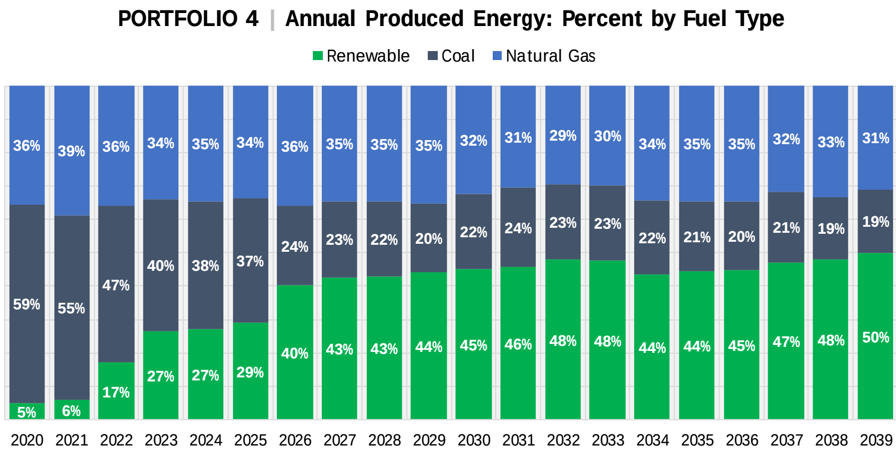
PORTFOLIO 4: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

28

PORTFOLIO 4: REFERENCE CASE ENERGY MIX (2 OF 2)



Energy mix for portfolios will vary across scenarios

PORTFOLIO 4 RECAP

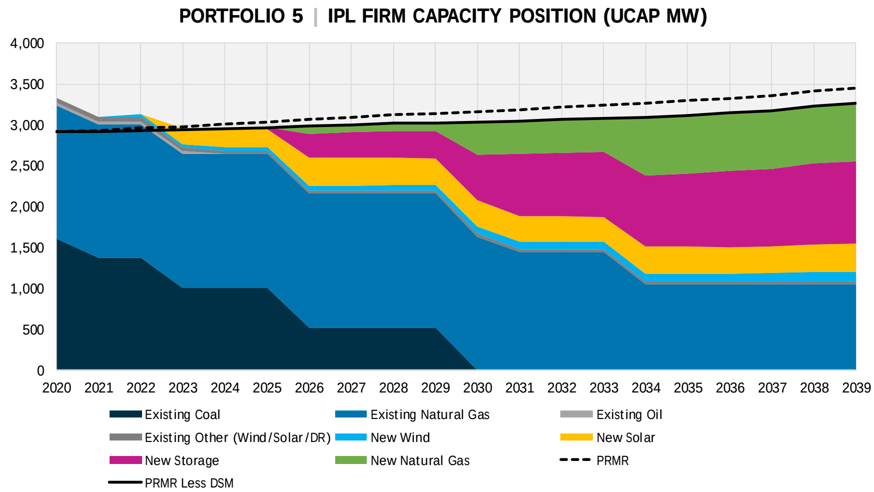
New Build by 2039

- First year short: 2023
- DSM: 185 MW
- Wind: 1,350 MW
- Solar: 1,475 MW
- Storage: 940 MW
- Gas CCGT: 325 MW

Retirements

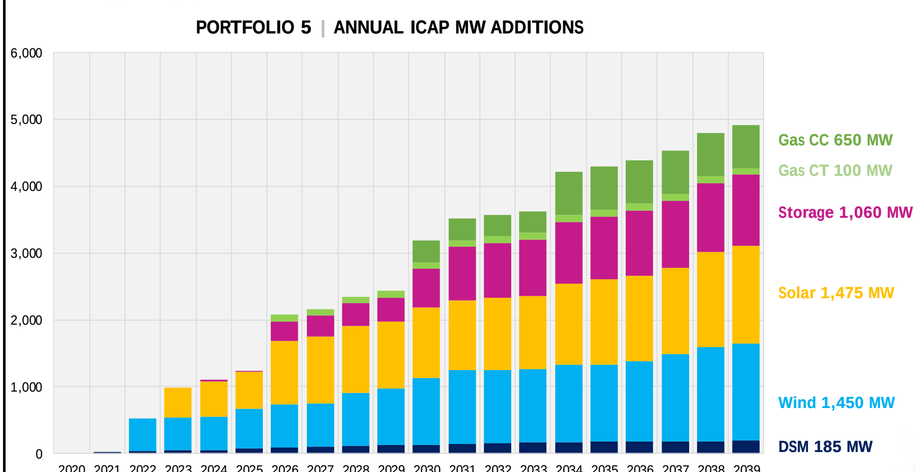
- Petersburg
  - Pete 1: 2021
  - Pete 2: 2023
  - Pete 3: 2026
  - Total UCAP: 1,076 MW
- Harding Street:
  - HS ST5: 2031
  - HS ST6: 2031
  - HS ST7: 2034
  - Total UCAP MW: 583

PORTFOLIO 5: FIRM UCAP CAPACITY



31

PORTFOLIO 5: ICAP MW ADDITIONS



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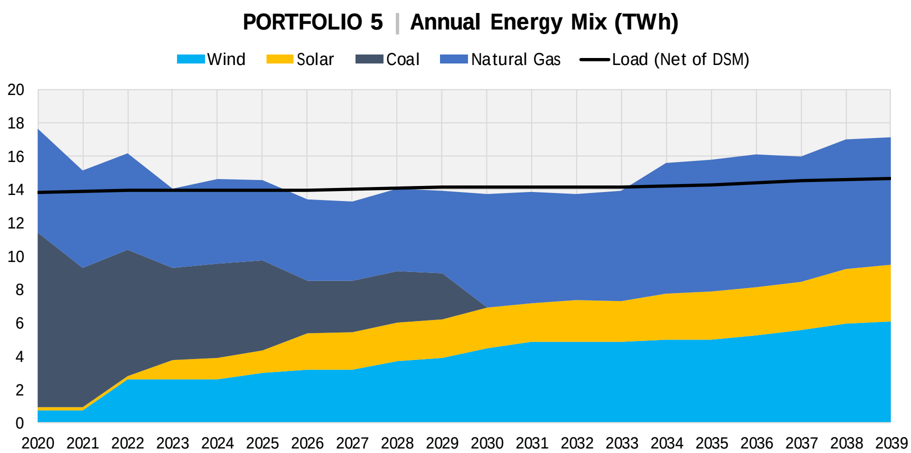
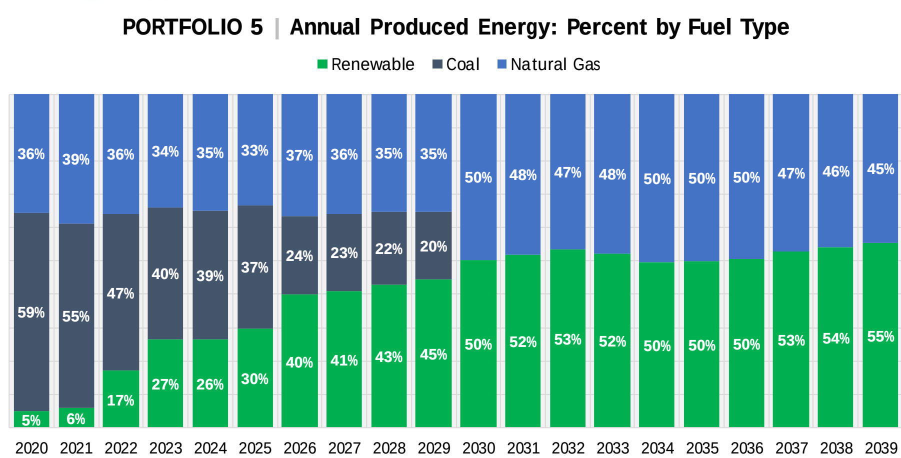
PORTFOLIO 5: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

PORTFOLIO 5: REFERENCE CASE ENERGY MIX (2 OF 2)



Energy mix for portfolios will vary across scenarios

PORTFOLIO 5 RECAP

New Build by 2039

- First year short: 2023
- DSM: 185 MW
- Wind: 1,450 MW
- Solar: 1,475 MW
- Storage: 1,060 MW
- Gas CCGT: 650 MW
- Gas CT: 100 MW

Retirements

- Petersburg
  - Pete 1: 2021
  - Pete 2: 2023
  - Pete 3: 2026
  - Pete 4: 2030
  - Total UCAP: 1,600 MW
- Harding Street:
  - HS ST5: 2031
  - HS ST6: 2031
  - HS ST7: 2034
  - Total UCAP MW: 583

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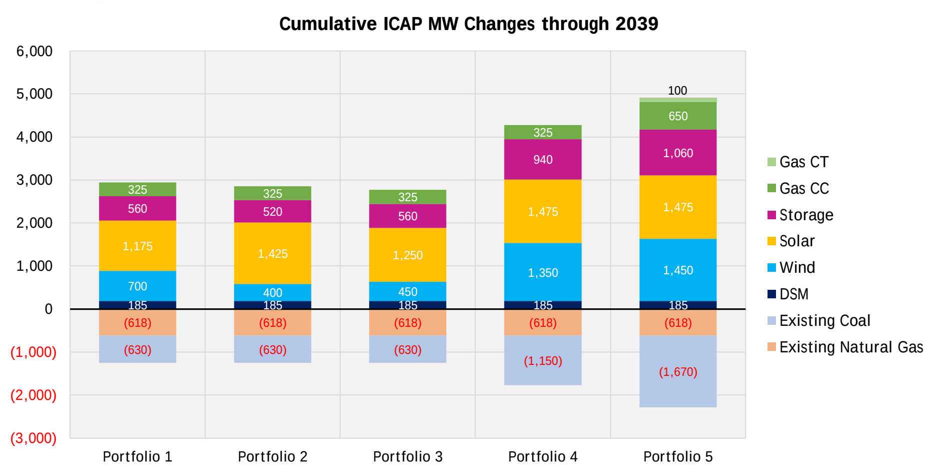
PORTFOLIO SUMMARIES



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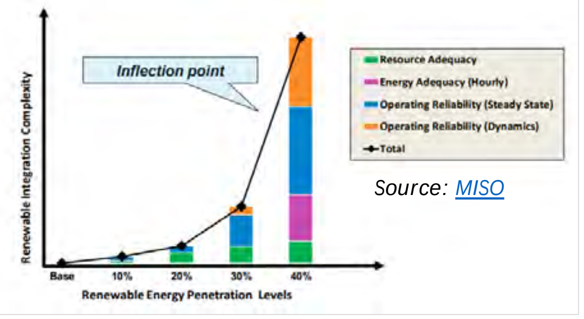
OBSERVATIONS AND TAKEAWAYS

- Clear that a high renewable future is expected in next 10-15 years: just a matter of timing and scale
- Studies from MISO indicate increased complexity of renewable integration as renewable energy share moves past 30%
- Level of IPL wind and solar build will change through time as company and industry work to solve issues and develop new modeling capabilities



Source: MISO

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PORTFOLIO METRICS

Patrick Maguire

Director of Resource Planning

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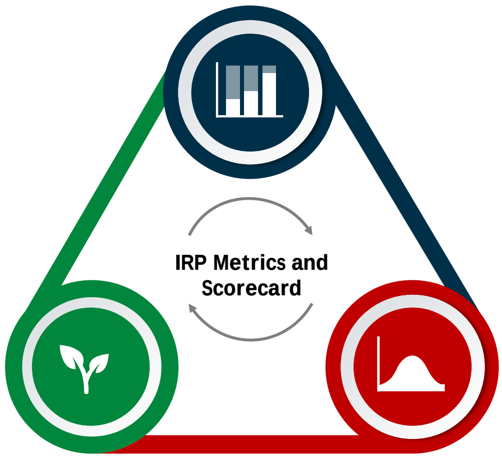
IRP PORTFOLIO METRICS

COST
What is the impact on customer rates in the short term and long term?



ENVIRONMENTAL
Consideration of air and water impacts

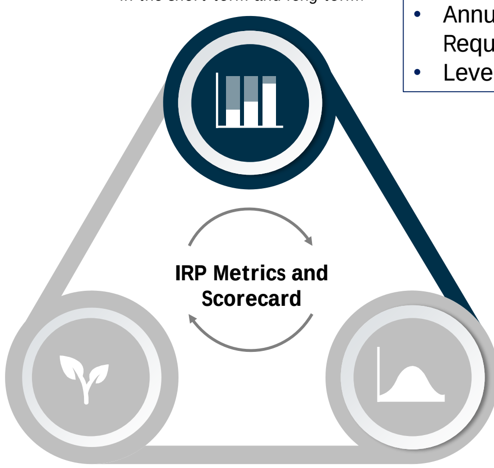
RISK
How much risk do the portfolios present to customers?

39

IRP PORTFOLIO METRICS

COST
What is the impact on customer rates in the short term and long term?

- 20-year PVRR
- Annual Revenue Requirement
- Levelized $/kWh rate



ENVIRONMENTAL
Consideration of air and water impacts

RISK
How much risk do the portfolios present to customers?

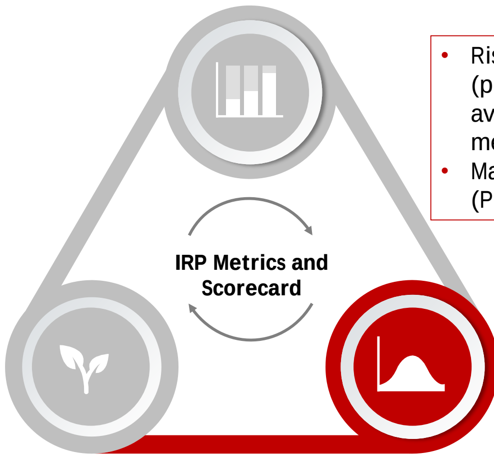
40

IRP PORTFOLIO METRICS

COST

What is the impact on customer rates in the short term and long term?

- Risk Premium (probability-weighted average above median)
- Market Interaction (Purchases and Sales)



ENVIRONMENTAL

Consideration of air and water impacts

RISK

How much risk do the portfolios present to customers?

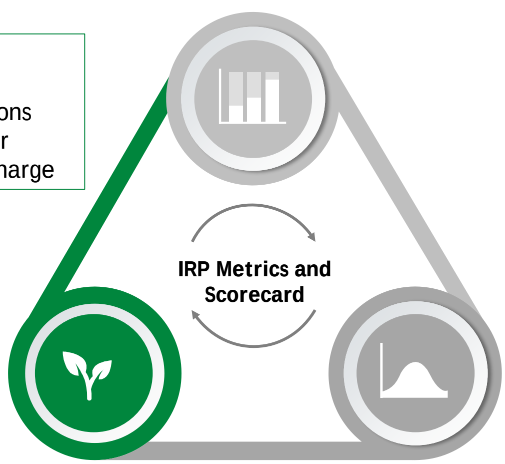
41

IRP PORTFOLIO METRICS

COST

What is the impact on customer rates in the short term and long term?

- CO_2 Emissions
- CO_2 Intensity
- NO_x, SO_2 Emissions
- Estimated water intake and discharge



ENVIRONMENTAL

Consideration of air and water impacts

RISK

How much risk do the portfolios present to customers?

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Q&A, CONCLUDING REMARKS, & NEXT STEPS

Stewart Ramsay
Meeting Facilitator

Patrick Maguire
Director of Resource Planning

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NEXT STEPS: SEP. 30 - DEC. 9

- Final optimized portfolios created and being run through full stochastic production cost model to generate PVRR and risk metrics
- Full optimization will provide metrics on cost, risk, emissions, market interaction, and more
- Additional portfolio runs to be conducted for DSM decrement analysis to test change in PVRR for adding additional decrements

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NEXT STEPS

- **Next Meeting: December 9, 2019**
- Meeting #5 Material:
  - Final portfolio results
  - Preferred Resource Plan
  - Short-Term Action Plan
- **IRP Filing Date: December 16, 2019**

Email questions, comments, or other feedback to ipl.irp@aes.com

APPENDIX

ACRONYM LIST

Acronym	Name
CCGT/CC	Combined Cycle
ST	Steam Turbine
CT	Combustion Turbine
UCAP	Unforced Capacity
ICAP	Installed Capacity
PRMR	Planning Reserve Margin Requirement
DR	Demand Response
DSM	Demand Side Management
MISO	Midcontinent Independent System Operator
RIIA	Renewable Integration Impact Assessment
PVRR	Present Value Revenue Requirement

INDIANAPOLIS POWER & LIGHT COMPANY

IPL 2019 IRP: PUBLIC ADVISORY MEETING #5

DECEMBER 9, 2019

ipl an AES company

INTRODUCTIONS & SAFETY MESSAGE

Shelby Houston

Regulatory Analyst, IPL

2

MEETING OBJECTIVES & AGENDA

Stewart Ramsey

Meeting Facilitator, Vanry & Associates

AGENDA

Topic	Time (Eastern)	Presenter(s)
Registration & Breakfast	9:00 – 9:30	-
Introductions & Safety Message	9:30 – 9:40	Shelby Houston, Regulatory Analyst, IPL
Meeting Objectives & Agenda	9:40 – 9:50	Stewart Ramsay, Meeting Facilitator, Vanry & Associates
Executive Summary of Preferred Resource Plan	9:50 – 10:20	Vince Parisi, President and CEO, IPL
2019 IRP: Modeling Insights	10:20 – 10:50	Patrick Maguire, Director of Resource Planning, IPL
BREAK	10:50 – 11:00	
Analysis of Alternatives: 2019 IRP Modeling	11:00 – 12:00	Patrick Maguire, Director of Resource Planning, IPL
LUNCH	12:00 – 12:45	
Sensitivity Analysis	12:45 – 1:15	Patrick Maguire, Director of Resource Planning, IPL
Preferred Resource Portfolio & Short Term Action Plan	1:15 – 1:30	Patrick Maguire, Director of Resource Planning, IPL
Concluding Remarks	1:30 – 2:00	Vince Parisi, President and CEO, IPL Stewart Ramsay, Meeting Facilitator, Vanry & Associates

EXECUTIVE SUMMARY OF SHORT TERM ACTION PLAN

Vince Parisi,

President and CEO, IPL

IPL 2019 IRP

INTEGRATED RESOURCE PLAN (IRP):
IPL's plan to provide safe, reliable, and sustainable energy solutions for the communities we serve

- IRP submitted every three years
- Plan created with stakeholder input
- 20-year look at how IPL will serve load
- Modeling and analysis culminates in a preferred resource portfolio

What is a preferred resource portfolio?

