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 IPL’s 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.

<table>
<thead>
<tr>
<th>Year</th>
<th>Coal</th>
<th>Natural Gas</th>
<th>Oil</th>
<th>Wind</th>
<th>Solar</th>
<th>Storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>79%</td>
<td>14%</td>
<td>7%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>43%</td>
<td>45%</td>
<td>8%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2023 Projected</td>
<td>28%</td>
<td>47%</td>
<td>11%</td>
<td>15%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2039 Projected</td>
<td>19%</td>
<td>27%</td>
<td>16%</td>
<td>29%</td>
<td>8%</td>
<td></td>
</tr>
</tbody>
</table>

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

- Hoosier Wind Park PPA—100MW
- Petersburg Generating Station—1,706 MW
- Eagle Valley Generating Station—671 MW
- Harding Street Station, Georgetown Station, Solar REP Projects—1,150 MW
- Lakefield Wind Park PPA—200 MW (in MN—not pictured)

IPL Service Area

*Lakefield Wind Park PPA—200 MW (in MN—not pictured)
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.

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Description</th>
<th>DSM Decrements 1-3</th>
<th>DSM Decrements 1-4</th>
<th>DSM Decrements 1-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 1</td>
<td>No Early Retirements</td>
<td>1a 1b 1c</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 2</td>
<td>Pete Unit 1 Retire 2021, Pete Units 2-4 Operational</td>
<td>2a 2b 2c</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 3</td>
<td>Pete Unit 1 Retire 2021, Pete 2 Retire 2023, Pete Units 3-4 Operational</td>
<td>3a 3b 3c</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 4</td>
<td>Pete Unit 1 Retire 2021, Pete 2 Retire 2023, Pete 3 Retire 2026, Pete Unit 4 Operational</td>
<td>4a 4b 4c</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 5</td>
<td>Pete Unit 1 Retire 2021, Pete 2 Retire 2023, Pete 3 Retire 2026, Pete 4 Retire 2030</td>
<td>5a 5b 5c</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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.
SHORT TERM ACTION PLAN

**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
IPL 2019 IRP: PUBLIC ADVISORY MEETING #1
January 29, 2019

WELCOME & OPENING REMARKS

Lisa Krueger
President, AES US SBU
# MEETING OBJECTIVES & AGENDA

**Stewart Ramsay**  
*Meeting Facilitator*

## AGENDA

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

2016 IRP SUMMARY

Meeting 1 (April)
- Supply Side and Distributed Resources
- Demand Side Resources
- DSM Modeling
- Risk Discussion
- Scenario Workshop

Meeting 2 (June)
- Metrics Exercise
- Resource Adequacy
- IPL T&D
- Load Forecast
- Environmental Risks
- Portfolio Exercise

Meeting 3 (August)
- IRP Modeling Update
- Sensitivity Analysis and Stochastic Setup

Meeting 4 (September)
- 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

<table>
<thead>
<tr>
<th>Topic</th>
<th>Comments Summary (not exhaustive)</th>
<th>2019 IRP Improvements</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Commodity Forecasts</strong></td>
<td>• Not enough narrative and underlying fundamental support data to support commodity price forecasts</td>
<td>• Scenarios will be built around varying commodity assumptions, with all supporting data clearly outlined</td>
</tr>
<tr>
<td></td>
<td>• Base forecast inconsistent with changing market fundamentals and trends</td>
<td>• Narrative and thorough set of supporting data will be provided well in advance of Nov. 1st filing date</td>
</tr>
<tr>
<td></td>
<td>• Changing resource mix and other fundamentals could materially change</td>
<td>• Data will be made available with signed NDA and public whenever possible</td>
</tr>
<tr>
<td><strong>Scenarios and Portfolios</strong></td>
<td>• Unclear modeling framework with regards to scenarios, portfolios, and stochastics</td>
<td>• March 13th Meeting will outline comprehensive scenario modeling framework to address concerns in 2016 IRP</td>
</tr>
<tr>
<td></td>
<td>• All portfolios weighed against base case assumptions</td>
<td>• Modeling types will be clearly identified and discussed (i.e. portfolios vs scenarios, optimized vs fixed portfolios, capacity expansion vs production cost model)</td>
</tr>
<tr>
<td></td>
<td>• Preferred plan not optimized in capacity expansion</td>
<td></td>
</tr>
<tr>
<td><strong>Metrics</strong></td>
<td>• Stochastic results not fully integrated with metrics scorecard and used in a limited manner</td>
<td>• IPL’s move to Ascend Analytics’ PowerSimm will enable IPL to more fully incorporate stochastic results into the metrics process</td>
</tr>
<tr>
<td></td>
<td>• No specific metrics related to portfolio diversity</td>
<td>• Metrics and risk analysis will be conducted using the same set of underlying data from PowerSimm</td>
</tr>
<tr>
<td></td>
<td>• Environmental metrics should also include land and water impacts</td>
<td>• IPL will consider additional environmental metrics</td>
</tr>
<tr>
<td><strong>DSM/EE Modeling</strong></td>
<td>• Inconsistent avoided cost values</td>
<td>• New model will allow for more DSM bundles and decision points</td>
</tr>
<tr>
<td></td>
<td>• Only two DSM/EE decision points considered</td>
<td>• IPL considering alternative approaches to accounting for changes in future DSM costs</td>
</tr>
<tr>
<td></td>
<td>• Assumptions on future DSM costs need to be reviewed</td>
<td>• Avoided costs will be consistent and presented clearly in meetings and/or provided data files</td>
</tr>
</tbody>
</table>
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
2019 IRP STAKEHOLDER PROCESS

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 → Model Portfolios → Create Scenarios → 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

NREL

Bloomberg
New Energy Finance

EIA

U.S. Energy Information Administration

Energy

BREAK
CAPACITY: DEFINING COMMON IRP MODELING TERMS

Patrick Maguire
Director of Resource Planning

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...”

XEFORD

$xeFORd = \text{Equivalent Demand Forced Outage Rate excluding some outages}$

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](https://www.misoenergy.org/planning/resource-adequacy)

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

<table>
<thead>
<tr>
<th>Planning Year 2018-2019 Pooled $eFORd$ Class</th>
<th>Pooled $eFORd$ (%)</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle</td>
<td>5.37</td>
<td>MISO</td>
</tr>
<tr>
<td>Combustion Turbine (60+ MW)</td>
<td>5.18</td>
<td>MISO</td>
</tr>
<tr>
<td>Diesel Engines</td>
<td>10.26</td>
<td>MISO</td>
</tr>
<tr>
<td>Steam - Coal (200-400 MW)</td>
<td>9.82</td>
<td>MISO</td>
</tr>
<tr>
<td>Steam - Coal (400-600 MW)</td>
<td>9.28</td>
<td>MISO*</td>
</tr>
<tr>
<td>Steam - Coal (600-800 MW)</td>
<td>8.22</td>
<td>MISO</td>
</tr>
<tr>
<td>Steam - Coal (800-1000 MW)</td>
<td>9.28</td>
<td>MISO*</td>
</tr>
<tr>
<td>Steam - Gas</td>
<td>11.56</td>
<td>MISO</td>
</tr>
</tbody>
</table>
ELCC = Effective Load Carrying Capability = Capacity Credit

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?

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

**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

For Solar: Capacity Credit = ELCC% until MISO conducts a formal ELCC study
### ICAP VS UCAP: EXAMPLES

<table>
<thead>
<tr>
<th>ICAP = Installed Capacity</th>
<th>UCAP = Unforced Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Thermal Unit (e.g. Coal, Gas)</strong></td>
<td>ICAP MW</td>
</tr>
<tr>
<td>10% xEFORd</td>
<td>100</td>
</tr>
<tr>
<td><strong>Wind</strong></td>
<td>7.8% Zone 6 ELCC</td>
</tr>
<tr>
<td><strong>Solar</strong></td>
<td>50% credit</td>
</tr>
<tr>
<td><strong>4-Hour Storage</strong>&lt;br&gt;100 MW, 400 MWh</td>
<td>5% xEFORd</td>
</tr>
<tr>
<td><strong>1-Hour Storage</strong>&lt;br&gt;100 MW, 100 MWh</td>
<td>5% xEFORd</td>
</tr>
</tbody>
</table>

To Cover a 1,000 MW UCAP Shortfall:

<table>
<thead>
<tr>
<th>ICAP MW</th>
<th>UCAP MW</th>
<th>ICAP MW Required</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal</td>
<td>100</td>
<td>90</td>
</tr>
<tr>
<td>Wind</td>
<td>100</td>
<td>7.8</td>
</tr>
<tr>
<td>Solar</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>4-Hour Storage</td>
<td>100</td>
<td>95</td>
</tr>
<tr>
<td>1-Hour Storage</td>
<td>100</td>
<td>23.8</td>
</tr>
</tbody>
</table>
Important to note that the UCAP contribution of a resource type is only one part of the valuation process.

**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
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**: 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

IRP STARTING POINT

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

Peak Load* + Reserve Margin

- **COAL**
  - Pete 1: 220 MW
  - Pete 2: 410 MW
  - 578 MW Harding Street Steam Units

- **NATURAL GAS**

- **Wind**
- **Solar**
- **Oil**
- **Other***

*Preliminary peak load forecast

Net UCAP Position (MW)

**ALL CAPACITY SHOWN IN UCAP MW**

*Other: ACLM (37 MW), CVR (17 MW), Rider 17 (1 MW)
IPL RESOURCES: SUMMARY

<table>
<thead>
<tr>
<th>Resource</th>
<th>ICAP</th>
<th>UCAP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1,706</td>
<td>1,608</td>
</tr>
<tr>
<td>Gas</td>
<td>1,725</td>
<td>1,634</td>
</tr>
<tr>
<td>Oil/Diesel</td>
<td>47</td>
<td>44</td>
</tr>
<tr>
<td>Wind/Solar</td>
<td>396</td>
<td>62</td>
</tr>
<tr>
<td>Other</td>
<td>54</td>
<td>54</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>3,929</td>
<td>3,402</td>
</tr>
</tbody>
</table>

ICAP = Installed Capacity  
UCAP = Unforced Capacity

ICAP / UCAP % of Total:
- Coal: 47% / 44%
- Gas: 48% / 44%
- Oil/Diesel: 1% / 1%
- Wind/Solar: 2% / 2%
- Other: 2% / 2%

IPL RESOURCES: NATURAL GAS

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

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

Total Natural Gas UCAP: 1,634 MW
## IPL RESOURCES: WIND AND SOLAR

<table>
<thead>
<tr>
<th>Name</th>
<th>Type</th>
<th>ICAP MW</th>
<th>UCAP MW</th>
<th>PPA Start</th>
<th>PPA Expiration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hoosier Wind Park (IN)</td>
<td>PPA</td>
<td>100</td>
<td>7.8</td>
<td>Nov-09</td>
<td>Nov-29</td>
</tr>
<tr>
<td>Lakefield Wind (MN)</td>
<td>PPA</td>
<td>200</td>
<td>0</td>
<td>Oct-11</td>
<td>Oct-31</td>
</tr>
<tr>
<td>Solar (Rate REP)</td>
<td>PPA</td>
<td>96</td>
<td>54</td>
<td>varies</td>
<td>varies</td>
</tr>
</tbody>
</table>

- **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

## IPL RESOURCES: COAL

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

Total Coal ICAP: 1,706 MW
Total Coal UCAP: 1,608 MW

*Framework for scenario analysis will be presented at the March 13th meeting*
INTRODUCTION TO ASCEND ANALYTICS

Patrick Maguire
Director of Resource Planning
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 | Differentiated Value
---|---

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 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

• 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 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**
- 1 to 10 days
  - 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

**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 vs. risk tradeoff resource analysis
  - Battery storage optimization
  - Financial analysis
Weather → Renewables/Load → Price Simulations

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

Weather

Renewables

Load

Price

Weather – Load – Delivery – Price Paradigm

Weather

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

Load

Renewables

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

During delivery simulations

Weather Sim → Renewables

Load Sim → Spot Price Sim

Calibrated Spot Prices → Optimal Dispatch

Forecasted monthly forward prices

Forward Price Sim Power, Gas, Coal, Oil, Emissions, …

Valuation/Selection

Portfolio Summarization

Optimal Dispatch

Valuation/Selection

Portfolio Summarization
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

PowerSimm Modeling Framework

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

During delivery simulations
- Weather Sim → Renewables

- Load Sim → Spot Price Sim → Calibrated Spot Prices → Optimal Dispatch

Forecasted monthly forward prices
- Forward Price Sim: Power, Gas, Coal, Oil, Emissions, ...

Valuation/Selection
- Portfolio Summarization
Wind tends to blow hard or not at all
Averaging smooths out variability

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

Why You Can’t Just Average Renewables: Solar in July
Renewables - Solar

**Simulated vs Historical:**
- Accurately capturing solar’s behavior in summer and winter months by modeling expected peaks in conjunction 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

2015 Solar, Jan 19th 2019

2015 Solar, June 22nd 2019

---

**PowerSimm Modeling Framework**

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

- Weather Sim
  - Renewables
    - Calibrated Spot Prices
      - Optimal Dispatch
        - Valuation/Selection
          - Portfolio Summarization
  - Load Sim
    - Spot Price Sim
      - Forward Price Sim (Power, Gas, Coal, Oil, Emissions, ...)

Forecasted monthly forward prices

During delivery simulations
Example: Simulated Temperature, Load, Gas and Power Prices

- Simulated Weather
- Simulated Gas
- Simulated Load
- Simulated Power

PowerSimm Modeling Framework

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

During delivery simulations:
- Weather Sim → Renewables
  - Load Sim → Spot Price Sim → Calibrated Spot Prices → Optimal Dispatch

Forecasted monthly forward prices:
- Forward Price Sim
  - Power, Gas, Coal, Oil, Emissions, ...

Valuation/Selection → Portfolio Summarization
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.

REPLACEMENT RESOURCES IN THE 2019 IRP

Patrick Maguire
Director of Resource Planning
REPLACEMENT RESOURCES MODELED

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)

Mature technologies with more certainty around operational parameters and capital costs

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
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


WIND (CONT’D)

Wind Capacity Credit

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*

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

- Monthly PV Yield (%)
  - Jan: 5%, 10%, 15%, 20%, 25%, 30%
  - Feb: 5%, 10%, 15%, 20%, 25%, 30%
  - Mar: 5%, 10%, 15%, 20%, 25%, 30%
  - Apr: 5%, 10%, 15%, 20%, 25%, 30%
  - May: 5%, 10%, 15%, 20%, 25%, 30%
  - Jun: 5%, 10%, 15%, 20%, 25%, 30%
  - Jul: 5%, 10%, 15%, 20%, 25%, 30%
  - Aug: 5%, 10%, 15%, 20%, 25%, 30%
  - Sep: 5%, 10%, 15%, 20%, 25%, 30%
  - Oct: 5%, 10%, 15%, 20%, 25%, 30%
  - Nov: 5%, 10%, 15%, 20%, 25%, 30%
  - Dec: 5%, 10%, 15%, 20%, 25%, 30%

- Hourly PV Yield (%)
  - 1-Aug-11: 5%, 10%, 15%, 20%, 25%, 30%
  - 2-Aug-11: 5%, 10%, 15%, 20%, 25%, 30%

Source: BloombergNEF & PVGIS.

