OFFICIAL EXHIBITS

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA ("AES INDIANA") FOR (1) ISSUANCE TO AES INDIANA OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE ACQUISITION AND DEVELOPMENT BY A WHOLLY OWNED AES INDIANA SUBSIDIARY OF A SOLAR POWER GENERATING FACILITY AND BATTERY ENERGY STORAGE SYSTEM PROJECT TO BE KNOWN AS THE PETERSBURG ENERGY CENTER ("THE PETERSBURG PROJECT"); (2) APPROVAL OF THE PETERSBURG PROJECT, INCLUDING A JOINT VENTURE STRUCTURE BETWEEN AN AES INDIANA SUBSIDIARY AND ONE OR MORE TAX EQUITY PARTNERS AND A CAPACITY AGREEMENT AND CONTRACT FOR DIFFERENCES BETWEEN AES INDIANA AND THE PROJECT COMPANY THAT HOLDS AND OPERATES THE SOLAR GENERATION AND STORAGE ASSETS, AS A CLEAN ENERGY PROJECT AND ASSOCIATED TIMELY COST RECOVERY UNDER IND. CODE § 8-1-8.8-11; (3) APPROVAL OF ACCOUNTING AND RATEMAKING FOR THE PETERSBURG PROJECT, INCLUDING AN ALTERNATIVE REGULATORY PLAN UNDER IND. CODE § 8-1-2.5-6 TO FACILITATE AES INDIANA'S INVESTMENT IN THE PETERSBURG PROJECT THROUGH A JOINT VENTURE; AND (4) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION OVER THE JOINT VENTURE, INCLUDING THE PROJECT COMPANY, AS A PUBLIC UTILITY.	)	IURC PETITIONER'S EXHIBIT NO. 6 10-25-21 AT DATE REPORTER **CAUSE NO.** 45591

PETITIONER'S SUBMISSION OF DIRECT TESTIMONY OF
<u>ERIK K. MILLER</u>

Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana" or "Petitioner"), by counsel, hereby submits the direct testimony and attachments of Erik K. Miller.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 30th day of July, 2021, by electronic transmission or United States Mail, first class, postage prepaid on:

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ATTORNEYS FOR PETITIONER
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

VERIFIED DIRECT TESTIMONY

OF

ERIK K. MILLER

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

D/B/A AES INDIANA

SPONSORING AES INDIANA ATTACHMENTS EKM-1, EKM-2, EKM-3, AES INDIANA CONFIDENTIAL ATTACHMENT EKM-4 AND AES INDIANA ATTACHMENTS EKM-5 AND EKM-5(C)

VERIFIED DIRECT TESTIMONY OF ERIK K. MILLER
ON BEHALF OF AES INDIANA

1. INTRODUCTION

Q1. Please state your name, employer and business address.

A1. My name is Erik K. Miller. I am employed by Indianapolis Power & Light Company d/b/a AES Indiana ("IPL", "AES Indiana", or "Company"), One Monument Circle, Indianapolis, Indiana 46204.

Q2. What is your position with AES Indiana?

A2. I am Manager, Resource Planning.

Q3. On whose behalf are you submitting this direct testimony?

A3. I am submitting this testimony on behalf of AES Indiana.

Q4. Please briefly describe your educational background and business experience.

A4. I hold a bachelor's degree from Indiana University's School of Journalism and a Master of Public Affairs degree from Indiana University's School of Public and Environmental Affairs. Prior to coming to AES Indiana, I worked as a Senior Project Manager for the energy efficiency consulting company, CLEAResult from 2012 – 2015 and prior to that as an Energy Efficiency Program Coordinator at Hoosier Energy Rural Electric Cooperative from 2009 – 2012.

Q5. What are your current duties and responsibilities at AES Indiana?

A5. I am responsible for the economics and decision support analysis in the areas of resource planning, environmental planning, and other strategic level analysis.

Q6. Have you previously testified before this Commission?

A6. Yes. I have previously testified before the Commission in Cause No. 44792, which concerned AES Indiana's DSM programs offered in 2017, Cause No. 44945, which concerned AES Indiana's DSM programs offered from 2018 – 2020, Cause No. 45370, which concerned AES Indiana's DSM programs offered from 2021 – 2023 and Cause No. 45493, which concerned the Hardy Hill's Solar Project that was approved by the Commission on 6/16/2021.

Q7. What is the purpose of your testimony in this proceeding?

A7. My testimony: 1) presents AES Indiana's Preferred Resource Portfolio and Short Term Action Plan defined in the Company's 2019 IRP; 2) describes the Resource Planning Production Cost analysis used in the RFP evaluation; and 3) demonstrates that the Petersburg Energy Center solar and energy storage project, when included in AES Indiana's resource mix, is consistent with AES Indiana's Preferred Resource Portfolio and Short Term Action Plan defined in the Company's 2019 Integrated Resource Plan ("IRP").

Q8. Please provide an overview of how your testimony is presented.

A8. My testimony is divided into the following sections:

1. <u>Introduction</u>
2. <u>AES Indiana's 2019 IRP Preferred Resource Portfolio and 2023 Unforced Capacity ("UCAP") Need</u> – This section discusses the 2019 IRP Short Term Action Plan to retire Petersburg Units 1 & 2 and the resulting capacity need in 2023.

3. Production Cost and Ranking Analysis Modeling – This section discusses the work performed by AES Indiana's Resource Planning team with support from Concentric and the Ranking Analysis conducted for the quantitative evaluation of the proposals.

4. Consistency with AES Indiana's 2019 IRP – This section demonstrates that the Preferred Resource Plan remains unchanged from AES Indiana's 2019 IRP based on AES Indiana's analysis of the total Company portfolio Present Value Revenue Requirement ("PVRR") with the Petersburg Energy Center included.

5. Levelized Cost of Energy – This section demonstrates that, despite having higher costs as compared to the solar and storage modeled within the 2019 IRP, the Petersburg Energy Center is still consistent with the Preferred Resources Portfolio in the 2019 IRP.

6. Consideration of Resource Alternatives – Per Ind. Code § 8-1-8.5-4, this section discusses how AES Indiana considered resource alternatives to the Petersburg Energy Center.

7. Consideration of the State Utility Forecasting Group (SUFG) Indiana Electricity Projections and the Indiana 21st Century Task Force Report

8. Conclusion

Q9. Are you sponsoring any attachments in this proceeding?

A9. Yes. I am sponsoring the following attachment(s):

- AES Indiana Attachment EKM-1, which is a copy of AES Indiana's 2019 IRP Volume 1.
- AES Indiana Attachment EKM-2, which is a copy of AES Indiana's 2019 IRP Volume 2.
- AES Indiana Attachment EKM-3, which is a copy of AES Indiana's 2019 IRP Volume 3.
- AES Indiana Confidential Attachment EKM-4, which is a copy of AES Indiana's 2019 IRP Confidential Volume.
- AES Indiana Attachment EKM-5 and EKM-5(C)[1], which is a copy of the public and confidential AES Indiana Attachments (Sections 1-8) included with AES Indiana's 2019 IRP .

Q10. Were these attachments prepared or assembled by you or under your direction and supervision?

A10. Yes.

Q11. Did you submit any workpapers?

A11. Yes. The table below lists and describes the workpapers submitted with my testimony.

[1] EKM-5(C) is the confidential version.

Workpaper	File/Folder Name	Description
AES Indiana Witness EKM Workpaper 1	Retirement Dates by IRP and RFP	AES Indiana generation station retirement years
AES Indiana Witness EKM Confidential Workpaper 2	2019 AES Indiana IRP Load and PRMR Forecast	AES Indiana load and PRMR forecast from the 2019 IRP
AES Indiana Witness EKM Confidential Workpaper 3	Net Capacity Position	Detailed build-up of AES Indiana resources and need by capacity
AES Indiana Witness EKM Confidential Workpaper 4	Forward Curves	Wood Mackenzie forward curves used in Production Cost modeling
AES Indiana Witness EKM Confidential Workpaper 5a	Pete Solar Resource Parameters	Petersburg Energy Center solar parameters provided by S&L for Production Cost modeling
AES Indiana Witness EKM Confidential Workpaper 5b	Pete Storage Resource Parameters	Petersburg Energy Center storage parameters provided by S&L for Production Cost modeling
AES Indiana Witness EKM Confidential Workpaper 6	Solar and Storage Maintenance O.and.M	Calculation of maintenance portion of Petersburg Energy Center's fixed costs
AES Indiana Witness EKM Confidential Workpaper 7	Solar ELCC Forecast	Wood Mackenzie forecast of solar ELCC in MISO Central
AES Indiana Witness EKM Workpaper 8	Petersburg Energy Center LMP Basis	Derivation of LMP basis from Indiana Hub for Petersburg Energy Center in Production Cost modeling
AES Indiana Witness EKM Workpaper 9a	IRP Cost Sensitivity Analysis	Table of total portfolio PVRRs with Petersburg Energy Center's costs
AES Indiana Witness EKM Confidential Workpaper 9b	2019 AES Indiana IRP PVRR (adjusted for Hardy Hills and Petersburg Energy Center)	PVRR files supporting the table in Workpaper 9a
AES Indiana Witness EKM Confidential Workpaper 10	LCOE Calculation	Calculation of Petersburg Energy Center and IRP LCOE and NREL methodology documentation

2. AES INDIANA'S 2019 IRP PREFERRED RESOURCE PORTFOLIO AND 2023 UNFORCED CAPACITY ("UCAP") NEED

Q12. Please provide an overview of AES Indiana's 2019 IRP and how it was developed.

A12. The objective of AES Indiana's IRP is to identify a Preferred Resource Portfolio to provide safe, reliable, sustainable, and reasonable least-cost electric service to AES Indiana customers. The study period for the 2019 IRP was 2020-2039, giving due consideration to various options, potential risks, and stakeholder input. AES Indiana submits an IRP to the IURC in accordance with Indiana Administrative Code (IAC 170 4-7) every three years. The Company's 2019 IRP was submitted to the Commission on December 16, 2019. The IRP development included input from stakeholders through what is known as a "Public Advisory" process. AES Indiana hosted five public advisory meetings to discuss the IRP process with interested parties and to solicit feedback from stakeholders. A copy of AES Indiana's 2019 IRP is attached as AES Indiana Attachment EKM-1 – EKM-4.

Q13. Has the Commission issued comments on AES Indiana's 2019 IRP. If so, can you summarize the comments?

A13. Yes. The Commission issued the draft Director's Report for IPL's 2019 Integrated Resource Plan on February 12, 2021. In the report, the Director commends AES Indiana for the high quality of its IRP and AES Indiana's "commitment to thorough well-written explanation of its planning actions."[2] More specifically, the Director commended: the participation by AES Indiana's top management; AES Indiana's willingness to use state-of-the-art software; AES Indiana's facilitation of a robust stakeholder process; its efforts to broaden the diversity of the stakeholder community; AES Indiana's leadership in utilizing AMI and other load resource data to better understand customers' needs; and AES Indiana's commitment to continual improvement.

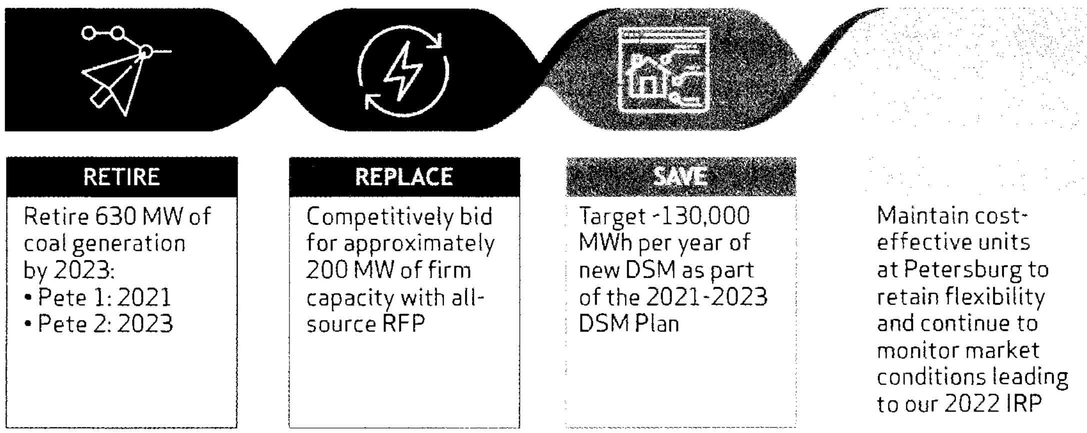
Q14. Please describe AES Indiana's Preferred Resource Portfolio and Short Term Action Plan, as identified in AES Indiana's 2019 IRP.