> " 'Preferred resource portfolio' means the utility's selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration."
>
> 170 IAC 4-7-1(cc)

2019 IRP STAKEHOLDER PROCESS

January 29th
- 2016 IRP Recap
- 2019 IRP Timeline, Objectives, Stakeholder Process
- Capacity Discussion
- IPL Existing Resources and Preliminary Load Forecast
- Introduction to Ascend Analytics
- Supply-Side Resource Types
- DSM/Load Forecast Schedule

March 13th
- Stakeholder Presentations
- Commodity Assumptions
- Capital Cost Assumptions
- IPL-Proposed Scenario Framework
- Scenario Workshop
- MPS Update and Plan

May 14th
- Summary of Stakeholder Feedback
- Present Final Scenarios
- Modeling Update
- Assumptions Review and Updates

September 30th
- Summary of Stakeholder Feedback
- Preliminary Model Results
- Scenario Descriptions and Results
- Portfolio metrics and scoring

December 9th
- Final Model Results
- Full set of portfolio metrics and scoring criteria
- Preferred Plan
- Short Term Action Plan

IPL set out to conduct a robust and collaborative stakeholder process. Multiple communication avenues were provided to ensure that all viewpoints and suggestions were heard from stakeholders wanting to participate in the 2019 IRP process.

IPL PORTFOLIO DIVERSIFICATION: 2009 - 2018

2009
Signed 100 MW PPA at Hoosier Wind Park in NW Indiana

2011
Signed 200 MW PPA at Lakefield Wind Farm in Minnesota

2013-2015
Signed 96 MW PPA for solar in Indianapolis through Rate REP

2016
Retired 260 MW of coal at Eagle Valley

2016
Finalized conversion of 630 MW of coal-fired generation at Harding Street to natural gas

2018
Eagle Valley 671 MW Gas-Fired Combined Cycle Plant Completed

IPL PREFERRED PORTFOLIO & SHORT-TERM ACTION PLAN

RETIRE

Retire **630 MW** of coal generation by 2023:
- Pete 1: 2021
- Pete 2: 2023

REPLACE

Competitively bid for approximately **200 MW** of firm capacity with all-source RFP

SAVE

Target ~130,000 MWh per year of new DSM as part of the 2021-2023 DSM Plan

MONITOR

Maintain cost-effective units to retain flexibility and continue to monitor market conditions leading to our 2022 IRP

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BENEFITS OF PREFERRED RESOURCE PORTFOLIO

IPL Preferred Portfolio: Areas of Focus

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Measured approach maintaining optionality

Greener Energy Future
Moves the company to more renewables

2019 IRP Stakeholder Meeting 12.9.19

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CUSTOMER CENTRICITY

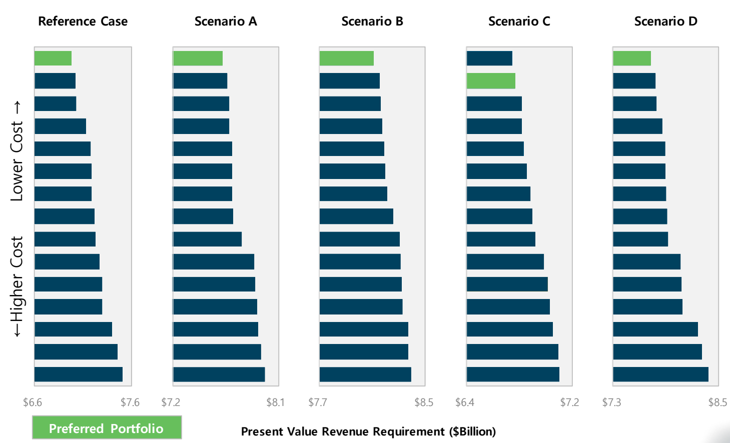
Focus on customer needs and wants

- IPL' s Preferred Resource Portfolio delivers safe, reliable, and economic electricity to customers at just and reasonable rates
- The preferred resource portfolio best serves IPL customers today and into the future, contemplates customers' evolving energy needs, and relies on data-driven models

LEAST COST

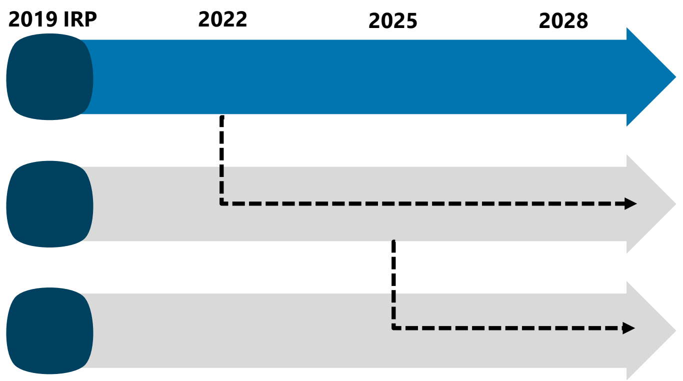
Minimizes total portfolio cost

Preferred Resource Portfolio is the lowest cost portfolio across a wide range of futures, mitigating rate impact and allowing customers to take advantage of low cost renewables in the short term



FLEXIBILITY & BALANCE

Measured approach maintaining optionality



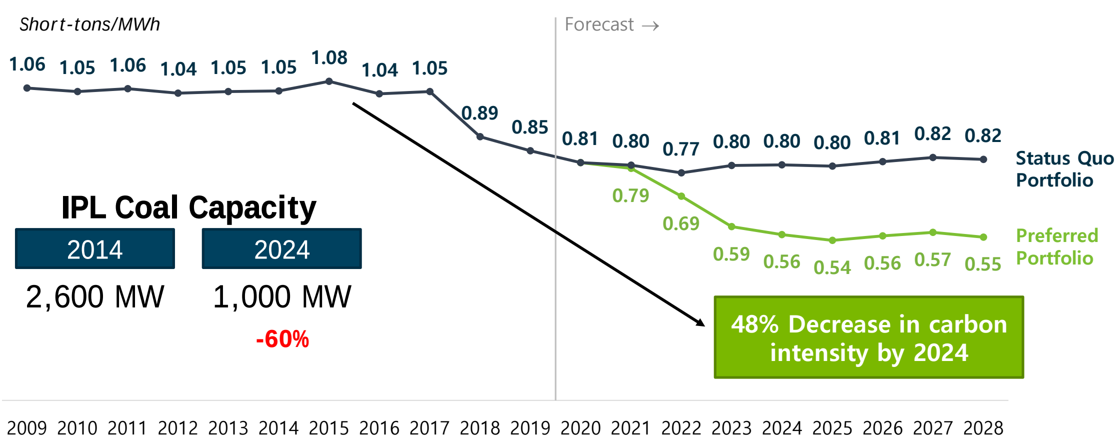
Preferred Portfolio provides lowest cost plan considering information known today

IPL has built-in flexibility to change direction in future IRPs with new information

Preferred portfolio contains embedded optionality with Petersburg Units 3 and 4

GREENER ENERGY FUTURE

Moves the company to more renewables



BENEFITS OF PREFERRED RESOURCE PORTFOLIO

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Measured approach maintaining optionality

Greener Energy Future
Moves the company to more renewables

2019 IRP: MODELING INSIGHTS

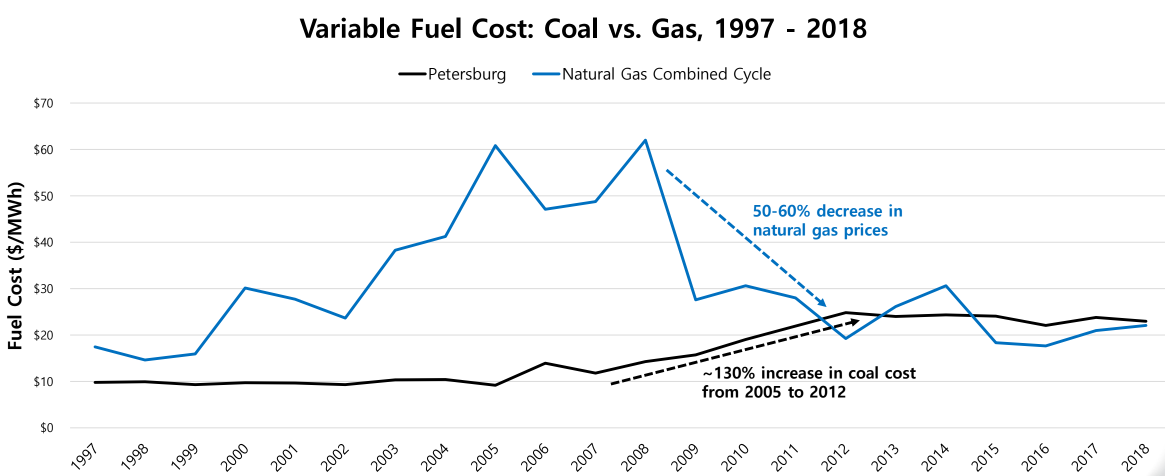
Patrick Maguire

Director of Resource Planning, IPL

HIGH IMPACT MARKET FORCES

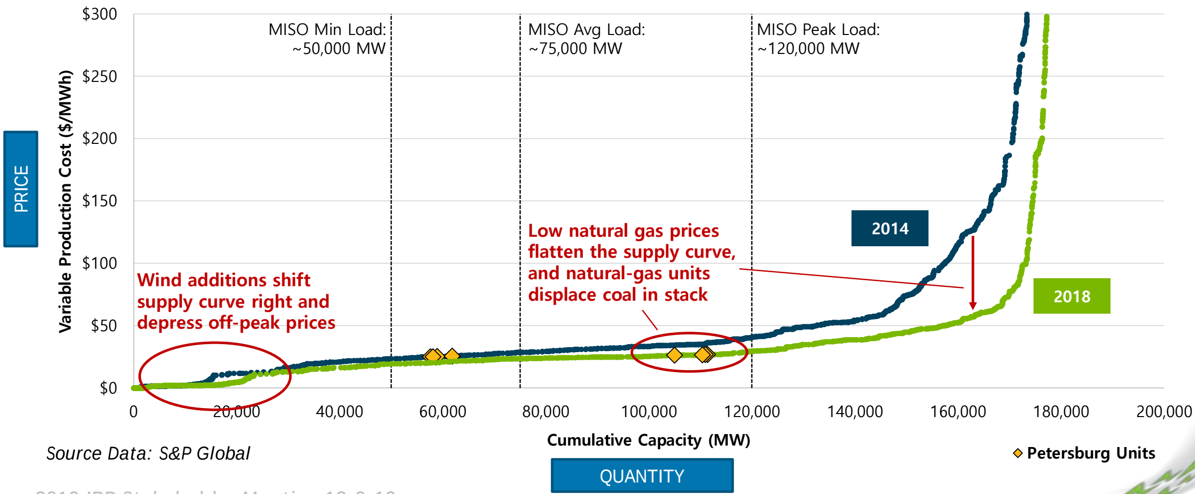
- Significant market changes over the past 10 years have impacted IPL's existing resources
- Opportunities and risk associated with alternative resources
- Present Value Revenue Requirement (PVRR) is key cost metric that is impacted by relative economics of resource technologies
  - Look at underlying fundamentals key to understanding high impact variables on all of the candidate portfolios

COAL ECONOMICS (1 OF 3)



COAL ECONOMICS (2 OF 3)

MISO Generation Supply Stack



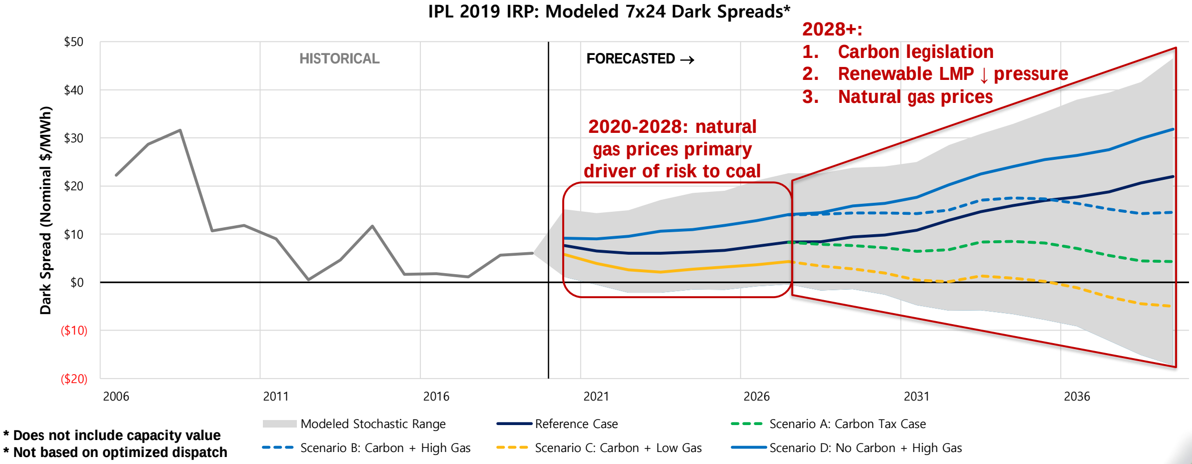
Source Data: S&P Global

COAL ECONOMICS (3 OF 3)

Dark spread = LMP – <u>variable</u> production cost (fuel, VOM, emissions)

Dark spread market indicator of variable margins to offset fixed costs. Does not include capacity value.

IPL 2019 IRP: Modeled 7x24 Dark Spreads*



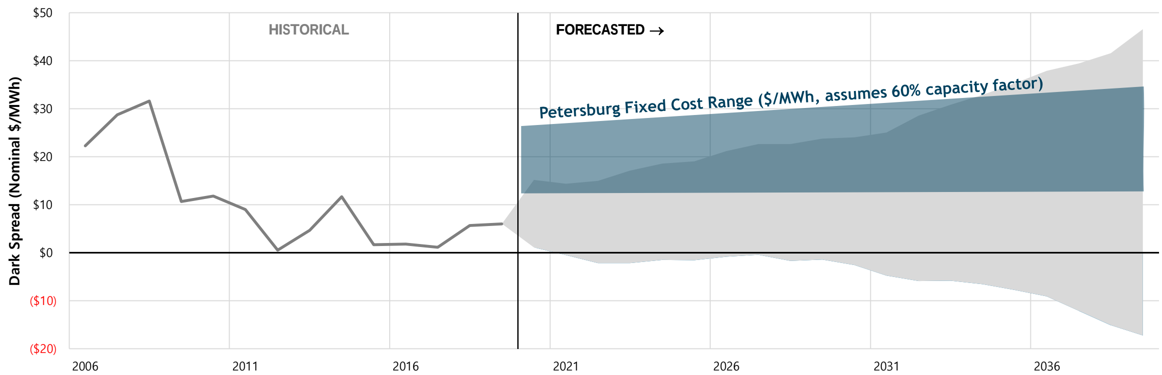
*** Does not include capacity value**
*** Not based on optimized dispatch**

COAL ECONOMICS (3 OF 3)

Dark spread = LMP – variable production cost (fuel, VOM, emissions)

Dark spread market indicator of variable margins to offset fixed costs. Does not include capacity value.

IPL 2019 IRP: Modeled 7x24 Dark Spreads*

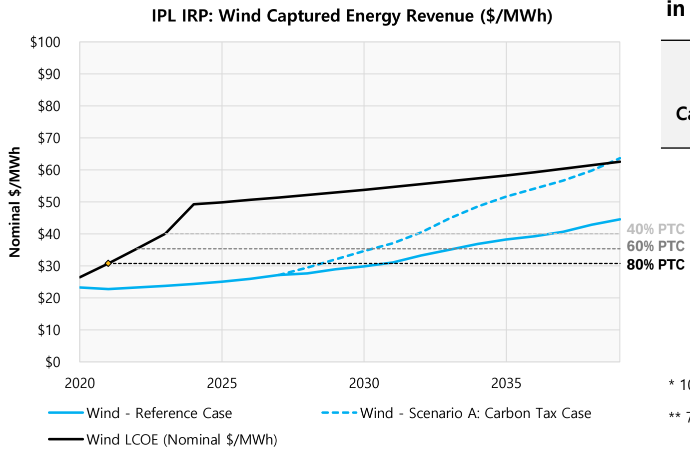


* Does not include capacity value
* Not based on optimized dispatch

This is illustrative to show macro-level trends and forecasts in coal unit economics and is not inclusive of all factors needed to make a decision. The full IRP modeling used detailed hourly economic dispatch models and full cost accounting for coal and new capacity in the total portfolio cost calculation.