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*

https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v6301579.pdf
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
- \[ UCAP = 20 \text{ MW} \times (1 - x\text{FORd\%}) \]
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

- Technical
- Economic
- Achievable

IRP Resource Selection Modeling

Selected Bundles into RFP for Vendor(s)

File Portfolio of Programs with IURC

DSM Filing

2021 - 2023 IPL DSM Program Implementation

DSM BUNDLES

Example of Bundles from the IPL 2016 IRP:

<table>
<thead>
<tr>
<th>Sector and Technology</th>
<th>Levelized Utility Cost per MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(up to $30/MWh)</td>
</tr>
<tr>
<td></td>
<td>($30-60/MWh)</td>
</tr>
<tr>
<td></td>
<td>($60+/MWh)</td>
</tr>
<tr>
<td>EE Residential HVAC</td>
<td>Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td>EE Residential Lighting</td>
<td>Selected</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
</tr>
<tr>
<td>EE Residential Other</td>
<td>Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td>EE C&amp;I HVAC</td>
<td>Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td>EE C&amp;I Lighting</td>
<td>Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td>EE C&amp;I Other</td>
<td>Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td>EE C&amp;I Process</td>
<td>Not Selected</td>
</tr>
<tr>
<td></td>
<td>Not Selected</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
</tr>
<tr>
<td>EE Residential Behavioral</td>
<td>Not Selected</td>
</tr>
<tr>
<td>OR Water Heating ØKC</td>
<td>Not Selected</td>
</tr>
<tr>
<td>OR Smart Thermostats</td>
<td>Not Selected</td>
</tr>
<tr>
<td>OR Emerging Tech</td>
<td>Not Selected</td>
</tr>
<tr>
<td>OR Curbal Agreements</td>
<td>Not Selected</td>
</tr>
<tr>
<td>OR Battery Storage</td>
<td>Not Selected</td>
</tr>
<tr>
<td>OR air Conditioning Load Mgmt</td>
<td>Not Selected</td>
</tr>
</tbody>
</table>

*Note: N/A indicates that a bundle was not modeled, all measures listed in lower cost bundles.*
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

LOAD FORECASTING UPDATE

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

- Economic Forecast (Moody Analytics)
- Weather HDD and CDD (Indianapolis Airport)
- Historic Class Sales, Customers, Price Data
- End-Use Saturation and Efficiency Trends (EIA)
- Historic DSM Data (EM&V)
- Historic Hourly System Load Data
- System Energy and Peak Forecast
- Peak-Day Weather Data
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

RESIDENTIAL MODEL FRAMEWORK

\[ \text{AvgUse}_m = a + b_1 \times XCool_m + b_2 \times XHeat_m + b_3 \times XOther_m + e_m \]
COMMERCIAL MODEL FRAMEWORK

Industrial sales are estimated with a generalized econometric model:

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

INDUSTRIAL MODEL FRAMEWORK

Industrial sales are estimated with a generalized econometric model:

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

FINAL Q&A AND NEXT STEPS

Patrick Maguire
Director of Resource Planning
NEXT STEPS

• **Next Meeting: March 13, 2019**
  - IPL Electric Building
  - Register at [http://iplpower.com/irp](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](mailto:ipl.irp@aes.com)
WELCOME & OPENING REMARKS

Lisa Krueger
President, AES US SBU
MEETING OBJECTIVES & AGENDA

Stewart Ramsay
Meeting Facilitator

AGENDA

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

Patrick Maguire  
Director of Resource Planning

---

#### 2019 IRP STAKEHOLDER PROCESS

<table>
<thead>
<tr>
<th>January 29th</th>
<th>March 26th</th>
<th>May</th>
<th>August</th>
<th>October</th>
</tr>
</thead>
</table>
| - 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

DETAILED LOAD FORECAST - PEAKS & ENERGY
Erik Miller
Senior Research Analyst
AGENDA

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

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
WEATHER 20-YR TRENDED

HDD Weather Trend Approach

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

CDD Weather Trend Approach

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

RESIDENTIAL MODEL

AvgUse_m = a + b_c × XCool_m + b_n × XHeat_m + b_p × XOther_m + e_m

HDD = Heating Degree Day
CDD = Cooling Degree Day
RESIDENTIAL END USE TRENDS

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

AAGR = Average Annual Growth Rate

RESIDENTIAL ECONOMIC DRIVERS

Moody’s Analytics Marion County Economic Forecast

Multifamily Growth:
- Increasing # of households
- Decreasing persons / household

AAGR = Average Annual Growth Rate
RESIDENTIAL FORECAST

Annual Average Use

- AAGR 2019 - 2039: 0.4%

Customers

- AAGR 2019 - 2039: 0.8%

Sales

- AAGR 2019 - 2039: 1.2%

AAGR = Average Annual Growth Rate

COMMERCIAL MODEL

End Use Index

- Saturation Efficiency Intensity Coding

Saturation Efficiency Intensity Heating

Saturation Efficiency Intensity Water Heat Refrigeration Lighting Densities etc.

Utilization

- Employment GDP Real Price

CDD

XCool

HDD

XHeat

XOther

Sales_m = a + b_c × XCool_m + b_h × XHeat_m + b_o × XOther_m + e_m
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

Weighted Econ Variable

AAGR 2019 - 2039: 1.04%
**INDUSTRIAL MODEL**

Industrial sales are estimated with a generalized econometric model

\[ \text{Sales}_m = a + b_{\text{cdd}} \times \text{CDD}_m + b_{\text{Econ}} \times \text{EconVariable}_m + e_m \]

- Cooling Degree Days
- Manufacturing Employment
- Manufacturing Output
- Price

**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

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
<th>Small C&amp;I</th>
<th>Large C&amp;I</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual Growth</td>
<td>1.2%</td>
<td>0.2%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Rate 2019 - 2039:</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

2019 - 2039 Lrg C&I: 49% - 45% of Sales
2019 - 2039 Sm C&I: 14% - 13% of Sales
2019 - 2039 Res: 38% - 42% of Sales

No Losses Included

Residential  ■  Small C&I  ■  Large C&I

Residential
Small C&I
Large C&I

PEAK MODEL

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

Class Sales Forecast Models

- Cooling Load Residential Commercial
- Heating Requirements Residential Commercial
- Peak-Day Temperature (CDD)
- Peak-Day Temperature (HDD)
- PKCool
- XHeat
- XOther
- Other Use Residential Commercial Industrial Street Lighting
- Share End-Use Energy at Time of Peak
IRP ENERGY & PEAK FORECAST

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

<table>
<thead>
<tr>
<th>Average Annual Growth Rate 2019 - 2039:</th>
<th>Energy</th>
<th>Peaks</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.4%</td>
<td>0.8%</td>
</tr>
</tbody>
</table>

![Graph showing energy and peak load forecasts from 2019 to 2039](image)

**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
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
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

DRAFT 03.19.19

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

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

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

Home Type

- Single Family, Detached, 75%
- Multifamily, 15%
- Mobile/Manufactured Home, 2%
- Townhome, 7%

Heating & Water Heating

- Heating
- Water Heating
- Electric
- Gas

Cooling

- Central AC
- Heat Pump
- Room AC

End Use Profiles

average annual kWh per home

- Gas Heat
  - Heating intensity: 6%
  - Cooling intensity: 21%
  - Water heating intensity: 8%
- Electric Heat
  - Heating intensity: 49%
  - Cooling intensity: 12%
  - Water heating intensity: 12%
LIGHTING

01 Self-responders tend to underestimate 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.

40.5 sockets

5.5 bulbs in storage

61% of storage are incandescent

Average bulbs per home

Distribution by Bulb Type

Lighting Sockets by Room Type
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

SEGMENTATION by Electric Consumption
Commercial Segmentation by Commercial Building Type

WAREHOUSE 3%
ASSEMBLY 19%
EDUCATION 11%
FOOD SALES 1%
FOOD SERVICES 7%
HEALTHCARE 4%
LODGING 10%
MERCHANDISE 28%
OFFICE 6%
OTHER (Manufacturing, Agriculture, Research, etc.) 1%
**End Use Profiles**

*average annual kWh per commercial site*

**Sites with Gas Heat**
- Heat: 2%
- Cool: 7%
- Vent: 16%
- EWHeat: 1%
- Cooking: 3%
- Refrig: 15%
- Light: 13%
- Office: 9%
- Misc: 34%

**Sites with Electric Heat**
- Heat: 5%
- Cool: 7%
- Vent: 15%
- EWHeat: 1%
- Cooking: 2%
- Refrig: 15%
- Light: 13%
- Office: 9%
- Misc: 33%

**LIGHTING**

*average 259 lamps per Site*

- 52% are T5/T8
- 20% are LED
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**

### DISTRIBUTION OF ENERGY SALES - INDUSTRIAL

- Manufacturing: 74%
- Non-Manufacturing: 26%

### DISTRIBUTION OF NON-MANUFACTURING SALES

- Wholesale Trade: 36%
- Accommodation & Food Services: 1%
- Admin & Support: 1%
- Agricultural: 0%
- Construction: 3%
- Education: 6%
- Financial & Insurance: 1%
- Health Care: 16%
- Information: 1%
- Mining: 2%
- Public Admin: 2%
- Professional Services: 1%
- Retail Trade: 3%
- Transport & Warehouse: 2%
- Utilities: 1%
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.
We are here in the process.

Technical
Economic
Achievable
Create IRP Inputs

IRP Resource Selection Modeling
Selected DSM into RFP for Vendor(s)

File Portfolio of Programs with IURC

Market Potential Study
IPL’s IRP modeling
DSM Filing

2021 - 2023 IPL DSM Program Implementation

POTENTIAL STUDY METHODOLOGY
METHODOLOGY-MEASURE CHARACTERIZATION

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-CLIMATE CHANGE ALLEVIATION

LOAD DISAGREGATION
States by Market Segment by End Use

DATA COLLECTION
- New & Existing End Use<br>- Secondary Data Collection

MARKET ADOPTION
- Historical Performance<br>- Short Term and Long Term Market Barriers

TECHNOLOGY CHARACTERISTICS
- Energy, Efficiency, Cost
- Technical Potential
- Economic Potential
- Achievable Potential

COST-EFFECTIVENESS
- Avoided Cost Benefits
- Market Costs / Price Trends
METHODOLOGY-TECHNICAL POTENTIAL

Draft Results
Residential Example (electric)

\[
\text{TECHNICAL POTENTIAL OF EFFICIENT MEASURE} = \text{total number of households} \times \text{base case end use intensity (kWh/unit)} \times \text{satisfaction share} \times \text{remaining factor} \times \text{feasibility factor} \times \text{savings factor}
\]

analysis covers a 20-year timeframe

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

METHODOLOGY-ECONOMIC POTENTIAL

Draft Results

\[
\text{ECONOMIC POTENTIAL} = \text{TECHNICAL} - \text{NON-COST EFFECTIVE}
\]

ECONOMIC POTENTIAL
Subset of the Technical Potential that is economically cost effective (based on screening with the Utility Cost Test)
ADOPTION RATES
- short term adoption rate (a)
- long term adoption rate (b)
- adoption curve
  • i.e. how you get from (a) to (b)

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
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.

RESIDENTIAL POTENTIAL RESULTS
Draft Results
2021-2039 Cumulative RAP (percent savings by end use)
RESIDENTIAL POTENTIAL RESULTS
Draft Results
Annual Incremental RAP 2021-2025 (gross MWh)

COMMERCIAL & INDUSTRIAL
C&I POTENTIAL RESULTS
Draft Results

C&I CUMULATIVE POTENTIAL 2021-2039 (GROSS MWH)

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

COMMERCIAL POTENTIAL RESULTS
Draft Results
2021-2039

Commercial Cumulative RAP by End Use
INDUSTRIAL POTENTIAL RESULTS
Draft Results
2021-2039

Industrial Cumulative RAP by End Use

- Lighting: 30%
- Machine Drive: 28%
- Space Cooling: 19%
- Process Heating and Cooling: 13%
- Ventilation: 3%
- Agriculture: 3%
- Space Heating: 3%
- Water Heating: 0%
- Computers & Office Equipment: 1%
- Other: 0%
- Water Heating: 0%
- Lighting: 0%
- Machine Drive: 0%
- Space Cooling: 0%
- Process Heating and Cooling: 0%
- Ventilation: 0%
- Agriculture: 0%
- Space Heating: 0%
- Water Heating: 0%
- Computers & Office Equipment: 0%
- Other: 0%
- Water Heating: 0%

TOTAL C&I 2021-2025 POTENTIAL
Draft Results

C&I Annual Incremental Potential (Gross MWh)

- 2021: 1.44%
- 2022: 1.43%
- 2023: 1.45%
- 2024: 1.51%
- 2025: 1.60%

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

Draft Results

Cumulative Annual DR Savings (Gross MW)

IPL RAP POTENTIAL

- 2021: 2.2%
- 2022: 4.2%
- 2023: 5.9%
- 2024: 6.8%
- 2025: 7.1%

Legend:
- Res DLC
- C&I Curtailable
- C&I DLC
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
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\textsubscript{x}, SO\textsubscript{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

FORWARD CURVE NOTES

<table>
<thead>
<tr>
<th></th>
<th>Deterministic Modeling</th>
<th>Stochastic Ranges</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>✓</td>
<td>✓</td>
<td>Internally sourced IPL coal curves.</td>
</tr>
<tr>
<td>Fuel Oil</td>
<td>✓</td>
<td>✓</td>
<td>Wood Mackenzie</td>
</tr>
<tr>
<td>Emissions</td>
<td>✓</td>
<td>×</td>
<td>NOx and SO2 curves will be sourced from forward curves. Carbon prices from Wood Mackenzie.</td>
</tr>
<tr>
<td>Capacity</td>
<td>✓</td>
<td>✓</td>
<td>Capacity will be valued at the estimated bilateral price for MISO Zone 6.</td>
</tr>
</tbody>
</table>
MISO Capacity Price Forecast

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

MISO’s Residual Capacity Market Results in Low Capacity Prices
Highly Uncertain Future Modeled with Triangular Distribution

Wood Mackenzie/CONE

Bilateral Ceiling: 60% of CONE
Bilateral Floor: 5% of CONE
Mode: 25% of CONE
ASSUMPTIONS FOR REPLACEMENT RESOURCES

Patrick Maguire
Director of Resource Planning

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
# KEY ASSUMPTIONS FOR NEW RESOURCES

<table>
<thead>
<tr>
<th>Variable</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Costs</td>
<td>Overnight costs to construct, typically represented in $/kW</td>
</tr>
<tr>
<td>Operating Costs</td>
<td>Fixed O&amp;M</td>
</tr>
<tr>
<td></td>
<td>Variable O&amp;M</td>
</tr>
<tr>
<td>Operating Characteristics</td>
<td>Heat Rates (natural gas units)</td>
</tr>
<tr>
<td></td>
<td>MW limits</td>
</tr>
<tr>
<td></td>
<td>Ramp rates</td>
</tr>
<tr>
<td></td>
<td>Capacity Factors/Profiles (wind/solar)</td>
</tr>
</tbody>
</table>

## 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)

Lazard
- Levelized Cost of Energy Analysis, Version 12.0
- Levelized Cost of Storage Analysis, Version 4.0

NIPSCO RFP Average Bid Prices
- NIPSCO 2018 Integrated Resource Plan
- 7-24-2018 Public Advisory Presentation

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

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

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
NATURAL GAS TECHNOLOGIES

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1x1 CCGT</td>
<td>$967</td>
<td>$14.22</td>
<td>$3.04</td>
</tr>
<tr>
<td>Frame CT</td>
<td>$754</td>
<td>$10.96</td>
<td>$6.94</td>
</tr>
</tbody>
</table>

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

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)
WIND: CAPITAL COSTS

Wind Capital Costs - No PTC (Real 2018 $/kW)

Wind Capital Costs: with and without PTC (Real 2018$/kW)
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

Generic Tracking Solar: Monthly Capacity Factors

<table>
<thead>
<tr>
<th>Month</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>8%</td>
</tr>
<tr>
<td>Feb</td>
<td>16%</td>
</tr>
<tr>
<td>Mar</td>
<td>23%</td>
</tr>
<tr>
<td>Apr</td>
<td>28%</td>
</tr>
<tr>
<td>May</td>
<td>32%</td>
</tr>
<tr>
<td>Jun</td>
<td>37%</td>
</tr>
<tr>
<td>Jul</td>
<td>35%</td>
</tr>
<tr>
<td>Aug</td>
<td>30%</td>
</tr>
<tr>
<td>Sep</td>
<td>27%</td>
</tr>
<tr>
<td>Oct</td>
<td>18%</td>
</tr>
<tr>
<td>Nov</td>
<td>13%</td>
</tr>
<tr>
<td>Dec</td>
<td>8%</td>
</tr>
</tbody>
</table>
### SOLAR: CAPACITY FACTORS