A14. The "Preferred Resource Portfolio" represents AES Indiana's selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, while taking cost, risk, and uncertainty into

[2] See p. 14 of IURC's Draft Director's Report for AES Indiana's 2019 integrated Resource Plan.

consideration.[3] The "Short Term Action Plan" is the schedule of activities and goals AES Indiana developed to begin efficient implementation of its Preferred Resource Portfolio.[4] As further discussed in the IRP, the 2019 AES Indiana Preferred Resource Portfolio Short Term Action Plan contains the following elements:

Figure 1. Short Term Action Plan



Source: AES Indiana's 2019 Integrated Resource Plan Non Technical Summary, page 6.

Along with Demand Side Management ("DSM"), AES Indiana's Preferred Resource Portfolio in its 2019 IRP indicated that a combination of wind, solar and storage resources would be the reasonable, least cost resources for replacement capacity over a wide range of scenarios. All existing AES Indiana owned generation continue to operate through their age-based retirement dates in AES Indiana's Preferred Resource Portfolio aside from Petersburg Units 1 and 2 which are planned to retire early in 2021 and 2023, respectively.[5,6]

[3] 170 IAC 4-7-1 (cc).
[4] 170 IAC 4-7-1(nn).
[5] AES Indiana 2019 IRP Volume 1, Executive Summary, p. xx.
[6] AES Indiana 2019 IRP Volume 1, p. 161.

Q15. Please describe the decision to retire Petersburg Units 1 and 2 and the near term replacement UCAP need identified in the IRP.

A15. Based on extensive IRP modeling of five portfolios across five future scenarios[7], AES Indiana has determined that the cost of operating Petersburg Units 1 and 2 is less attractive than alternative resources. Retiring these units according to the Short Term Action Plan allows AES Indiana to diversify the portfolio and transition to cleaner resources while maintaining a reliable system at a reasonable, least cost. AES Indiana's 2019 Preferred Resource Portfolio forecasted the retirements of Petersburg Units 1 and 2 and would create an incremental UCAP need of approximately 200 MW by June 1, 2023. For additional information regarding AES Indiana's Short Term Action Plan, please see "Section 9: Short Term Action Plan and Conclusion" beginning on p. 201 of AES Indiana's 2019 IRP (Volume 1) (included as AES Indiana Attachment EKM-1.)[8]

Q16. Please discuss the timing of the Petersburg retirements and the implementation of replacement resources to fill the incremental UCAP need by June 1, 2023.

A16. The 2019 IRP shows AES Indiana is in a long capacity position in 2020, and that will continue even after Petersburg Unit 1 is retired in 2021. However, once Petersburg Unit 2 is retired in 2023, AES Indiana is forecasted to be in a short capacity position. AES Indiana must fill this short capacity position with additional capacity prior to the 2023-2024 Midcontinent Independent System Operator ("MISO") Planning Year. June 1, 2023

[7] See "Section 7: Resource Portfolio Modeling" beginning on p. 119 of AES Indiana's 2019 IRP (Volume 1) for additional information regarding the portfolios and scenarios AES Indiana modeled in the 2019 IRP.
[8] See Section 2.1.2. Resource Capacity Credit of AES Indiana's 2019 IRP Volume 1 for explanation of the UCAP calculation for solar and other resources.

corresponds to the start of the MISO 2023-2024 Planning Year, which is defined in seasonal terms of June 1 through May 31.

Table 1 below provides a comparison of the retirement dates: age-based vs. the 2019 Preferred Resource Portfolio vs. those modeled in the RFP. For the purpose of the RFP, Petersburg Units 1 and 2 and the Harding Street GT1 and GT2 were adjusted to correspond with MISO Planning Years.[9]

Table 1. Unit Retirement Dates

	Age-Based Retirement Date	2019 IRP Retirement Date	All-Source RFP Retirement Date
Pete 1	Jan-1-2033	Jan-1-2021	Jun-1-2021
Pete 2	Jan-1-2035	Jan-1-2023	Jun-1-2023
Pete 3	Jan-1-2043	Jan-1-2043	Jan-1-2043
Pete 4	Jan-1-2043	Jan-1-2043	Jan-1-2043
Eagle Valley	Jan-1-2069	Jan-1-2069	Jan-1-2069
HS CT4	Jan-1-2045	Jan-1-2045	Jan-1-2045
HS CT5	Jan-1-2046	Jan-1-2046	Jan-1-2046
HS CT6	Jan-1-2053	Jan-1-2053	Jan-1-2053
HS ST5	Jan-1-2031	Jan-1-2031	Jan-1-2031
HS ST6	Jan-1-2031	Jan-1-2031	Jan-1-2031
HS ST7	Jan-1-2034	Jan-1-2034	Jan-1-2034
HS GT1 & GT2	Jan-1-2024	Jan-1-2024	Jun-1-2023
Gtwn 1	Jan-1-2051	Jan-1-2051	Jan-1-2051
Gtwn 4	Jan-1-2053	Jan-1-2053	Jan-1-2053

Q17. Has AES Indiana confirmed that its 2023 UCAP need remains consistent with the 2019 IRP results?

A17. Yes. As noted above, AES Indiana's 2019 IRP Preferred Resource Portfolio projected a capacity shortfall of approximately 200 MW (UCAP) by 2023 with the retirements of

[9] The Harding Street GT1 and GT2 retirements were referenced on pg. 61 of AES Indiana's 2019 IRP. These units are fueled using #2 fuel oil and supply 36 MW UCAP

Petersburg Units 1 and 2. Some assumption updates were made for the RFP evaluation to incorporate recent changes. Figure 2 below provides an illustration of these updates. They include (as they appear from left to right in Figure 2):

1) updating to the most current MISO calculations which increased the planning reserve margin requirement ("PRMR"), coincident peak factor, and transmission losses;

2) updating the existing resource capacity accreditation resulting from annual testing;

3) including a more precise date for the retirement of the Harding Street GT1 and GT2 oil combustion turbines. Because the IRP used calendar years, the IRP reflects retirements of these units January 1, 2024. Rather than retire the units in the middle of the MISO capacity Planning Year, the retirement date was updated to the beginning of the MISO capacity Planning Year or June 1, 2023.

4) updating the load forecast to reflect the economic impacts of COVID-19.

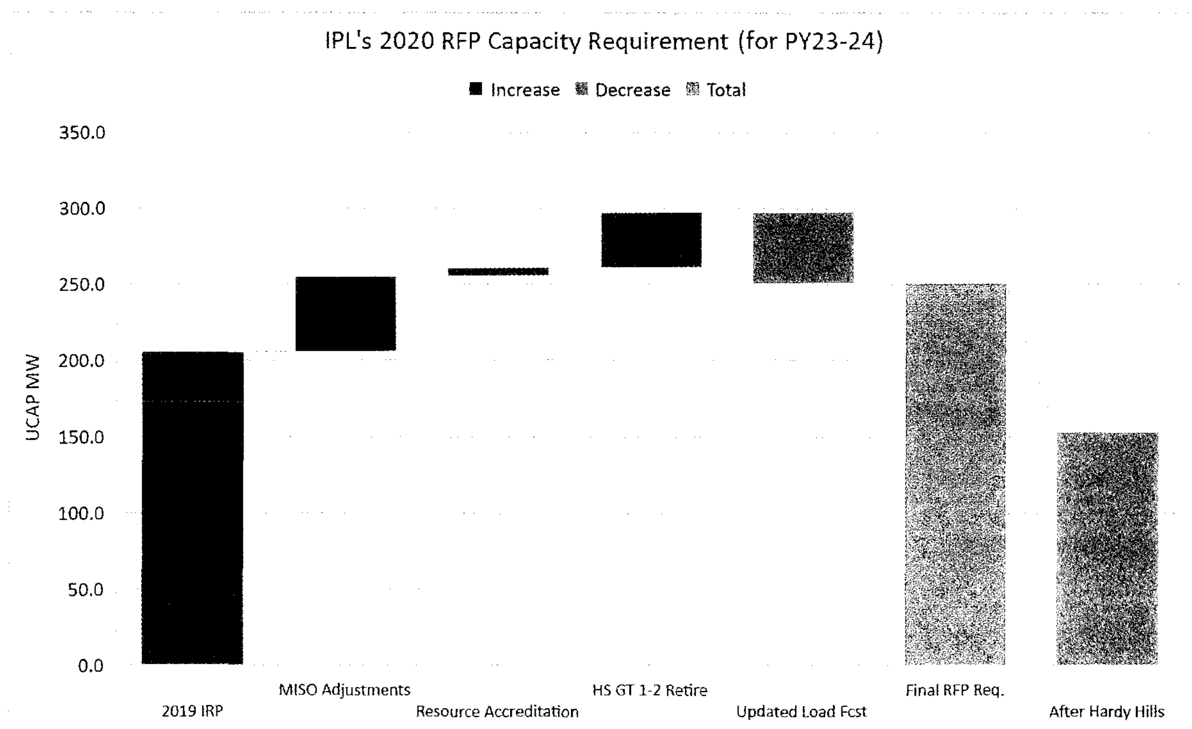
As demonstrated in Figure 2 below, these updates result in a modest increase in the 2023 capacity need from approximately 200 MW to 250 MW (UCAP).

In Cause No. 45493, AES Indiana received approval from the Commission for Hardy Hills, a 195 MWac (ICAP) solar project located in Clinton County.[10] This project is a replacement resource that fills part of the capacity need resulting from the retirement of Petersburg Units 1 and 2 in 2023. The figure below illustrates that with the inclusion of the Hardy Hills 98-megawatt (UCAP) solar project, the remaining capacity need in 2023

[10] The Order for Cause No. 45493 was issued by the IURC on June 16, 2021.

drops to 155MW (UCAP).

Figure 2. AES Indiana's 2020 RFP Capacity Requirement (for PY23-24)



Q18. You note above that AES Indiana's updated load forecast includes the economic impacts resulting from COVID-19. How were these impacts captured in the updated load forecast?

A18. The COVID-19 pandemic, business shutdowns, and resulting recession that commenced in the spring of 2020 caused AES Indiana's load to drop. Economic forecasts of gross domestic product ("GDP") and employment are the key driving variables in AES Indiana's load forecasting to recovery from this recession. AES Indiana uses economic data for the Indianapolis Metropolitan Area and Marion County in the load forecast models to draw the correlation between the economy and customer sales. AES Indiana worked with Itron Inc. ("Itron") to estimate the recovery from the COVID-19 recession and include this projection as inputs in the load forecast models. AES Indiana subsequently validated the projected recovery by comparing it to Moody's Q4 of 2020 economic forecast. The forecast developed with Itron is included in the capacity position analysis described in Q/A 17. When the recession impacts are reflected in the forecast models, AES Indiana's electricity peak is projected to be down 1.6% in 2023 compared to the forecast included in the IRP. "Section 4: Load Research, Load Forecast, and Forecasting Methodology" of AES Indiana's 2019 IRP Volume 1 provides additional detail regarding AES Indiana's load forecasting methodology and the role of economic data in the forecast.[11]

3. <u>PRODUCTION COST AND RANKING ANALYSIS MODELING</u>

Q19. Please briefly describe the RFP evaluation process and the AES Indiana Resource Planning team's responsibilities as it pertains to this process.

A19. As explained by AES Indiana Witness Cooper, AES Indiana used a three phase process to evaluate the proposals received in the RFP.

Phase 1: Initial Screening and Shortlisting of Proposals Based on Qualitative and Initial Pricing Evaluation.

Phase 2: Selection of Proposals for Contract Negotiations Based on Qualitative and Quantitative Evaluation of Shortlisted Proposals.

Phase 3: Quantitative Evaluation Refinement, Contract Negotiation and Due Diligence.

[11] Itron is a global technology company. They build solutions that help utilities measure, manage, and analyze energy, and water. Their product portfolio includes electricity, gas, water, and thermal energy measurement and control technology; communications systems; software; forecasting; and professional services,

For the quantitative evaluation, Concentric Energy Advisors, Inc. ("Concentric") along with AES Indiana's Resource Planning team conducted a Ranking Analysis of the proposals. At a high level, this analysis calculated each individual proposal's impact to AES Indiana's total portfolio PVRR – where a proposal that demonstrates a negative PVRR is expected to have a downward impact on the Company's total portfolio PVRR. The more negative a proposal's PVRR impact, the more cost effective the proposal is assumed to be. This metric was used by Concentric and AES Indiana in ranking the proposals.[12]

The Ranking Analysis was completed in two parts:

1) AES Indiana's Resource Planning Team performed a Production Cost analysis for each proposal included in the Phase 2 and Phase 3 evaluation. This analysis is described in more detail in the next Q/A.

2) The outputs from the Production Cost analysis were provided to Concentric and used as inputs into their Ranking Analysis model. Concentric's analysis is described in detail in AES Indiana Witness Powers Direct Testimony included in this filing.

Q20. Describe the Production Cost analysis performed by AES Indiana's Resource Planning Team for use in Concentric's Ranking Analysis model.