WIND ECONOMICS: HEADWINDS AND UPSIDE POTENTIAL

IPL IRP: Wind Captured Energy Revenue ($/MWh)



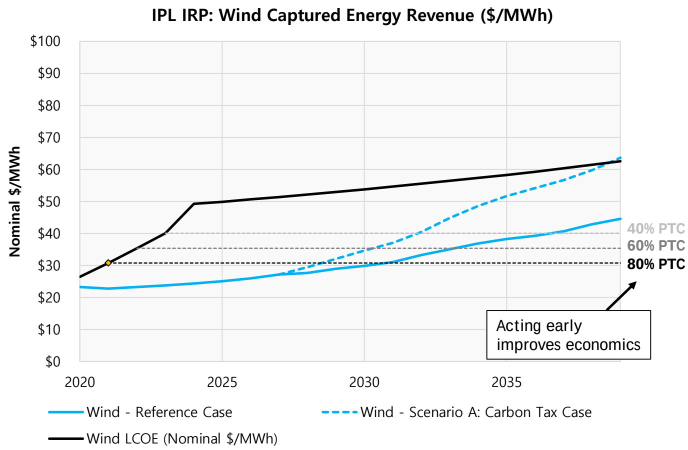
Carbon tax increases wholesale prices via increase in variable cost of fossil units on the margin

Carbon Price ($/ton)	Increase in Variable Cost ($/MWh) Coal Plant*	Natural Gas Combined Cycle**
$2	$2	$1
$5	$5	$2
$10	$11	$4
$20	$22	$8
$40	$43	$17

* 10.5 MMBtu/MWh heat rate, 206 lb/MMBtu CO2 emission rate

** 7.0 MMBtu/MWh heat rate, 119 lb/MMBtu CO2 emission rate

WIND ECONOMICS: HEADWINDS AND UPSIDE POTENTIAL



Challenging wind economics with PTC phaseout

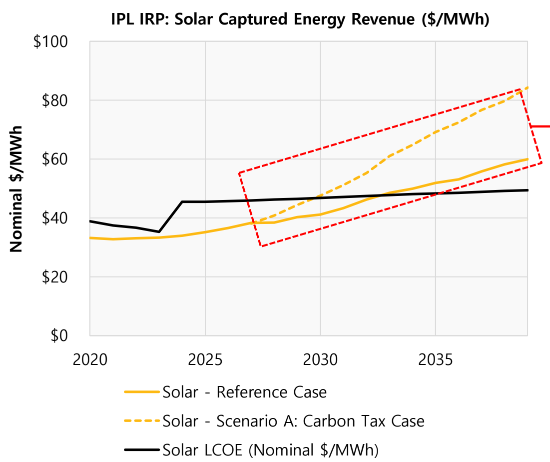
Headwinds:

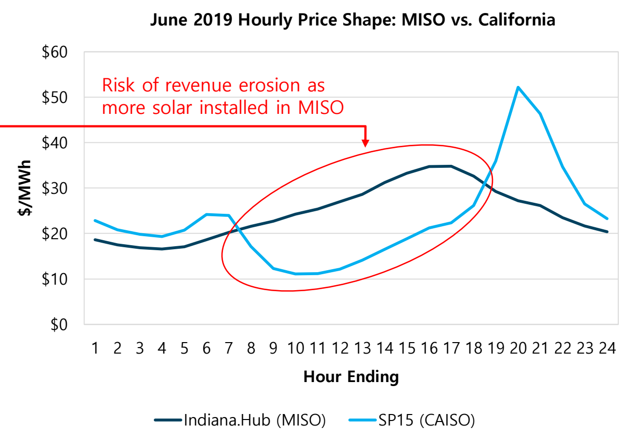
- Each 20% reduction in PTC increases LCOE by $3-$5/MWh
- Captured revenue remains hampered by production shapes, congestion

Upside potential:

- New bulk transmission
- Co-located storage
- New load near site
- Carbon Tax
- PTC Extension

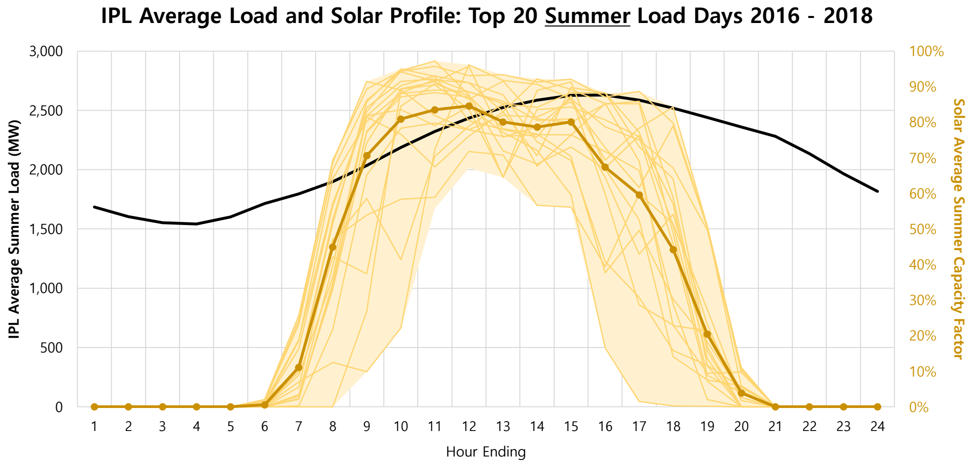
SOLAR ECONOMICS: FAVORABLE IN SHORT TERM, LONG TERM RISKS





SOLAR CAPACITY CREDIT: SUMMER

Summer capacity credit for single-axis tracking solar is 60-70% at low penetration levels



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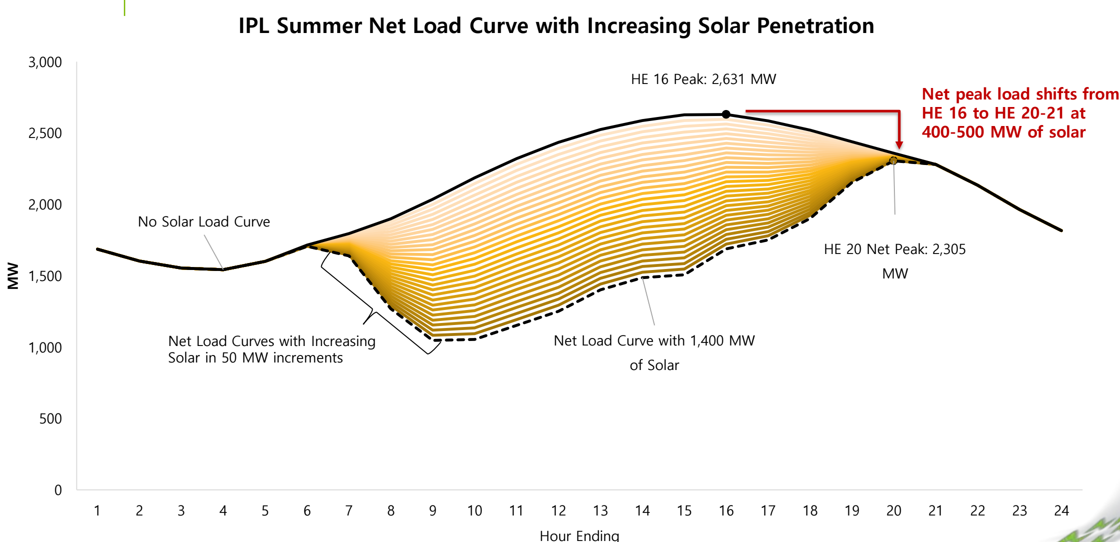
SUMMER NET LOAD CURVE



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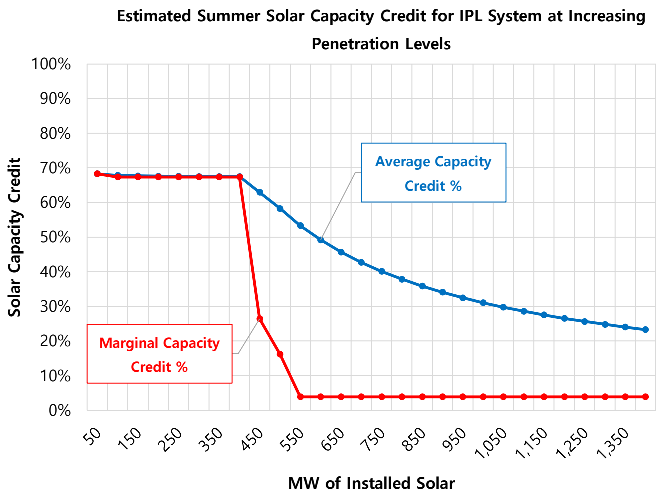
SOLAR CAPACITY CREDIT

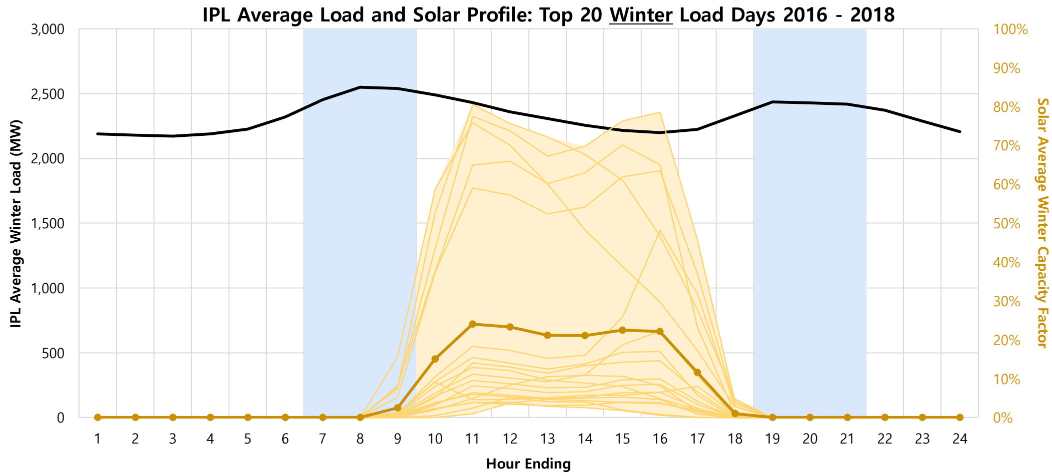


Marginal capacity credit for solar erodes quickly past 400-500 MW without intervention

Mitigation measures to improve solar capacity value: storage, demand response, geographically diverse locations, load shifting DSM/EE measures

SOLAR CAPACITY CREDIT: WINTER

Limited capacity value in the winter for solar as a standalone resource



BREAK

ANALYSIS OF ALTERNATIVES: 2019 IRP MODELING

Patrick Maguire

Director of Resource Planning, IPL

2019 IRP MODELING FRAMEWORK

	PORTFOLIOS	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas	Scenario D: No Carbon + High Gas
Portfolio 1	No Early Retirements					
Portfolio 2	Pete Unit 1 Retire 2021 Pete Units 2-4 Operational					
Portfolio 3	Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational					
Portfolio 4	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational					
Portfolio 5	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030					

SCENARIOS

IRP Modeling Framework:
- Systematic evaluation of coal retirements based on age, size, and reasonable transition pathways to allow for construction or acquisition of replacement capacity
- Stochastic capacity expansion with hourly chronological dispatch
- Candidate portfolios stressed against a wide range of uncertainty with stochastic scenario analysis

TESTING FOR COST EFFECTIVENESS OF INCREMENTAL DSM

Presented at Sep. 30th Meeting ↓ New portfolios

	Description	DSM Decrements 1-3	DSM Decrements 1-4	DSM Decrements 1-5
Portfolio 1	No Early Retirements	1a	1b	1c
Portfolio 2	Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	2a	2b	2c
Portfolio 3	Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	3a	3b	3c
Portfolio 4	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	4a	4b	4c
Portfolio 5	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	5a	5b	5c

IPL ran 10 additional capacity expansion runs with DSM decrements/bundles forced in to ensure optimal level of DSM targeted in 2021-2023 plan

MODELING SUMMARY

- **Final modeling framework:**
  - o 15 candidate resource portfolios containing a wide variety of technologies, DSM, and coal retirements
  - o 75 stochastic production cost runs
  - o Total of 9,000 iterations across all model runs
  - o 1,500+ hours of model simulation time

2019 IMPROVEMENTS

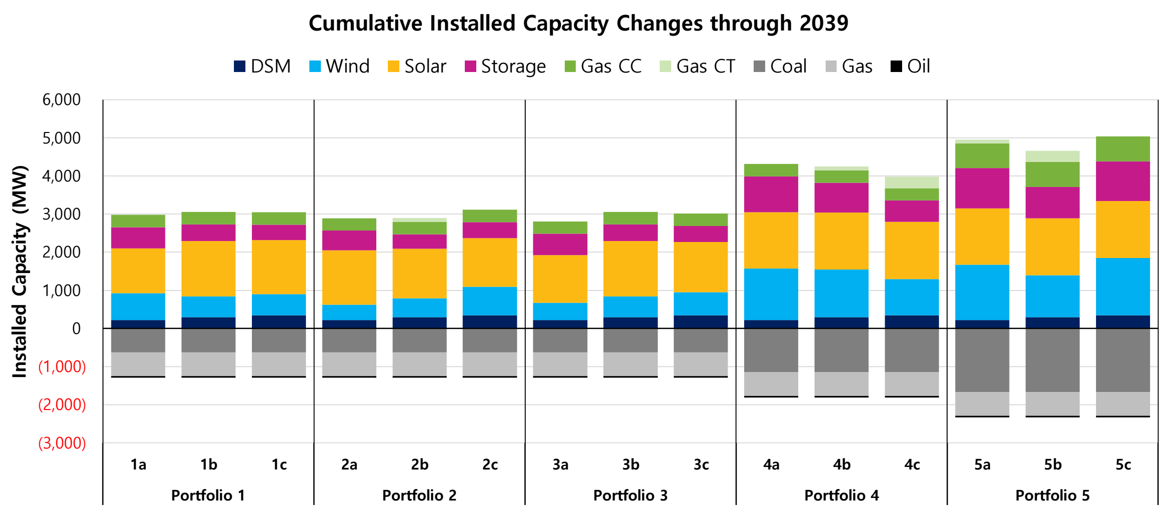
Modeling Tools and Analysis

- Entirely new modeling platform with enhanced load, dispatch, renewable, storage, and stochastic capabilities
- Added power price basis analysis, which is especially important for wind
- Revised scenario framework to allow more portfolio comparison across futures
- Robust risk analysis, both quantitative and qualitative
- Detailed EV and Distributed PV analysis
- Overall improvement in data sharing, transparency, and visibility into modeling and analysis

Renewable Modeling

- Robust development of wind and solar profiles
- Solar ELCC and net price shape analysis
- Capital costs: transparent, multi-source cost estimates benchmarked to market bids
- Improved storage modeling

CANDIDATE RESOURCE PORTFOLIOS



2019 IRP Stakeholder Meeting 12.9.19

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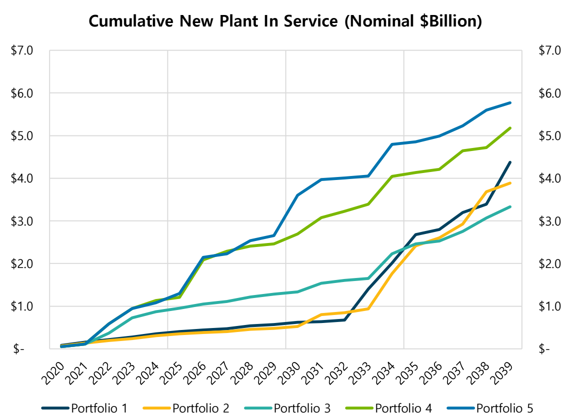
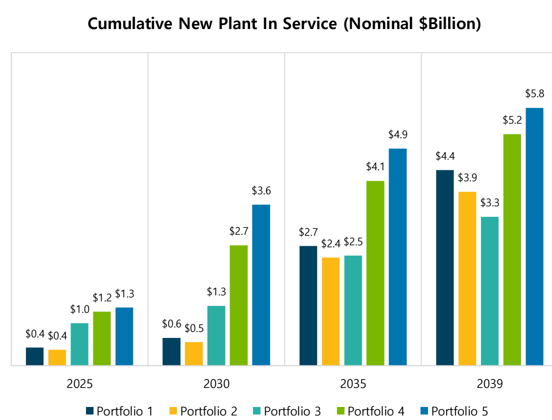
CAPEX REQUIREMENTS BY PORTFOLIO





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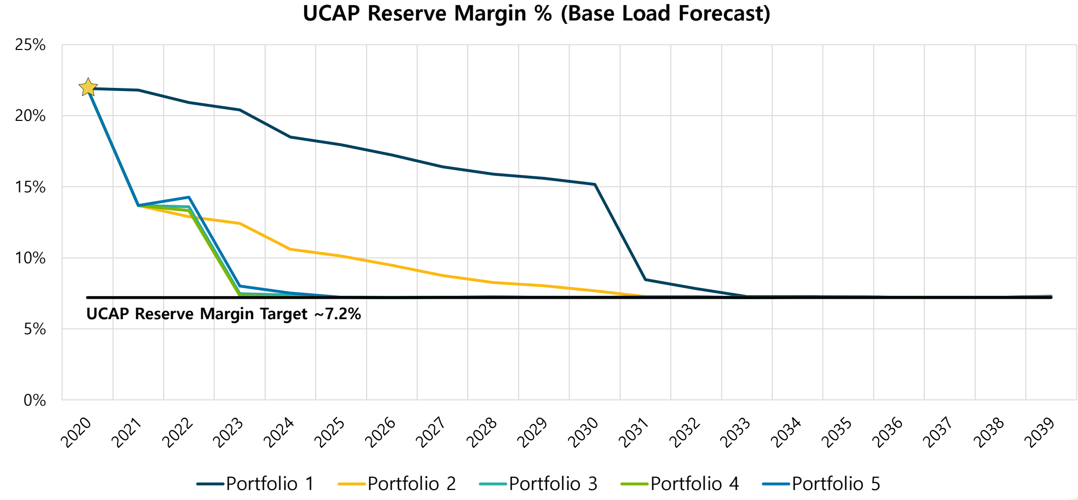
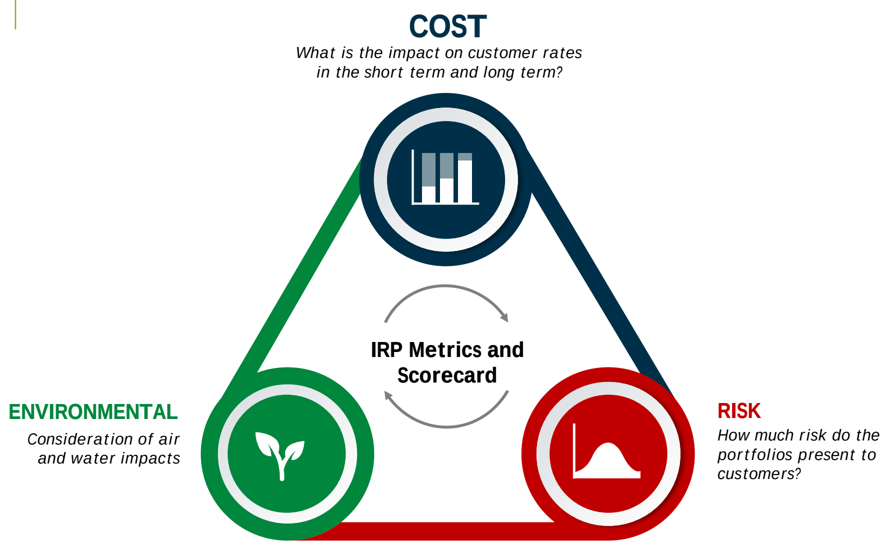
RESERVE MARGIN



PORTFOLIO METRICS

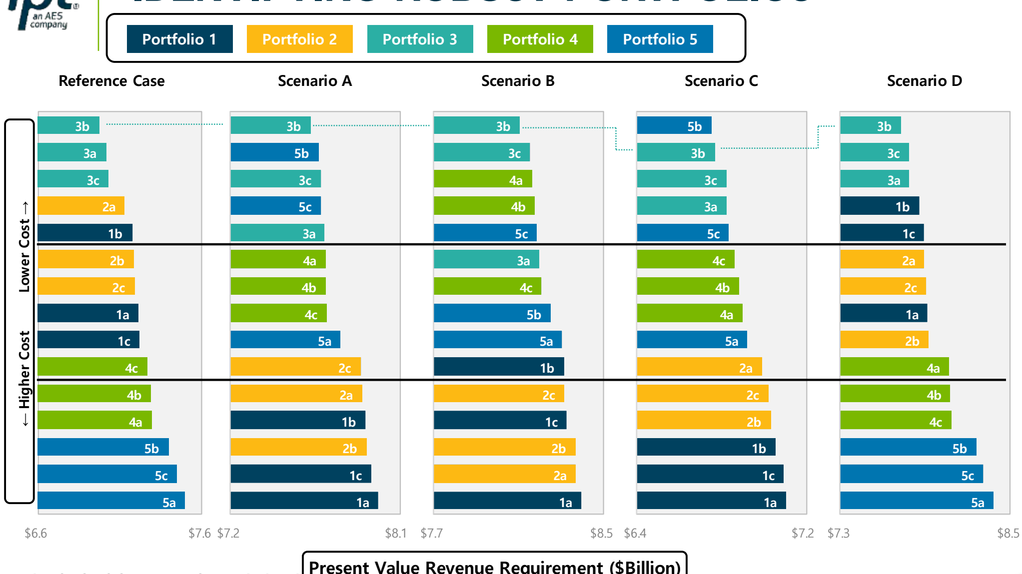


PVRR SUMMARY TABLE BY SCENARIO

20-Year PVRR ($MM)