#### IPL Rate REP Solar: 2016-2018 Monthly Capacity Factors

<table>
<thead>
<tr>
<th></th>
<th>GROUND FIXED TILT</th>
<th>TRACKING</th>
<th>COMMERCIAL ROOFTOP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>9.8%</td>
<td>5.2%</td>
<td>7.0%</td>
</tr>
<tr>
<td>Feb</td>
<td>16.5%</td>
<td>15.7%</td>
<td>9.9%</td>
</tr>
<tr>
<td>Mar</td>
<td>19.5%</td>
<td>18.6%</td>
<td>15.7%</td>
</tr>
<tr>
<td>Apr</td>
<td>19.3%</td>
<td>21.3%</td>
<td>21.8%</td>
</tr>
<tr>
<td>May</td>
<td>21.9%</td>
<td>22.9%</td>
<td>24.4%</td>
</tr>
<tr>
<td>Jun</td>
<td>26.8%</td>
<td>25.2%</td>
<td>24.5%</td>
</tr>
<tr>
<td>Jul</td>
<td>22.9%</td>
<td>25.3%</td>
<td>24.4%</td>
</tr>
<tr>
<td>Aug</td>
<td>21.0%</td>
<td>23.5%</td>
<td>22.6%</td>
</tr>
<tr>
<td>Sep</td>
<td>22.0%</td>
<td>21.6%</td>
<td>18.5%</td>
</tr>
<tr>
<td>Oct</td>
<td>18.9%</td>
<td>12.6%</td>
<td>16.9%</td>
</tr>
<tr>
<td>Nov</td>
<td>15.0%</td>
<td>13.4%</td>
<td>9.5%</td>
</tr>
<tr>
<td>Dec</td>
<td>7.1%</td>
<td>9.6%</td>
<td>8.9%</td>
</tr>
<tr>
<td><strong>Annual</strong></td>
<td>18.4%</td>
<td>17.9%</td>
<td>17.0%</td>
</tr>
</tbody>
</table>

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

### 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

---

**Annual Solar Capacity Credit**

- 2019: 51%
- 2020: 46%
- 2021: 41%
- 2022: 38%
- 2023: 34%
- 2024: 32%
- 2025: 31%
- 2026: 30%
- 2027: 29%
- 2028: 29%
- 2029: 28%
- 2030: 27%
- 2031: 27%
- 2032: 26%
- 2033: 25%
- 2034: 25%
- 2035: 24%
- 2036: 24%
- 2037: 23%
- 2038: 23%
- 2039: 23%
- 2040: 23%

---

**Source:** MISO
**SOLAR: LCOE**

<table>
<thead>
<tr>
<th>ITC Safe Harbor</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024+</th>
</tr>
</thead>
<tbody>
<tr>
<td>ITC Safe Harbor</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>10%</td>
</tr>
</tbody>
</table>

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

**STORAGE CAPITAL COST**

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

<table>
<thead>
<tr>
<th>Natural Gas Prices</th>
<th>Reference Case</th>
<th>Scenario A: Carbon Tax</th>
<th>Scenario B: Carbon Tax + High Gas</th>
<th>Scenario C: Carbon Tax + Low Gas</th>
<th>Scenario D: No Carbon Tax + High Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>Base</td>
<td>HIGH †</td>
<td>LOW ‖</td>
<td>HIGH †</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Carbon Tax</th>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B: Carbon Price (2028+)</th>
<th>Scenario C: Carbon Price (2028+)</th>
<th>Scenario D: No Carbon Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Carbon Price</td>
<td>No Carbon Price</td>
<td>Carbon Price (2028+)</td>
<td>Carbon Price (2028+)</td>
<td>No Carbon Price</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Coal Prices</th>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>IPL Load</th>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>LOW ‖</td>
<td>HIGH †</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Capital Costs for Wind, Solar, and Storage</th>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
</tr>
</tbody>
</table>

### PROPOSED SCENARIO FRAMEWORK

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

<table>
<thead>
<tr>
<th>Retired Units</th>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Accelerated Retirements</td>
<td>Portfolio 1</td>
<td>1a</td>
<td>1b</td>
<td>1c</td>
<td>1d</td>
</tr>
<tr>
<td>Pete Unit 1 Retire 2021 Pete Units 2-4 Operational</td>
<td>Portfolio 2</td>
<td>2a</td>
<td>2b</td>
<td>2c</td>
<td>2d</td>
</tr>
<tr>
<td>Pete 1 Retire 2021, Pete 2 Retire 2023 Pete Units 3-4 Operational</td>
<td>Portfolio 3</td>
<td>3a</td>
<td>3b</td>
<td>3c</td>
<td>3d</td>
</tr>
<tr>
<td>Pete 1 Retire 2021, Pete 2 Retire 2023, Pete 3 Retire 2026 Pete Unit 4 Operational</td>
<td>Portfolio 4</td>
<td>4a</td>
<td>4b</td>
<td>4c</td>
<td>4d</td>
</tr>
<tr>
<td>Pete 1 Retire 2021, Pete 2 Retire 2023, Pete 3 Retire 2026, Pete 4 Retire 2030</td>
<td>Portfolio 5</td>
<td>5a</td>
<td>5b</td>
<td>5c</td>
<td>5d</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>BASE CASE: NO ACCELERATED RETIREMENTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Case</td>
</tr>
<tr>
<td>No Accelerated Retirements</td>
</tr>
</tbody>
</table>

**Capacity Expansion optimally fills shortfall**

RETIREMENT PORTFOLIOS (1 OF 4)

<table>
<thead>
<tr>
<th>RETIREMENT PORTFOLIOS (1 OF 4)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Case</td>
</tr>
<tr>
<td>Pete Unit 1 Retire <strong>2021</strong> Pete Units 2-4 Operational</td>
</tr>
</tbody>
</table>

**Pete 1 EARLY RETIRE**

**Capacity Expansion optimally fills shortfall**
### RETIREMENT PORTFOLIOS (2 OF 4)

<table>
<thead>
<tr>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational Portfolio 3</td>
<td>3a</td>
<td>3b</td>
<td>3c</td>
<td>3d</td>
</tr>
</tbody>
</table>

### RETIREMENT PORTFOLIO (3 OF 4)

<table>
<thead>
<tr>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete 3 Retire 2026 Pete Unit 4 Operational Portfolio 4</td>
<td>4a</td>
<td>4b</td>
<td>4c</td>
<td>4d</td>
</tr>
</tbody>
</table>

**Pete 1 - Pete 2 - Pete 3 Early Retire**

- **Capacity Expansion optimally fills shortfall**
RETIREMENT PORTFOLIOS (4 OF 4)

<table>
<thead>
<tr>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030</td>
<td>5a</td>
<td>5b</td>
<td>5c</td>
<td>5d</td>
</tr>
</tbody>
</table>

PORTFOLIO COMPARISON

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

<table>
<thead>
<tr>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Accelerated Retirements</td>
<td>Portfolio 1</td>
<td>1a</td>
<td>1b</td>
<td>1c</td>
</tr>
<tr>
<td>Pete Unit 1 Retire 2021 Pete Units 2-4 Operational</td>
<td>Portfolio 2</td>
<td>2a</td>
<td>2b</td>
<td>2c</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational</td>
<td>Portfolio 3</td>
<td>3a</td>
<td>3b</td>
<td>3c</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete 3 Retire 2026 Pete Unit 4 Operational</td>
<td>Portfolio 4</td>
<td>4a</td>
<td>4b</td>
<td>4c</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete 3 Retire 2026 Pete 4 Retire 2030</td>
<td>Portfolio 5</td>
<td>5a</td>
<td>5b</td>
<td>5c</td>
</tr>
</tbody>
</table>

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

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

FINAL Q&A AND NEXT STEPS
NEXT STEPS

• **Next Meeting: May 14, 2019**
  - IPL Morris Street Operations Center
  - Register at [http://iplpower.com/irp](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](mailto:ipl.irp@aes.com)
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

<table>
<thead>
<tr>
<th>Topic</th>
<th>Time (Eastern)</th>
<th>Presenter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Registration</td>
<td>9:00 – 9:30</td>
<td>-</td>
</tr>
<tr>
<td>Welcome &amp; Opening Remarks</td>
<td>9:30 – 9:35</td>
<td>Lisa Krueger, President AES US SBU</td>
</tr>
<tr>
<td>Meeting Objectives &amp; Agenda</td>
<td>9:35 – 9:40</td>
<td>Stewart Ramsay, Meeting Facilitator</td>
</tr>
<tr>
<td>Meeting 2 Recap</td>
<td>9:40 – 9:50</td>
<td>Patrick Maguire, Director of Resource Planning</td>
</tr>
<tr>
<td>Stakeholder Presentation: Indiana Chapter of the National Association for the Advancement of Colored People (NAACP)</td>
<td>9:50 – 10:05</td>
<td>Denise Abdul-Rahman, NAACP</td>
</tr>
<tr>
<td>Stakeholder Presentation: Advanced Energy Management Alliance (AEMA)</td>
<td>10:05 – 10:20</td>
<td>Ingrid Bjorklund, AEMA Consultant</td>
</tr>
<tr>
<td>Electric Vehicle (EV) &amp; Distributed Solar Forecast</td>
<td>10:20 – 11:10</td>
<td>Ed Schmidt, MCR</td>
</tr>
<tr>
<td>BREAK</td>
<td>11:10 – 11:25</td>
<td>-</td>
</tr>
<tr>
<td>Load Forecast – High &amp; Low Presentation Recap Customer Class Breakout</td>
<td>11:25 – 11:40</td>
<td>Erik Miller, Senior Research Analyst</td>
</tr>
<tr>
<td>DSM Bundles for IRP Modeling</td>
<td>11:40 – 12:00</td>
<td>Erik Miller, Senior Research Analyst</td>
</tr>
<tr>
<td>LUNCH</td>
<td>12:00 – 12:45</td>
<td>-</td>
</tr>
<tr>
<td>Modeling and Scenario Recap</td>
<td>12:45 – 1:45</td>
<td>Patrick Maguire, Director of Resource Planning</td>
</tr>
<tr>
<td>Final Q&amp;A, Concluding Remarks &amp; Next Steps</td>
<td>1:45 – 2:00</td>
<td>Stewart Ramsay, Meeting Facilitator</td>
</tr>
</tbody>
</table>
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
2019 IRP STAKEHOLDER PROCESS

Dates to follow for Meeting #4 & Meeting #5

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
• Stakeholder Presentations
• Summary of Stakeholder Feedback
• Present Final Scenarios
• Modeling Update
• Assumptions Review and Updates

August
• Stakeholder Presentations
• Summary of Stakeholder Feedback
• Preliminary Model Results
• Scenario Descriptions and Results
• Preliminary Look at Risk Analysis and Stochastics

October
• 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.

STAKEHOLDER PRESENTATION

Denise Abdul-Rahman

NAACP
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

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
- 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

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>BNEF</td>
<td>Bloomberg New Energy Finance</td>
</tr>
<tr>
<td>BRT</td>
<td>IndyGo bus rapid transit routes</td>
</tr>
<tr>
<td>BYD</td>
<td>IndyGo-selected bus manufacturer</td>
</tr>
<tr>
<td>CAGR</td>
<td>Compound annual growth rate</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>Commercial and industrial</td>
</tr>
<tr>
<td>EEI</td>
<td>Edison Electric Institute</td>
</tr>
<tr>
<td>EIA</td>
<td>US Energy Information Administration</td>
</tr>
<tr>
<td>EV</td>
<td>Electric vehicle</td>
</tr>
<tr>
<td>GTM</td>
<td>GreenTech Media</td>
</tr>
<tr>
<td>ICE</td>
<td>Internal combustion engine</td>
</tr>
<tr>
<td>IHS</td>
<td>IHS Markit Company</td>
</tr>
<tr>
<td>IU</td>
<td>Indiana University</td>
</tr>
<tr>
<td>LDEV</td>
<td>Light duty electric vehicle</td>
</tr>
<tr>
<td>NEM</td>
<td>Net metered</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic, or distributed, solar</td>
</tr>
<tr>
<td>PVWatts</td>
<td>US National Renewable Energy Laboratory PV calculation tool</td>
</tr>
</tbody>
</table>

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
**Light Duty EV (LDEV)**

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Value</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Count</td>
<td>515</td>
<td>IPL-provided IHS/Polk</td>
</tr>
<tr>
<td>kWh/100 miles</td>
<td>31</td>
<td><a href="http://www.fueleconomy.gov">www.fueleconomy.gov</a></td>
</tr>
<tr>
<td>Annual miles</td>
<td>11,655</td>
<td><a href="http://www.carinsurance.com">www.carinsurance.com</a></td>
</tr>
<tr>
<td>Annual kWh</td>
<td>3,613</td>
<td>= 31 * (11,655/100)</td>
</tr>
</tbody>
</table>

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

Marion County EV Fleet

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of Vehicles</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>0</td>
</tr>
<tr>
<td>2011</td>
<td>100</td>
</tr>
<tr>
<td>2012</td>
<td>200</td>
</tr>
<tr>
<td>2013</td>
<td>300</td>
</tr>
<tr>
<td>2014</td>
<td>400</td>
</tr>
<tr>
<td>2015</td>
<td>500</td>
</tr>
<tr>
<td>2016</td>
<td>600</td>
</tr>
<tr>
<td>2017</td>
<td>700</td>
</tr>
<tr>
<td>2018</td>
<td>800</td>
</tr>
</tbody>
</table>

2010-2018: 47.5% CAGR

EV Charging Curve – IPL Electric Vehicle Rates

Actual kWh Curve for EV Charging, 2018

<table>
<thead>
<tr>
<th>Hour Beginning</th>
<th>Sum of Annual kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1.0</td>
<td>10,000</td>
</tr>
<tr>
<td>3.0</td>
<td>20,000</td>
</tr>
<tr>
<td>5.0</td>
<td>30,000</td>
</tr>
<tr>
<td>7.0</td>
<td>40,000</td>
</tr>
<tr>
<td>9.0</td>
<td>50,000</td>
</tr>
<tr>
<td>11.0</td>
<td>60,000</td>
</tr>
<tr>
<td>13.0</td>
<td>70,000</td>
</tr>
<tr>
<td>15.0</td>
<td>80,000</td>
</tr>
<tr>
<td>17.0</td>
<td>90,000</td>
</tr>
<tr>
<td>19.0</td>
<td>100,000</td>
</tr>
<tr>
<td>21.0</td>
<td>110,000</td>
</tr>
<tr>
<td>23.0</td>
<td>120,000</td>
</tr>
</tbody>
</table>
IndyGO Electric Buses

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

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

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

Marion County EV Percent of Fleet by Year

EV MWh Forecasting Methodology

- 3,613 kWh/year used, as discussed above
- Rate EVX pricing periods used
- 2.5% of charging occurs in the Summer peak period
- Annual energy usage based on vehicle specs and operations
- Annual energy and impacts driven by fleet size and unit kWh
Electric Vehicle MWh Impacts through 2040

Marion County EV MWh by Year

2030: 1.67% of 2017 FERC Form 1 sales
2040: 5.53% of 2017 FERC Form 1 sales

Distributed Solar Forecast
2018 Residential and Commercial Distributed Solar Baseline

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Residential</th>
<th>C&amp;I</th>
</tr>
</thead>
<tbody>
<tr>
<td>IPL NEM count (Adjusted EIA counts from IPL 2018 NEM file)</td>
<td>177</td>
<td>21</td>
</tr>
<tr>
<td>Size (kW - DC)</td>
<td>8</td>
<td>125</td>
</tr>
<tr>
<td>Panel type</td>
<td>Anti-reflective crystalline silicon</td>
<td>Anti-reflective crystalline silicon</td>
</tr>
<tr>
<td>Array type</td>
<td>Fixed</td>
<td>Fixed</td>
</tr>
<tr>
<td>Capacity factor (AC)</td>
<td>15.8%</td>
<td>15.8%</td>
</tr>
<tr>
<td>Production basis</td>
<td>PVWatts – 46241</td>
<td>PVWatts – 46241</td>
</tr>
</tbody>
</table>