A20. The PowerSimm Production Cost model was used to forecast the energy revenues and costs for each proposal included in the Phase 2 and Phase 3 Ranking Analysis. The

[12] Concentric is a management consulting and economic advisory firm focused on the North American energy and water industries. Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

model forecasts the proposal revenues and costs by dispatching resources using forward energy and fuel price curves as the key drivers to when units operate. A Production Cost analysis was performed for each individual proposal. Outputs from the Production Cost model that became inputs for Concentric's Ranking Analysis model include energy revenue, fuel costs, variable Operation & Maintenance ("O&M") costs, energy storage charging costs, emission costs, and energy generation. These outputs make up the energy revenue and operation cost streams used in Concentric's Ranking Analysis.[13,14]

Q21. Was the PowerSimm Production Cost Model the same model used in AES Indiana's 2019 IRP?

A21. Yes, this is the same model that was used in the 2019 IRP to determine revenues and costs.[15]

Q22. Did any assumptions in the Production Cost modeling (that the Resource Planning team performed) and the Ranking Analysis (that Concentric performed) change as compared to the analysis for the 2019 IRP?

A22. Yes. Certain modeling inputs were appropriately updated to reflect changing market prices, known proposal costs and parameters. These updates included the following:

1) Forecasted prices for power, natural gas, emissions, renewable energy credits ("RECs"), and capacity were refreshed to use the Wood Mackenzie long term

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[13] Power purchase agreements are contracts entered into by a utility, power producer, or provider for the energy, capacity, and potentially environmental value of a generation asset owned by a private entity or developer.
[14] Variable O&M costs associated with Petersburg Energy Center include preventative maintenance, corrective maintenance, consumables, spare parts, inverter replacement reserve, other major maintenance, vegetation management, module washing, plant/high voltage maintenance, general asset management, and telecommunications.
[15] See Section 7.2: Modeling Tools of AES Indiana's 2019 IRP Volume 1 for more information on the Ascend PowerSimm models.

outlook as of year-end 2019 which was issued after AES Indiana conducted its IRP analysis. Forecasted prices used in the 2019 IRP were from the Wood Mackenzie long term outlook as of 2018.

2) The estimated resource costs and characteristics were replaced with proposal-specific details. Updates included:

   a. Operating parameters for thermal and energy storage proposals and energy and peak forecasts for renewable proposals were updated to proposal assumptions.

   b. Fixed costs were updated to better represent the specific types and sizes of resources.

   c. Solar proposals were modeled with annual degradation of energy output based on assumptions provided by bidders.

   d. Energy storage proposals were estimated to receive an additional revenue stream for participating in ancillary service markets. This was captured using a percent increase to the resource's energy revenue based on analysis done by Concentric.

   e. Proposals' generic locational marginal prices ("LMP") were updated with specific LMPs because approximate locations are known to the modelers.

3) The Production Cost modeling period was extended from twenty years to thirty years. This update was made because Wood Mackenzie began providing an additional 10 years in their long term outlook.

4) The solar effective load carrying capability ("ELCC")[16] value was updated to reflect Wood Mackenzie's year-end 2019 ELCC forecast for MISO; the result was an increase in the ELCC value.

5) Wind ELCC value was updated to reflect the value specific to the wind proposal bids' zone in MISO and to be consistent with MISO's most recent Wind & Solar Capacity Credit Report (December 2019);[17] the result was an increase in the ELCC value.

6) Generic renewable generation profiles were refined to reflect profiles specific to proposed locations.

7) REC values are assessed in the model.

8) Resources were given capacity revenue to recognize the value of firm capacity contribution. See AES Indiana Witness Powers Direct Testimony at Q/A 49 for additional detail regarding how capacity revenues were modeled in the Ranking Analysis.

4. CONSISTENCY WITH AES INDIANA'S 2019 IRP

Q23. Please explain how the 2019 IRP analysis evaluated and ensured reliability, resilience, and cost effectiveness to determine the Company's Preferred Resource Portfolio and Short Term Action Plan.

A23. Guided by the IURC IRP rules 170 IAC 4-7, AES Indiana strove to achieve a well-reasoned, transparent, and comprehensive 2019 IRP process. The overarching purpose of

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[16] See Section 2.1.2: Resource Capacity Credit of AES Indiana's 2019 IRP Volume 1 for additional information regarding the ELCC and resource capacity credit.
[17] https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

the IRP was to develop a long-term plan to guide investments to provide safe and reliable electric power at a reasonable, least cost. AES Indiana achieved these objectives by evaluating a set of fifteen (15) candidate resource portfolios created from a modeling process that incorporated an evaluation of coal retirement dates, DSM market potential, and new resource economics in a probabilistic optimization framework. The candidate resource portfolios were stressed across a wide range of scenarios, which allowed AES Indiana to identify the portfolio that mitigates risk and performs the best across multiple futures. Ultimately, a Preferred Resource Portfolio was selected that was demonstrated to be low risk, reasonable, and least cost across a range of scenarios and risk sensitivities. Additionally, the Preferred Resource Portfolio preserves flexibility and optionality benefits to customers. The gradual approach to coal unit retirements reflects the economic conditions underlying the 2019 IRP. Because the 2019 IRP Preferred Resource Portfolio focuses on a 2023 UCAP need of approximately 250 MW, this approach provides AES Indiana options and flexibility going forward with respect to resource needs beyond this timeframe.

Q24. Did AES Indiana consider other factors, such as fuel diversity and environmental regulation, as part of its integrated resource planning analyses?

A24. Yes. AES Indiana considered fuel diversity in reviewing the candidate portfolios included in the 2019 IRP analysis. The Preferred Resource Portfolio results in a more diverse, scalable, and balanced fleet and protects against fuel price swings and capacity factor variances of different generation resources.

The 2019 IRP analysis considered planned and potential environmental regulations in the candidate portfolios, which includes costs to upgrade plants spurred by environmental regulations. Also, AES Indiana included three scenarios that include a future carbon tax. Please see Section 8.3 Scenarios and Metrics in the 2019 IRP (Volume 1) for further discussion of the scenarios and carbon tax modeling (AES Indiana Attachment EKM-1 at pp. 191-214).

Q25. Turning now to the proposed project in the filing, please briefly describe this project.

A25. As also discussed by AES Indiana Witness Cooper, the Petersburg Energy Center will be a 250 MWac, 335 MWdc, solar photovoltaic electric generation facility, coupled with a 180 MWh DC battery energy storage system (60 MW, 3-hour discharge power capacity – AES Indiana expects to operate it as a 45 MW, 4-hour capacity resource for MISO capacity) located in Pike County, IN and developed by an indirect subsidiary of NextEra Energy Resources, LLC, ("NextEra"). It will contribute 168 MW of UCAP to AES Indiana's remaining 155 MW UCAP need.

Q26. Please describe the cost AES Indiana used for solar and energy storage in the 2019 IRP.

A26. To model solar and energy storage resource costs, the 2019 IRP used a blend of National Renewable Energy Laboratory (NREL), IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance capital costs and O&M cost projections as outlined in Section 5.3.2 of the 2019 IRP. AES Indiana assumed that solar projects through 2023 would qualify for 100% of the Investment Tax Credit (ITC), reducing capital costs by 30% through 2023 before stepping down to 26% in 2024. In the IRP, AES Indiana used a sensitivity analysis to assess cost variances, such as interconnection costs and tax equity costs. This analysis is described in more detail in Q/A 28.

Q27. Is the addition of the Petersburg Energy Center consistent with the Preferred Resource Portfolio and the Short-Term Action Plan identified in the 2019 IRP?

A27. Yes. The addition of the Petersburg Energy Center is consistent with the 2019 IRP based on additional analysis that the Resource Planning team performed.

Q28. Please explain.

A28. In the 2019 IRP, AES Indiana conducted a capital cost sensitivity analysis[18] to assess whether portfolio 3b – (the Preferred Resource Portfolio that plans retirement of Petersburg Units 1 and 2 by 2023) would change if renewable energy and storage capital costs increase or decrease. These capital cost differences may arise through the RFP process or as the market for renewable energy changes. Table 2 below, columns a – e, provides the results from this IRP analysis. The table compares the total Company PVRR for each portfolio with the base case in column c and the sensitivities in columns a, b, d, and e at -30%, -15%, 15%, and 30%, respectively. The analysis demonstrates that, even if the capital costs for renewables and storage change by +/- 15% (columns b & d) and +/- 30% (columns a & e), portfolio 3b remains the Preferred Resource Portfolio with the lowest PVRR, holding all other cost assumptions constant.

AES Indiana updated this capital cost sensitivity analysis with the actual contracted project cost assumptions. This capital cost sensitivity analysis is a reasonable means to

[18] See p. 189 of Volume 1 of AES Indiana 2019 IRP for additional details regarding the capital cost sensitivity analysis performed in the 2019 IRP.

verify the Short Term Action Plan remains sound. As such, aside from the assumptions for the contracted project, the assumptions in the capital cost sensitivity analysis summarized herein are held constant to those included in the 2019 IRP.

In Cause No. 45493 concerning the Hardy Hills Project, AES Indiana presented a capital cost sensitivity analysis with the costs associated with Hardy Hills included. The results concluded that with the inclusion of the cost for Hardy Hills in the analysis, portfolio 3b remains the Preferred Resource Portfolio with the lowest PVRR.[19] The Commission ultimately approved the Hardy Hills project in Cause No. 45493.

The Resource Planning team has now added the cost of the Petersburg Energy Center to the capital cost sensitivity analysis performed in Cause No. 45493. As demonstrated in column f of Table 2, portfolio 3b – the Preferred Resource Portoflio – provides a PVRR that is approximately the same as portolios 3a and 2a.[20]

[19] See Q/A 26 – Q/A 32 in AES Indiana Witness Miller Direct Testimony in Cause No. 45493.

[20] Consistent with the treatment of RECs in AES Indiana's 2019 IRP, this analysis assumes that the RECs associated with these projects are not monetized. If the Company were to monetize these RECs it would have a downward impact on PVRR.

Table 2. IRP Capital Cost Sensitivity Analysis with Petersburg Energy Center ($MM)
IRP Reference Case assumes no carbon tax

	a	b	c	d	e	f
	Percent Change by 2030		PVRR w/ Base Capital Costs	Percent Change by 2030		**Blending Pete and Hardy Hills**
	-30%	-15%		+15%	+30%	
Portfolio 3b	$6,775	$6,874	$6,976	$7,077	$7,177	$7,167
Portfolio 3a	$6,841	$6,927	$7,016	$7,105	$7,191	$7,166
Portfolio 3c	$6,843	$6,938	$7,034	$7,131	$7,225	$7,196
Portfolio 2a	$6,965	$7,049	$7,132	$7,214	$7,298	$7,165
Portfolio 1b	$7,004	$7,091	$7,176	$7,261	$7,348	$7,218
Portfolio 2b	$7,010	$7,100	$7,188	$7,276	$7,366	$7,224
Portfolio 2c	$6,986	$7,089	$7,191	$7,292	$7,396	$7,233
Portfolio 1a	$7,043	$7,130	$7,215	$7,300	$7,387	$7,245
Portfolio 1c	$7,043	$7,134	$7,223	$7,312	$7,403	$7,263
Portfolio 4c	$6,978	$7,121	$7,267	$7,417	$7,560	$7,469
Portfolio 4b	$6,928	$7,107	$7,293	$7,478	$7,658	$7,510
Portfolio 4a	$6,912	$7,100	$7,295	$7,490	$7,678	$7,523
Portfolio 5b	$7,073	$7,234	$7,400	$7,565	$7,726	$7,619
Portfolio 5c	$7,001	$7,224	$7,449	$7,679	$7,902	$7,652
Portfolio 5a	$7,100	$7,309	$7,500	$7,741	$7,950	$7,705

Q29. Does this analysis support the ongoing implementation of the Preferred Resource Portfolio Short Term Action Plan?

A29. Yes. As stated above, column f of Table 2 shows portfolio 3b provides a PVRR that is approximately the same as portfolios 3a and 2a. While Table 2 also shows that the portfolio PVRR results are close for these three portfolios (3b, 3a, and 2a), the analysis is based on updating the Reference Case scenario in the 2019 IRP, which included no costs for future carbon reduction. As noted in Q/A 24, in the 2019 IRP, the growing importance of carbon reduction and associated cost was evaluated via separate carbon tax scenarios. Carbon reduction and the associated costs remain an important consideration. To assess the impacts from a carbon tax, we updated portfolio 3b, portfolio 3a and portfolio 2a in Scenario A from the IRP (which includes a carbon tax) to include the

Petersburg Energy Center and Hardy Hills costs.[21] With this update, the portfolio PVRR for portfolio 3b changes to $7,863, portfolio 3a changes to $7,896 and portfolio 2a changes to $7,971. Portfolio 3b is the lowest of the three.

Based on the results of the analyses, portfolio 3b remains a reasonable least cost resource plan portfolio and the Preferred Resource Portfolio that serves as a basis for the Short Term Action Plan.