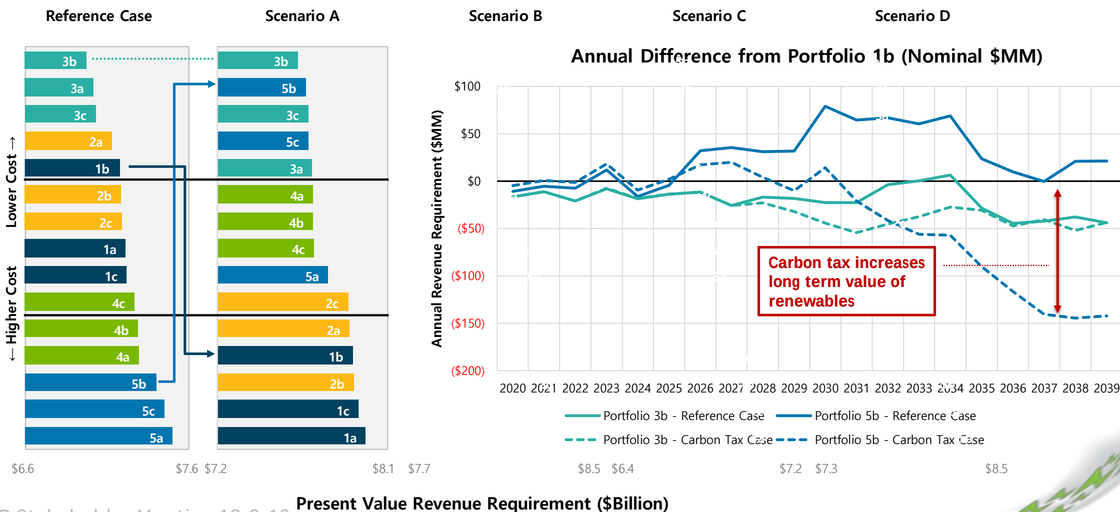
	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas	Scenario D: No Carbon + High Gas
Portfolio 1a	$7,215	$8,018	$8,427	$7,137	$7,923
Portfolio 2a	$7,132	$7,932	$8,399	$7,017	$7,900
Portfolio 3a	(2) $7,016	$7,737	$8,211	(3) $6,843	(3) $7,798
Portfolio 4a	$7,295	$7,740	(3) $8,174	$6,922	$8,070
Portfolio 5a	$7,500	$7,819	$8,329	$6,948	$8,376
Portfolio 1b	$7,176	$7,950	$8,338	$7,087	$7,864
Portfolio 2b	$7,188	$7,956	$8,398	$7,062	$7,932
Portfolio 3b	(1) $6,976	(1) $7,661	(1) $8,114	(2) $6,786	(1) $7,739
Portfolio 4b	$7,293	$7,742	$8,191	$6,907	$8,082
Portfolio 5b	$7,400	$7,703	$8,272	(1) $6,769	$8,259
Portfolio 1c	$7,223	$7,980	$8,355	$7,128	$7,899
Portfolio 2c	$7,191	$7,923	$8,341	$7,051	$7,912
Portfolio 3c	(3) $7,034	(2) $7,716	(2) $8,165	$6,842	(2) $7,794
Portfolio 4c	$7,269	$7,747	$8,225	$6,883	$8,086
Portfolio 5c	$7,452	(3) $7,716	$8,202	$6,857	$8,306

IDENTIFYING ROBUST PORTFOLIOS



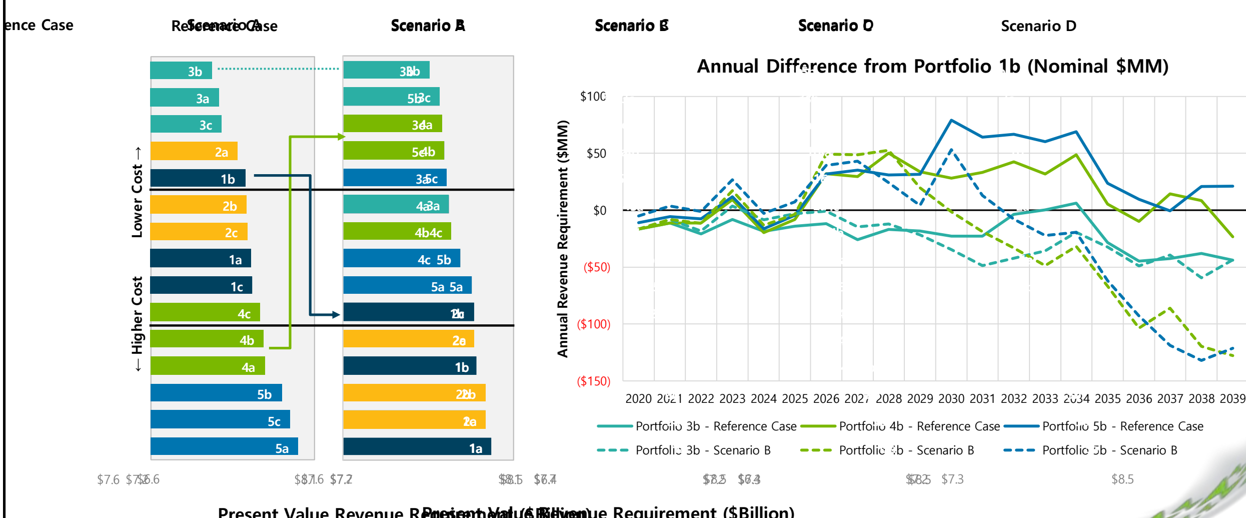
SCENARIO A: CARBON TAX CASE

Portfolio 1 | Portfolio 2 | Portfolio 3 | Portfolio 4 | Portfolio 5



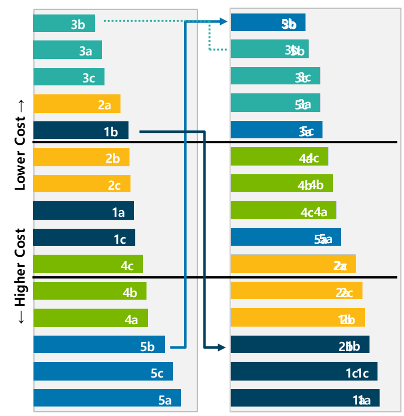
SCENARIO B: CARBON TAX + HIGH GAS

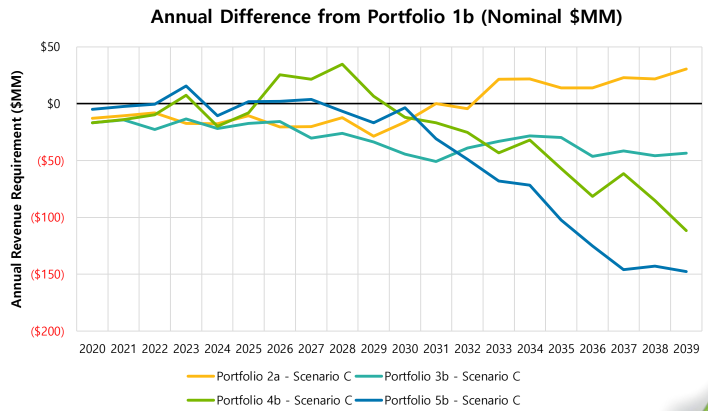
Portfolio 1 | Portfolio 2 | Portfolio 3 | Portfolio 4 | Portfolio 5



SCENARIO C: CARBON TAX + LOW GAS + LOW LOAD

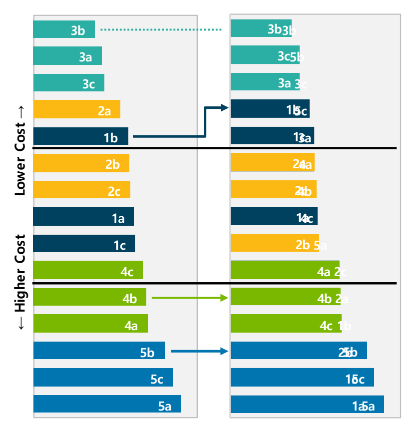
Portfolio 1 | Portfolio 2 | Portfolio 3 | Portfolio 4 | Portfolio 5

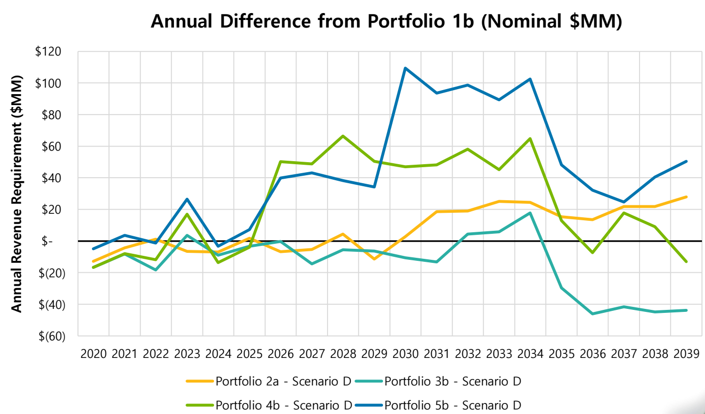




SCENARIO D: NO CARBON TAX + HIGH GAS + HIGH LOAD

Portfolio 1 | Portfolio 2 | Portfolio 3 | Portfolio 4 | Portfolio 5





PVRR TAKEAWAYS

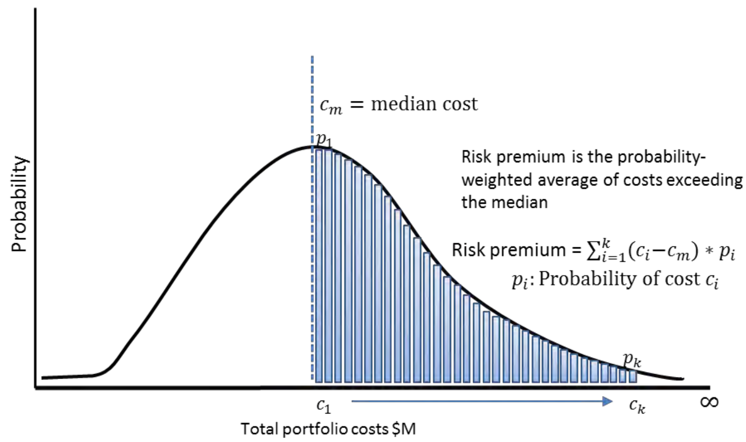
- **Carbon tax single largest driver of changes in PVRR**
  - Coal margins 40-50% lower with carbon tax
  - Renewable captured revenue 30-40% higher because of higher wholesale power prices
  - Reducing exposure to future carbon legislation important
- Natural gas will continue to be a high impact variable as coal and combined cycle units compete for positions in the dispatch stack
- Benefits of portfolio diversity on display:
  - Portfolio 3, which moves toward a 30/40/30 mix of coal, natural gas, and renewables, is the lowest cost across a range of futures

RATE IMPACTS

Levelized Rate $/kWh

	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas	Scenario D: No Carbon + High Gas
Portfolio 1a	$0.046	$0.051	$0.053	$0.047	$0.048
Portfolio 2a	$0.045	$0.050	$0.053	$0.046	$0.048
Portfolio 3a	$0.044	$0.049	$0.052	$0.045	$0.047
Portfolio 4a	$0.046	$0.049	$0.052	$0.045	$0.049
Portfolio 5a	$0.047	$0.049	$0.053	$0.045	$0.051
Portfolio 1b	$0.046	$0.051	$0.053	$0.047	$0.048
Portfolio 2b	$0.046	$0.051	$0.054	$0.047	$0.049
Portfolio 3b	$0.045	$0.049	$0.052	$0.045	$0.047
Portfolio 4b	$0.047	$0.049	$0.052	$0.046	$0.049
Portfolio 5b	$0.047	$0.049	$0.053	$0.045	$0.051
Portfolio 1c	$0.047	$0.052	$0.054	$0.048	$0.049
Portfolio 2c	$0.046	$0.051	$0.054	$0.047	$0.049
Portfolio 3c	$0.045	$0.050	$0.053	$0.046	$0.048
Portfolio 4c	$0.047	$0.050	$0.053	$0.046	$0.050
Portfolio 5c	$0.048	$0.050	$0.053	$0.046	$0.051

RISK PREMIUM METRIC



The risk premium metric assesses the risk of high cost outcomes based on the stochastic results for each portfolio

Taking the average of the outcomes above the mean captures tail risk better than P75 or P95

RISK PREMIUM ($MM)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1a	$329	$383	$406	$353	$400
Portfolio 2a	$370	$425	$465	$384	$452
Portfolio 3a	$367	$419	$464	$370	$448
Portfolio 4a	$466	$537	$611	$466	$554
Portfolio 5a	$441	$498	$574	$431	$539
Portfolio 1b	$358	$420	$447	$385	$430
Portfolio 2b	$354	$407	$442	$363	$431
Portfolio 3b	$408	$468	$532	$415	$495
Portfolio 4b	$461	$534	$609	$467	$554
Portfolio 5b	$493	$565	$649	$481	$595
Portfolio 1c	$348	$406	$430	$374	$416
Portfolio 2c	$360	$412	$449	$368	$438
Portfolio 3c	$372	$424	$476	$378	$448
Portfolio 4c	$457	$534	$612	$464	$554
Portfolio 5c	$442	$507	$584	$448	$543

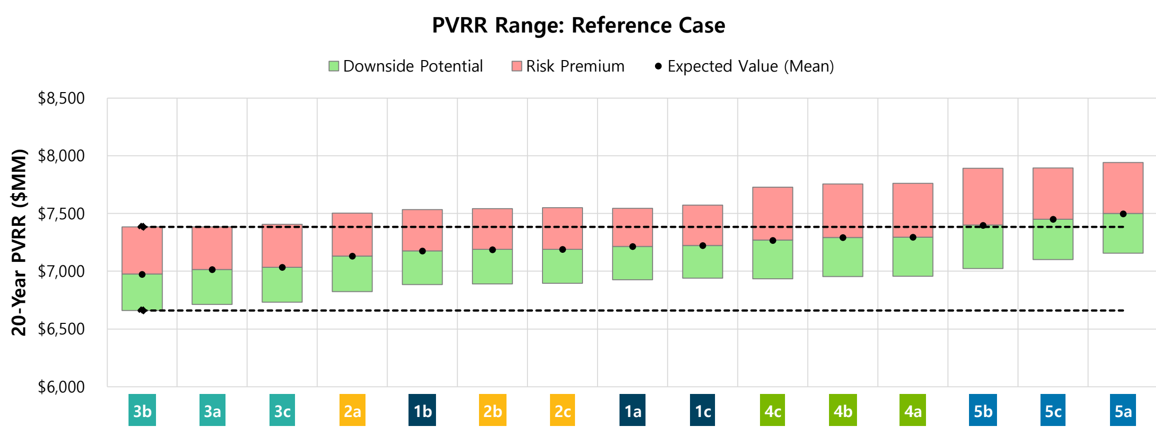
- Risk premiums are 4-7% of total cost
- Risk premium lowest for Portfolios 1 and 2
- Coal prices relatively stable, dispatchability improves economics
- High renewable portfolios can create mismatch between load and generation

RISK-ADJUSTED PVRR ($MM)

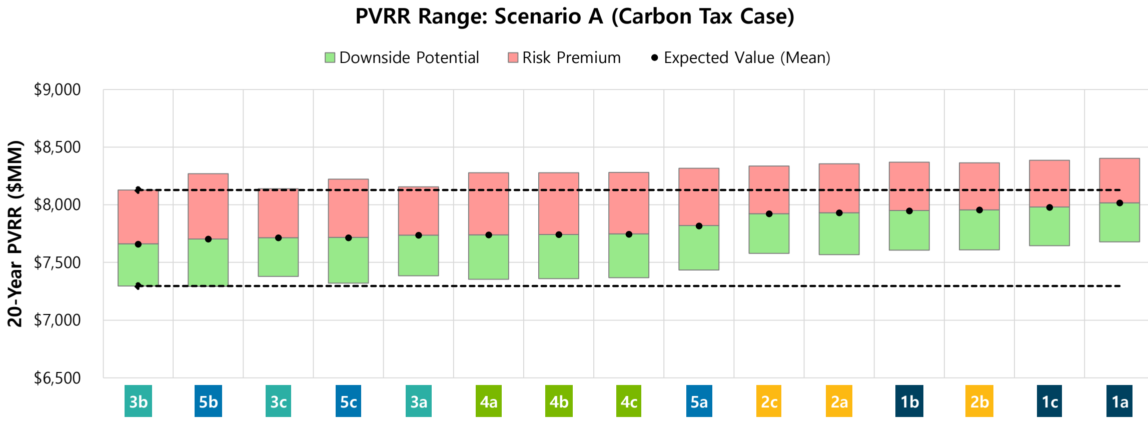
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1a	$7,544	$8,401	$8,833	$7,489	$8,324
Portfolio 2a	$7,502	$8,356	$8,865	$7,401	$8,351
Portfolio 3a	$7,383	$8,156	$8,676	$7,213	$8,246
Portfolio 4a	$7,761	$8,278	$8,784	$7,388	$8,623
Portfolio 5a	$7,941	$8,317	$8,904	$7,379	$8,915
Portfolio 1b	$7,533	$8,370	$8,785	$7,472	$8,294
Portfolio 2b	$7,542	$8,363	$8,840	$7,425	$8,363
Portfolio 3b	$7,384	$8,129	$8,646	$7,201	$8,234
Portfolio 4b	$7,754	$8,277	$8,800	$7,374	$8,636
Portfolio 5b	$7,892	$8,268	$8,921	$7,250	$8,854
Portfolio 1c	$7,571	$8,387	$8,785	$7,502	$8,315
Portfolio 2c	$7,551	$8,335	$8,791	$7,418	$8,350
Portfolio 3c	$7,407	$8,139	$8,642	$7,221	$8,242
Portfolio 4c	$7,726	$8,281	$8,837	$7,347	$8,640
Portfolio 5c	$7,893	$8,223	$8,786	$7,305	$8,849

- Adding risk premium to expected value PVRR puts all portfolios on level playing field
- **Portfolio 3 is lowest cost on a risk-adjusted basis in all scenarios**