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

Historical Distributed Solar System Growth

Marion County PV Systems

2011-2018: 58.2% CAGR
Distributed Solar Production Curve

Hour Beginning

0.00%  10.00%  20.00%  30.00%  40.00%  50.00%  60.00%  70.00%  80.00%

1:00  3:00  5:00  7:00  9:00  11:00  13:00  15:00  17:00  19:00  21:00  23:00

Distributed Solar Unit Forecasting Methodology

- Cleaned input 2018 IPL NEM census dataset
- Retained all NEM records showing non-null system size and installation date
- 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.
- Computed 2019-2023 compound annual growth rates for residential and non-residential MWdc installed nationally
- 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

IPL 2018 NEM Baseline

GTM 4Q18 Solar Outlook

2019-23 GTM-based CAGR

Apply CAGR to IPL NEM Baseline
Input Data: GTM-based CAGR

<table>
<thead>
<tr>
<th>Year</th>
<th>Incremental Residential MWdc</th>
<th>Incremental Residential Growth Rate</th>
<th>Incremental C&amp;I MWdc</th>
<th>Incremental C&amp;I Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>2,510</td>
<td>10.62%</td>
<td>1,761</td>
<td>-16.70%</td>
</tr>
<tr>
<td>2020</td>
<td>2,827</td>
<td>12.63%</td>
<td>1,853</td>
<td>5.22%</td>
</tr>
<tr>
<td>2021</td>
<td>3,302</td>
<td>16.80%</td>
<td>1,965</td>
<td>6.04%</td>
</tr>
<tr>
<td>2022</td>
<td>3,424</td>
<td>3.69%</td>
<td>1,944</td>
<td>-1.07%</td>
</tr>
<tr>
<td>2023</td>
<td>3,775</td>
<td>10.25%</td>
<td>2,144</td>
<td>10.29%</td>
</tr>
<tr>
<td>CAGR</td>
<td></td>
<td>10.74%</td>
<td></td>
<td>5.04%</td>
</tr>
</tbody>
</table>

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**

*Marion County PV MWh by Year*

- **2030:** (0.09)% of 2017 FERC Form 1 sales
- **2040:** (0.21)% of 2017 FERC Form 1 sales

---

**Summary: EV and Distributed Solar Forecast**
<table>
<thead>
<tr>
<th>Year</th>
<th>EV Summer Peak MWh</th>
<th>EV Summer Mid-Peak MWh</th>
<th>EV Summer Off-Peak MWh</th>
<th>EV Non-Summer Peak MWh</th>
<th>EV Non-Summer Off-Peak MWh</th>
<th>EV Annual MWh</th>
<th>PV Peak MWh</th>
<th>PV Off-Peak MWh</th>
<th>PV Annual MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>500</td>
<td>1,076</td>
<td>6,273</td>
<td>3,610</td>
<td>13,506</td>
<td>24,965</td>
<td>4,388</td>
<td>1,619</td>
<td>6,007</td>
</tr>
<tr>
<td>2021</td>
<td>697</td>
<td>1,500</td>
<td>9,129</td>
<td>5,031</td>
<td>19,595</td>
<td>35,952</td>
<td>4,701</td>
<td>1,734</td>
<td>6,435</td>
</tr>
<tr>
<td>2022</td>
<td>887</td>
<td>1,908</td>
<td>11,277</td>
<td>6,399</td>
<td>24,255</td>
<td>44,726</td>
<td>5,035</td>
<td>1,858</td>
<td>6,893</td>
</tr>
<tr>
<td>2023</td>
<td>1,063</td>
<td>2,287</td>
<td>13,296</td>
<td>7,668</td>
<td>28,631</td>
<td>52,944</td>
<td>5,399</td>
<td>1,992</td>
<td>7,391</td>
</tr>
<tr>
<td>2024</td>
<td>1,378</td>
<td>2,966</td>
<td>16,620</td>
<td>9,947</td>
<td>35,883</td>
<td>66,795</td>
<td>5,783</td>
<td>2,134</td>
<td>7,917</td>
</tr>
<tr>
<td>2025</td>
<td>1,743</td>
<td>3,751</td>
<td>20,399</td>
<td>12,578</td>
<td>44,140</td>
<td>82,611</td>
<td>6,197</td>
<td>2,286</td>
<td>8,483</td>
</tr>
<tr>
<td>2026</td>
<td>2,175</td>
<td>4,680</td>
<td>24,803</td>
<td>15,693</td>
<td>53,776</td>
<td>101,126</td>
<td>6,632</td>
<td>2,447</td>
<td>9,079</td>
</tr>
<tr>
<td>2027</td>
<td>2,730</td>
<td>5,875</td>
<td>30,362</td>
<td>19,702</td>
<td>65,961</td>
<td>124,630</td>
<td>7,114</td>
<td>2,626</td>
<td>9,740</td>
</tr>
<tr>
<td>2028</td>
<td>3,374</td>
<td>7,259</td>
<td>36,738</td>
<td>24,343</td>
<td>79,945</td>
<td>151,657</td>
<td>7,754</td>
<td>2,861</td>
<td>10,615</td>
</tr>
<tr>
<td>2029</td>
<td>4,138</td>
<td>8,903</td>
<td>44,241</td>
<td>29,856</td>
<td>96,417</td>
<td>183,555</td>
<td>8,432</td>
<td>3,111</td>
<td>11,543</td>
</tr>
<tr>
<td>2030</td>
<td>5,023</td>
<td>10,809</td>
<td>52,878</td>
<td>36,248</td>
<td>115,389</td>
<td>220,348</td>
<td>9,170</td>
<td>3,383</td>
<td>12,553</td>
</tr>
<tr>
<td>2031</td>
<td>6,117</td>
<td>13,163</td>
<td>63,456</td>
<td>44,142</td>
<td>138,644</td>
<td>265,523</td>
<td>9,498</td>
<td>3,670</td>
<td>13,618</td>
</tr>
<tr>
<td>2032</td>
<td>7,358</td>
<td>15,833</td>
<td>75,151</td>
<td>53,094</td>
<td>164,413</td>
<td>315,848</td>
<td>10,777</td>
<td>3,976</td>
<td>14,753</td>
</tr>
<tr>
<td>2033</td>
<td>8,706</td>
<td>18,734</td>
<td>87,718</td>
<td>62,822</td>
<td>192,132</td>
<td>370,112</td>
<td>11,677</td>
<td>4,308</td>
<td>15,985</td>
</tr>
<tr>
<td>2034</td>
<td>10,095</td>
<td>21,723</td>
<td>100,667</td>
<td>72,845</td>
<td>220,694</td>
<td>426,023</td>
<td>12,648</td>
<td>4,666</td>
<td>17,314</td>
</tr>
<tr>
<td>2035</td>
<td>11,483</td>
<td>24,709</td>
<td>113,604</td>
<td>82,859</td>
<td>249,229</td>
<td>481,884</td>
<td>13,689</td>
<td>5,050</td>
<td>18,739</td>
</tr>
<tr>
<td>2036</td>
<td>12,843</td>
<td>27,636</td>
<td>126,285</td>
<td>92,675</td>
<td>277,200</td>
<td>536,639</td>
<td>14,811</td>
<td>5,464</td>
<td>20,275</td>
</tr>
<tr>
<td>2037</td>
<td>14,156</td>
<td>30,462</td>
<td>138,525</td>
<td>102,150</td>
<td>304,200</td>
<td>589,493</td>
<td>16,034</td>
<td>5,916</td>
<td>21,950</td>
</tr>
<tr>
<td>2038</td>
<td>15,414</td>
<td>33,168</td>
<td>150,251</td>
<td>111,227</td>
<td>330,063</td>
<td>640,122</td>
<td>17,490</td>
<td>6,453</td>
<td>23,943</td>
</tr>
<tr>
<td>2039</td>
<td>16,615</td>
<td>35,751</td>
<td>161,440</td>
<td>119,888</td>
<td>354,744</td>
<td>688,439</td>
<td>19,057</td>
<td>7,031</td>
<td>26,088</td>
</tr>
<tr>
<td>2040</td>
<td>17,681</td>
<td>38,045</td>
<td>171,380</td>
<td>127,583</td>
<td>376,669</td>
<td>731,358</td>
<td>20,756</td>
<td>7,658</td>
<td>28,414</td>
</tr>
</tbody>
</table>
LOAD FORECAST - HIGH & LOW
RECAP OF CUSTOMER CLASS BREAKOUT

Erik Miller
Senior Research Analyst

EV & PV ADJUSTMENT

Electric Vehicle and Distributed Solar Annual kWh for IPL Service Territory
IPL LOAD FORECAST
EV & PV ADJUSTMENT

IPL Load Forecast - EV and PV Adjustments

EV & PV adjustment increase load forecast by 4% in 2039

IPL BASE, HIGH & LOW LOAD FORECAST
INCLUDES PRIOR YEAR DSM IMPACTS; FUTURE DSM WILL BE MODELED IN THE IRP

IPL Base, High & Low Load Forecast
CLASS SALES FORECAST

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

Average Annual Growth Rate 2020 - 2039:

<table>
<thead>
<tr>
<th>Class</th>
<th>Residential</th>
<th>Small C&amp;I</th>
<th>Large C&amp;I</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual Growth Rate</td>
<td>1.2%</td>
<td>0.2%</td>
<td>0.3%</td>
</tr>
</tbody>
</table>

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

Average Annual Growth Rate 2020 - 2039:

<table>
<thead>
<tr>
<th>Class</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual Growth Rate</td>
<td>1.7%</td>
<td>0.5%</td>
<td>-0.1%</td>
</tr>
</tbody>
</table>
DSM BUNDLES IN IRP MODELING

Erik Miller
Senior Research Analyst

DSM PROCESS & THE IRP

We are here in the process

Technical
Economic
Achievable
Market Potential Study

Create IRP Inputs

IRP Resource Selection Modeling
Selected DSM into RFP for Vendor(s)

IPL’s IRP modeling

File Portfolio of Programs with IURC

DSM Filing

2021 - 2023 IPL DSM Program Implementation
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

DSM DECREMENT BUNDLES

MPS - Realistic Achievable Potential Supply Curve

Data from IRP/MPS Planning Year: 2026
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

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
Next Steps:

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

Patrick Maguire
Director of Resource Planning

RECAP: SCENARIO DRIVERS

<table>
<thead>
<tr>
<th></th>
<th>Reference Case</th>
<th>Scenario A: Carbon Tax</th>
<th>Scenario B: Carbon Tax + High Gas</th>
<th>Scenario C: Carbon Tax + Low Gas</th>
<th>Scenario D: No Carbon Tax + High Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Prices</td>
<td>Base</td>
<td>Base</td>
<td>HIGH  †</td>
<td>LOW ‡</td>
<td>HIGH  †</td>
</tr>
<tr>
<td>Coal Prices</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
</tr>
<tr>
<td>IPL Load</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>LOW ‡</td>
<td>HIGH  †</td>
</tr>
<tr>
<td>Capital Costs for Wind, Solar, and Storage</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
</tr>
</tbody>
</table>
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

RECAP: FORWARD CURVES

<table>
<thead>
<tr>
<th></th>
<th>Deterministic Modeling</th>
<th>Stochastic Ranges</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>✓</td>
<td>✓</td>
<td>Internally sourced IPL coal curves.</td>
</tr>
<tr>
<td>Fuel Oil</td>
<td>✓</td>
<td>✓</td>
<td>Wood Mackenzie</td>
</tr>
<tr>
<td>Emissions</td>
<td>✓</td>
<td>×</td>
<td>NOx and SO2 curves will be sourced from forward curves. Carbon prices from Wood Mackenzie.</td>
</tr>
<tr>
<td>Capacity</td>
<td>✓</td>
<td>✓</td>
<td>Capacity will be valued at the estimated bilateral price for MISO Zone 6.</td>
</tr>
</tbody>
</table>


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

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

IPL Coal Price Volatility Tied to Contracted Percentage
### SCENARIO FRAMEWORK

<table>
<thead>
<tr>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Accelerated Retirements</td>
<td>Portfolio 1</td>
<td>1a</td>
<td>1b</td>
<td>1c</td>
</tr>
<tr>
<td>Pete Unit 1 Retire 2021 Pete Units 2-4 Operational</td>
<td>Portfolio 2</td>
<td>2a</td>
<td>2b</td>
<td>2c</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational</td>
<td>Portfolio 3</td>
<td>3a</td>
<td>3b</td>
<td>3c</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026 Pete Unit 4 Operational</td>
<td>Portfolio 4</td>
<td>4a</td>
<td>4b</td>
<td>4c</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030</td>
<td>Portfolio 5</td>
<td>5a</td>
<td>5b</td>
<td>5c</td>
</tr>
</tbody>
</table>

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

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

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 2019 IRP: PUBLIC ADVISORY MEETING #4
September 30, 2019

WELCOME & OPENING REMARKS

Vince Parisi
IPL President and CEO
MEETING OBJECTIVES & AGENDA

Stewart Ramsay
Meeting Facilitator

AGENDA

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

<table>
<thead>
<tr>
<th>No Accelerated Retirements</th>
<th>Portfolio 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pete Unit 1 Retire 2021</td>
<td>Portfolio 2</td>
</tr>
<tr>
<td>Pete Units 2-4 Operational</td>
<td></td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete Units 3-4 Operational</td>
<td>Portfolio 3</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational</td>
<td>Portfolio 4</td>
</tr>
<tr>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030</td>
<td>Portfolio 5</td>
</tr>
</tbody>
</table>

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)

PRELIMINARY MODEL RESULTS: OPTIMIZED PORTFOLIOS

Patrick Maguire
Director of Resource Planning
PORTFOLIO 1: FIRM UCAP POSITION

PORTFOLIO 1 | FIRM CAPACITY POSITION (UCAP MW)

PORTFOLIO 1: ICAP MW ADDITIONS

PORTFOLIO 1 | ANNUAL ICAP MW ADDITIONS

- Existing Coal
- Existing Natural Gas
- Existing Oil
- Existing Other (Wind/Solar/DR)
- New Wind
- New Solar
- New Storage
- New Natural Gas
- PRMR
- PRMR Less DSM

- Gas CC 325 MW
- Storage 560 MW
- Solar 1,175 MW
- Wind 700 MW
- DSM 185 MW
PORTFOLIO 1: REFERENCE CASE
ENERGY MIX (1 OF 2)

Energy mix for portfolios will vary across scenarios

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

Energy mix for portfolios will vary across scenarios
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

PORTFOLIO 2: FIRM UCAP CAPACITY

PORTFOLIO 2 | IPL FIRM CAPACITY POSITION (UCAP MW)
PORTFOLIO 2: ICAP MW ADDITIONS

PORTFOLIO 2 | ANNUAL ICAP MW ADDITIONS

Energy mix for portfolios will vary across scenarios
PORTFOLIO 2: REFERENCE CASE
ENERGY MIX (2 OF 2)