Q30. How does the PVRR calculation that you discuss in Q/A 28 and 29 differ from the PVRR calculation that Concentric performed in the Ranking Analysis referenced in Q/A 19?

A30. In the analyses discussed in Q/A 28 and Q/A 29 above, AES Indiana estimated the total Company portfolio PVRR which is expressed in millions of dollars. Whereas, in the Ranking Analysis, Concentric calculated the approximate incremental impact to the total Company portfolio PVRR from implementing each individual proposal which is expressed in millions of dollars. It is important to distinguish that the Ranking Analysis does not put individual proposals into the total Company PVRR portfolio.

Q31. How does the addition of the Petersburg Energy Center change the total Company portfolio PVRR presented in Table 2 when compared to the Preferred Resource Portfolio 3b identified in the IRP?

A31. As presented in Table 2 (column f), there is a 2.7% increase in PVRR by adding the Petersburg Energy Center to the portfolio when compared to the portfolio 3b reference

[21] Please see p. 124 of AES Indiana's 2019 IRP Volume 1 for more information regarding the IRP Scenarios that were modeled.

case. With this increase, the portfolio falls within the sensitivity range modeled in the 2019 IRP and remains a reasonable least cost plan with the addition of the Petersburg Energy Center.

Q32. Are there other ways in which the Petersburg Energy Center is consistent with AES Indiana's 2019 IRP and Short Term Action Plan?

A32. Yes. Consistent with the IRP – through the RFP process, AES Indiana has identified solar as the primary technology to replace Petersburg Units 1 and 2.

Q33. Aside from ensuring the Petersburg Energy Center is a reasonable, least cost option that remains consistent with the 2019 IRP results, please describe other benefits that demonstrate this resource is reasonable.

A33. The Petersburg Energy Center provides AES Indiana's customers with clean and sustainable energy generated in Indiana. Further, the addition of solar energy to AES Indiana's portfolio enhances AES Indiana's resource diversity which currently has significant percentages of coal and gas capacity. Additionally, solar energy does not increase AES Indiana's fuel price risk. Complementing the solar, the project's energy storage component can be dispatched with flexibility and provide firm capacity benefits in all seasons. For further discussion, see AES Indiana Witness Lund Direct Testimony and 2019 IRP Executive Summary, at p. xx.

5. <u>LEVELIZED COST OF ENERGY ("LCOE")</u>

Q34. Are you able to compare the total cost of the Petersburg Energy Center to resource costs used in the 2019 IRP modeling?

A34. Yes. The cost of Petersburg Energy Center can be compared to the cost of the solar and energy storage inputs used in the 2019 IRP modeling through the levelized cost of energy ("LCOE") calculation. The LCOE calculation provides a total levelized cost for the resource over the project period on a per MWh basis. The 2019 IRP modeled solar and energy storage as independent resources. We combined these resource costs to calculate an IRP solar and energy storage LCOE to compare to the Petersburg Energy Center LCOE.[22] I provide a comparison with and without the interconnection costs and payments to the tax equity partner included for the Petersburg Energy Center because interconnection costs and payments to the tax equity partner were assessed via the IRP capital cost sensitivity analysis (described in Q/As 28 and 29) instead of as explicit cost assumptions. Excluding these costs from the Petersburg Energy Center LCOE provides an apples-to-apples comparison to the IRP solar and energy storage LCOE.

Q35. Please explain the source methodology for LCOE calculation and inputs.

A35. AES Indiana used NREL's methodology, included in <u>AES Indiana Witness EKM Confidential Workpaper-10</u>, to make the LCOE calculation for the Petersburg Energy Center and the solar and storage cost in the 2019 IRP. NREL's LCOE methodology is commonly used in the industry and thus provides a reasonable approach for cost comparison. The NREL calculation includes the following inputs: the capital cost of the project in dollars per installed kW (ICAP) adjusted for the tax equity contribution, AES Indiana's weighted average cost of capital ("WACC") as of December 31, 2019, the expected fixed operation and maintenance costs over the project horizon, the property

[22] See AES Indiana Workpaper EKM-10 for this calculation.

taxes over the project horizon and the expected generation output (levelized capacity factor) with expected degradation over the project horizon.

Q36. How does the Petersburg Energy Center LCOE compare to the IRP solar with storage resource LCOE assumption in 2023?

A36. As explained above, for an apple-to-apples comparison of the IRP solar and energy storage LCOE assumption, the LCOE for the Petersburg Energy Center should exclude the transmission interconnection costs and payments to the tax equity partner. Excluding these items from the Petersburg Energy Center costs, the LCOE for the Petersburg Energy Center is [redacted] This is [redacted] than the LCOE calculated in the IRP of $46.43/MWh for solar and energy storage resource using the NREL methodology included in AES Indiana Witness EKM Confidential Workpaper-10. When transmission interconnection costs and payments to the tax equity partner are included for the Petersburg Energy Center, the LCOE is [redacted] or [redacted] compared to the IRP solar and energy storage LCOE assumption (which does *not* include transmission interconnection costs and payments to the tax equity partner).[23]

Q37. How does the Petersburg Energy Center compare to other solar plus energy storage projects in the State of Indiana?

A37. The Petersburg Energy Center LCOE is within the range of the LCOEs calculated for other solar plus energy storage project in Indiana. For example, in Northern Indiana Public Service Company ("NIPSCO") Witness Patrick Augustine's Direct Testimony at

[23] The LCOE calculations were made using the real AES Indiana 2019 WACC as a discount rate and are therefore expressed in real 2019 dollars.

p. 28 in NIPSCO 45462, Witness Augustine provided the weighted average 30-year LCOE of $56.28/MWh for NIPSCO's Bridge I solar project, Bridge II solar plus energy storage project and Calvary solar plus energy storage project. At [redacted], the Petersburg Energy Center is very close to the weighted average of NIPSCO's projects. Importantly, NIPSCO's weighted average calculation contains a solar only project that likely brings their weighted average LCOE calculation down.

Q38. Does the solar and energy storage LCOE calculation capture the full value of the energy storage component?

A38. No. The LCOE calculation computes the levelized cost of <u>energy</u> – since energy storage does not produce energy (rather it has to be charged with energy and then discharged onto the system), only the costs for the energy storage component are included in the LCOE calculation and none of the benefits. More specifically, the LCOE calculation does not capture the capacity value benefit of the energy storage component. Thus, it would be inappropriate to compare the LCOE for a solar and energy storage project to the LCOE of a solar only project. The solar and energy storage project will most likely have higher LCOE due to the cost of the energy storage component.

Q39. How can one appropriately compare a solar and energy storage project to other solar only projects or to projects that utilize other resources, e.g., natural gas?

A39. In order to make this comparison, one must use a metric that captures the full value of the energy storage component of a solar and energy storage project. AES Indiana accomplished this in the Ranking Analysis performed by Concentric which uses a present value of revenue requirements (PVRR) calculation to rank proposals.[24] This calculation captures the full costs and benefits associated with each proposal including the capacity benefit of energy storage that is associated with solar and energy storage projects.

Q40. You state that transmission interconnection costs and payments to the tax equity partner are not explicitly included in the solar with storage resource cost modeled in the IRP. Does that mean these costs were ignored in the IRP?

A40. No. As discussed in Q/A 26 and the first paragraph of Q/A 28, these cost variances are analyzed in the capital cost sensitivity in the IRP (Table 2 above, columns a-e). This analysis was conducted to confirm that portfolio 3b remains the Preferred Resource Portfolio with higher (or lower) costs that may result through the RFP process or due to changes in the market for renewables. Transmission interconnection costs and payments to the tax equity partner are examples of such costs.

Also as discussed in Q/A 28, AES Indiana updated this capital cost sensitivity analysis in our assessment of the Petersburg Energy Center Project. The transmission interconnection costs and payments to the tax equity partner are included in the costs for the Petersburg Energy Center used to calculate the PVRR results presented in column f of Table 2. As the analysis demonstrates, the PVRR remains reasonable across portfolios with the Petersburg Energy Center (transmission interconnection costs and payments to the tax equity partner included) as a replacement resource for the Petersburg retirements. Portfolio 3b continues to be the Preferred Resource Portfolio.

[24] See AES Indiana Witness Powers Direct Testimony for more information on the Ranking Analysis and project PVRR calculations.

6. CONSIDERATION OF RESOURCE ALTERNATIVES

Q41. Ind. Code § 8-1-8.5-4 provides that in acting upon a petition under this statute, the Commission shall take into account the utility's other resource options. Did AES Indiana consider other resource options?

A41. Yes, that is the purpose of the IRP. I elaborate on this in the following Q/As.

Q42. Did the Company consider retrofitting or refueling rather than retiring the Petersburg Units?

A42. Yes. Due to the age of Petersburg Units 1 and 2, refueling to gas fired generation would be a costly endeavor and therefore not a viable option. A conversion would not provide a significant benefit to these older coal plants' economics, which would lead to lower capacity factors.

As noted on p. 123 of the 2019 IRP (Volume 1):

> Unit Age: Petersburg Units 1 and 2 are 52 and 49 years old, respectively, and have age-based retirement dates of 2033 and 2035. Costly unit overhauls and maintenance are required on the units to maintain performance and safety targets, so IPL wanted to evaluate the economics of the ongoing, all-in costs and net benefits of operating those units through the early 2030s compared to alternatives.

While Petersburg Units 1 and 2 have previously been retrofitted to meet all current environmental regulations, environmental regulations continue to evolve.[25] Retrofits to comply with future environmental regulations would make the units more costly to operate and would make the retirement decisions even more favorable. Also, efficiency

[25] See Section 6.2 of the 2019 AES Indiana IRP Volume 1 for additional information on existing retrofits. (AES Indiana Attachment EKM-1 at pp. 106-116).

improvement retrofit projects are analyzed as part of routine plant management, and no specific projects were identified for analysis as part of the 2019 IRP.

Q43. Was the purchase of power through the spot energy market considered as an alternative to the proposed replacement generation projects?

A43. Yes. However, relying on the market for spot energy purchases would expose customers to price volatility without the natural hedge of generation. Consequently, relying on the market is not an appropriate long-term solution.

Q44. Please comment on the "interchange of power" or "pooling of facilities" as these phrases are used in Ind. Code § 8-1-8.5-4.

A44. These statutory references predate the development of MISO and AES Indiana's membership in MISO. The current MISO market is very effective at fully utilizing the existing capacity resources in the region. However, it does not eliminate the need for new capacity resources to address potential load growth and the retirements of older, less efficient coal fired units in the region.

Q45. Were wind and other solar resources considered as an alternative?

A45. Yes. In 2019 IRP, AES Indiana considered other renewable resource options, like wind as alternatives to solar generation and battery energy storage.[26] The Preferred Resource Portfolio identified a mix of these resources with solar being the dominant technology to

[26] See Section 5: Resource Options of the AES Indiana's 2019 IRP (Volume 1). (AES Indiana Attachment EKM-1 at pp. 83-104).

replace Petersburg Units 1 and 2.[27] The RFP and RFP evaluation further explored these options as explained by AES Indiana Witness Cooper.

Q46. Is AES Indiana's target of DSM savings in 2021-2023 consistent with the 2019 IRP?

A46. Yes. In the 2019 IRP, AES Indiana included demand response and energy efficiency as viable generation alternatives. These resources were evaluated on a consistent and comparable basis with supply-side resource per the IURC rule 170 IAC 4-7-8(c)(4). Through this process, the Short Term Action Plan identified approximately 130,000 net MWh of DSM per year as a target in 2021 – 2023.

Consistent with the IRP Short Term Action Plan, AES Indiana received IURC approval on December 29, 2020 in Cause No. 45370 to target approximately 130,000 net MWh of DSM per year in 2021 - 2023, with an opportunity to pursue an additional 50,000 MWh over the three-year DSM Plan. While this DSM Plan period captures three years of the 2019 IRP study period, the Company plans to continue to request Commission approval of DSM Plans pursuant to Ind. Code § 8-1-8.5-10.

Q47. Can DSM eliminate the need for the proposed replacement generation?

A47. No. AES Indiana included eight energy efficiency ("EE") and two demand response ("DR") bundles as a selectable resource in the 2019 IRP. The IRP Preferred Resource Portfolio and Short-Term Action Plan identified the first four of the eight EE bundles as a cost effective alternative to replacement generation; no DR bundles were selected. This level of energy efficiency will cost effectively reduce load to reach the currently expected

[27] See Figure 8.7 – Portfolio 3 Installed Capacity Additions (MW) on p. 161 of AES Indiana's 2019 IRP (Volume 1).

capacity need of approximately 250 MW in 2023. Even if AES Indiana were to implement the full volume of EE and DR available for selection in the IRP or all 10 EE and DR bundles, the Company would not be able to eliminate the 250 MW capacity need. Importantly, the full volume of EE and DR was not selected by the 2019 IRP (as previously noted, only the first four bundles are identified in the Preferred Resource Portfolio as cost effective) and would therefore not be a cost effective alternative to replacement generation.