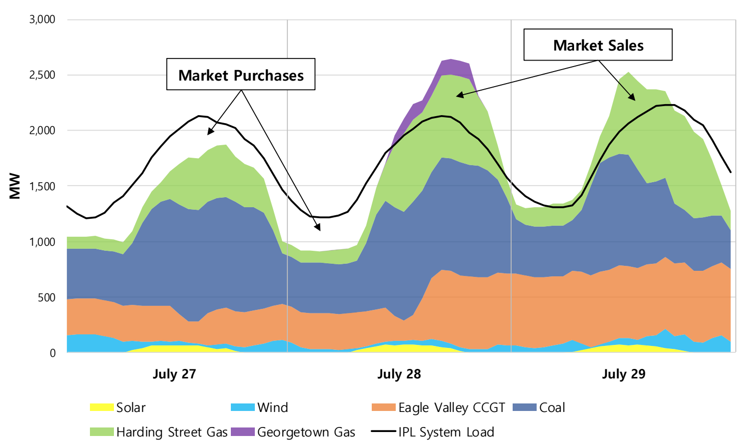
PVRR WITH RISK DISTRIBUTIONS: REFERENCE CASE



PVRR WITH RISK DISTRIBUTIONS: SCENARIO A (CARBON TAX CASE)



RISK METRIC: MARKET INTERACTION



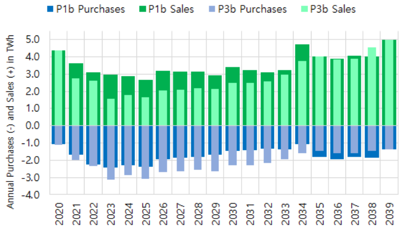
- Looking only at annual energy misses the actual market interaction that will occur hourly
- Market purchases and sales occur in all portfolios
- Relying too heavily on market purchases introduces risk
- Relying on value from market sales is equally risky

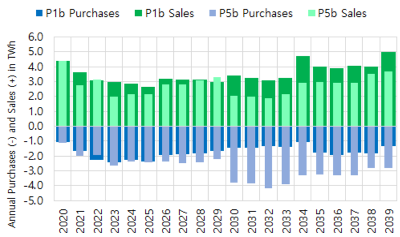
RELIANCE ON THE MARKET: BALANCED APPROACH

Portfolio 1 vs. Portfolio 3

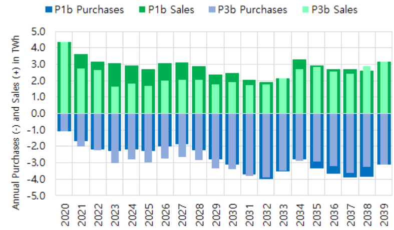
Portfolio 1 vs. Portfolio 5

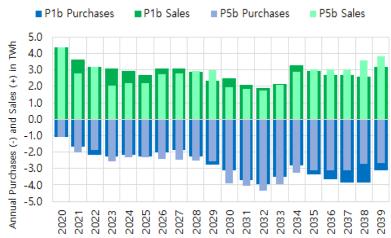
Reference Case





Scenario A: Carbon Case





Market Interaction

(in Millions of MWh)

|Purchases| + |Sales|

Reference Case	
Portfolio	
1b	5.2
3b	5.0
5b	5.6

Scenario A: Carbon Case	
Portfolio	
1b	5.7
3b	5.4
5b	5.6

ENVIRONMENTAL: AIR EMISSIONS

Reference Case

	CO_2 (million short-tons)	CO_2 Intensity (short-tons/MWh)	NO_x (short-tons)	SO_2 (short-tons)
2010 - 2012 Baseline (3-year average)	**16.1**	**1.05**	**14,255**	**53,107**
	20-Year Average (2020 - 2039)			
Portfolio 1a	11.9	0.75	8,028	10,972
Portfolio 2a	11.0	0.73	7,120	10,477
Portfolio 3a	9.5	0.64	6,371	9,577
Portfolio 4a	7.0	0.46	5,152	6,038
Portfolio 5a	5.6	0.38	2,991	3,582
Portfolio 1b	11.9	0.74	8,028	10,972
Portfolio 2b	11.1	0.72	7,124	10,477
Portfolio 3b	9.5	0.63	6,371	9,577
Portfolio 4b	7.0	0.47	5,164	6,039
Portfolio 5b	5.8	0.41	3,014	3,583
Portfolio 1c	11.9	0.74	8,028	10,972
Portfolio 2c	11.0	0.71	7,120	10,477
Portfolio 3c	9.5	0.64	6,371	9,577
Portfolio 4c	7.1	0.49	5,182	6,039
Portfolio 5c	5.7	0.38	2,988	3,583

Scenario A: Carbon Tax Case

	CO_2 (million short-tons)	CO_2 Intensity (short-tons/MWh)	NO_x (short-tons)	SO_2 (short-tons)
2010 - 2012 Baseline (3-year average)	**16.1**	**1.05**	**14,255**	**53,107**
Portfolio 1a	10.0	0.71	6,547	8,653
Portfolio 2a	9.3	0.69	5,722	8,203
Portfolio 3a	8.0	0.59	5,085	7,438
Portfolio 4a	6.3	0.43	4,265	5,059
Portfolio 5a	5.6	0.38	2,952	3,552
Portfolio 1b	10.0	0.70	6,547	8,653
Portfolio 2b	9.3	0.68	5,726	8,203
Portfolio 3b	8.0	0.58	5,085	7,438
Portfolio 4b	6.3	0.44	4,277	5,059
Portfolio 5b	5.8	0.41	2,974	3,553
Portfolio 1c	10.0	0.70	6,547	8,653
Portfolio 2c	9.3	0.67	5,722	8,203
Portfolio 3c	8.0	0.59	5,085	7,438
Portfolio 4c	6.4	0.46	4,294	5,060
Portfolio 5c	5.7	0.38	2,950	3,552

ENVIRONMENTAL: NON-AIR IMPACTS

- Impact of coal retirements on water:
  - Retire Units 1 and 2: significant reduction in actual intake flow (estimate: greater than 67%);
  - Retire Units 1-4 (assume no water withdrawal): result in the elimination of 354 million gallons per day (MGD) (100% reduction) of water withdraw from the river

PORTFOLIO METRICS SUMMARY

Cost	Risk	Environmental
• Portfolio 3b is the lowest cost portfolio across wide range scenarios • O&M and Capex savings from retirements mitigates rate impacts of cost of new capacity	• Portfolio 3b lowest cost on risk-adjusted basis • Portfolio 3b resource mix provides balanced energy and load profile and reduction total market interaction	• Portfolio 3b benefits: • Near term reductions in CO_2, NOx, SO_2 • 60-70% reduction in water intake flow at the plant

LUNCH BREAK

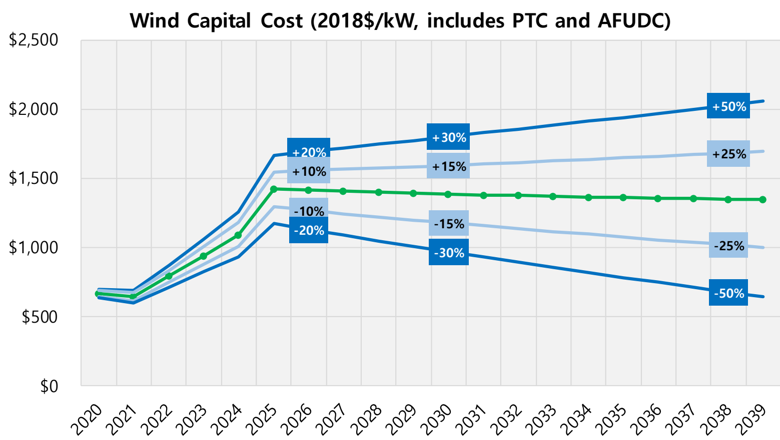
SENSITIVITY ANALYSIS

Patrick Maguire
Director of Resource Planning, IPL

SENSITIVITY ANALYSIS

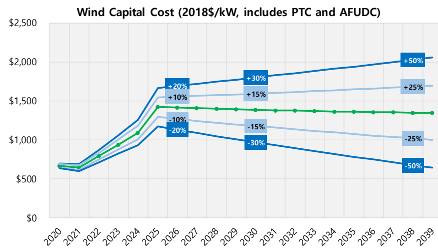
- **Sensitivity: change of a single variable to isolate the impact of future uncertainty**
- Four deterministic analyses conducted:
  1. Capital Costs for wind, solar, and storage
  2. MISO Capacity Prices
  3. Wind Capacity Factor
  4. Wind LMP Basis

CAPITAL COST SENSITIVITY (1 OF 4)

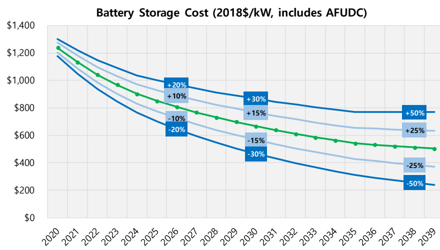


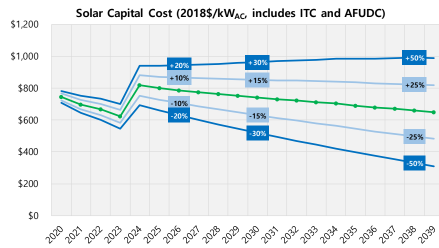
High and low capital cost ranges established for wind, solar, and storage

CAPITAL COST SENSITIVITY (2 OF 4)



- Wind, solar, and storage cost sensitivities applied to fixed portfolios
- All three costs moved together





CAPITAL COST SENSITIVITY (3 OF 4)

Reference Case PVRR ($MM)

	Percent Change by 2030		PVRR w/ Base Capital Costs ↓	Percent Change by 2030	
	-30%	-15%		+15%	+30%
Portfolio 3b	$6,775	$6,874	$6,976	$7,077	$7,177
Portfolio 3a	$6,841	$6,927	$7,016	$7,105	$7,191
Portfolio 3c	$6,843	$6,938	$7,034	$7,131	$7,225
Portfolio 2a	$6,965	$7,049	$7,132	$7,214	$7,298
Portfolio 1b	$7,004	$7,091	$7,176	$7,261	$7,348
Portfolio 2b	$7,010	$7,100	$7,188	$7,276	$7,366
Portfolio 2c	$6,986	$7,089	$7,191	$7,292	$7,396
Portfolio 1a	$7,043	$7,130	$7,215	$7,300	$7,387
Portfolio 1c	$7,043	$7,134	$7,223	$7,312	$7,403
Portfolio 4c	$6,978	$7,121	$7,269	$7,417	$7,560
Portfolio 4b	$6,928	$7,107	$7,293	$7,478	$7,658
Portfolio 4a	$6,912	$7,100	$7,295	$7,490	$7,678
Portfolio 5b	$7,073	$7,234	$7,400	$7,565	$7,726
Portfolio 5c	$7,001	$7,224	$7,452	$7,679	$7,902
Portfolio 5a	$7,100	$7,309	$7,500	$7,741	$7,950

Takeaways:

1. Portfolio 3b lowest cost with a 30% reduction from base cost forecasts for wind, solar, and storage
2. Portfolio 3b lowest cost with a significant increase in capital costs for wind, solar, and storage

CAPITAL COST SENSITIVITY (4 OF 4)

Scenario A (Carbon Tax Case) PVRR ($MM)

	Percent Change by 2030 -30%	Percent Change by 2030 -15%	PVRR w/ Base Capital Costs ↓	Percent Change by 2030 +15%	Percent Change by 2030 +30%
Portfolio 3b	$7,460	$7,560	$7,661	$7,763	$7,862
Portfolio 5b	$7,377	$7,538	$7,703	$7,869	$8,030
Portfolio 3c	$7,524	$7,619	$7,716	$7,812	$7,907
Portfolio 5c	$7,266	$7,489	$7,716	$7,944	$8,166
Portfolio 3a	$7,562	$7,648	$7,737	$7,826	$7,912
Portfolio 4a	$7,357	$7,546	$7,740	$7,935	$8,123
Portfolio 4b	$7,377	$7,538	$7,742	$7,928	$8,107
Portfolio 4c	$7,456	$7,599	$7,747	$7,896	$8,039
Portfolio 5a	$7,394	$7,603	$7,819	$8,035	$8,244
Portfolio 2c	$7,719	$7,822	$7,923	$8,025	$8,128
Portfolio 2a	$7,765	$7,849	$7,932	$8,014	$8,098
Portfolio 1b	$7,778	$7,865	$7,950	$8,035	$8,122
Portfolio 2b	$7,778	$7,868	$7,956	$8,044	$8,134
Portfolio 1c	$7,800	$7,891	$7,980	$8,069	$8,160
Portfolio 1a	$7,846	$7,933	$8,018	$8,103	$8,190

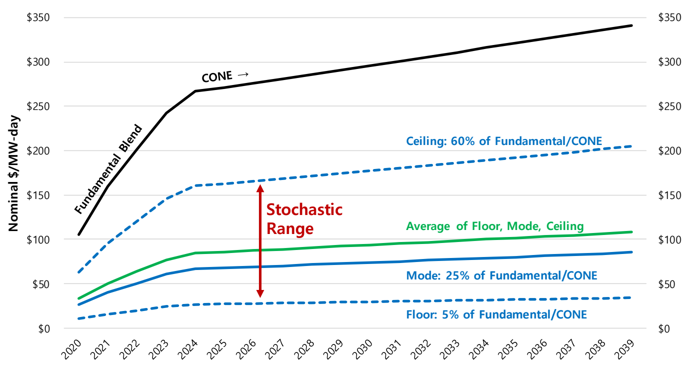
Carbon Tax Case Results:

1. Portfolio 5 becomes lowest cost with (a) federal price on carbon and (b) cost declines (from base forecast) in wind, solar, and storage

2. Portfolio 3b lowest cost with a significant increase in capital costs for wind, solar, and storage

MISO CAPACITY PRICE SENSITIVITY (1 OF 3)

MISO Zone 6 Modeled Capacity Prices



- MISO capacity prices applied to portfolio position imbalances (long/short)
- Greatest impact on Portfolios 1 and 2 because IPL is in a net long capacity position today
- Capacity prices modeled stochastically to capture range of uncertainty
- Deterministic sensitivities conducted to measure impact of capacity prices on PVRR results

MISO CAPACITY PRICE SENSITIVITY (2 OF 2)

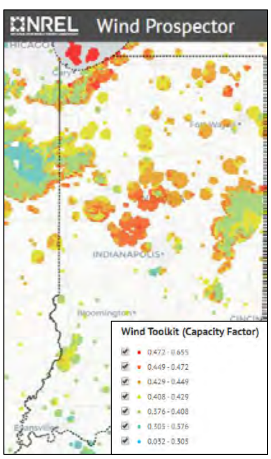
Reference Case PVRR ($MM)

	Bilateral Floor	Bilateral Most Likely	[Base] Stochastic Mean ↓	Bilateral Ceiling	CONE
Portfolio 3b	$6,983	$6,978	$6,976	$6,966	$6,953
Portfolio 3a	$7,024	$7,018	$7,016	$7,006	$6,993
Portfolio 3c	$7,034	$7,034	$7,034	$7,034	$7,034
Portfolio 2a	$7,146	$7,136	$7,132	$7,113	$7,087
Portfolio 1b	$7,221	$7,190	$7,176	$7,116	$7,035
Portfolio 2b	$7,203	$7,193	$7,188	$7,169	$7,144
Portfolio 2c	$7,191	$7,191	$7,191	$7,191	$7,191
Portfolio 1a	$7,260	$7,229	$7,215	$7,156	$7,074
Portfolio 1c	$7,223	$7,223	$7,223	$7,223	$7,223
Portfolio 4c	$7,269	$7,269	$7,269	$7,269	$7,269
Portfolio 4b	$7,301	$7,295	$7,293	$7,281	$7,267
Portfolio 4a	$7,304	$7,298	$7,295	$7,284	$7,269
Portfolio 5b	$7,408	$7,402	$7,400	$7,389	$7,375
Portfolio 5c	$7,452	$7,452	$7,452	$7,452	$7,452
Portfolio 5a	$7,508	$7,503	$7,500	$7,489	$7,475

Reference Case Results:

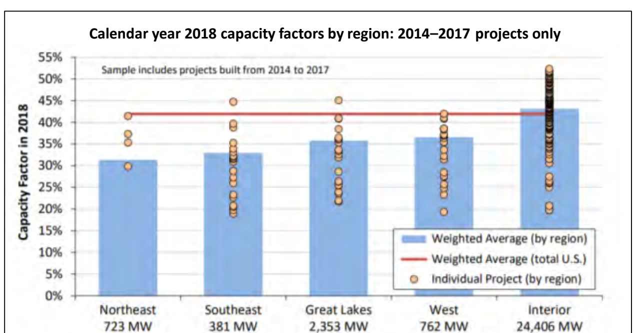
1. Portfolio 3b lowest cost even with applying CONE capacity price to capacity length in Portfolios 1 and 2
2. Sustained low capacity prices increases value of Portfolio 3 relative to Portfolios 1 and 2

WIND CAPACITY FACTOR (1 OF 3)



Source: NREL

- IPL utilized the NREL Wind Toolkit to source generic hourly wind profiles
- Capacity factor sensitivity evaluates PVRR impact of lower actual wind production compared to modeled
- Captured revenue "locked" from base, MWh adjusted



DOE 2018 Wind Technologies Market Report (PDF)

WIND CAPACITY FACTOR (2 OF 3)

Reference Case PVRR ($MM)

Wind annual capacity factor →	46%	44%	Base (42%) ↓	40%	38%	36%	34%	32%	30%
Portfolio 3b	$6,959	$6,968	$6,976	$6,987	$6,996	$7,005	$7,014	$7,024	$7,033
Portfolio 3a	$6,991	$7,004	$7,016	$7,032	$7,046	$7,059	$7,073	$7,087	$7,101
Portfolio 3c	$7,012	$7,024	$7,034	$7,049	$7,061	$7,073	$7,086	$7,098	$7,110
Portfolio 2a	$7,128	$7,130	$7,132	$7,134	$7,136	$7,138	$7,140	$7,142	$7,144
Portfolio 1b	$7,172	$7,174	$7,176	$7,178	$7,180	$7,182	$7,184	$7,186	$7,187
Portfolio 2b	$7,179	$7,184	$7,188	$7,194	$7,199	$7,203	$7,208	$7,213	$7,218
Portfolio 2c	$7,180	$7,186	$7,191	$7,198	$7,204	$7,210	$7,215	$7,221	$7,227
Portfolio 1a	$7,208	$7,212	$7,215	$7,219	$7,223	$7,227	$7,230	$7,234	$7,238
Portfolio 1c	$7,217	$7,221	$7,223	$7,227	$7,230	$7,233	$7,237	$7,240	$7,243
Portfolio 4c	$7,222	$7,248	$7,269	$7,299	$7,325	$7,350	$7,376	$7,401	$7,427
Portfolio 4b	$7,234	$7,266	$7,293	$7,330	$7,362	$7,394	$7,426	$7,458	$7,489
Portfolio 4a	$7,228	$7,265	$7,295	$7,338	$7,375	$7,411	$7,448	$7,484	$7,521
Portfolio 5b	$7,355	$7,379	$7,400	$7,428	$7,453	$7,477	$7,502	$7,526	$7,551
Portfolio 5c	$7,372	$7,416	$7,452	$7,503	$7,546	$7,589	$7,633	$7,676	$7,720
Portfolio 5a	$7,417	$7,461	$7,500	$7,549	$7,593	$7,638	$7,682	$7,726	$7,770