Energy mix for portfolios will vary across scenarios

PORTFOLIO 2

<table>
<thead>
<tr>
<th>Annual Produced Energy: Percent by Fuel Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Renewable</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Renewable</th>
<th>Coal</th>
<th>Natural Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>36%</td>
<td>59%</td>
<td>5%</td>
</tr>
<tr>
<td>2021</td>
<td>39%</td>
<td>55%</td>
<td>6%</td>
</tr>
<tr>
<td>2022</td>
<td>41%</td>
<td>53%</td>
<td>6%</td>
</tr>
<tr>
<td>2023</td>
<td>35%</td>
<td>58%</td>
<td>7%</td>
</tr>
<tr>
<td>2024</td>
<td>33%</td>
<td>61%</td>
<td>6%</td>
</tr>
<tr>
<td>2025</td>
<td>37%</td>
<td>61%</td>
<td>6%</td>
</tr>
<tr>
<td>2026</td>
<td>36%</td>
<td>60%</td>
<td>6%</td>
</tr>
<tr>
<td>2027</td>
<td>36%</td>
<td>60%</td>
<td>6%</td>
</tr>
<tr>
<td>2028</td>
<td>34%</td>
<td>63%</td>
<td>8%</td>
</tr>
<tr>
<td>2029</td>
<td>32%</td>
<td>62%</td>
<td>8%</td>
</tr>
<tr>
<td>2030</td>
<td>30%</td>
<td>63%</td>
<td>8%</td>
</tr>
<tr>
<td>2031</td>
<td>31%</td>
<td>63%</td>
<td>11%</td>
</tr>
<tr>
<td>2032</td>
<td>33%</td>
<td>55%</td>
<td>18%</td>
</tr>
<tr>
<td>2033</td>
<td>37%</td>
<td>46%</td>
<td>20%</td>
</tr>
<tr>
<td>2034</td>
<td>34%</td>
<td>44%</td>
<td>22%</td>
</tr>
<tr>
<td>2035</td>
<td>32%</td>
<td>39%</td>
<td>29%</td>
</tr>
<tr>
<td>2036</td>
<td>31%</td>
<td>39%</td>
<td>30%</td>
</tr>
<tr>
<td>2037</td>
<td>30%</td>
<td>39%</td>
<td></td>
</tr>
<tr>
<td>2038</td>
<td>29%</td>
<td>39%</td>
<td></td>
</tr>
<tr>
<td>2039</td>
<td>33%</td>
<td>39%</td>
<td></td>
</tr>
</tbody>
</table>

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

PORTFOLIO 3 | Annual Energy Mix (TWh)

Energy mix for portfolios will vary across scenarios

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

PORTFOLIO 3 | Annual Produced Energy: Percent by Fuel Type
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

PORTFOLIO 4: FIRM UCAP CAPACITY

PORTFOLIO 4 | IPL FIRM CAPACITY POSITION (UCAP MW)
PORTFOLIO 4: ICAP MW ADDITIONS

PORTFOLIO 4 | ANNUAL ICAP MW ADDITIONS

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

Energy mix for portfolios will vary across scenarios
PORTFOLIO 4: REFERENCE CASE
ENERGY MIX (2 OF 2)

PORTFOLIO 4 Annual Produced Energy: Percent by Fuel Type

<table>
<thead>
<tr>
<th>Year</th>
<th>Renewable</th>
<th>Coal</th>
<th>Natural Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>36%</td>
<td>39%</td>
<td>6%</td>
</tr>
<tr>
<td>2021</td>
<td>36%</td>
<td>34%</td>
<td>5%</td>
</tr>
<tr>
<td>2022</td>
<td>34%</td>
<td>36%</td>
<td>5%</td>
</tr>
<tr>
<td>2023</td>
<td>35%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2024</td>
<td>35%</td>
<td>34%</td>
<td>4%</td>
</tr>
<tr>
<td>2025</td>
<td>36%</td>
<td>35%</td>
<td>5%</td>
</tr>
<tr>
<td>2026</td>
<td>35%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2027</td>
<td>35%</td>
<td>34%</td>
<td>4%</td>
</tr>
<tr>
<td>2028</td>
<td>35%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2029</td>
<td>36%</td>
<td>34%</td>
<td>4%</td>
</tr>
<tr>
<td>2030</td>
<td>35%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2031</td>
<td>35%</td>
<td>34%</td>
<td>4%</td>
</tr>
<tr>
<td>2032</td>
<td>36%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2033</td>
<td>35%</td>
<td>34%</td>
<td>4%</td>
</tr>
<tr>
<td>2034</td>
<td>36%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2035</td>
<td>35%</td>
<td>34%</td>
<td>4%</td>
</tr>
<tr>
<td>2036</td>
<td>36%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2037</td>
<td>35%</td>
<td>34%</td>
<td>4%</td>
</tr>
<tr>
<td>2038</td>
<td>36%</td>
<td>35%</td>
<td>3%</td>
</tr>
<tr>
<td>2039</td>
<td>35%</td>
<td>34%</td>
<td>4%</td>
</tr>
</tbody>
</table>

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
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

PORTFOLIO SUMMARIES

Cumulative ICAP MW Changes through 2039
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

PORTFOLIO METRICS

Patrick Maguire
Director of Resource Planning
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?

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

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

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

• CO₂ Emissions
• CO₂ Intensity
• NOₓ, SO₂ Emissions
• Estimated water intake and discharge
Q&A, CONCLUDING REMARKS, & NEXT STEPS

Stewart Ramsay  
Meeting Facilitator

Patrick Maguire  
Director of Resource Planning

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
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](mailto:ipl.irp@aes.com)

---

APPENDIX
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT/CC</td>
<td>Combined Cycle</td>
</tr>
<tr>
<td>ST</td>
<td>Steam Turbine</td>
</tr>
<tr>
<td>CT</td>
<td>Combustion Turbine</td>
</tr>
<tr>
<td>UCAP</td>
<td>Unforced Capacity</td>
</tr>
<tr>
<td>ICAP</td>
<td>Installed Capacity</td>
</tr>
<tr>
<td>PRMR</td>
<td>Planning Reserve Margin Requirement</td>
</tr>
<tr>
<td>DR</td>
<td>Demand Response</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand Side Management</td>
</tr>
<tr>
<td>MISO</td>
<td>Midcontinent Independent System Operator</td>
</tr>
<tr>
<td>RIIA</td>
<td>Renewable Integration Impact Assessment</td>
</tr>
<tr>
<td>PVRR</td>
<td>Present Value Revenue Requirement</td>
</tr>
</tbody>
</table>
INDIANAPOLIS POWER & LIGHT COMPANY

IPL 2019 IRP: PUBLIC ADVISORY MEETING #5
DECEMBER 9, 2019

INTRODUCTIONS & SAFETY MESSAGE

Shelby Houston
Regulatory Analyst, IPL
## MEETING OBJECTIVES & AGENDA

Stewart Ramsey  
*Meeting Facilitator, Vanry & Associates*

### AGENDA

<table>
<thead>
<tr>
<th>Topic</th>
<th>Time (Eastern)</th>
<th>Presenter(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Registration &amp; Breakfast</td>
<td>9:00 – 9:30</td>
<td>-</td>
</tr>
<tr>
<td>Introductions &amp; Safety Message</td>
<td>9:30 – 9:40</td>
<td>Shelby Houston, Regulatory Analyst, IPL</td>
</tr>
<tr>
<td>Meeting Objectives &amp; Agenda</td>
<td>9:40 – 9:50</td>
<td>Stewart Ramsay, Meeting Facilitator, Vanry &amp; Associates</td>
</tr>
<tr>
<td>Executive Summary of Preferred Resource Plan</td>
<td>9:50 – 10:20</td>
<td>Vince Parisi, President and CEO, IPL</td>
</tr>
<tr>
<td><strong>BREAK</strong></td>
<td>10:50 – 11:00</td>
<td></td>
</tr>
<tr>
<td>Analysis of Alternatives: 2019 IRP Modeling</td>
<td>11:00 – 12:00</td>
<td>Patrick Maguire, Director of Resource Planning, IPL</td>
</tr>
<tr>
<td><strong>LUNCH</strong></td>
<td>12:00 – 12:45</td>
<td></td>
</tr>
<tr>
<td>Sensitivity Analysis</td>
<td>12:45 – 1:15</td>
<td>Patrick Maguire, Director of Resource Planning, IPL</td>
</tr>
<tr>
<td>Preferred Resource Portfolio &amp; Short Term Action Plan</td>
<td>1:15 – 1:30</td>
<td>Patrick Maguire, Director of Resource Planning, IPL</td>
</tr>
<tr>
<td>Concluding Remarks</td>
<td>1:30 – 2:00</td>
<td>Vince Parisi, President and CEO, IPL Stewart Ramsay, Meeting Facilitator, Vanry &amp; Associates</td>
</tr>
</tbody>
</table>
EXECUTIVE SUMMARY OF SHORT TERM ACTION PLAN

Vince Parisi,
President and CEO, IPL

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)
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

---

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 Stakeholder Meeting 12.9.19
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

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

Short-tons/MWh

Forecast →

Status Quo

Portfolio

Preferred Portfolio

48% Decrease in carbon intensity by 2024

2019 IRP Stakeholder Meeting 12.9.19
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

IPL Preferred Portfolio: Areas of Focus

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)

Variable Fuel Cost: Coal vs. Gas, 1997 - 2018

- 50-60% decrease in natural gas prices
- ~130% increase in coal cost from 2005 to 2012
**COAL ECONOMICS (2 OF 3)**

### MISO Generation Supply Stack

- **MISO Min Load:** ~50,000 MW
- **MISO Avg Load:** ~75,000 MW
- **MISO Peak Load:** ~120,000 MW

**Variable Production Cost ($/MWh)**

- $0
- $50
- $100
- $150
- $200
- $250
- $300

**Cumulative Capacity (MW)**

- 0
- 20,000
- 40,000
- 60,000
- 80,000
- 100,000
- 120,000
- 140,000
- 160,000
- 180,000
- 200,000

**Wind additions shift supply curve right and depress off-peak prices**

- Low natural gas prices flatten the supply curve, and natural-gas units displace coal in stack

**Source Data:** S&P Global

---

**COAL ECONOMICS (3 OF 3)**

### IPL 2019 IRP: Modeled 7x24 Dark Spreads*

**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.

**2028+:**

1. Carbon legislation
2. Renewable LMP ↓ pressure
3. Natural gas prices

**2020-2028:** natural gas prices primary driver of risk to coal

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

---

2019 IRP Stakeholder Meeting 12.9.19
**COAL ECONOMICS (3 OF 3)**

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**

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

<table>
<thead>
<tr>
<th>Carbon Price ($/ton)</th>
<th>Increase in Variable Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Coal Plant*</td>
</tr>
<tr>
<td>$2</td>
<td>$2</td>
</tr>
<tr>
<td>$5</td>
<td>$5</td>
</tr>
<tr>
<td>$10</td>
<td>$11</td>
</tr>
<tr>
<td>$20</td>
<td>$22</td>
</tr>
<tr>
<td>$40</td>
<td>$43</td>
</tr>
</tbody>
</table>

* 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

Risk of revenue erosion as more solar installed in MISO
SOLAR CAPACITY CREDIT: SUMMER

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

IPL Average Load and Solar Profile: Top 20 Summer Load Days 2016 - 2018

SUMMER NET LOAD CURVE

IPL Summer Net Load Curve with Increasing Solar Penetration

Net peak load shifts from HE 16 to HE 20-21 at 400-500 MW of solar
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

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

IPL Average Load and Solar Profile: Top 20 Winter Load Days 2016 - 2018
BREAK

ANALYSIS OF ALTERNATIVES: 2019 IRP MODELING
Patrick Maguire

Director of Resource Planning, IPL
2019 IRP MODELING FRAMEWORK

PORTFOLIOS

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Description</th>
<th>Reference Case</th>
<th>Scenario A: Carbon Tax Case</th>
<th>Scenario B: Carbon + High Gas</th>
<th>Scenario C: Carbon + Low Gas</th>
<th>Scenario D: No Carbon + High Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 1</td>
<td>No Early Retirements</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 2</td>
<td>Pete Unit 1 Retire 2021 Pete Units 2-4 Operational</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 3</td>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 4</td>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 5</td>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

SCENARIOS

TESTING FOR COST EFFECTIVENESS OF INCREMENTAL DSM

Presented at Sep. 30th Meeting ↓ New portfolios

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Description</th>
<th>DSM Decrements 1-3</th>
<th>DSM Decrements 1-4</th>
<th>DSM Decrements 1-5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 1</td>
<td>No Early Retirements</td>
<td>1a</td>
<td>1b</td>
<td>1c</td>
</tr>
<tr>
<td>Portfolio 2</td>
<td>Pete Unit 1 Retire 2021 Pete Units 2-4 Operational</td>
<td>2a</td>
<td>2b</td>
<td>2c</td>
</tr>
<tr>
<td>Portfolio 3</td>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational</td>
<td>3a</td>
<td>3b</td>
<td>3c</td>
</tr>
<tr>
<td>Portfolio 4</td>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational</td>
<td>4a</td>
<td>4b</td>
<td>4c</td>
</tr>
<tr>
<td>Portfolio 5</td>
<td>Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030</td>
<td>5a</td>
<td>5b</td>
<td>5c</td>
</tr>
</tbody>
</table>

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:**
  - 15 candidate resource portfolios containing a wide variety of technologies, DSM, and coal retirements
  - 75 stochastic production cost runs
  - Total of 9,000 iterations across all model runs
  - 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

Cumulative Installed Capacity Changes through 2039

- DSM
- Wind
- Solar
- Storage
- Gas CC
- Gas CT
- Coal
- Gas
- Oil

CAPEX REQUIREMENTS BY PORTFOLIO

Cumulative New Plant In Service (Nominal $Billion)
RESERVE MARGIN

UCAP Reserve Margin % (Base Load Forecast)

- UCAP Reserve Margin Target ~7.2%
- Portfolio 1
- Portfolio 2
- Portfolio 3
- Portfolio 4
- Portfolio 5

2019 IRP Stakeholder Meeting 12.9.19

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?

IRP Metrics and Scorecard

2019 IRP Stakeholder Meeting 12.9.19
# PVRR SUMMARY TABLE BY SCENARIO

## 20-Year PVRR ($MM)

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Reference Case</th>
<th>Scenario A: Carbon Tax Case</th>
<th>Scenario B: Carbon + High Gas</th>
<th>Scenario C: Carbon + Low Gas</th>
<th>Scenario D: No Carbon + High Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a</td>
<td>$7,215</td>
<td>$8,018</td>
<td>$8,427</td>
<td>$7,137</td>
<td>$7,923</td>
</tr>
<tr>
<td>2a</td>
<td>$7,132</td>
<td>$7,932</td>
<td>$8,399</td>
<td>$7,017</td>
<td>$7,900</td>
</tr>
<tr>
<td>3a</td>
<td>$7,016</td>
<td>$7,737</td>
<td>$8,211</td>
<td>$6,843</td>
<td>$7,798</td>
</tr>
<tr>
<td>4a</td>
<td>$7,295</td>
<td>$7,740</td>
<td>$8,174</td>
<td>$6,922</td>
<td>$8,070</td>
</tr>
<tr>
<td>5a</td>
<td>$7,500</td>
<td>$7,819</td>
<td>$8,329</td>
<td>$6,948</td>
<td>$8,376</td>
</tr>
<tr>
<td>1b</td>
<td>$7,176</td>
<td>$7,950</td>
<td>$8,383</td>
<td>$7,087</td>
<td>$7,864</td>
</tr>
<tr>
<td>2b</td>
<td>$7,188</td>
<td>$7,956</td>
<td>$8,398</td>
<td>$7,062</td>
<td>$7,932</td>
</tr>
<tr>
<td>3b</td>
<td>$6,976</td>
<td>$7,661</td>
<td>$8,114</td>
<td>$6,796</td>
<td>$7,739</td>
</tr>
<tr>
<td>4b</td>
<td>$7,293</td>
<td>$7,742</td>
<td>$8,191</td>
<td>$6,907</td>
<td>$8,082</td>
</tr>
<tr>
<td>5b</td>
<td>$7,400</td>
<td>$7,703</td>
<td>$8,272</td>
<td>$6,769</td>
<td>$8,259</td>
</tr>
<tr>
<td>1c</td>
<td>$7,223</td>
<td>$7,980</td>
<td>$8,355</td>
<td>$7,128</td>
<td>$7,899</td>
</tr>
<tr>
<td>2c</td>
<td>$7,191</td>
<td>$7,923</td>
<td>$8,341</td>
<td>$7,051</td>
<td>$7,912</td>
</tr>
<tr>
<td>3c</td>
<td>$7,034</td>
<td>$7,716</td>
<td>$8,165</td>
<td>$6,883</td>
<td>$8,086</td>
</tr>
<tr>
<td>4c</td>
<td>$7,269</td>
<td>$7,747</td>
<td>$8,225</td>
<td>$6,857</td>
<td>$8,306</td>
</tr>
<tr>
<td>5c</td>
<td>$7,452</td>
<td>$7,716</td>
<td>$8,202</td>
<td>$6,857</td>
<td></td>
</tr>
</tbody>
</table>