7. CONSIDERATION OF THE STATE UTILITY FORECASTING GROUP (SUFG) INDIANA ELECTRICITY PROJECTIONS, THE INDIANA 21ST CENTURY TASK FORCE REPORT AND MISO'S RIIA REPORT

Q48. Has AES Indiana considered the State Utility Forecasting Group ("SUFG") Electricity Projections?

A48. Yes, AES Indiana reviewed the SUFG's most recent Indiana Electricity Projections report from 2019. In the report, the SUFG projected that the State of Indiana would need additional resources in 2024 due to little peak demand growth and the retirements of existing capacity. The retirement of Petersburg Units 1 and 2 and addition of Petersburg Energy Center to fill the resource need is consistent with the timing of their projection.[28] This analysis was updated for the Task Force Report discussed below.

Q49. Has AES Indiana considered the findings of the Indiana 21st Century Task Force Report and the IURC/SUFG 2020 Study Report?

[28] "Indiana Electricity Projections: The 2019 Forecast," State Utility Forecasting Group, November 2019 at ch. 1, p. 5.

A49. Yes. The final 21st Century Task Force Report defines the "Five Pillars" of Utility Electric Service and State Energy Policy as reliability, resilience, stability, affordability, and environmental sustainability. As discussed in the report – these pillars serve as a lens through which the Task Force views all potential policy options, as well as the framework for the Task Force findings and recommendations to the State Legislature. AES Indiana understands the importance of each pillar and considered all five in the development of the Company's IRP, in general planning, and in the selection of the reasonable, least cost resource included in this filing.

1. Reliability – AES Indiana addresses reliability by ensuring the Company's capacity requirement is met with firm UCAP.
2. Resilience & Stability – AES Indiana worked with Burns and McDonnell – 1898 to complete an interconnection analysis of the project in this filing. The results of the analysis informed the interconnection costs required to interconnect Petersburg Energy Center to the grid and established that this new project will not adversely affect the resilience and stability of the system. Additionally, this project will take advantage of AES Indiana's existing Petersburg 345 kv interconnection. Please see AES Indiana Witness Lind's testimony for 1898's discussion of the interconnection analysis performed for this filing and AES Indiana Witness Cooper's testimony for a discussion of the project's use of AES Indiana's existing Petersburg connection.
3. Affordability – The Company selects its Preferred Resource Portfolio in the IRP and the resource identified in this plan by targeting a low PVRR. Using this approach helps to achieve affordability to customers.

4. Environmental Sustainability –AES Indiana's Preferred Resource Portfolio provides a more environmentally sustainable and diverse generation mix for customers. This porfolio recognizes the evolving role of renewable generation and customers increasing demand for cleaner sources of energy.

AES Indiana also reviewed the SUFG's "Scenario Analysis for IURC Report to the 21st Century Task Force" report that was performed for the IURC's report to the Task Force. As noted by the IURC on p. 27 in the "2020 Report to the 21st Century Energy Policy Development Task Force" regarding the SUFG's scenario analysis – "The results of various scenarios and sensitivities for the 20-year forecast period 2018 – 2037 are meant to be informational rather than actionable. Further, the scenarios modeled are not intended to represent specific realistic futures, but instead to move the needle sufficiently to see the impact of different factors." The SUFG analysis fostered some key findings by the IURC as noted in the "2020 Report to the 21st Century Energy Policy Development Task Force" at p. 41. Two of which include: 1) "SUFG's analysis highlights the critical impact that some variables, such as natural gas prices, renewables costs, and carbon prices, can have on the timing and type of resource commitment actions"; and 2) "The inability to predict with any precision how these key variables will change over time underscores that maintaining optionality is critical."[29,30]

Consistent with the IURC's findings noted above, AES Indiana has considered flexibility and optionality in its IRP planning. As stated above (Q/A 22), the approach to coal unit

[29] See "Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force," State Utility Forecasting Group, May 2020.
[30] "2020 Report to the 21st Century Energy Policy Development Task Force," Indiana Utility Regulatory Commission, August 14, 2020.

retirements in the 2019 IRP Preferred Resource Portfolio Short Term Action Plan reflects the economic conditions underlying the 2019 IRP. Because the 2019 IRP Preferred Resource Portfolio focuses on a 2023 UCAP need of approximately 250 MW, this approach provides AES Indiana options and flexibility going forward with respect to resource needs beyond this timeframe. This in turn provides the Company with flexibility to change course as appropriate as key variables – like fuel prices, resource costs, carbon regulation and consumer needs – change over time.

Q50. Are you familiar with MISO's Resource Integration Impact Assessment (RIIA) study? If so, can you briefly describe this study?

A50. Yes. MISO conducted a study to assess the challenges of integrating increasing levels of renewable energy resources within the MISO footprint. The study summarizes that certain actions will need to be taken to mitigate risks to the system with renewable energy penetration below 30%, above 30% and above 50%.[31]

Q51. Going forward does AES Indiana plan to consider the conclusions of MISO's RIIA Study and associated developments?

A51. Yes. Based on the conclusions of MISO's RIIA Study, AES Indiana thinks that the penetration of renewable energy within MISO is something to monitor and to take into consideration in long-term planning as well as the ongoing work to fill the Company's remaining capacity need resulting from the retirement of Petersburg Units 1 and 2. While important to monitor, the current level of renewable penetration within MISO remains

[31] See MISO's RIIA Report for more information regarding the study: https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#t=10&p=0&s=&sd=

low and does not affect the reasonableness of the proposal in this proceeding. AES Indiana will work with stakeholders during the 2022 IRP to ensure that the underlying planning assumptions account for the implications of shifting to more renewable energy within MISO.

8. CONCLUSION

Q52. Please summarize your recommendation.

A52. In sum, AES Indiana's decision to proceed with procuring 168 MW UCAP of solar plus storage through the Petersburg Energy Center is a reasonable, least cost option to meet the Company's need for additional capacity. The project will enable AES Indiana to make progress towards meeting resource adequacy requirements while providing optionality and a transition to a greener energy future. Therefore, I recommend Commission approval of the Petersburg Energy Center as proposed by AES Indiana.

Q53. Does this conclude your verified prepared direct testimony?

A53. Yes.

VERIFICATION

I, Erik K. Miller, AES Indiana Manager, Resource Planning, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Dated July 30, 2021

Erik K. Miller

AES Indiana Attachment EKM-1
(2019 IPL IRP Public Volume 1)

[BOUND SEPARATELY - NOT REPRODUCED HEREIN]

AES Indiana Attachment EKM-2
(2019 IPL IRP Public Volume 2)

[BOUND SEPARATELY - NOT REPRODUCED HEREIN]

AES Indiana Attachment EKM-3
(2019 IPL IRP Public Volume 3)

[BOUND SEPARATELY - NOT REPRODUCED HEREIN]

AES Indiana Confidential Attachment EKM-4
(Confidential Volume of IPL's 2019 IRP)

[CONFIDENTIAL – NOT REPRODUCED HEREIN]

AES Indiana Attachment EKM-5
(2019 IPL IRP Public Attachments)

[FILED SEPARATELY - NOT REPRODUCED HEREIN]

Cause No. 38703 FAC133

Technical Conference

October 21, 2021

aes Indiana

AES Indiana Team

Presenters

Kristina Lund

President, US Utilities

John Bigalbal

Chief Operating Officer,
US Conventional Generation

David Jackson

Director, Commercial Operations

Other Team Members Present

Generation
- John Arose – Generation Complex Leader
- Kevin Cook – Plant Manager, Eagle Valley

Commercial Operations
- Aaron Cooper – Chief Commercial Officer

RCA Facilitator
- H. Holcombe Baird, III, Reliability Center, Inc. – Senior Reliability Consultant

Legal & Regulatory
- Judi Sobecki – General Counsel
- Nick Grimmer – Indiana Regulatory Counsel
- Kim Aliff – Senior Regulatory Analyst
- Teresa Morton Nyhart, Barnes & Thornburg LLP – Counsel

Regulatory Accounting
- Natalie Coklow – Manager, Regulatory Accounting

Agenda

- → Eagle Valley Overview
- → Outage Management and Status
- → Summary of Incident
- → Root Cause Analysis
- → Action Plan & Recommendations
- → Peak Power Hedges
- → FAC Impacts
- → Discussion & Questions

Eagle Valley Overview

Eagle Valley CCGT

→ 671 MW Combined Cycle Gas Turbine

→ Commenced Commercial Operations on April 28, 2018

→ Portfolio benefits

- Fast response and flexibility
- High efficiency
- Fuel source and technology diversification
- Lower carbon emissions

→ Solid performance as Baseload Unit

- Top decile and top quartile annual Equivalent Availability Factors in 2019 and 2020, respectively
- Heat rate is top decile
- Eagle Valley CCGT operates as a baseload plant with high capacity factors

Outage Management and Status

→ Outage Period

- Began April 25, 2021
  - Incident occurred due to failure of unit to synchronize to grid after planned maintenance
  - A rewind of the field and repairs to the rotor are required to restart operations
- Eagle Valley is expected to return to service the second week of November 2021

→ Management Approach

- Objective: Mitigate the cost impact to customers
- Expedite Eagle Valley's return to service
- Identify root cause and take corrective actions for the future
- AES Indiana implemented first power hedging program to reduce price risk to our customers during the outage period

→ FAC Reconciliation Impact

- In total, the hedge reduced fuel and purchased power costs by $1.6M
- Purchased power costs above the benchmark attributable to the Eagle Valley Outage net of the hedge are $247K

Summary of Incident

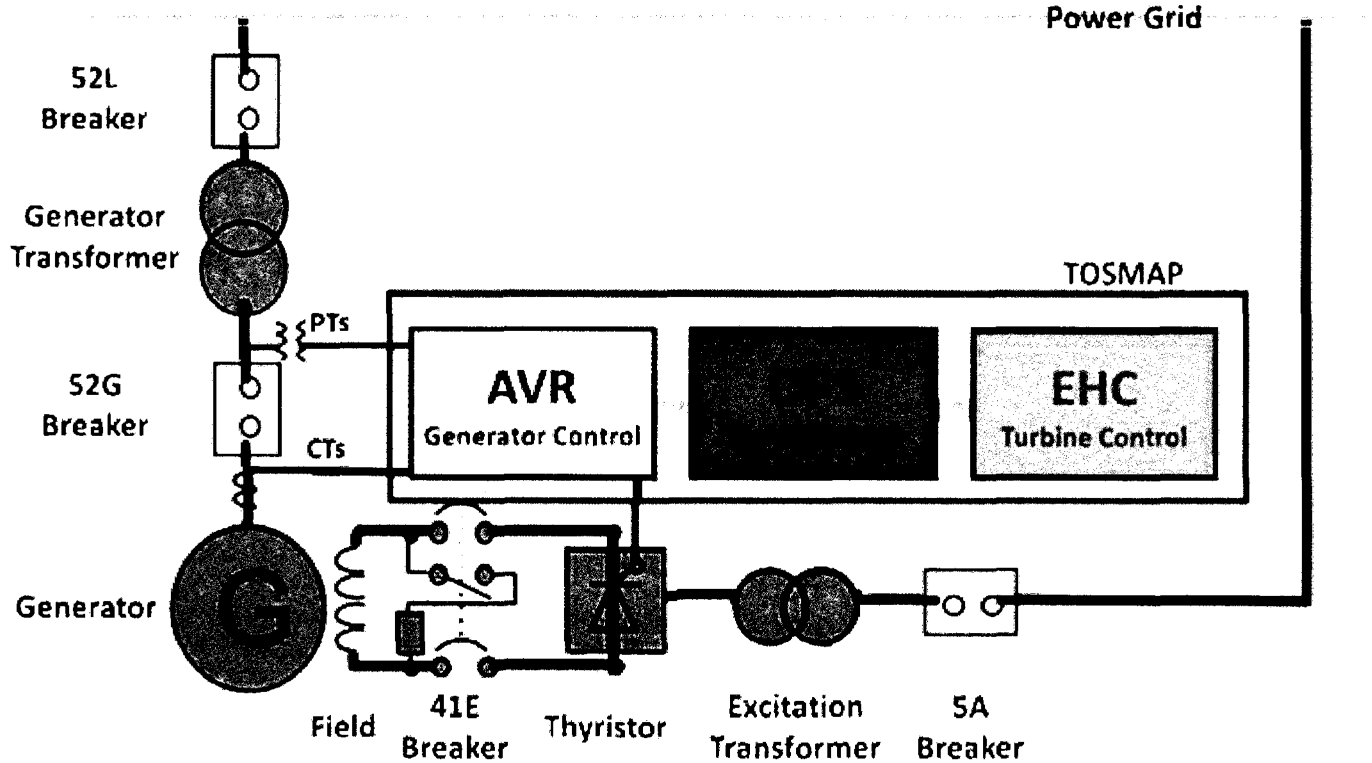


Figure 1. Simplistic diagram of generator protection and control components

Summary of Incident

- → Eagle Valley completed a planned maintenance outage
- → During restart, the unit was not able to synchronize with the grid due to an issue with the generator breaker (52G)
  - Status mismatch - the generator breaker (52G) was showing closed on one indication and open on another
- → Hours of troubleshooting, with support from Toshiba, led to discovery of a disconnected wire in the generator breaker cabinet
  - Reconnecting the wire based on schematics did not resolve the breaker issue
- → As work proceeded into late night hours, shutdown of the plant was initiated with a plan to resume troubleshooting the next day
- → The generator lockout protective relays (86G) were reset while the field breaker (41E) was closed
- → The next morning, the connection of a jumper wire in the field breaker (41E) cabinet opened the field breaker and resolved the generator breaker (52G) issue
- → A short to ground in the field was identified and an RCA commenced immediately