Reference Case Results:

1. Very low capacity factor for wind does not change lowest cost portfolio in Reference Case
2. Every 2% decrease in annual net capacity factor for wind increases Portfolio 5 PVRR by ~$43M, or 1%

WIND CAPACITY FACTOR (3 OF 3)

Scenario A (Carbon Tax Case) PVRR ($MM)

Wind annual capacity factor →	46%	44%	Base (42%) ↓	40%	38%	36%	34%	32%	30%
Portfolio 3b	$7,640	$7,652	$7,661	$7,675	$7,686	$7,698	$7,709	$7,721	$7,733
Portfolio 5b	$7,649	$7,679	$7,703	$7,739	$7,769	$7,798	$7,828	$7,858	$7,888
Portfolio 3c	$7,688	$7,703	$7,716	$7,733	$7,748	$7,764	$7,779	$7,794	$7,809
Portfolio 5c	$7,619	$7,672	$7,716	$7,779	$7,832	$7,886	$7,939	$7,993	$8,046
Portfolio 3a	$7,707	$7,723	$7,737	$7,756	$7,772	$7,789	$7,805	$7,822	$7,838
Portfolio 4a	$7,659	$7,704	$7,740	$7,793	$7,837	$7,881	$7,926	$7,970	$8,015
Portfolio 4b	$7,671	$7,710	$7,742	$7,788	$7,827	$7,867	$7,906	$7,945	$7,984
Portfolio 4c	$7,691	$7,722	$7,747	$7,784	$7,815	$7,845	$7,876	$7,907	$7,938
Portfolio 5a	$7,718	$7,772	$7,819	$7,879	$7,933	$7,986	$8,040	$8,094	$8,148
Portfolio 2c	$7,909	$7,917	$7,923	$7,933	$7,941	$7,949	$7,958	$7,966	$7,974
Portfolio 2a	$7,927	$7,929	$7,932	$7,935	$7,937	$7,940	$7,943	$7,946	$7,948
Portfolio 1b	$7,945	$7,948	$7,950	$7,953	$7,956	$7,959	$7,961	$7,964	$7,967
Portfolio 2b	$7,944	$7,950	$7,956	$7,964	$7,970	$7,977	$7,983	$7,990	$7,996
Portfolio 1c	$7,972	$7,977	$7,980	$7,985	$7,990	$7,994	$7,999	$8,003	$8,008
Portfolio 1a	$8,009	$8,014	$8,018	$8,024	$8,029	$8,034	$8,039	$8,044	$8,050

Carbon Tax Case Results:

1. Portfolio 3b still lowest cost in Carbon Tax case.
2. Lower realized capacity factor for wind moves Portfolio 4 ahead of 5; Portfolio 3 still lowest cost

WIND LMP BASIS/CAPTURED REVENUE (1 OF 3)

- Congestion, due to transmission constraints, outages, and other factors, results in price separation from generator to IPL load
- LMP basis to MISO Indiana Hub applied to existing and new resources to account for congestion impacts on nodal LMPs
- Sensitivity analysis designed to evaluate the impact of removing that LMP discount for wind
- Wind production (MWh) locked and fixed across portfolios
- Captured revenue increased in 5% increments to remove LMP discount

WIND LMP BASIS/CAPTURED REVENUE (2 OF 3)

Reference Case PVRR ($MM)

	Base	Revenue +5%	Revenue +10%	Revenue +15%	Revenue +20%
Portfolio 3b	$6,976	$6,966	$6,956	$6,946	$6,937
Portfolio 3a	$7,016	$7,001	$6,987	$6,972	$6,958
Portfolio 3c	$7,034	$7,021	$7,008	$6,995	$6,982
Portfolio 2a	$7,132	$7,130	$7,128	$7,126	$7,124
Portfolio 1b	$7,176	$7,174	$7,172	$7,170	$7,168
Portfolio 2b	$7,188	$7,183	$7,178	$7,173	$7,168
Portfolio 2c	$7,191	$7,185	$7,178	$7,172	$7,166
Portfolio 1a	$7,215	$7,211	$7,207	$7,203	$7,199
Portfolio 1c	$7,223	$7,220	$7,216	$7,213	$7,210
Portfolio 4c	$7,269	$7,242	$7,215	$7,188	$7,161
Portfolio 4b	$7,293	$7,259	$7,225	$7,191	$7,158
Portfolio 4a	$7,295	$7,256	$7,218	$7,179	$7,140
Portfolio 5b	$7,400	$7,374	$7,348	$7,322	$7,296
Portfolio 5c	$7,452	$7,406	$7,360	$7,314	$7,268
Portfolio 5a	$7,500	$7,453	$7,407	$7,360	$7,314

Reference Case Results:

1. Removing the LMP basis on wind closes the gap between Portfolio 5 and Portfolio 3 by ~$124M; Portfolio 3 still lowest cost

WIND LMP BASIS/CAPTURED REVENUE (3 OF 3)

Scenario A (Carbon Tax Case) PVRR ($MM)

	Base	Revenue +5%	Revenue +10%	Revenue +15%	Revenue +20%
Portfolio 3b	$7,661	$7,649	$7,637	$7,625	$7,612
Portfolio 5b	$7,703	$7,672	$7,640	$7,608	$7,576
Portfolio 3c	$7,716	$7,699	$7,683	$7,667	$7,651
Portfolio 5c	$7,716	$7,660	$7,603	$7,547	$7,490
Portfolio 3a	$7,737	$7,720	$7,702	$7,685	$7,668
Portfolio 4a	$7,740	$7,693	$7,646	$7,599	$7,552
Portfolio 4b	$7,742	$7,701	$7,659	$7,618	$7,576
Portfolio 4c	$7,747	$7,715	$7,682	$7,649	$7,616
Portfolio 5a	$7,819	$7,763	$7,706	$7,649	$7,593
Portfolio 2c	$7,923	$7,915	$7,906	$7,898	$7,889
Portfolio 2a	$7,932	$7,929	$7,926	$7,923	$7,920
Portfolio 1b	$7,950	$7,947	$7,944	$7,941	$7,939
Portfolio 2b	$7,956	$7,949	$7,942	$7,935	$7,928
Portfolio 1c	$7,980	$7,976	$7,971	$7,966	$7,961
Portfolio 1a	$8,018	$8,013	$8,007	$8,002	$7,996

Carbon Tax Case Results:

1. Improved congestion, and therefore revenue, for wind increases value of Portfolio 5 compared to Portfolio 3 with a federal price on carbon

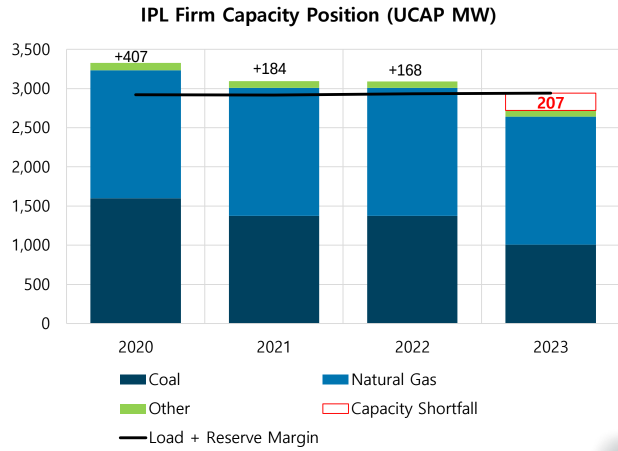
PREFERRED RESOURCE PORTFOLIO & SHORT TERM ACTION PLAN

Patrick Maguire

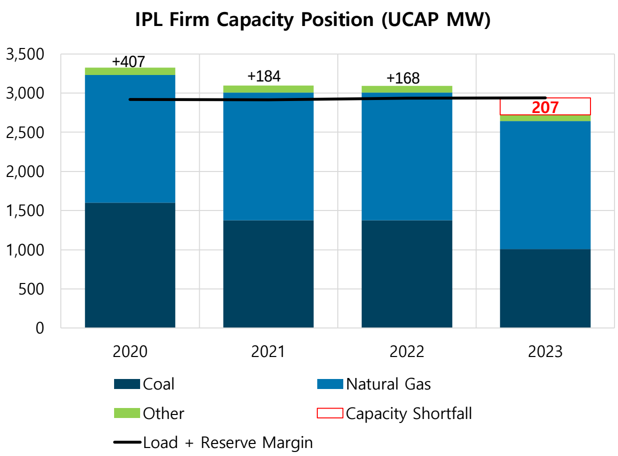
Director of Resource Planning, IPL

PREFERRED PORTFOLIO

- Portfolio 3b:
  - Least cost portfolio on a risk-adjusted basis across a wide range of futures
  - Retirement of Pete 1 and 2 lowest cost when stressing capacity value, cost of replacement capacity, and value of replacement capacity
  - Preserve flexibility and optionality in the face of uncertainty over the next 3-5 years



PREFERRED PORTFOLIO



Model indicating that lowest cost portfolio fills capacity shortfall with a combination of wind, solar, storage, and DSM

~200 MW of firm capacity =

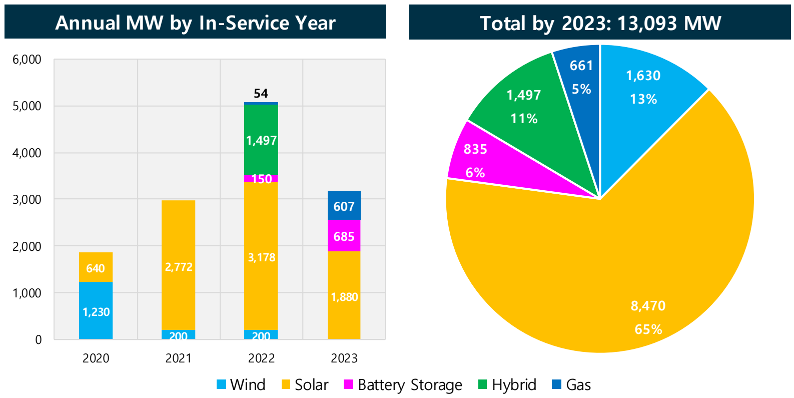
	Portfolio 3a	Portfolio 3b	Portfolio 3c
Wind	250	100	150
Solar	375	450	400
Storage	40	0	20
Total ICAP MW	**665**	**550**	**570**

Actual mix will be influenced by bids received in all-source RFP

ALL-SOURCE RFP

- Sargent & Lundy contracted to run competitively bid, all-source RFP
- More detail will be released in the upcoming weeks
- All information will be hosted at iplpower.com/RFP

MISO Generation Interconnection Queue: Indiana Projects



Source Data: MISO Generation Inteconnection Queue as of 11/10/2019

DSM ACTION PLAN 2021 - 2023

	2021	2022	2023
Decrements 1 - 3 (Gross MWh)	116,376	112,403	113,197
Decrements 1 - 4 (Gross MWh) *	144,890	146,158	146,490
DSM Action Plan Target (Gross MWh)	116,376 - 144,890	112,403 - 146,158	113,197 - 146,490
***DSM level in Reference Case**			

- IPL will target the level of DSM included in Decrement 4 (Ref Case)
  - Decrement 4 is equivalent to roughly 1% of sales
- Residential general service LEDs will no longer be offered in 2021 – 2023 due to lighting baseline change
  - Currently lighting makes up 40% of Residential savings
  - Change possibly eliminates some Residential programs
  - General service LEDs will still be available to income qualified customers

FUTURE MODELING ENHANCEMENTS

Renewables and storage introduce complexity in the market and fundamentally change the type of modeling required for long-term resource planning

Previous IPL IRPs	2019 IPL IRP	Considerations for Future IRPs
• Annual Reserve Margin Target based on Summer Peak • "Typical week" capacity expansion • Deterministic view with a single normalized set of load, price, and renewable shapes • Fixed capacity values for renewables • Cursory look at electric vehicle and distributed solar	• Annual Reserve Margin Target based on Summer Peak • Hourly chronological capacity expansion with stochastic weather, load, and commodity prices • Solar ELCC considerations through time • Hourly stochastic variations in weather with an integrated weather-load-price-renewable model • Top down annual electric vehicle and distributed solar forecasts at the system level	• Seasonal capacity assessment • Hourly and sub-hourly modeling • DSM, EE, and DR shapes modeled hourly and sub-hourly to assess peak reduction, load shifting value • Dynamic wind, solar, and storage ELCC • Bottom up electric vehicle and distributed solar forecast integrated with generation, transmission, and distribution planning • Scenario planning centered around decarbonization pathways that prioritize least cost, reliability, and effectiveness

CONCLUDING REMARKS

Vince Parisi

President and CEO, IPL

APPENDIX

ACRONYM LIST

Acronym	Name
CCGT/CC	Combined Cycle
ST	Steam Turbine
CT	Combustion Turbine
UCAP	Unforced Capacity
ICAP	Installed Capacity
PRMR	Planning Reserve Margin Requirement
ELCC	Effective Load Carrying Capability
DR	Demand Response
DSM	Demand Side Management
MISO	Midcontinent Independent System Operator

Acronym	Name
RFP	Request for Proposals
LCOE	Levelized Cost of Energy
LMP	Locational Marginal Price
PPA	Power Purchase Agreement
PTC	Production Tax Credit
ITC	Investment Tax Credit
CONE	Cost of New Entry
NREL	National Renewable Energy Laboratory
RIIA	Renewable Integration Impact Assessment
PVRR	Present Value Revenue Requirement

PORTFOLIO 1 ICAP CHANGES

Portfolio 1a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	250	250	700
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	425	475	875	950	1,025	1,175	1,175
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200	500	520	520	560	560
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 1b: Includes Decrements 1-4

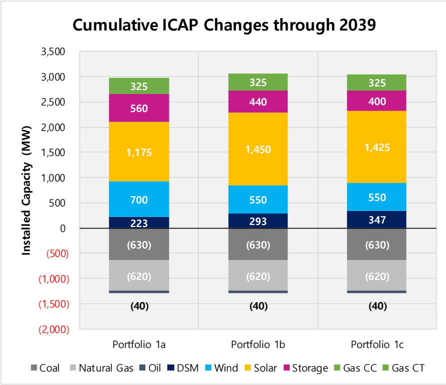
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	550
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	500	900	1,375	1,375	1,450	1,450	1,450
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	40	40	320	360	360	440	440
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 1c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	250	400	550
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	500	825	1,250	1,325	1,325	1,425	1,425
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	300	320	340	380	400
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 1 Runs

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	-220	-220	-630	-630	-630	-630	-630
Gas	0	0	0	0	0	0	0	0	0	0	-200	-200	-200	-200	-620	-620	-620	-620	-620	-620
Oil	0	0	0	0	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40



2019 IRP Stakeholder Meeting 12.9.19

PORTFOLIO 2 ICAP CHANGES

Portfolio 2a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	350	400
New Solar	0	0	0	0	0	0	0	0	0	0	0	125	125	175	500	900	1,050	1,150	1,375	1,425
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	160	180	180	200	500	500	500	500	520
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 2b: Includes Decrements 1-4

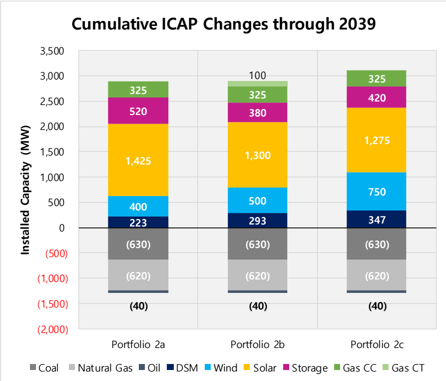
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	450	500	500
New Solar	0	0	0	0	0	0	0	0	0	0	0	350	350	400	800	900	900	900	1,175	1,300
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	40	60	60	60	340	380	380	380	380
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100

Portfolio 2c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
New Wind	0	0	0	0	0	0	0	0	0	0	0	50	50	100	100	200	200	500	600	750
New Solar	0	0	0	0	0	0	0	0	0	0	0	400	450	475	800	1,150	1,150	1,175	1,200	1,275
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	320	360	360	420	420
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 1 Runs

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-630	-630	-630	-630	-630
Gas	0	0	0	0	0	0	0	0	0	0	-200	-200	-200	-200	-620	-620	-620	-620	-620	-620
Oil	0	0	0	0	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40



2019 IRP Stakeholder Meeting 12.9.19

PORTFOLIO 3 ICAP CHANGES

Portfolio 3a: Includes DSM Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	250	250	250	250	250	250	250	250	250	250	250	250	250	350	350	400	400	450
Solar	0	0	0	375	425	475	550	575	650	700	700	700	725	725	725	725	725	825	1,125	1,250
Battery Storage	0	0	0	40	80	80	80	100	100	100	120	340	360	380	500	520	560	560	560	560
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 3b: Includes DSM Decrements 1-4

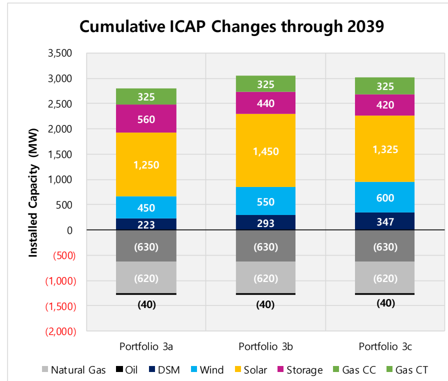
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	100	100	100	100	100	100	150	150	150	150	150	250	250	250	250	300	450	550
Solar	0	0	0	450	600	650	725	750	750	800	850	925	1,000	1,050	1,050	1,075	1,075	1,175	1,350	1,450
Battery Storage	0	0	0	0	0	0	0	20	40	40	40	240	240	240	360	380	420	420	440	440
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 3c: Includes DSM Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	150	150	150	150	150	150	150	200	250	250	300	300	300	350	350	400	450	600
Solar	0	0	0	400	525	575	575	575	625	650	675	725	725	775	825	825	875	975	1,250	1,325
Battery Storage	0	0	0	20	20	20	40	60	60	60	60	260	280	280	380	400	420	420	420	420
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 3 Runs:

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	(220)	(220)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)
Natural Gas	0	0	0	0	0	0	0	0	0	0	(200)	(200)	(200)	(200)	(620)	(620)	(620)	(620)	(620)	(620)
Oil	0	0	0	0	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)



2019 IRP Stakeholder Meeting 12.9.19

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PORTFOLIO 4 ICAP CHANGES

Portfolio 4a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	500	500	500	500	550	600	600	600	700	800	850	900	950	950	950	1,150	1,150	1,350
Solar	0	0	0	450	600	650	1,125	1,225	1,325	1,350	1,350	1,350	1,375	1,400	1,400	1,450	1,475	1,475	1,475	1,475
Battery Storage	0	0	0	0	0	0	340	340	340	360	380	600	620	640	760	780	820	840	920	940
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 4b: Includes Decrements 1-4