# IDENTIFYING ROBUST PORTFOLIOS

## Portfolio 1
- **Reference Case**
- **Scenario A**
- **Scenario B**
- **Scenario C**
- **Scenario D**

<table>
<thead>
<tr>
<th>Reference Case</th>
<th>Scenario A</th>
<th>Scenario B</th>
<th>Scenario C</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>1b</td>
<td>3b</td>
<td>3b</td>
<td>3b</td>
<td>3b</td>
</tr>
<tr>
<td>2b</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
</tr>
<tr>
<td>3b</td>
<td>5a</td>
<td>5a</td>
<td>5a</td>
<td>5a</td>
</tr>
<tr>
<td>4b</td>
<td>1a</td>
<td>1a</td>
<td>1a</td>
<td>1a</td>
</tr>
<tr>
<td>5b</td>
<td>2a</td>
<td>2a</td>
<td>2a</td>
<td>2a</td>
</tr>
<tr>
<td>3a</td>
<td>1b</td>
<td>1b</td>
<td>1b</td>
<td>1b</td>
</tr>
<tr>
<td>2a</td>
<td>3b</td>
<td>3b</td>
<td>3b</td>
<td>3b</td>
</tr>
<tr>
<td>1a</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
</tr>
<tr>
<td>5a</td>
<td>2b</td>
<td>2b</td>
<td>2b</td>
<td>2b</td>
</tr>
<tr>
<td>3c</td>
<td>4b</td>
<td>4b</td>
<td>4b</td>
<td>4b</td>
</tr>
<tr>
<td>2c</td>
<td>5a</td>
<td>5a</td>
<td>5a</td>
<td>5a</td>
</tr>
<tr>
<td>1c</td>
<td>3a</td>
<td>3a</td>
<td>3a</td>
<td>3a</td>
</tr>
<tr>
<td>5b</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
</tr>
<tr>
<td>2a</td>
<td>1b</td>
<td>1b</td>
<td>1b</td>
<td>1b</td>
</tr>
<tr>
<td>4b</td>
<td>2a</td>
<td>2a</td>
<td>2a</td>
<td>2a</td>
</tr>
<tr>
<td>1b</td>
<td>3c</td>
<td>3c</td>
<td>3c</td>
<td>3c</td>
</tr>
<tr>
<td>3a</td>
<td>4b</td>
<td>4b</td>
<td>4b</td>
<td>4b</td>
</tr>
<tr>
<td>2c</td>
<td>5a</td>
<td>5a</td>
<td>5a</td>
<td>5a</td>
</tr>
<tr>
<td>1c</td>
<td>3b</td>
<td>3b</td>
<td>3b</td>
<td>3b</td>
</tr>
<tr>
<td>5b</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
<td>4a</td>
</tr>
<tr>
<td>2a</td>
<td>1b</td>
<td>1b</td>
<td>1b</td>
<td>1b</td>
</tr>
<tr>
<td>4b</td>
<td>1a</td>
<td>1a</td>
<td>1a</td>
<td>1a</td>
</tr>
</tbody>
</table>

## Present Value Revenue Requirement ($Billion)

- **Portfolio 1**: $6.6
- **Portfolio 2**: $7.6
- **Portfolio 3**: $8.1
- **Portfolio 4**: $8.5
- **Portfolio 5**: $8.5
**SCENARIO A: CARBON TAX CASE**

Present Value Revenue Requirement ($Billion)

- Reference Case
- Scenario A
- Scenario B
- Scenario C
- Scenario D

Annual Difference from Portfolio 1b (Nominal $MM)

Carbon tax increases long term value of renewables

**SCENARIO B: CARBON TAX + HIGH GAS**

Present Value Revenue Requirement ($Billion)

- Reference Case
- Scenario A
- Scenario B
- Scenario C
- Scenario D

Annual Difference from Portfolio 1b (Nominal $MM)
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**

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Reference Case</th>
<th>Scenario A: Carbon Tax Case</th>
<th>Scenario B: Carbon + High Gas</th>
<th>Scenario C: Carbon + Low Gas</th>
<th>Scenario D: No Carbon + High Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 1a</td>
<td>$0.046</td>
<td>$0.051</td>
<td>$0.053</td>
<td>$0.047</td>
<td>$0.048</td>
</tr>
<tr>
<td>Portfolio 2a</td>
<td>$0.045</td>
<td>$0.050</td>
<td>$0.053</td>
<td>$0.046</td>
<td>$0.048</td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>$0.044</td>
<td>$0.049</td>
<td>$0.052</td>
<td>$0.045</td>
<td>$0.047</td>
</tr>
<tr>
<td>Portfolio 4a</td>
<td>$0.046</td>
<td>$0.049</td>
<td>$0.052</td>
<td>$0.045</td>
<td>$0.049</td>
</tr>
<tr>
<td>Portfolio 5a</td>
<td>$0.047</td>
<td>$0.049</td>
<td>$0.053</td>
<td>$0.045</td>
<td>$0.051</td>
</tr>
<tr>
<td>Portfolio 1b</td>
<td>$0.046</td>
<td>$0.051</td>
<td>$0.053</td>
<td>$0.047</td>
<td>$0.048</td>
</tr>
<tr>
<td>Portfolio 2b</td>
<td>$0.046</td>
<td>$0.051</td>
<td>$0.054</td>
<td>$0.047</td>
<td>$0.049</td>
</tr>
<tr>
<td>Portfolio 3b</td>
<td>$0.045</td>
<td>$0.049</td>
<td>$0.052</td>
<td>$0.045</td>
<td>$0.047</td>
</tr>
<tr>
<td>Portfolio 4b</td>
<td>$0.047</td>
<td>$0.049</td>
<td>$0.052</td>
<td>$0.046</td>
<td>$0.049</td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>$0.047</td>
<td>$0.049</td>
<td>$0.053</td>
<td>$0.045</td>
<td>$0.051</td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>$0.047</td>
<td>$0.052</td>
<td>$0.054</td>
<td>$0.048</td>
<td>$0.049</td>
</tr>
<tr>
<td>Portfolio 2c</td>
<td>$0.046</td>
<td>$0.051</td>
<td>$0.054</td>
<td>$0.047</td>
<td>$0.049</td>
</tr>
<tr>
<td>Portfolio 3c</td>
<td>$0.045</td>
<td>$0.050</td>
<td>$0.053</td>
<td>$0.046</td>
<td>$0.048</td>
</tr>
<tr>
<td>Portfolio 4c</td>
<td>$0.047</td>
<td>$0.050</td>
<td>$0.053</td>
<td>$0.046</td>
<td>$0.050</td>
</tr>
<tr>
<td>Portfolio 5c</td>
<td>$0.048</td>
<td>$0.050</td>
<td>$0.053</td>
<td>$0.046</td>
<td>$0.051</td>
</tr>
</tbody>
</table>
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 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)

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

- 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 RANGE: REFERENCE CASE

- Downside Potential
- Risk Premium
- Expected Value (Mean)
**PVRR WITH RISK DISTRIBUTIONS: SCENARIO A (CARBON TAX CASE)**

![PVRR Range: Scenario A (Carbon Tax Case) Graph]

- **PVRR Range**:
  - Downside Potential
  - Risk Premium
  - Expected Value (Mean)

**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

Market Interaction

<table>
<thead>
<tr>
<th>Purchases</th>
<th>Sales</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Case</td>
<td>Portfolio 1b</td>
</tr>
<tr>
<td>Portfolio 1b</td>
<td>5.2</td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>5.7</td>
</tr>
<tr>
<td>Portfolio 1d</td>
<td>5.4</td>
</tr>
<tr>
<td>Portfolio 1e</td>
<td>5.6</td>
</tr>
</tbody>
</table>

ENVIRONMENTAL: AIR EMISSIONS

Environmental: Air Emissions

<table>
<thead>
<tr>
<th>Year</th>
<th>CO₂ (million short-tons)</th>
<th>CO₂ Intensity (short-tons/MWh)</th>
<th>NOₓ (short-tons)</th>
<th>SO₂ (short-tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010-2012 Baseline (3-year average)</td>
<td>16.1</td>
<td>1.05</td>
<td>14,255</td>
<td>53,107</td>
</tr>
<tr>
<td>Portfolio 1a</td>
<td>11.9</td>
<td>0.73</td>
<td>8,028</td>
<td>10,972</td>
</tr>
<tr>
<td>Portfolio 1b</td>
<td>11.1</td>
<td>0.72</td>
<td>7,124</td>
<td>10,477</td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>11.9</td>
<td>0.74</td>
<td>8,028</td>
<td>10,972</td>
</tr>
<tr>
<td>Portfolio 1d</td>
<td>11.0</td>
<td>0.71</td>
<td>7,120</td>
<td>10,477</td>
</tr>
<tr>
<td>Portfolio 1e</td>
<td>9.5</td>
<td>0.64</td>
<td>6,371</td>
<td>9,577</td>
</tr>
<tr>
<td>Portfolio 2a</td>
<td>11.0</td>
<td>0.73</td>
<td>7,120</td>
<td>10,477</td>
</tr>
<tr>
<td>Portfolio 2b</td>
<td>9.5</td>
<td>0.64</td>
<td>6,371</td>
<td>9,577</td>
</tr>
<tr>
<td>Portfolio 2c</td>
<td>11.1</td>
<td>0.72</td>
<td>7,124</td>
<td>10,477</td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>9.5</td>
<td>0.63</td>
<td>6,371</td>
<td>9,577</td>
</tr>
<tr>
<td>Portfolio 3b</td>
<td>9.5</td>
<td>0.63</td>
<td>6,371</td>
<td>9,577</td>
</tr>
<tr>
<td>Portfolio 4a</td>
<td>7.0</td>
<td>0.46</td>
<td>5,152</td>
<td>6,038</td>
</tr>
<tr>
<td>Portfolio 4b</td>
<td>7.0</td>
<td>0.46</td>
<td>5,152</td>
<td>6,038</td>
</tr>
<tr>
<td>Portfolio 5a</td>
<td>5.6</td>
<td>0.38</td>
<td>2,991</td>
<td>3,582</td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>5.6</td>
<td>0.38</td>
<td>2,991</td>
<td>3,582</td>
</tr>
<tr>
<td>Portfolio 1a</td>
<td>10.0</td>
<td>0.71</td>
<td>6,547</td>
<td>8,653</td>
</tr>
<tr>
<td>Portfolio 1b</td>
<td>9.3</td>
<td>0.69</td>
<td>5,722</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>9.3</td>
<td>0.68</td>
<td>5,726</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 1d</td>
<td>9.3</td>
<td>0.68</td>
<td>5,726</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 1e</td>
<td>9.3</td>
<td>0.68</td>
<td>5,726</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 2a</td>
<td>8.0</td>
<td>0.59</td>
<td>5,085</td>
<td>7,438</td>
</tr>
<tr>
<td>Portfolio 2b</td>
<td>8.0</td>
<td>0.58</td>
<td>5,085</td>
<td>7,438</td>
</tr>
<tr>
<td>Portfolio 2c</td>
<td>8.0</td>
<td>0.58</td>
<td>5,085</td>
<td>7,438</td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>6.3</td>
<td>0.43</td>
<td>4,265</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 3b</td>
<td>6.3</td>
<td>0.43</td>
<td>4,265</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 4a</td>
<td>6.3</td>
<td>0.44</td>
<td>4,277</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 4b</td>
<td>6.3</td>
<td>0.44</td>
<td>4,277</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 5a</td>
<td>5.6</td>
<td>0.38</td>
<td>2,952</td>
<td>3,552</td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>5.6</td>
<td>0.38</td>
<td>2,952</td>
<td>3,552</td>
</tr>
<tr>
<td>Portfolio 1a</td>
<td>10.0</td>
<td>0.70</td>
<td>6,547</td>
<td>8,653</td>
</tr>
<tr>
<td>Portfolio 1b</td>
<td>9.3</td>
<td>0.68</td>
<td>5,726</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>9.3</td>
<td>0.68</td>
<td>5,726</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 1d</td>
<td>9.3</td>
<td>0.68</td>
<td>5,726</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 1e</td>
<td>9.3</td>
<td>0.68</td>
<td>5,726</td>
<td>8,203</td>
</tr>
<tr>
<td>Portfolio 2a</td>
<td>8.0</td>
<td>0.59</td>
<td>5,085</td>
<td>7,438</td>
</tr>
<tr>
<td>Portfolio 2b</td>
<td>8.0</td>
<td>0.58</td>
<td>5,085</td>
<td>7,438</td>
</tr>
<tr>
<td>Portfolio 2c</td>
<td>8.0</td>
<td>0.58</td>
<td>5,085</td>
<td>7,438</td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>6.3</td>
<td>0.44</td>
<td>4,277</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 3b</td>
<td>6.3</td>
<td>0.44</td>
<td>4,277</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 4a</td>
<td>6.3</td>
<td>0.44</td>
<td>4,277</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 4b</td>
<td>6.3</td>
<td>0.44</td>
<td>4,277</td>
<td>5,059</td>
</tr>
<tr>
<td>Portfolio 5a</td>
<td>5.6</td>
<td>0.38</td>
<td>2,952</td>
<td>3,552</td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>5.6</td>
<td>0.38</td>
<td>2,952</td>
<td>3,552</td>
</tr>
</tbody>
</table>
ENVIRONMENTAL: NON-AIR IMPACTS

• Impact of coal retirements on water:
  o Retire Units 1 and 2: significant reduction in actual intake flow (estimate: greater than 67%);
  o 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
• 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

Risk
• Portfolio 3b lowest cost on risk-adjusted basis
• Portfolio 3b resource mix provides balanced energy and load profile and reduction total market interaction

Environmental
• Portfolio 3b benefits:
  • Near term reductions in CO2, NOx, SO2
  • 60-70% reduction in water intake flow at the plant
LUNCH BREAK

SENSITIVITY ANALYSIS

Patrick Maguire
Director of Resource Planning, IPL
SEN SITIVITY 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

2019 IRP Stakeholder Meeting 12.9.19

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)

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)

<table>
<thead>
<tr>
<th>Portfolio 3b</th>
<th>Percent Change by 2030</th>
<th>PVRR w/ Base Capital Costs</th>
<th>Percent Change by 2030</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>-30%</td>
<td>$7,661</td>
<td>+15%</td>
</tr>
<tr>
<td></td>
<td>-15%</td>
<td>$7,763</td>
<td>+30%</td>
</tr>
<tr>
<td></td>
<td>+15%</td>
<td>$7,862</td>
<td></td>
</tr>
<tr>
<td></td>
<td>+30%</td>
<td>$7,862</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,460</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,560</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,661</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,763</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,862</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>$7,460</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,560</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,661</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,763</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,862</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 3c</td>
<td>$7,460</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,560</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,661</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,763</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,862</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 5c</td>
<td>$7,460</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,560</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,661</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,763</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,862</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>$7,460</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,560</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,661</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,763</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$7,862</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**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.