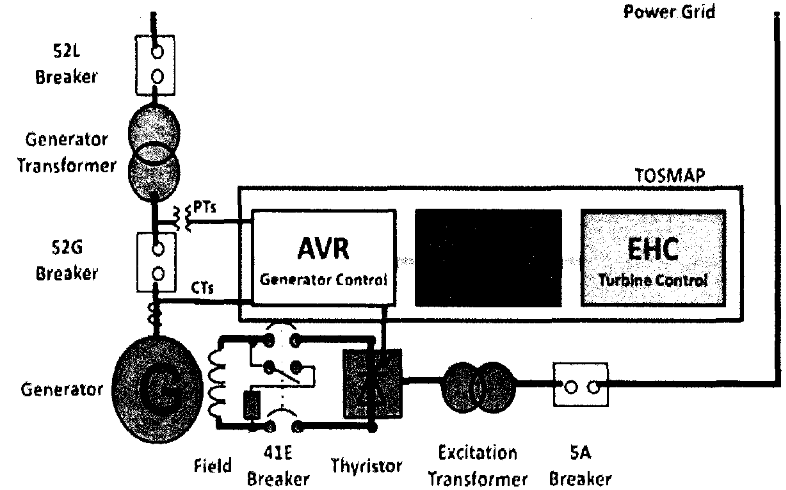


Figure 1, Simplistic diagram of generator protection and control components

Root Cause Analysis (RCA)

- → RCA is a systematic process to identify all aspects of a system failure or identified problem, documenting what happened, how it happened and most importantly why it happened, so that actions can be developed for preventing reoccurrences

- → The purpose of an RCA is to determine the most probable cause of an event and factors, that if eliminated, would have the highest probability of preventing a reoccurrence

- → While an important tool, an RCA reviews an event after the fact and outside the plant environment – it is a hindsight analysis

- → The RCA process allows us to learn through hindsight analysis how to improve our business on a going forward basis so we can better serve our customers

Root Cause Analysis (RCA)

→ Immediately following incident, AES Indiana mobilized an RCA team

→ Team facilitated by third party – Holcombe Baird – Senior Reliability Consultant, Reliability Center, Inc.

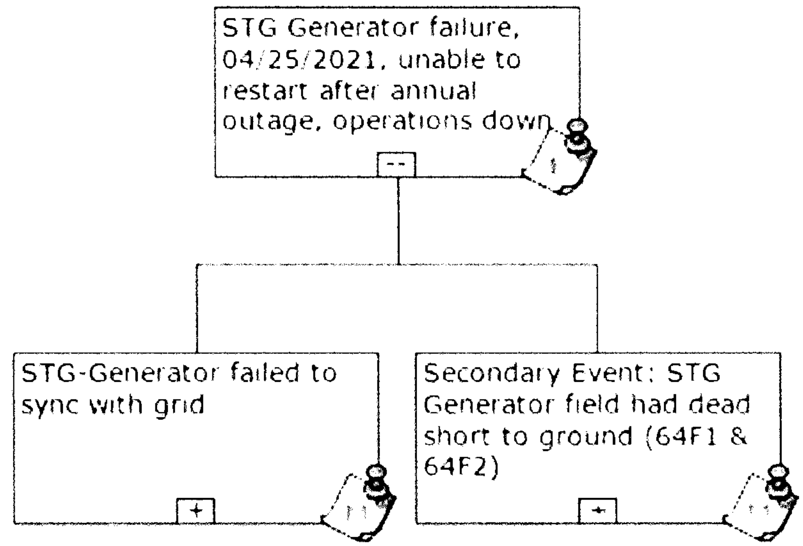
→ RCA is completed and a copy has been provided in this Cause

→ RCA recommended action plan currently being implemented or completed

Root Cause Analysis (RCA)

→ Analysis broken down into two separate investigative efforts

1. Why the Steam Turbine Generator (STG) unit failed to synchronize to the power grid
2. What caused the field short to ground



→ The RCA involved:

- Review of drawings to determine how the STG protection and controls system functioned during the start-up
- Review of historical data trends
- Interviews with the people that were involved in the event

Root Cause Analysis (RCA) Findings

1 Why the Steam Turbine Generator Failed to Synchronize to the Grid

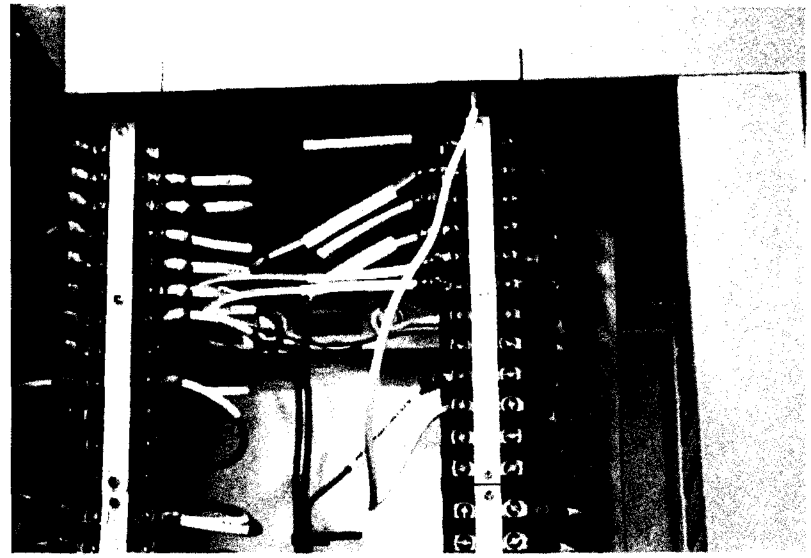
→ The steam turbine generator could not synchronize because the generator breaker (52G) was falsely indicating closed, but the breaker was actually open

→ The control system thought the generator was online

→ The generator breaker (52G) false indication was caused by a disconnected wire

- Breaker cabinet is 30 feet off the ground, accessible via a ladder

→ It is undetermined how the wire became disconnected, but the wire was never properly terminated



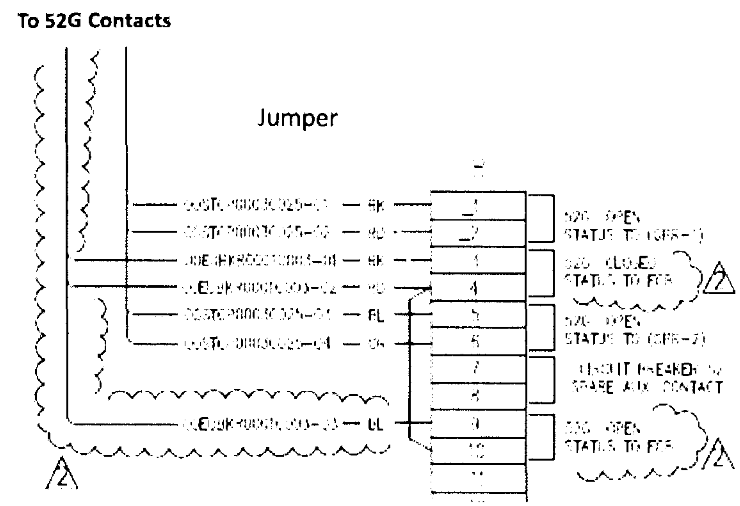
Disconnected yellow wire in STG 52G Breaker Cabinet
(with loose end lifted out of the way)

aes Indiana

Root Cause Analysis (RCA) Findings

1 Why the Steam Turbine Generator Failed to Synchronize to the Grid (continued)

- → Troubleshooting was on the correct path to resolve the synchronization issue
- → Incorrect as-built drawings led efforts elsewhere rather than confirming the problem
- → RCA confirmed through re-enactment that the disconnected wire caused the synchronization issue and the status mismatch
  - Historical trend data showed the 41E Breaker and 52G Breaker functioned normally prior to the maintenance outage. Therefore, it is reasonable to conclude that the wire was connected when the STG was shut down on April10th.



Wiring connection diagram in 52G Breaker Cabinet.

Root Cause Analysis (RCA) Findings

2 What Caused the Field Short to Ground

→ The field breaker (41E) should open to protect the generator due to any of 3 conditions:

- #1 TOSMAP signal
- #2 Turbine trip
- #3 86G protective relays

→ Due to the disconnected wire, the field breaker (41E) did not open to protect the generator because:

- #1 TOSMAP did not open the 41E breaker because it thought the generator was online
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→ The 86G protective relays did shutdown the AVR and stop the current to the field

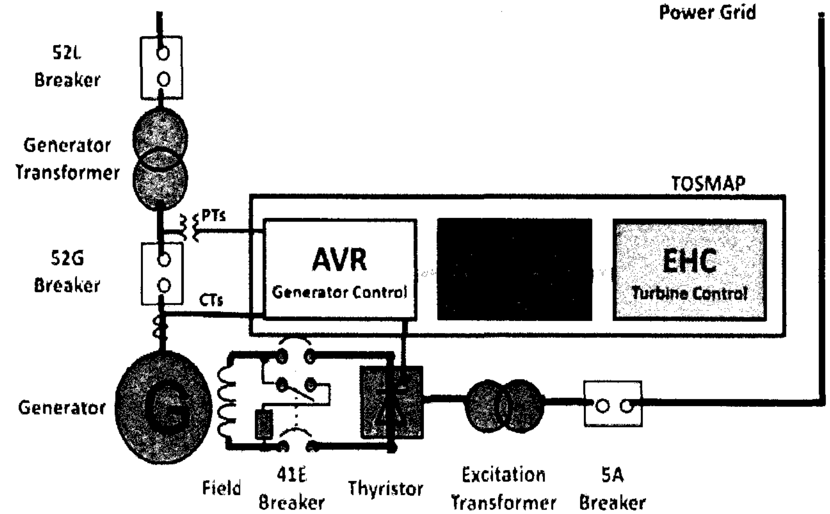

Figure 1. Simplistic diagram of generator protection and control components

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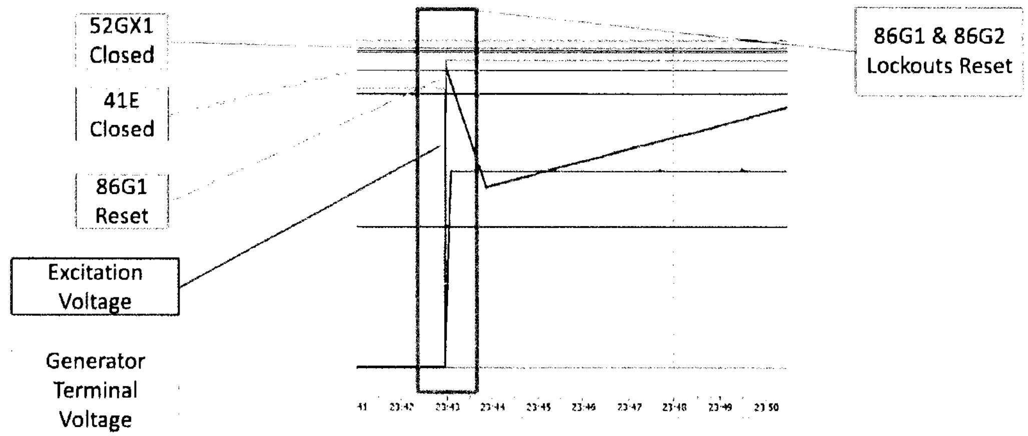
Root Cause Analysis (RCA) Findings

2 What Caused the Field Short to Ground (continued)

- → The generator protective relay (86G) lockouts were manually reset after the shutdown, and the AVR went back into service and sent current to the field
- → The steam turbine was on turning gear which was too slow to provide effective cooling of the field
- → Overheating of the field broke down the insulation causing the short to ground



Trend data when 86G1 and 86G2 Lockout Relays were reset.