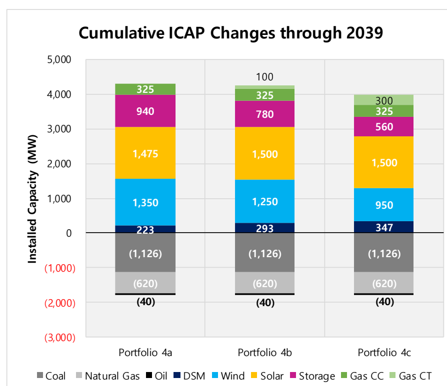
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	400	400	400	400	400	400	550	550	600	600	700	800	800	850	950	1,100	1,250	1,250
Solar	0	0	0	425	550	600	1,100	1,200	1,250	1,325	1,325	1,350	1,350	1,350	1,350	1,375	1,425	1,425	1,450	1,500
Battery Storage	0	0	0	0	0	0	240	240	240	240	260	480	500	520	640	660	680	700	760	780
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Portfolio 4c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	400	400	400	400	400	400	450	450	450	450	550	600	600	650	650	800	800	950
Solar	0	0	0	400	400	400	900	925	925	975	1,025	1,475	1,475	1,475	1,475	1,500	1,500	1,500	1,500	1,500
Battery Storage	0	0	0	20	80	80	200	220	240	240	240	320	340	360	380	400	440	460	540	560
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	200	200	200	200	200	200	200	200	300	300	300	300	300	300

Retirements in All Portfolio 3 Runs:

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	(220)	(220)	(630)	(630)	(630)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)
Natural Gas	0	0	0	0	0	0	0	0	0	0	(200)	(200)	(200)	(200)	(620)	(620)	(620)	(620)	(620)	(620)
Oil	0	0	0	0	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)



2019 IRP Stakeholder Meeting 12.9.19

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PORTFOLIO 5 ICAP CHANGES

Portfolio 5a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	500	500	500	500	550	600	600	600	700	800	850	900	950	950	950	1,150	1,150	1,350
Solar	0	0	0	450	600	650	1,125	1,225	1,325	1,350	1,350	1,350	1,375	1,400	1,400	1,450	1,475	1,475	1,475	1,475
Battery Storage	0	0	0	0	0	0	340	340	340	360	380	600	620	640	760	780	820	840	920	940
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 5b: Includes Decrements 1-4

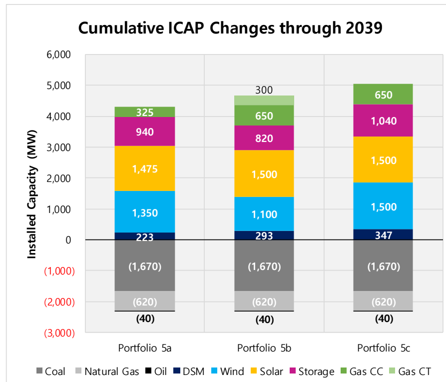
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	350	350	350	350	350	350	400	450	450	450	450	550	550	600	600	800	1,000	1,100
Solar	0	0	0	425	550	600	1,100	1,200	1,275	1,275	1,325	1,350	1,375	1,375	1,450	1,475	1,475	1,475	1,475	1,500
Battery Storage	0	0	0	0	0	0	20	20	20	40	300	520	540	560	660	680	720	740	800	820
Gas CC	0	0	0	0	0	0	325	325	325	325	325	325	325	325	650	650	650	650	650	650
Gas CT	0	0	0	0	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300

Portfolio 5c: Includes Decrements 1-5

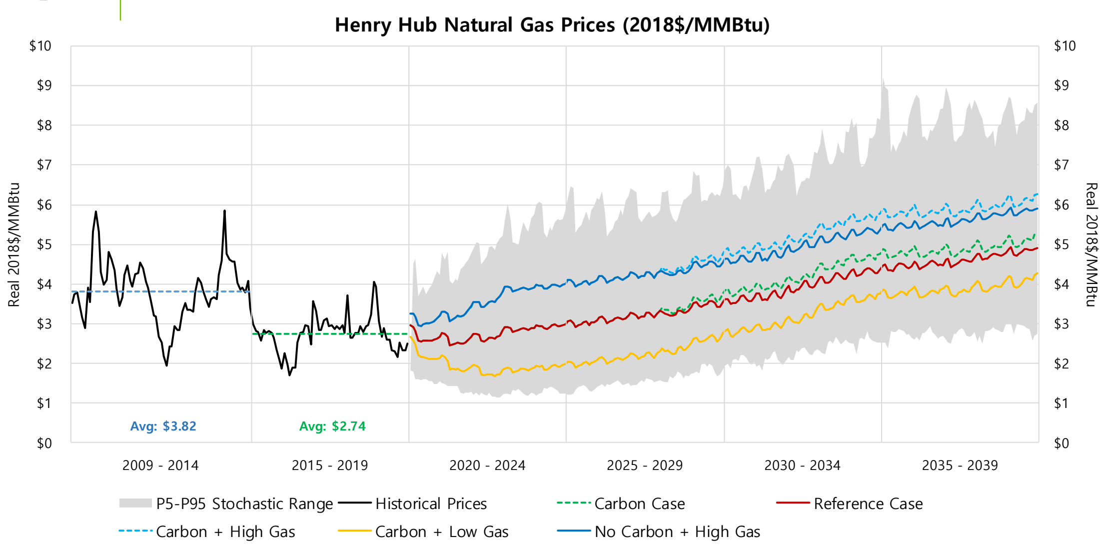
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	500	500	500	500	500	550	550	750	950	1,150	1,150	1,200	1,200	1,300	1,300	1,300	1,500	1,500
Solar	0	0	0	425	500	525	725	775	775	775	1,225	1,375	1,400	1,400	1,400	1,400	1,400	1,450	1,450	1,500
Battery Storage	0	0	0	0	20	20	140	140	160	160	560	720	740	760	880	900	940	960	1,020	1,040
Gas CC	0	0	0	0	0	0	325	325	325	325	325	325	325	325	650	650	650	650	650	650
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 3 Runs:

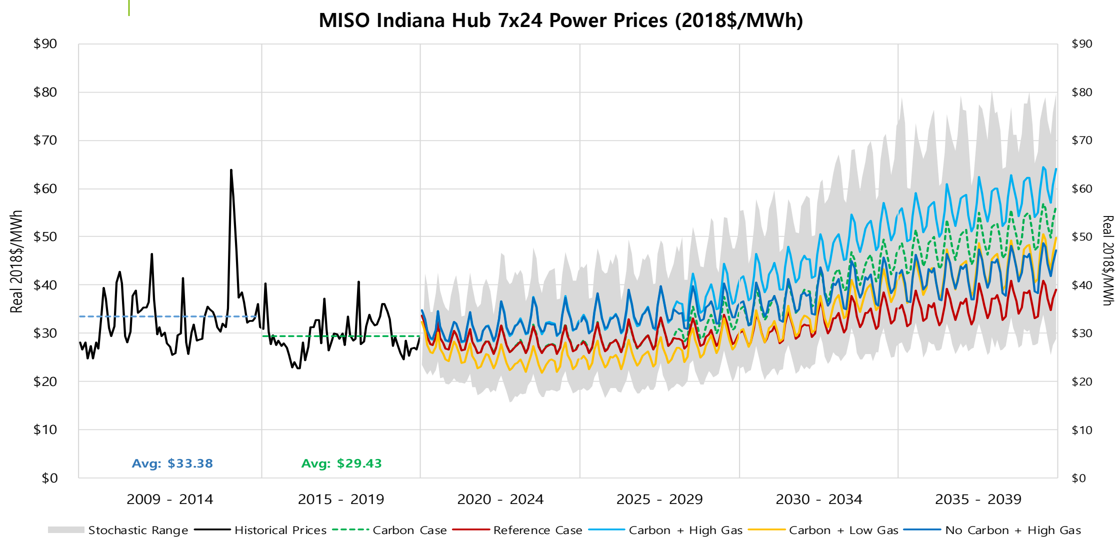
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	(220)	(220)	(630)	(630)	(630)	(1,126)	(1,126)	(1,126)	(1,126)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)
Natural Gas	0	0	0	0	0	0	0	0	0	0	(200)	(200)	(200)	(200)	(620)	(620)	(620)	(620)	(620)	(620)
Oil	0	0	0	0	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)



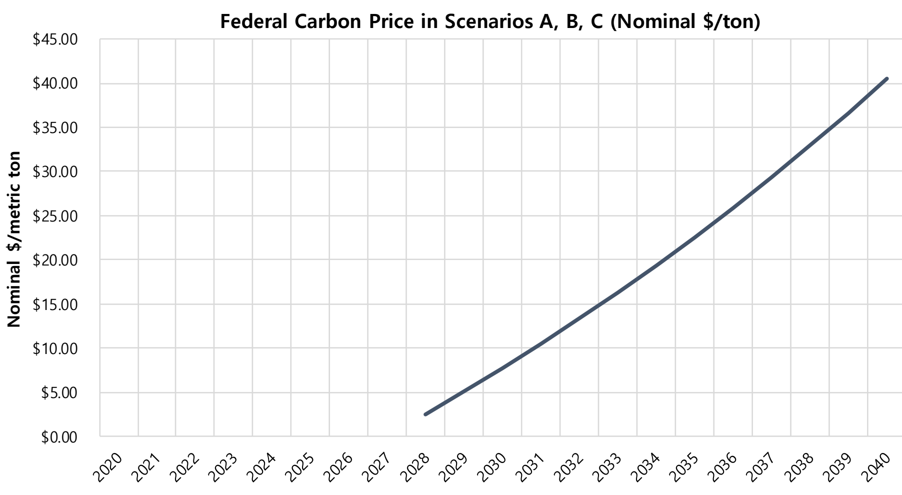
NATURAL GAS PRICES



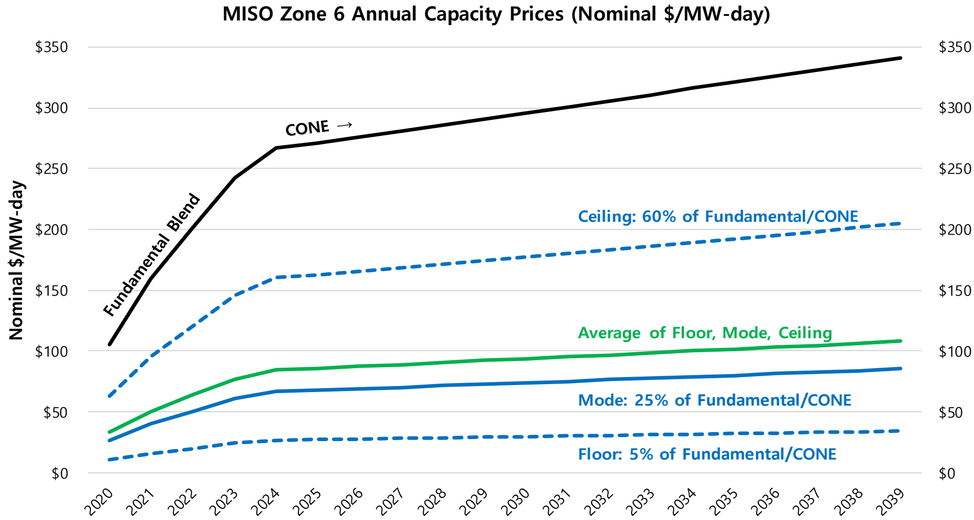
POWER PRICES



CARBON PRICE



CAPACITY PRICES



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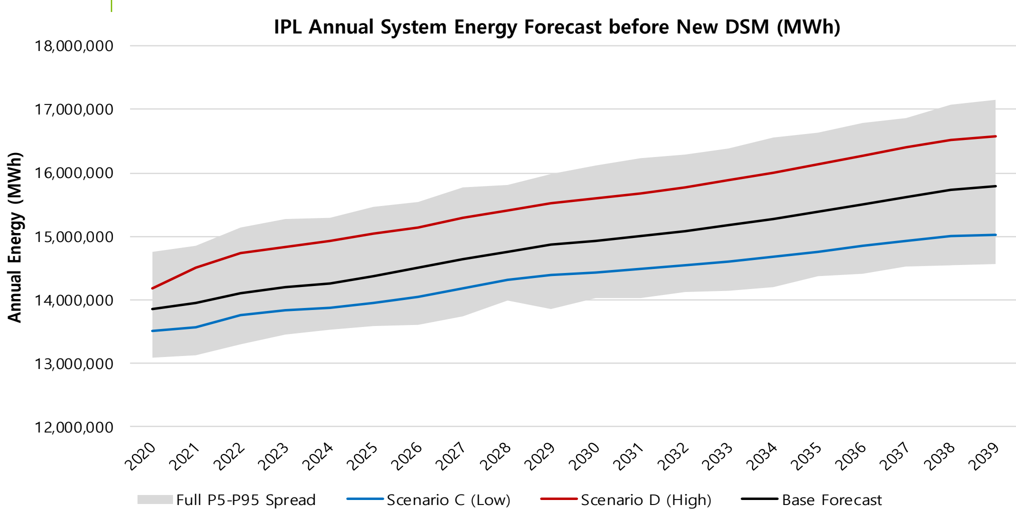
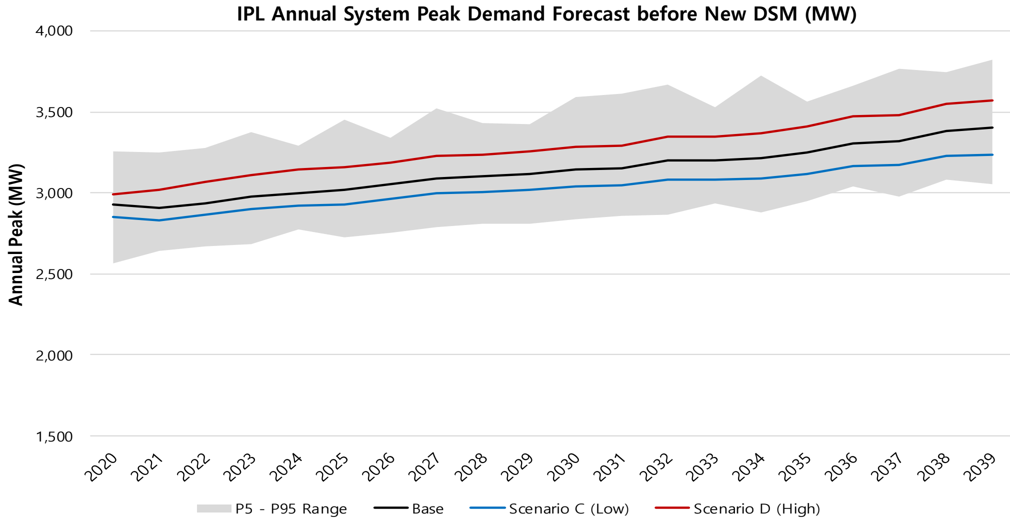
LOAD FORECAST (ENERGY)



90

LOAD FORECAST (PEAK)



STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED
December 21, 2017
INDIANA UTILITY
REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY, AN INDIANA CORPORATION, FOR APPROVAL OF ALTERNATIVE REGULATION PLAN FOR EXTENSION OF DISTRIBUTION AND SERVICE LINES, INSTALLATION OF FACILITIES AND ACCOUNTING AND RATEMAKING OF COSTS THEREOF FOR PURPOSES OF THE CITY OF INDIANAPOLIS' AND BLUEINDY'S ELECTRIC VEHICLE SHARING PROGRAM PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.*	)	**CAUSE NO. 44478**

SUBMISSION OF COMPLIANCE FILING

Petitioner, Indianapolis Power & Light Company ("IPL"), in accordance with the Commission's February 11, 2015 Order in this Cause, files the attached annual report.

Respectfully submitted,

By: [signature]

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
BARNES & THORNBURG LLP
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Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 21st day of December 2017, via electronic mail, on the following:

Randall Helmen
Tiffany Murray
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DMS 4569304v1

THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM ANNUAL REPORT

DECEMBER 31, 2017

GENERAL UPDATE

As of November 30, 2017, BlueIndy has deployed 90 electric car sharing charging stations, which includes approximately 450 electric vehicle chargers and 281 vehicles. Since its launch, BlueIndy has sold over 6,295 memberships and currently has over 2,142 yearly members. Members have logged over 82,624 rides. There is currently one site under construction with additional locations being considered throughout the IPL service territory.

The line extension costs incurred as of the most recent reporting cycle (November 30, 2017) approximates $1,130,000 and is below the IURC approved amount.

The BlueIndy Advisory Board, which is led by the City of Indianapolis and includes IPL, BlueIndy, and the Office of Utility Consumer Counselor, has continued to meet annually to discuss overall program performance, project details, and implementation progress.

The original Extension Services Agreement between IPL and the City of Indianapolis was restated and amended to reflect changes made in the IURC Order. The Agreement term has been extended through April 1, 2018 to allow for additional site deployment.

PROFIT SHARE RECEIVED

Indianapolis Power & Light Company ("IPL") has not received profit share at the time of this filing.

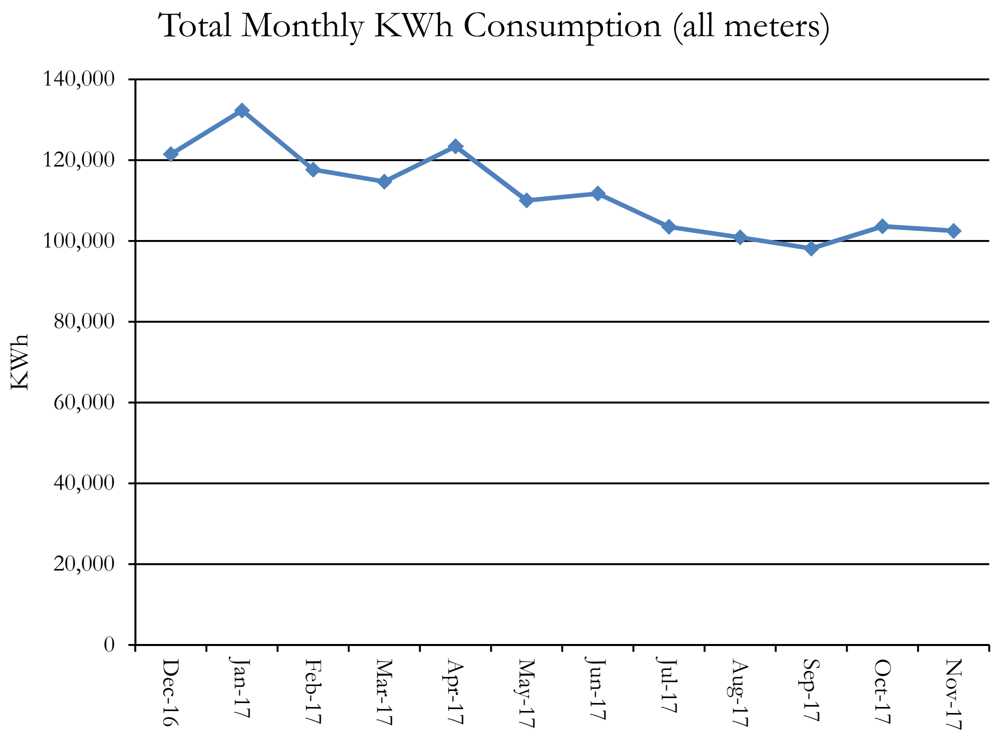
DATA GATHERED

Each BlueIndy Station generally consists of five (5) parking spots (each spot with a Charging Point Station Kiosk for powering Bluecars or members' personal Electric Vehicles), a Reservation Kiosk and a Meter Pedestal. Approximately, every 10th Station also has a covered Enrollment Kiosk. BlueIndy memberships can be secured online, in person with a BlueIndy Ambassador's iPad, via smartphones or via an Enrollment Kiosk. BlueIndy has steadily added Bluecars and Stations to the service since 2015. In 2018, they will likely not add more BlueCars but will continue to evaluate the need for more Stations.