### MISIO CAPACITY PRICE SENSITIVITY (1 OF 3)

- 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)

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Bilateral Floor</th>
<th>Bilateral Most Likely</th>
<th>Stochastic Mean</th>
<th>Bilateral Ceiling</th>
<th>CONE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 3b</td>
<td>$6,983</td>
<td>$7,014</td>
<td>$7,034</td>
<td>$7,066</td>
<td>$7,111</td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>$7,024</td>
<td>$7,018</td>
<td>$7,016</td>
<td>$7,006</td>
<td>$7,093</td>
</tr>
<tr>
<td>Portfolio 3c</td>
<td>$7,034</td>
<td>$7,016</td>
<td>$7,034</td>
<td>$7,034</td>
<td>$7,034</td>
</tr>
<tr>
<td>Portfolio 2a</td>
<td>$7,146</td>
<td>$7,132</td>
<td>$7,113</td>
<td>$7,081</td>
<td>$7,057</td>
</tr>
<tr>
<td>Portfolio 1b</td>
<td>$7,221</td>
<td>$7,190</td>
<td>$7,176</td>
<td>$7,116</td>
<td>$7,035</td>
</tr>
<tr>
<td>Portfolio 2b</td>
<td>$7,207</td>
<td>$7,194</td>
<td>$7,188</td>
<td>$7,169</td>
<td>$7,144</td>
</tr>
<tr>
<td>Portfolio 2c</td>
<td>$7,191</td>
<td>$7,191</td>
<td>$7,191</td>
<td>$7,191</td>
<td>$7,191</td>
</tr>
<tr>
<td>Portfolio 1a</td>
<td>$7,260</td>
<td>$7,229</td>
<td>$7,215</td>
<td>$7,156</td>
<td>$7,074</td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>$7,223</td>
<td>$7,223</td>
<td>$7,223</td>
<td>$7,223</td>
<td>$7,223</td>
</tr>
<tr>
<td>Portfolio 4c</td>
<td>$7,269</td>
<td>$7,269</td>
<td>$7,269</td>
<td>$7,269</td>
<td>$7,269</td>
</tr>
<tr>
<td>Portfolio 4b</td>
<td>$7,301</td>
<td>$7,295</td>
<td>$7,293</td>
<td>$7,281</td>
<td>$7,267</td>
</tr>
<tr>
<td>Portfolio 4a</td>
<td>$7,304</td>
<td>$7,298</td>
<td>$7,295</td>
<td>$7,284</td>
<td>$7,269</td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>$7,408</td>
<td>$7,402</td>
<td>$7,400</td>
<td>$7,389</td>
<td>$7,375</td>
</tr>
<tr>
<td>Portfolio 5c</td>
<td>$7,452</td>
<td>$7,452</td>
<td>$7,452</td>
<td>$7,452</td>
<td>$7,452</td>
</tr>
<tr>
<td>Portfolio 5a</td>
<td>$7,508</td>
<td>$7,503</td>
<td>$7,500</td>
<td>$7,489</td>
<td>$7,475</td>
</tr>
</tbody>
</table>

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)

- 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

Calendar year 2018 capacity factors by region: 2014–2017 projects only

Source: NREL
WIND CAPACITY FACTOR (2 OF 3)

Reference Case PVRR ($MM)

<table>
<thead>
<tr>
<th>Wind annual capacity factor</th>
<th>Base (42%)</th>
<th>46%</th>
<th>44%</th>
<th>40%</th>
<th>38%</th>
<th>36%</th>
<th>34%</th>
<th>32%</th>
<th>30%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 3b</td>
<td>$6,959</td>
<td>$6,976</td>
<td>$7,016</td>
<td>$7,046</td>
<td>$7,099</td>
<td>$7,073</td>
<td>$7,024</td>
<td>$7,031</td>
<td></td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>$6,991</td>
<td>$7,004</td>
<td>$7,021</td>
<td>$7,049</td>
<td>$7,073</td>
<td>$7,086</td>
<td>$7,098</td>
<td>$7,110</td>
<td></td>
</tr>
<tr>
<td>Portfolio 3c</td>
<td>$7,012</td>
<td>$7,024</td>
<td>$7,034</td>
<td>$7,061</td>
<td>$7,073</td>
<td>$7,140</td>
<td>$7,142</td>
<td>$7,144</td>
<td></td>
</tr>
<tr>
<td>Portfolio 2a</td>
<td>$7,128</td>
<td>$7,130</td>
<td>$7,132</td>
<td>$7,134</td>
<td>$7,136</td>
<td>$7,138</td>
<td>$7,184</td>
<td>$7,186</td>
<td></td>
</tr>
<tr>
<td>Portfolio 1b</td>
<td>$7,172</td>
<td>$7,174</td>
<td>$7,176</td>
<td>$7,178</td>
<td>$7,180</td>
<td>$7,182</td>
<td>$7,184</td>
<td>$7,187</td>
<td></td>
</tr>
<tr>
<td>Portfolio 2b</td>
<td>$7,179</td>
<td>$7,184</td>
<td>$7,188</td>
<td>$7,194</td>
<td>$7,199</td>
<td>$7,203</td>
<td>$7,208</td>
<td>$7,213</td>
<td></td>
</tr>
<tr>
<td>Portfolio 2c</td>
<td>$7,180</td>
<td>$7,186</td>
<td>$7,191</td>
<td>$7,198</td>
<td>$7,204</td>
<td>$7,210</td>
<td>$7,215</td>
<td>$7,221</td>
<td></td>
</tr>
<tr>
<td>Portfolio 1a</td>
<td>$7,208</td>
<td>$7,212</td>
<td>$7,215</td>
<td>$7,219</td>
<td>$7,223</td>
<td>$7,227</td>
<td>$7,230</td>
<td>$7,234</td>
<td></td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>$7,217</td>
<td>$7,221</td>
<td>$7,223</td>
<td>$7,227</td>
<td>$7,230</td>
<td>$7,233</td>
<td>$7,237</td>
<td>$7,240</td>
<td></td>
</tr>
<tr>
<td>Portfolio 4c</td>
<td>$7,222</td>
<td>$7,248</td>
<td>$7,269</td>
<td>$7,299</td>
<td>$7,325</td>
<td>$7,350</td>
<td>$7,401</td>
<td>$7,427</td>
<td></td>
</tr>
<tr>
<td>Portfolio 4b</td>
<td>$7,234</td>
<td>$7,266</td>
<td>$7,293</td>
<td>$7,330</td>
<td>$7,362</td>
<td>$7,394</td>
<td>$7,426</td>
<td>$7,458</td>
<td></td>
</tr>
<tr>
<td>Portfolio 4a</td>
<td>$7,228</td>
<td>$7,265</td>
<td>$7,295</td>
<td>$7,338</td>
<td>$7,375</td>
<td>$7,411</td>
<td>$7,448</td>
<td>$7,484</td>
<td></td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>$7,355</td>
<td>$7,379</td>
<td>$7,400</td>
<td>$7,428</td>
<td>$7,453</td>
<td>$7,477</td>
<td>$7,502</td>
<td>$7,526</td>
<td></td>
</tr>
<tr>
<td>Portfolio 5c</td>
<td>$7,372</td>
<td>$7,416</td>
<td>$7,452</td>
<td>$7,503</td>
<td>$7,546</td>
<td>$7,589</td>
<td>$7,633</td>
<td>$7,676</td>
<td></td>
</tr>
<tr>
<td>Portfolio 5a</td>
<td>$7,417</td>
<td>$7,461</td>
<td>$7,500</td>
<td>$7,549</td>
<td>$7,593</td>
<td>$7,638</td>
<td>$7,682</td>
<td>$7,726</td>
<td></td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>Wind annual capacity factor</th>
<th>Base (42%)</th>
<th>46%</th>
<th>44%</th>
<th>40%</th>
<th>38%</th>
<th>36%</th>
<th>34%</th>
<th>32%</th>
<th>30%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portfolio 3b</td>
<td>$7,640</td>
<td>$7,652</td>
<td>$7,661</td>
<td>$7,675</td>
<td>$7,686</td>
<td>$7,688</td>
<td>$7,709</td>
<td>$7,721</td>
<td>$7,731</td>
</tr>
<tr>
<td>Portfolio 5b</td>
<td>$7,649</td>
<td>$7,679</td>
<td>$7,703</td>
<td>$7,739</td>
<td>$7,769</td>
<td>$7,798</td>
<td>$7,828</td>
<td>$7,858</td>
<td>$7,888</td>
</tr>
<tr>
<td>Portfolio 3c</td>
<td>$7,688</td>
<td>$7,703</td>
<td>$7,716</td>
<td>$7,733</td>
<td>$7,748</td>
<td>$7,764</td>
<td>$7,779</td>
<td>$7,794</td>
<td>$7,809</td>
</tr>
<tr>
<td>Portfolio 5c</td>
<td>$7,619</td>
<td>$7,672</td>
<td>$7,716</td>
<td>$7,779</td>
<td>$7,832</td>
<td>$7,886</td>
<td>$7,939</td>
<td>$7,993</td>
<td>$8,046</td>
</tr>
<tr>
<td>Portfolio 3a</td>
<td>$7,707</td>
<td>$7,723</td>
<td>$7,737</td>
<td>$7,756</td>
<td>$7,772</td>
<td>$7,789</td>
<td>$7,805</td>
<td>$7,822</td>
<td>$7,838</td>
</tr>
<tr>
<td>Portfolio 4a</td>
<td>$7,659</td>
<td>$7,704</td>
<td>$7,740</td>
<td>$7,793</td>
<td>$7,857</td>
<td>$7,881</td>
<td>$7,920</td>
<td>$7,970</td>
<td>$8,015</td>
</tr>
<tr>
<td>Portfolio 4b</td>
<td>$7,671</td>
<td>$7,710</td>
<td>$7,742</td>
<td>$7,788</td>
<td>$7,827</td>
<td>$7,867</td>
<td>$7,906</td>
<td>$7,945</td>
<td>$7,984</td>
</tr>
<tr>
<td>Portfolio 4c</td>
<td>$7,691</td>
<td>$7,722</td>
<td>$7,747</td>
<td>$7,784</td>
<td>$7,815</td>
<td>$7,845</td>
<td>$7,878</td>
<td>$7,907</td>
<td>$7,938</td>
</tr>
<tr>
<td>Portfolio 5a</td>
<td>$7,718</td>
<td>$7,772</td>
<td>$7,819</td>
<td>$7,879</td>
<td>$7,933</td>
<td>$7,986</td>
<td>$8,046</td>
<td>$8,094</td>
<td>$8,148</td>
</tr>
<tr>
<td>Portfolio 4c</td>
<td>$7,749</td>
<td>$7,817</td>
<td>$7,823</td>
<td>$7,833</td>
<td>$7,941</td>
<td>$7,949</td>
<td>$7,958</td>
<td>$7,966</td>
<td>$7,974</td>
</tr>
<tr>
<td>Portfolio 2a</td>
<td>$7,927</td>
<td>$7,929</td>
<td>$7,932</td>
<td>$7,935</td>
<td>$7,947</td>
<td>$7,940</td>
<td>$7,943</td>
<td>$7,946</td>
<td>$7,948</td>
</tr>
<tr>
<td>Portfolio 2b</td>
<td>$7,945</td>
<td>$7,948</td>
<td>$7,950</td>
<td>$7,953</td>
<td>$7,956</td>
<td>$7,959</td>
<td>$7,961</td>
<td>$7,964</td>
<td>$7,967</td>
</tr>
<tr>
<td>Portfolio 2c</td>
<td>$7,944</td>
<td>$7,950</td>
<td>$7,956</td>
<td>$7,964</td>
<td>$7,970</td>
<td>$7,977</td>
<td>$7,983</td>
<td>$7,990</td>
<td>$7,996</td>
</tr>
<tr>
<td>Portfolio 1c</td>
<td>$7,972</td>
<td>$7,977</td>
<td>$7,980</td>
<td>$7,985</td>
<td>$7,990</td>
<td>$7,994</td>
<td>$7,999</td>
<td>$8,003</td>
<td>$8,008</td>
</tr>
<tr>
<td>Portfolio 1a</td>
<td>$8,009</td>
<td>$8,014</td>
<td>$8,018</td>
<td>$8,024</td>
<td>$8,029</td>
<td>$8,034</td>
<td>$8,039</td>
<td>$8,044</td>
<td>$8,050</td>
</tr>
</tbody>
</table>

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 Results:

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

#### Reference Case PVRR ($MM)

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

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

**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 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

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

<table>
<thead>
<tr>
<th></th>
<th>Portfolio 3a</th>
<th>Portfolio 3b</th>
<th>Portfolio 3c</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>250</td>
<td>100</td>
<td>150</td>
</tr>
<tr>
<td>Solar</td>
<td>375</td>
<td>450</td>
<td>400</td>
</tr>
<tr>
<td>Storage</td>
<td>40</td>
<td>0</td>
<td>20</td>
</tr>
<tr>
<td><strong>Total ICAP MW</strong></td>
<td>665</td>
<td>550</td>
<td>570</td>
</tr>
</tbody>
</table>

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

**Annual MW by In-Service Year**

<table>
<thead>
<tr>
<th>Year</th>
<th>Wind</th>
<th>Solar</th>
<th>Battery Storage</th>
<th>Hybrid</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>1,150</td>
<td>2,772</td>
<td>1,178</td>
<td>1,497</td>
<td>607</td>
</tr>
<tr>
<td>2021</td>
<td>1,150</td>
<td>2,772</td>
<td>1,178</td>
<td>1,497</td>
<td>607</td>
</tr>
<tr>
<td>2022</td>
<td>1,150</td>
<td>2,772</td>
<td>1,178</td>
<td>1,497</td>
<td>607</td>
</tr>
<tr>
<td>2023</td>
<td>1,150</td>
<td>2,772</td>
<td>1,178</td>
<td>1,497</td>
<td>607</td>
</tr>
</tbody>
</table>

**Total by 2023: 13,093 MW**

- Wind: 8,470 (65%)
- Solar: 1,630 (13%)
- Battery Storage: 661 (5%)
- Hybrid: 835 (6%)
- Gas: 1,497 (11%)

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

DSM ACTION PLAN 2021 - 2023

<table>
<thead>
<tr>
<th>Decrement</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Decrement 1 - 3 (Gross MWh)</td>
<td>116,376</td>
<td>112,403</td>
<td>113,197</td>
</tr>
<tr>
<td>Decrement 1 - 4 (Gross MWh) *</td>
<td>144,890</td>
<td>146,158</td>
<td>146,490</td>
</tr>
<tr>
<td>DSM Action Plan Target (Gross MWh)</td>
<td>116,376 - 144,890</td>
<td>112,403 - 146,158</td>
<td>113,197 - 146,490</td>
</tr>
</tbody>
</table>

*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
• 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

2019 IPL IRP
• 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

Considerations for Future IRPs
• 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

2019 IRP Stakeholder Meeting 12.9.19

### ACRONYM LIST

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

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>RFP</td>
<td>Request for Proposals</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized Cost of Energy</td>
</tr>
<tr>
<td>LMP</td>
<td>Locational Marginal Price</td>
</tr>
<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
</tr>
<tr>
<td>PTC</td>
<td>Production Tax Credit</td>
</tr>
<tr>
<td>ITC</td>
<td>Investment Tax Credit</td>
</tr>
<tr>
<td>CONE</td>
<td>Cost of New Entry</td>
</tr>
<tr>
<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
</tr>
<tr>
<td>RIIA</td>
<td>Renewable Integration Impact Assessment</td>
</tr>
<tr>
<td>PVRR</td>
<td>Present Value Revenue Requirement</td>
</tr>
</tbody>
</table>
## PORTFOLIO 1 ICAP CHANGES

### Resource Type 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035
---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
**New Gas CC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Solar** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Storage** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Gas CC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Gas CT** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0

### Cumulative ICAP Changes through 2039

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
**Portfolio 1a** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**Portfolio 1b** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**Portfolio 1c** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0

## PORTFOLIO 2 ICAP CHANGES

### Resource Type 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035
---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
**New Gas CC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Solar** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Storage** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Gas CC** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**New Gas CT** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0

### Cumulative ICAP Changes through 2039

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
**Portfolio 2a** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**Portfolio 2b** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0
**Portfolio 2c** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0

---

12/11/2019
### PORTFOLIO 3 ICAP CHANGES

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Portfolio 3a: Includes DSM Decrements 1-3</th>
<th>Portfolio 3b: Includes DSM Decrements 1-3</th>
<th>Portfolio 3c: Includes DSM Decrements 1-3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2020</td>
<td>2021</td>
<td>2022</td>
</tr>
<tr>
<td>DSM</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Wind</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Solar</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Battery Storage</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Gas CC</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Gas CT</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