Root Cause Analysis (RCA) Action Plan

AES Indiana is proactively implementing the RCA recommendations

Action	Status
Re-terminate the disconnected wire in using OEM standards	Complete
Clean up wiring in the 41E Breaker cabinet	Completed; final inspection is underway
Establish 86 series lockout relay reset Standard Operating Procedure	Complete
Establish operational pre-startup step to confirm agreement in status indicators for the 52G and 41E breakers	Will be completed this week

Recommendations

Recommendation	Status
Conduct an engineering review of the 41E Breaker open signal circuit hardwired interlocks and control system interlocks for effective redundancy as well as compliance with IEEE and EPRI standards	*Third party review has been solicited and work has begun*
OEM review of the incident details to consider installing provisions in the AVR (Automatic Voltage Regulator) logic to detect and alert operators of a discrepancy in the generator (52G Breaker) and field (41E Breaker) breaker status	*Toshiba is reviewing, and AES Indiana is awaiting a response*
Perform an audit of all wiring diagrams for accuracy of generator protection systems and document the findings and develop a plan to correct discrepancies	*Inspection and a redline markup of the drawings is complete CAD drawing update is underway*
Implement a training program for operators and technicians specifically on the design and operation of the generator protection system, including processes for operating breakers and resetting lockout relays	*Completed*

Peak Power Hedges

- AES Indiana transacted power hedges to safeguard customer price risk over summer months
- Hedges were modeled to determine appropriate hedge size to reduce net market exposure during June (345 MW), July, and August (365 MW each month)
- Additional hedges for September and October were transacted using the same methodology once more information about the outage duration became available
- The June and July peak power hedges realized a gain of $1,590,975 during the historical FAC period, which reduced overall fuel costs
- Actual fuel costs (natural gas and purchased power) were higher than forecast during the historical FAC period and resulted in cost increases outside of the Eagle Valley outage

FAC Impacts

→ Purchased power costs above the benchmark attributable to the Eagle Valley Outage net of the hedge are $247k

→ In total, the hedge reduced fuel costs by $1.6M (see slide 19)

		Actual		Offset by Hedge	Purchased Power Over the Benchmark Net of Hedge
Total MWh Purchased Over the Benchmark		76,140		21,206	
Total Purchased Power Over the Benchmark	$	1,198,183	$	861,342	
Purchased Power Attributable to EV (up to 650MW per hour)	$	1,108,511	$	861,342	$ 247,169

FAC Factor Breakdown

	per MWh		
	FAC 132	FAC 133	Difference
Forecast	$31.86	$34.58	$2.73
Earnings Test	($1.10)	$0.00	$1.10
Current variance 50%	$2.15	$1.86	($0.29)
FAC 132 carryover	$0.00	$1.77	$1.77
	$32.90	$38.21	$5.30
Base cost of fuel	$32.94	$32.94	$0.00
FAC Factor before URT	($0.04)	$5.27	$5.30
FAC Factor grossed up for URT	($0.04)	$5.35	$5.39

Discussion & Questions

Appendix

→ **AVR**: is the abbreviation for Automatic Voltage Regulator which controls the voltage of the generator to match the requirement of the power grid.

→ **Breaker**: Often referred to as a circuit breaker, is an automatic device for stopping the flow of current in an electric circuit as a safety measure to protect an electrical device.

- 41E Breaker: also called the FCB, Field Circuit Breaker, is a device that functions to apply or interrupt the field excitation to the generator.
- 52G Breaker: also called the GCB, Generator Circuit breaker, is device that is used to close and interrupt an a-c power circuit between the power gid and the generator under normal conditions or to interrupt this circuit under fault or emergency conditions.

→ **EHC**: Electro-Hydraulic Controller provides the operational control of the steam turbine, including start-up, shutdown, speed regulation and power generation.

→ **Excitation Transformer**: used to ultimately provide power to the field windings.

→ **86G1 and 86G2 Lockouts**: are 86 Series Lockout Relays which function to shut down and hold the STG equipment out of service upon the occurrence of abnormal generator conditions.

→ **OPS**: Operation System which provides the human machine interface for the operators, including the display consoles and data trending functions.

→ **Relay**: an electrical device, typically incorporating an electromagnet, which is activated by a current or signal in one circuit to open or close another circuit.

- 64F1 and 64F2 Relays: or the Ground Protective Relays, are relays which actuate on failure of the insulation of the generator field, allowing current to short circuit to ground.

→ **Synchronize**: the process of connecting the generator to the power grid. The process requires the parameters of the power produced by the generator match the parameters of the power grid, including voltage, frequency, phase sequence and phase angle.

→ **Thyristor**: a solid-state semiconductor device.

Cause No. 38703 FAC133
Technical Conference

October 21, 2021

aes Indiana

AES Indiana Team

Presenters

Kristina Lund

President, US Utilities

John Bigalbal

Chief Operating Officer,
US Conventional Generation

David Jackson

Director, Commercial Operations

Other Team Members Present

Generation
- John Arose – Generation Complex Leader
- Kevin Cook – Plant Manager, Eagle Valley

Commercial Operations
- Aaron Cooper – Chief Commercial Officer

RCA Facilitator
- H. Holcombe Baird, III, Reliability Center, Inc. – Senior Reliability Consultant

Legal & Regulatory
- Judi Sobecki – General Counsel
- Nick Grimmer – Indiana Regulatory Counsel
- Kim Aliff – Senior Regulatory Analyst
- Teresa Morton Nyhart, Barnes & Thornburg LLP – Counsel

Regulatory Accounting
- Natalie Coklow – Manager, Regulatory Accounting

Agenda

- → Eagle Valley Overview
- → Outage Management and Status
- → Summary of Incident
- → Root Cause Analysis
- → Action Plan & Recommendations
- → Peak Power Hedges
- → FAC Impacts
- → Discussion & Questions

Eagle Valley Overview

Eagle Valley CCGT

→ 671 MW Combined Cycle Gas Turbine

→ Commenced Commercial Operations on April 28, 2018

→ Portfolio benefits
- Fast response and flexibility
- High efficiency
- Fuel source and technology diversification
- Lower carbon emissions

→ Solid performance as Baseload Unit
- Top decile and top quartile annual Equivalent Availability Factors in 2019 and 2020, respectively
- Heat rate is top decile
- Eagle Valley CCGT operates as a baseload plant with high capacity factors

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Outage Management and Status

→ Outage Period

- Began April 25, 2021
  - Incident occurred due to failure of unit to synchronize to grid after planned maintenance
  - A rewind of the field and repairs to the rotor are required to restart operations
- Eagle Valley is expected to return to service the second week of November 2021

→ Management Approach

- Objective: Mitigate the cost impact to customers
- Expedite Eagle Valley's return to service
- Identify root cause and take corrective actions for the future
- AES Indiana implemented first power hedging program to reduce price risk to our customers during the outage period

→ FAC Reconciliation Impact

- In total, the hedge reduced fuel and purchased power costs by $1.6M
- Purchased power costs above the benchmark attributable to the Eagle Valley Outage net of the hedge are $247K

Summary of Incident

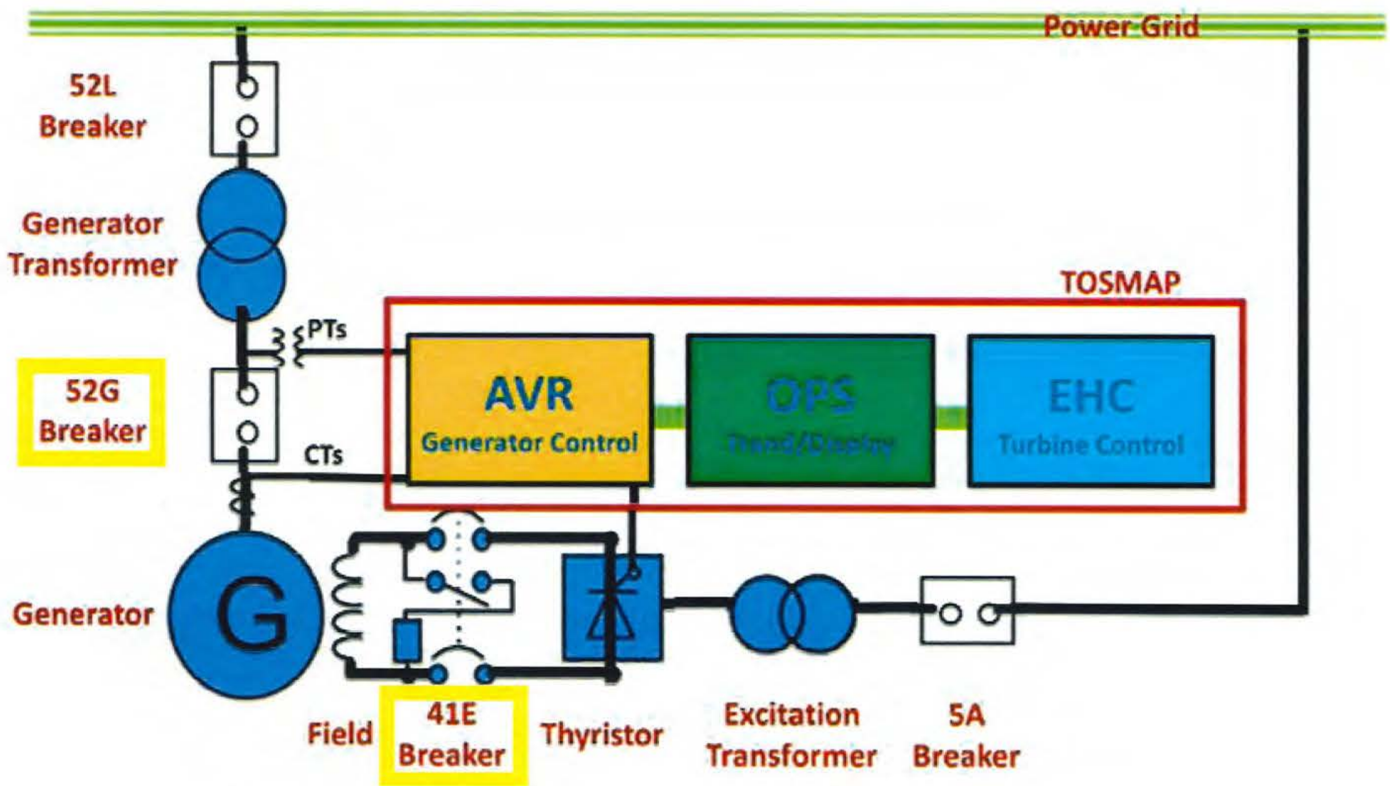


Figure 1, Simplistic diagram of generator protection and control components

Summary of Incident

→ Eagle Valley completed a planned maintenance outage

→ During restart, the unit was not able to synchronize with the grid due to an issue with the generator breaker (52G)

- Status mismatch - the generator breaker (52G) was showing closed on one indication and open on another

→ Hours of troubleshooting, with support from Toshiba, led to discovery of a disconnected wire in the generator breaker cabinet

- Reconnecting the wire based on schematics did not resolve the breaker issue

→ As work proceeded into late night hours, shutdown of the plant was initiated with a plan to resume troubleshooting the next day

→ The generator lockout protective relays (86G) were reset while the field breaker (41E) was closed

→ The next morning, the connection of a jumper wire in the field breaker (41E) cabinet opened the field breaker and resolved the generator breaker (52G) issue

→ A short to ground in the field was identified and an RCA commenced immediately

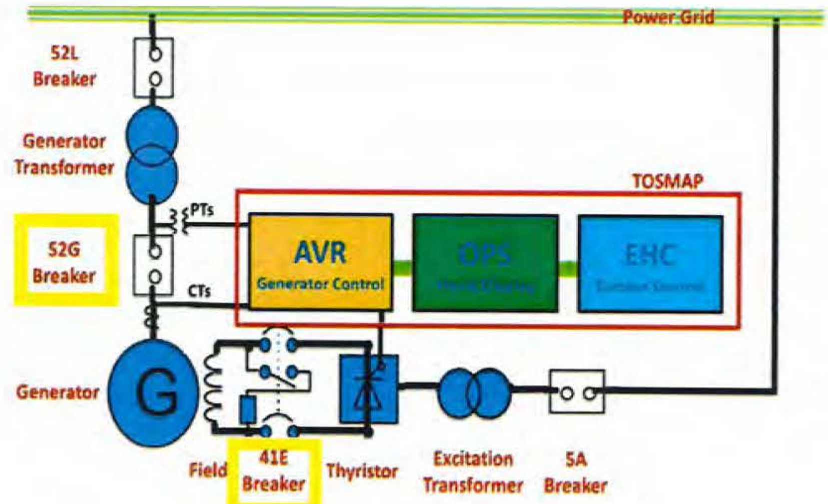


Figure 1. Simplistic diagram of generator protection and control components

Root Cause Analysis (RCA)

→ RCA is a systematic process to identify all aspects of a system failure or identified problem, documenting what happened, how it happened and most importantly why it happened, so that actions can be developed for preventing reoccurrences

→ The purpose of an RCA is to determine the most probable cause of an event and factors, that if eliminated, would have the highest probability of preventing a reoccurrence

→ While an important tool, an RCA reviews an event after the fact and outside the plant environment – it is a hindsight analysis

→ The RCA process allows us to learn through hindsight analysis how to improve our business on a going forward basis so we can better serve our customers

Root Cause Analysis (RCA)

→ Immediately following incident, AES Indiana mobilized an RCA team

→ Team facilitated by third party – Holcombe Baird – Senior Reliability Consultant, Reliability Center, Inc.