Continuous strategic load balancing is performed by BlueIndy Ambassadors to try to make sure no Station has no more than four (4) and no fewer than one (1) Bluecar charging at any point in time to provide maximum Bluecar and parking availability, which is especially important before the two (2) daily weekday rush hours.

BlueIndy has 189 "Electric Vehicle Charging Members" who use the Stations to charge their personal EVs. These EV Charging Members connected their personal vehicles to the BlueIndy charging network for approximately 4,236 hours since opening.

IPL's analysis as of November 2017 depicted that the meters in service during the most recent 12 month period revealed an average meter consumption of ~1,400 KWh/month. Please see the graphical representation of aggregate BlueIndy energy consumption below.



The impacts to the IPL system have been minimal and represent a modest load growth.

Photos of BlueIndy Local Use

BlueIndy Station downtown Indianapolis showing Bluecars, Reservation Kiosk and Meter Pedestal.

BlueIndy Enrollment Kiosk downtown Indianapolis.
(Typically 1 per location, at select locations only)

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY, AN INDIANA CORPORATION, FOR APPROVAL OF ALTERNATIVE REGULATION PLAN FOR EXTENSION OF DISTRIBUTION AND SERVICE LINES, INSTALLATION OF FACILITIES AND ACCOUNTING AND RATEMAKING OF COSTS THEREOF FOR PURPOSES OF THE CITY OF INDIANAPOLIS' AND BLUEINDY'S ELECTRIC VEHICLE SHARING PROGRAM PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.*	)	**CAUSE NO. 44478**

SUBMISSION OF COMPLIANCE FILING

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Respectfully submitted,

By: ______________________________

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Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 21st day of December 2018, via electronic mail, on the following:

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Tiffany Murray
Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor
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DMS 13718691v1

THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM FINAL REPORT

DECEMBER 31, 2018

GENERAL UPDATE

As of November 30, 2018, BlueIndy has deployed 92 electric car sharing charging stations, which includes approximately 455 electric vehicle chargers and 196 vehicles. Since its launch, BlueIndy has sold over 8,525 memberships and currently has 3279 active members. Members have logged over 133,763 rides. There are currently no sites under construction. However, BlueIndy continues to evaluate additional locations throughout the IPL service territory. The most recent station opening was on the campus of IUPUI in Fall 2018.

The line extension costs incurred as of the most recent reporting cycle (November 30, 2018) approximates $1,135,000 and is below the IURC approved amount. As of the December 5th effective date of IPL's new basic rates and charges, no further carrying charges will be accrued, and amortization of the regulatory asset will begin.

The BlueIndy Advisory Board, which is led by the City of Indianapolis and includes IPL, BlueIndy, and the Office of Utility Consumer Counselor, has continued to meet annually to discuss overall program performance, project details, and implementation progress. The Commission Order in Cause No. 44478 dated February 11, 2015 directed the City and IPL to file two reports – one on or before December 31, 2015 and a second within one year of the public opening. These reporting requirements have been satisfied.

As of December 2018, the BlueIndy Advisory Board believes that all the reporting requirements have been satisfied. Therefore, given that there will be no additional service extensions funded by IPL for BlueIndy charging stations, IPL and the other members of the BlueIndy Advisory Board view this as the final report

PROFIT SHARE RECEIVED

Indianapolis Power & Light Company ("IPL") has not received profit share at the time of this filing.

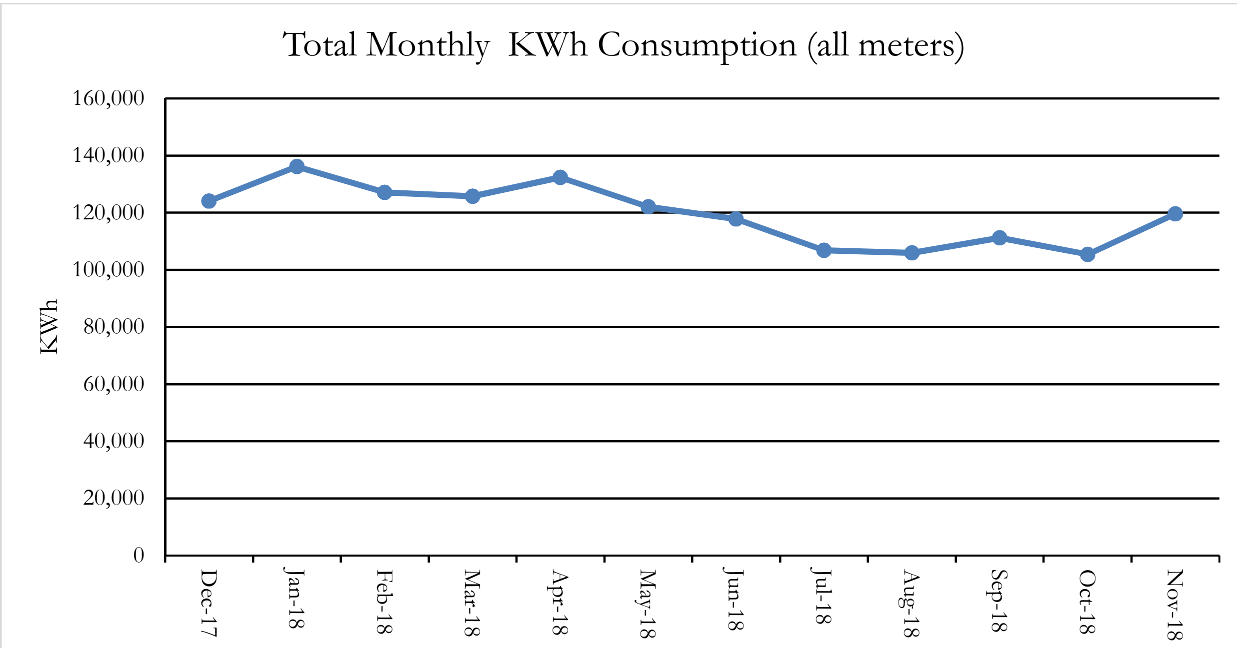
DATA GATHERED

Each BlueIndy Station generally consists of five (5) parking spots (each spot with a Charging Point Station Kiosk for powering Bluecars or members' personal Electric Vehicles), a Reservation Kiosk and a Meter Pedestal. Approximately, every 10th Station also has a covered Enrollment Kiosk. BlueIndy memberships can be secured online, in person with a BlueIndy Ambassador's iPad, via smartphones or via an Enrollment Kiosk. BlueIndy has steadily added Bluecars and Stations to the service since 2015. In 2018, they will likely not add more BlueCars but will continue to evaluate the need for more Stations.

Continuous strategic load balancing is performed by BlueIndy Ambassadors to try to make sure no Station has no more than four (4) and no fewer than one (1) Bluecar charging at any point in time to provide maximum Bluecar and parking availability, which is especially important before the two (2) daily weekday rush hours.

BlueIndy has 294 "Electric Vehicle Charging Members" who use the Stations to charge their personal EVs. These EV Charging Members connected their personal vehicles to the BlueIndy charging network for approximately 7927 hours since opening.

IPL's analysis as of November 2018 depicted that the meters in service during the most recent 12-month period revealed an average meter consumption of ~1,400 KWh/month. Please see the graphical representation of aggregate BlueIndy energy consumption below.

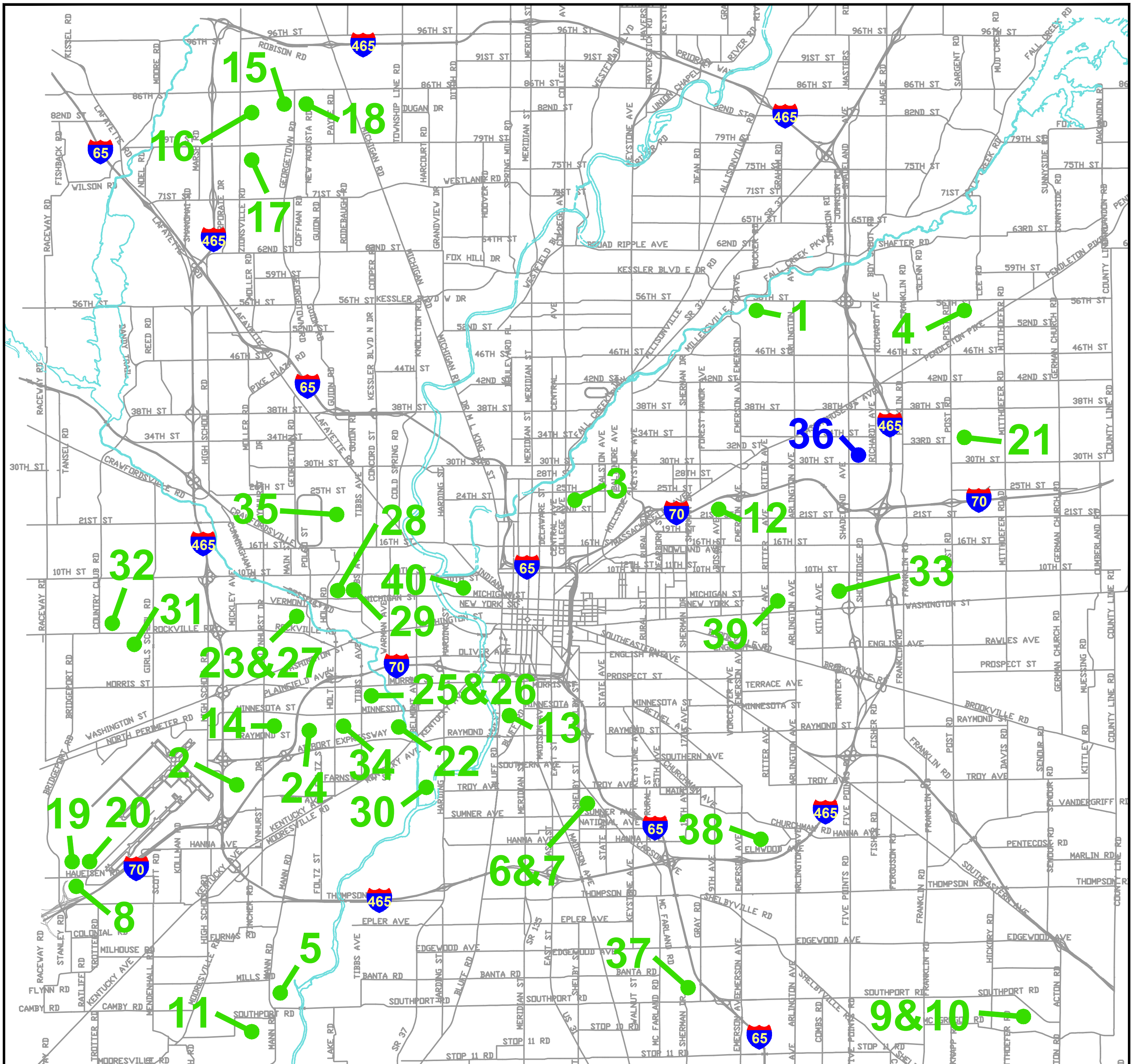


The impacts to the IPL system have been minimal and represent a modest load growth.

Photos of BlueIndy Local Use

BlueIndy Station downtown Indianapolis showing Bluecars, Reservation Kiosk and Meter Pedestal.

BlueIndy Enrollment Kiosk downtown Indianapolis.
(Typically 1 per location, at select locations only)



1. CATHEDRAL HIGH SCHOOL
2. ES by JMS
3. INDIANA VENEERS
4. GSA BEAN FINANCE CENTER
5. MELLOH ENTERPRISES
6. L&R #1 (LAURELWOOD APTS.)
7. L&R #2 (LAURELWOOD APTS.)
8. AIRPORT I
9. INDY SOLAR I
10. INDY SOLAR II
11. INDY SOLAR III
12. INDY DPW
13. INDY DPW
14. SCHAEFER TECHNOLOGIES
15. CITIZENS ENERGY (LNG NORTH)
16. DUKE REALTY #98
17. DUKE REALTY #87
18. DUKE REALTY #129
19. AIRPORT PHASE IIA
20. AIRPORT PHASE IIB
21. CELADON TRUCKING SERVICES
22. VERTELLUS
23. MERRELL BROTHERS
24. GROCERS' SUPPLY CO.
25. A-PALLET CO.
26. A-PALLET CO.
27. TOWN OF SPEEDWAY, IN
28. GenNx PROPERTIES VI, LLC. (MAPLE CREEK APTS.)
29. GenNx PROPERTIES VI, LLC. (MAPLE CREEK APTS.)
30. CITIZENS ENERGY/CWA AUTHORITY
31. REXNORD INDUSTRIES
32. EQUITY INDUSTRIAL A-ROCKVILLE LLC.
33. LIFELINE DATA CENTERS
34. OMNISOURCE
35. INDIANAPOLIS MOTOR SPEEDWAY
36. DEEM
37. INDY SOUTHSIDE SPORTS ACADEMY
38. MARINE CENTER OF INDIANA
39. 5855 LP
40. IUPUI

LEGEND

- # - OPERATING
- # - UNDER CONSTRUCTION
- # - IN DEVELOPMENT

ipl an AES company

INDIANAPOLIS POWER & LIGHT CO.

SOLAR FACILITIES

DRAWN BY: RLW

5-18-15

solar-REP-GIS-map

REV. 11-1-19 WJK

IPL 2019 IRP

Attachment 4.1 (Test Year July 2016 through June 2017 Hourly Loads MW Rate Case) is provided electronically

IPL 2019 IRP

Attachment 4.2a (IPL_LCIIndices_RS18) is provided electronically

IPL 2019 IRP

Attachment 4.2b (IPL_LCIIndices_RC18) is provided electronically

IPL 2019 IRP

Attachment 4.2c (IPL_LCIIndices_RH18) is provided electronically

IPL 2019 IRP

Attachment 4.2d (IPL_LCIIndices_SS18) is provided electronically

IPL 2019 IRP

Attachment 4.2e (IPL_LCIIndices_SH18) is provided electronically

IPL 2019 IRP

Attachment 4.2f (IPL_LCIIndices_SL18) is provided electronically

IPL 2019 IRP

Attachment 4.2g (IPL_LCIIndices_PL18) is provided electronically

Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \text{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \quad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \middle/ Eff_{05}^{Type} \right)} \quad (4)$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2005 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \quad (5)$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \quad (6)$$

In Equation 4, 2005 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \quad (7)$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2005 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	505
Electric Space Heating Heat Pump	190

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a ten year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectric\,\mathrm{Pr}ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\,\mathrm{Pr}ice_{y,m}\right)^{\gamma} \quad (8)$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05,7}}\right)^{\kappa} \quad (9)$$

Where:

- *BDays* is the number of billing days in year (*y*) and month (*m*), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2005
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \tag{11}$$

Data values in 2005 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times CoolShare_{05}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2005 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,661
Space Cooling Heat Pump	369
Room Air Conditioning	315

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectric\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\Pr ice_{y,m}\right)^{\gamma} \quad (13)$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{05}}\right)^{\kappa} \quad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2005.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \quad (15)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(\dfrac{Sat_y^{Type}}{\dfrac{1}{UEC_y^{Type}}} \right)}{\left(\dfrac{Sat_{05}^{Type}}{\dfrac{1}{UEC_{05}^{Type}}} \right)} \times MoMult_m^{Type} \times$$
$$(TenYearMovingAverageElectric\,Price)^{\lambda} \times (TenYearMovingAverageGas\,Price)^{\kappa} \quad (16)$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{HHSize_y}{HHSize_{05}} \right)^{0.46} \times \left(\frac{Income_y}{Income_{05}} \right)^{0.10} \times$$
$$\left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05}} \right)^{\phi} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05}} \right)^{\lambda} \quad (17)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \qquad (18)$$

Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.2 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

where, $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),

$HeatIndex_y$ is the annual index of heating equipment, and

$HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(\frac{HeatShare_y}{Eff_y} \right)}{\left(\frac{HeatShare_{04}}{Eff_{04}} \right)} \quad (4)$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e {kWh}/{Sqft}_e}\right) \quad (5)$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{04}}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \quad (6)$$

where, *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days
WgtHDD is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
HDD is the annual heating degree days for 2004,
Output is a real commercial output driver in year (y),
Price is the average real price of electricity in month (m) and year (y),

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{y,m} = \mathrm{CoolIndex}_{y} \times \mathrm{CoolUse}_{y,m} \qquad (7)$$

where, $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
$CoolIndex_y$ is an index of cooling equipment, and
$CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left(CoolShare_y / Eff_y \right)}{\left(CoolShare_{04} / Eff_{04} \right)} \qquad (8)$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh/Sqft_{e}}\right) \quad (9)$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \quad (10)$$

where, *WgtCDD* is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
CDD is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_y^{Type} / Eff_y^{Type}}{Share_{04}^{Type} / Eff_{04}^{Type}} \right) \tag{12}$$

where, *Weight* is the weight for each equipment type,
Share represents the fraction of floor stock with an equipment type, and
Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{Output_y}{Output_{04}} \right)^{0.20} \times \left(\frac{Price_{y.m}}{Price_{04}} \right)^{-0.18} \tag{14}$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

IPL 2019 IRP

Confidential Attachments 4.4 a-c (Moodys Q4 2018 Base, Exceptionally Strong, and Lower Trend) are provided electronically as part of the Confidential version of the IRP

IPL 2019 IRP

Attachment 4.5 (10yr base by rate code) is provided electronically

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Attachment 4.6 (20yr base, high, low forecast) is provided electronically

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Attachment 4.7a (Energy Input Data - Residential) is provided electronically

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Attachment 4.7b (Energy Input Data - Small CI) is provided electronically

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Attachment 4.7c (Energy Input Data - Large CI) is provided electronically

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Attachment 4.8 (Peak-Forecast Drivers and Input Data) is provided electronically

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Attachment 4.9 (Forecast Analysis) is provided electronically