### PORTFOLIO 4 ICAP CHANGES

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Portfolio 4a: Includes Decrements 1-3</th>
<th>Portfolio 4b: Includes Decrements 1-4</th>
<th>Portfolio 4c: Includes Decrements 1-5</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2020</td>
<td>2021</td>
<td>2022</td>
</tr>
<tr>
<td>DSM</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Wind</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Solar</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Battery Storage</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Gas CC</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Gas CT</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

### Cumulative ICAP Changes through 2039

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Installed Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3a</td>
<td>1,325</td>
</tr>
<tr>
<td>3b</td>
<td>1,225</td>
</tr>
<tr>
<td>3c</td>
<td>1,125</td>
</tr>
<tr>
<td>4a</td>
<td>1,125</td>
</tr>
<tr>
<td>4b</td>
<td>1,125</td>
</tr>
<tr>
<td>4c</td>
<td>1,125</td>
</tr>
</tbody>
</table>

2019 IRP Stakeholder Meeting 12.9.19
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

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:

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Phone: (317) 231-7716
Peabody Phone (317) 231-6465
Fax: (317) 231-7433
Nyhart Email: ntyhart@btlaw.com
Peabody Email jeffrey.peabody@btlaw.com

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
Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor
PNC Center, Suite 1500 South
115 W. Washington Street
Indianapolis, Indiana 46204
rhelmen@oucc.IN.gov
timurray@oucc.in.gov
infomgt@oucc.in.gov

Jennifer A. Washburn
Citizens Action Coalition
1915 W. 18th Street, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org

Tim Joyce
Deputy Director for Policy and Planning
City of Indianapolis-Department of Public Works
Tim.Joyce@Indy.Gov

Jeffrey M. Peabody
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

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:

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Phone: (317) 231-7716
Peabody Phone (317) 231-6465
Fax: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email jeffrey.peabody@btlaw.com

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:

Randall Helmen
Tiffany Murray
Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor
PNC Center, Suite 1500 South
115 W. Washington Street
Indianapolis, Indiana 46204
rhelmen@oucc.IN.gov
timurray@oucc.in.gov
infomgt@oucc.in.gov

Tim Joyce
Deputy Director for Policy and Planning
City of Indianapolis-Department of Public Works
Tim.Joyce@Indy.Gov

Jennifer A. Washburn
Citizens Action Coalition
1915 W. 18th Street, Suite C
Indianapolis, Indiana 46202
jwashburn@citact.org

Teresa Morton Nyhart (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Phone: (317) 231-7716
Peabody Phone (317) 231-6465
Fax: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email jeffrey.peabody@btlaw.com

Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY
DMS 13718691v1
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.

![Graph of Total Monthly KWh Consumption (all meters)](image)

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)
This material is furnished for General Information only. Any user of this material hereby assumes complete responsibility for its use and agrees that Indianapolis Power & Light Company shall not be liable for any claims or other actions for damages that in any way may result from any use of this material. This material is for reference only and is licensed for a one time only use, to the company requesting the information for the specified project. Duplicating or partial copying of this electronic or paper material is strictly prohibited without written permission from Indianapolis Power & Light Co. and remains the sole property of said company. IPL material shall be returned to IPL upon request.

LEGEND

# - OPERATING
# - UNDER CONSTRUCTION
# - IN DEVELOPMENT

INDIANAPOLIS POWER & LIGHT CO.
SOLAR FACILITIES

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 SOUTHIDE SPORTS ACADEMY
38. MARINE CENTER OF INDIANA
39. 5855 LP
40. IUPUI
Attachment 4.1 (Test Year July 2016 through June 2017 Hourly Loads MW Rate Case) is provided electronically
Attachment 4.2a (IPL_LCIIndices_RS18) is provided electronically
Attachment 4.2b (IPL_LCIIndices_RC18) is provided electronically
Attachment 4.2c (IPL_LCIIndices_RH18) is provided electronically
Attachment 4.2d (IPL_LCIIndices_SS18) is provided electronically
Attachment 4.2e (IPL_LCIIndices_SH18) is provided electronically
Attachment 4.2f (IPL_LCIIndices_SL18) is provided electronically
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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m}$$

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.
\[
USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m
\]  \hspace{1cm} (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,

\[
XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m}
\]  \hspace{1cm} (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:
\[ HeatIndex_y = StructuralIndex_y \times \sum_{Type} \text{Weight}_y \times \left( \frac{Sat_{Type_y} \times Eff_{Type_y}}{Sat_{05} \times Eff_{05}} \right) \]  

(4)

The \textit{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:

\[ StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \]  

(5)

The \textit{StructuralIndex} is defined on the \textit{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:

\[ SurfaceArea_y = 892 + 1.44 \times \text{Footage}_y \]  

(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.

\[ Weight_{Type} = \frac{Energy_{Type_{05}}}{HH_{05}} \times HeatShare_{Type_{05}} \]  

(7)

In the SAE spreadsheets, these weights are referred to as \textit{Intensities} and are defined on the \textit{EIAData} tab. With these weights, the \textit{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

<table>
<thead>
<tr>
<th>Equipment Type</th>
<th>Weight (kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Resistance Furnace/Room units</td>
<td>505</td>
</tr>
<tr>
<td>Electric Space Heating Heat Pump</td>
<td>190</td>
</tr>
</tbody>
</table>

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,

\[
\text{HeatIndex}_{y} = \text{StructuralIndex}_{y} \times \sum_{\text{Type}} \text{Weight}_{\text{Type}} \times \frac{\text{Sat}_{y}^{\text{Type}}}{\text{Eff}_{y}^{\text{Type}}} \times \frac{\text{Sat}_{05}^{\text{Type}}}{\text{Eff}_{05}^{\text{Type}}} \times \left( \text{TenYearMovingAverageElectric Price}_{y,m} \right) \times \left( \text{TenYearMovingAverageGas Price}_{y,m} \right)
\]

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:
\[
HeatUse_{y,m} = \left( \frac{BDays_{y,m}}{30.5} \right) \times \left( \frac{WgtHDD_{y,m}}{HDD_{05}} \right) \times \left( \frac{HHSize_{y}}{HHSize_{05}} \right)^{0.25} \times \left( \frac{Income_{y}}{Income_{05}} \right)^{0.20} \\
\times \left( \frac{ElecPrice_{y,m}}{ElecPrice_{05,7}} \right)^{4} \times \left( \frac{GasPrice_{y,m}}{GasPrice_{05,7}} \right)^{k}
\]

(9)

Where:

- \textit{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.
- \textit{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.
- \textit{HDD} is the annual heating degree days for 2005.
- \textit{HHSize} is average household size in a year \((y)\).
- \textit{Income} is average real income per household in year \((y)\).
- \textit{ElecPrice} is the average real price of electricity in month \((m)\) and year \((y)\).
- \textit{GasPrice} is the average real price of natural gas in month \((m)\) and year \((y)\).

By construction, the \textit{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,

\[ X_{\text{Cool},y,m} = \text{CoolIndex}_y \times \text{CoolUse}_{y,m} \quad (10) \]

Where

- \( X_{\text{Cool},y,m} \) is estimated cooling energy use in year \( (y) \) and month \( (m) \)
- \( \text{CoolIndex}_y \) is an index of cooling equipment
- \( \text{CoolUse}_{y,m} \) 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:

\[ \text{CoolIndex}_y = \text{StructuralIndex}_y \times \sum_{\text{Type}} \text{Weight}^{\text{Type}} \times \frac{\text{Sat}^{\text{Type}}_y / \text{Eff}^{\text{Type}}_y}{\text{Sat}^{\text{Type}}_{05} / \text{Eff}^{\text{Type}}_{05}} \quad (11) \]

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.

\[ \text{Weight}^{\text{Type}} = \frac{\text{Energy}^{\text{Type}}_{05}}{\text{HH}_{05}} \times \text{CoolShare}^{\text{Type}}_{05} \quad (12) \]

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

<table>
<thead>
<tr>
<th>Equipment Type</th>
<th>Weight (kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Air Conditioning</td>
<td>1,661</td>
</tr>
<tr>
<td>Space Cooling Heat Pump</td>
<td>369</td>
</tr>
<tr>
<td>Room Air Conditioning</td>
<td>315</td>
</tr>
</tbody>
</table>

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,

\[
\text{CoolIndex}_y = \text{StructuralIndex}_y \times \sum_{\text{Type}} \text{Weight}_{\text{Type}} \times \frac{\text{Sat}_{\text{Type}}}{\text{Eff}_{\text{Type}}} \times \left( \left( \text{TenYearMovingAverageElectric Price}_{y,m} \right) \times \left( \text{TenYearMovingAverageGas Price}_{y,m} \right) \right)
\]

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:
\[
CoolUse_{y,m} = \left( \frac{BDays_{y,m}}{30.5} \right) \times \left( \frac{WgtCDD_{y,m}}{CDD_{05}} \right) \times \left( \frac{HHSize_y}{HHSize_{05}} \right)^{0.25} \times \left( \frac{Income_y}{Income_{05}} \right)^{0.20} \times \left( \frac{Elec Price_{y,m}}{Elec Price_{05}} \right)^{\rho} \times \left( \frac{Gas Price_{y,m}}{Gas Price_{05}} \right)^{\nu}
\]  

(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:

\[
XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m}
\]  

(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.

\[
\text{ApplianceIndex}_{y,m} = \text{Weight}^{Type} \times \left( \frac{\text{Sat}_{y}^{Type}}{\text{UEC}_{y}^{Type}} \right) \times \text{MoMult}_{m}^{Type} \times \left( \frac{\text{Sat}_{05}^{Type}}{\text{UEC}_{05}^{Type}} \right) \times (\text{TenYearMovingAverageElectric Price})^d \times (\text{TenYearMovingAverageGas Price})^e
\]

(16)

Where:

- **Weight** is the weight for each appliance type
- **Sat** represents the fraction of households, who own an appliance type
- **MoMult** 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:

\[
\text{ApplianceUse}_{y,m} = \left( \frac{\text{BDays}_{y,m}}{30.5} \right) \times \left( \frac{\text{HHSSize}_{y}}{\text{HHSSize}_{05}} \right)^{0.46} \times \left( \frac{\text{Income}_{y}}{\text{Income}_{05}} \right)^{0.10} \times \left( \frac{\text{Elec Price}_{y,m}}{\text{Elec Price}_{05}} \right)^d \times \left( \frac{\text{Gas Price}_{y,m}}{\text{Gas Price}_{05}} \right)^e
\]

(17)

The index for other uses is derived then by summing across the appliances:
\[ \text{OtherEqpIndex}_{y,m} = \sum_k \text{ApplianceIndex}_{y,m} \times \text{ApplianceUse}_{y,m} \]
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,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m}$$  \hspace{1cm} (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.
\[ \text{USE}_m = a + b_1 \times X_{\text{Heat}}_m + b_2 \times X_{\text{Cool}}_m + b_3 \times X_{\text{Other}}_m + \epsilon_m \]  

(2)

Here, \( X_{\text{Heat}}_m, X_{\text{Cool}}_m, \) and \( X_{\text{Other}}_m \) 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,

\[ X_{\text{Heat}}_{y,m} = \text{HeatIndex}_{y} \times \text{HeatUse}_{y,m} \]  

(3)

where, \( X_{\text{Heat}}_{y,m} \) is estimated heating energy use in year (\( y \)) and month (\( m \)),

- \( \text{HeatIndex}_{y} \) is the annual index of heating equipment, and
- \( \text{HeatUse}_{y,m} \) 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 (\( \text{HeatShare} \)) and operating efficiencies (\( \text{Eff} \)). Formally, the equipment index is defined as:

\[ \text{HeatIndex}_{y} = \text{HeatSales}_{04} \times \frac{\left( \frac{\text{HeatShare}_{y}}{\text{Eff}_{y}} \right)}{\left( \frac{\text{HeatShare}_{04}}{\text{Eff}_{04}} \right)} \]  

(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.

\[
HeatSales_{04} = \left( \frac{kWh}{Sqft} \right)_{Heating} \times \left( \frac{CommercialSales_{04}}{\sum_{e} kWh/\text{Sqft}_e} \right)
\]  

(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\textsubscript{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:

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

(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,

\[ X_{\text{Cool}}_{y,m} = \text{CoolIndex}_y \times \text{CoolUse}_{y,m} \]  

(7)

where, \( X_{\text{Cool}}_{y,m} \) is estimated cooling energy use in year (y) and month (m),  
\( \text{CoolIndex}_y \) is an index of cooling equipment, and  
\( \text{CoolUse}_{y,m} \) is the monthly usage multiplier.

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

\[ \text{CoolIndex}_y = \text{CoolSales}_{04} \times \frac{\left( \frac{\text{CoolShare}_y}{\text{Eff}_y}\right)}{\left( \frac{\text{CoolShare}_{04}}{\text{Eff}_{04}}\right)} \]  

(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.
\[
\text{CoolSales}_{04} = \left( \frac{\text{kWh}}{\text{Sqft}} \right)_{\text{Cooling}} \times \left( \frac{\text{CommercialSales}_{04}}{\sum_{e} \text{kWh}/\text{Sqft}_e} \right)
\]  

(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 \textit{BaseYrInput} tab. The resulting \textit{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 \textsc{CommeND} default parameters, the estimates of cooling equipment usage levels are computed as follows:

\[
\text{CoolUse}_{y,m} = \left( \frac{\text{BDays}_{y,m}}{30.5} \right) \times \left( \frac{\text{WgtCDD}_{y,m}}{\text{CDD}_{04}} \right) \times \left( \frac{\text{Output}_y}{\text{Output}_{04}} \right)^{0.20} \times \left( \frac{\text{Price}_{y,m}}{\text{Price}_{04}} \right)^{-0.18}
\]

(10)

where, \text{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.

\text{CDD} is the annual cooling degree days for 2004.

By construction, the \textit{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.

\textit{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:

\[ X_{\text{Other}_{y,m}} = \text{OtherIndex}_{y,m} \times \text{OtherUse}_{y,m} \quad (11) \]

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:

\[ \text{OtherIndex}_{y,m} = \sum_{\text{Type}} \text{Weight}_{04}^{\text{Type}} \times \left( \frac{\text{Share}_{y}^{\text{Type}}}{\text{Eff}_{y}^{\text{Type}}} \right) \]

\[ \text{OtherIndex}_{y,m} = \sum_{\text{Type}} \text{Weight}_{04}^{\text{Type}} \times \left( \frac{\text{Share}_{04}^{\text{Type}}}{\text{Eff}_{04}^{\text{Type}}} \right) \quad (12) \]

where, \( \text{Weight} \) is the weight for each equipment type, \( \text{Share} \) represents the fraction of floor stock with an equipment type, and \( \text{Eff} \) 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.

\[ \text{Weight}_{04}^{\text{Type}} = \left( \frac{\text{kWh}}{\text{Sqft}} \right)_{\text{Type}} \times \left( \frac{\text{CommercialSales}_{04}}{\sum_{e} \text{kWh}_{e}/\text{Sqft}_{e}} \right) \quad (13) \]

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

\[ \text{OtherUse}_{y,m} = \left( \frac{B\text{Days}_{x,m}}{30.5} \right) \times \left( \frac{\text{Output}_{y}}{\text{Output}_{04}} \right)^{0.20} \times \left( \frac{\text{Price}_{y,m}}{\text{Price}_{04}} \right)^{-0.18} \quad (14) \]

In this expression, the elasticities on output and real price are computed from the COMMEND default values.
Confidential Attachments 4.4 a-c (Moody's Q4 2018 Base, Exceptionally Strong, and Lower Trend) are provided electronically as part of the Confidential version of the IRP.
Attachment 4.5 (10yr base by rate code) is provided electronically
Attachment 4.6 (20yr base, high, low forecast) is provided electronically
Attachment 4.7a (Energy Input Data - Residential) is provided electronically
Attachment 4.7b (Energy Input Data - Small CI) is provided electronically
Attachment 4.7c (Energy Input Data - Large CI) is provided electronically
Attachment 4.8 (Peak-Forecast Drivers and Input Data) is provided electronically
Attachment 4.9 (Forecast Analysis) is provided electronically