→ RCA is completed and a copy has been provided in this Cause

→ RCA recommended action plan currently being implemented or completed

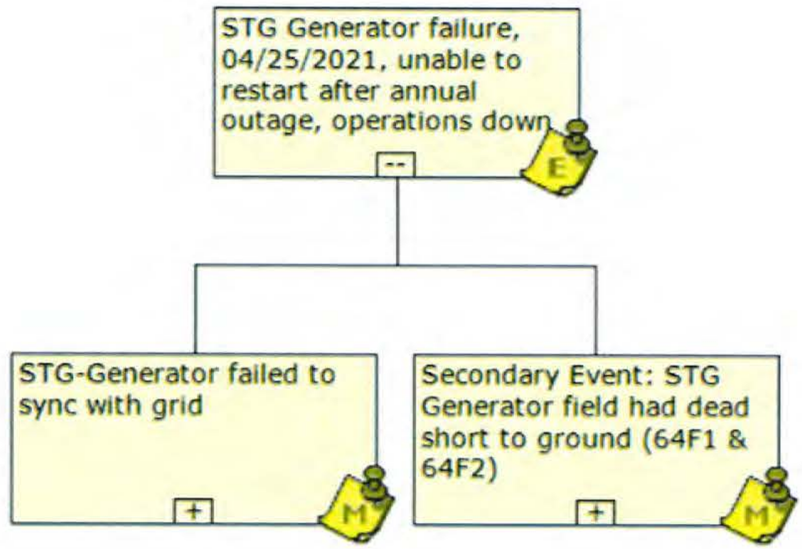
Root Cause Analysis (RCA)

→ Analysis broken down into two separate investigative efforts

1. Why the Steam Turbine Generator (STG) unit failed to synchronize to the power grid
2. What caused the field short to ground

→ The RCA involved:

- Review of drawings to determine how the STG protection and controls system functioned during the start-up
- Review of historical data trends
- Interviews with the people that were involved in the event



Root Cause Analysis (RCA) Findings

1 Why the Steam Turbine Generator Failed to Synchronize to the Grid

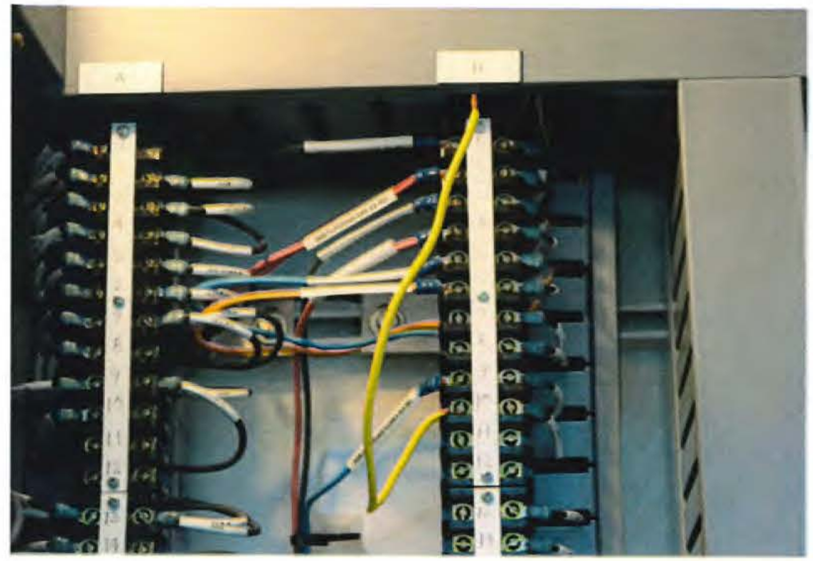
→ The steam turbine generator could not synchronize because the generator breaker (52G) was falsely indicating closed, but the breaker was actually open

→ The control system thought the generator was online

→ The generator breaker (52G) false indication was caused by a disconnected wire

- Breaker cabinet is 30 feet off the ground, accessible via a ladder

→ It is undetermined how the wire became disconnected, but the wire was never properly terminated



Disconnected yellow wire in STG 52G Breaker Cabinet
(with loose end lifted out of the way)

Root Cause Analysis (RCA) Findings

1 Why the Steam Turbine Generator Failed to Synchronize to the Grid (continued)

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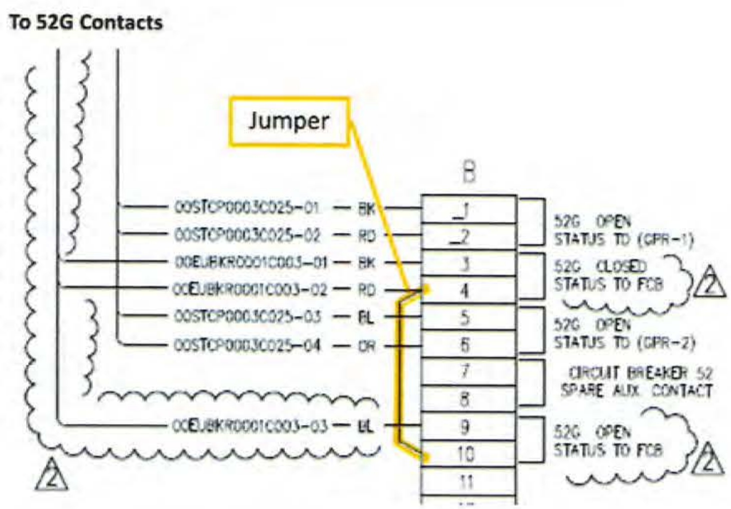

Wiring connection diagram in 52G Breaker Cabinet.

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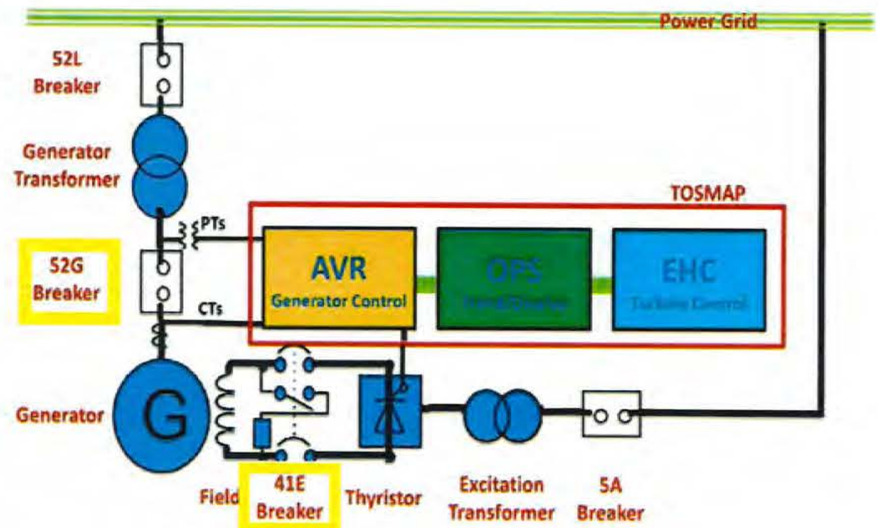

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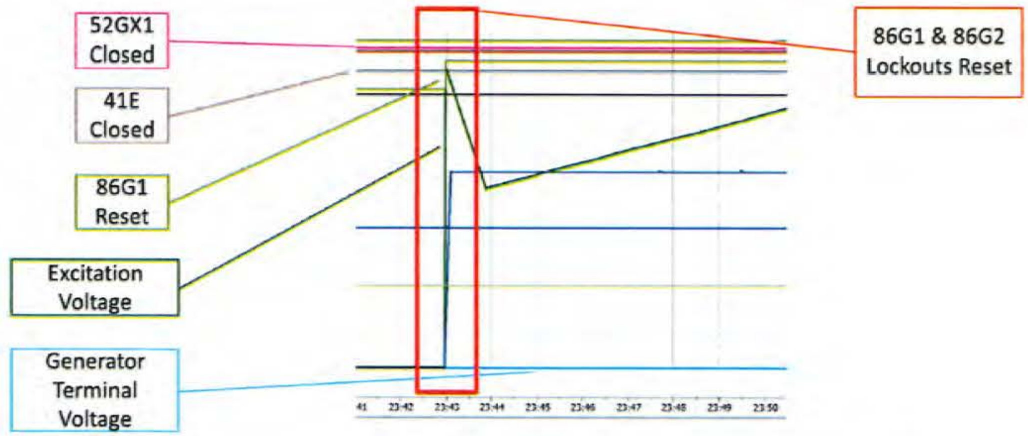

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IURC
JOINT
EXHIBIT No. 1
10-22-21
DATE REPORTER

FILED
October 6, 2021
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

OFFICIAL
EXHIBITS

IN THE MATTER OF THE PETITION OF BLOOMINGTON, INDIANA, FOR APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES FOR WATER UTILITY SERVICE AND FOR AUTHORITY TO ISSUE AND APPROVAL OF BONDS, NOTES, OR OTHER OBLIGATIONS	)))))))	**CAUSE NO. 45533**

JOINT STIPULATION AND SETTLEMENT AGREEMENT

On April 16, 2021, the City of Bloomington, Indiana ("Petitioner" or "Bloomington") filed with the Indiana Utility Regulatory Commission (the "Commission") its Petition initiating this Cause and its case-in-chief. Washington Township Water Authority ("WTWA") and the Trustees of Indiana University on behalf of its Bloomington Campus ("IU"), respectively, filed petitions to intervene in this Cause, which were each granted by the presiding officers.

The Indiana Office of the Utility Consumer Counselor ("OUCC"), WTWA and IU (collectively, the "Consumer Parties") filed their respective cases-in-chief on July 30, 2021. The Consumer Parties filed their cross-answering evidence on September 3, 2021. Petitioner filed its rebuttal evidence on September 3, 2021.

Bloomington, the OUCC, IU and WTWA (collectively, the "Parties", and individually, a "Party") have after arms-length and protracted settlement negotiations reached an agreement with respect to all of the issues before the Commission in this Cause. The Parties therefore stipulate and agree for purposes of resolving all of the issues in this Cause, to the terms and conditions set forth in this Joint Stipulation and Settlement Agreement (this "Settlement").

1. **Borrowing Authority.**

A. Approval of Debt; Authorization to Issue Bonds. The Parties stipulate and agree that the Commission should approve Bloomington's request for authorization to issue water utility revenue bonds (the "Bonds") in an amount not to exceed the $17.2 million principal amount at interest rates not to exceed six percent (6%) per annum as described in the testimony of Bloomington's witness, Jennifer Z. Wilson.

B. Borrowing Authority & Capital Projects. Petitioner agrees to forego its request for additional borrowing authority beyond that approved as part of this Settlement and associated with the identified projects and costs in its Capital Improvement Program ("CIP") as set forth in Attachment JZW-1 to its case-in-chief. Petitioner agrees to fund an additional $333,000 of its CIP from that set forth in its case-in-chief through the Bonds and as a result, to reduce the rate revenue funding of the CIP from the amount set forth in its case-in-chief. While the amount of the CIP to be funded by the Bonds increased by $333,000 from the case-in-chief, the Parties acknowledge that, as set forth in Attachment 1 to this Settlement, other changes related to the change in coupon rates result in a net increase of $205,000 to the par amount of the issuance from the $15,745,000 set forth in Petitioner's case-in-chief. Bloomington agrees to use all reasonable efforts to obtain, at least, the interest yields set forth in Attachment 1 at the time the Bonds are issued at market. The Parties stipulate and agree that the annual revenue funded portion of Bloomington's proposed CIP in Phase II will be reduced to $3,700,000. Petitioner retains discretion as to what capital projects it undertakes. For example, in the event the costs of the capital projects proposed in this case are higher than shown in Attachment JZW-1 and not all can be completed or that unexpected capital projects must be completed. Petitioner agrees it will prioritize the projects identified in Attachment JZW-1 unless, in Petitioner's discretion, unanticipated and unforeseen events arise making an unidentified project necessary to complete in order to continue the provision of safe drinking water.

i. Petitioner agrees to file annual status reports in this Cause within sixty (60) days of the end of the calendar year identifying which capital projects it completed during the preceding period, the final costs for each project (total and a detailed breakdown, including soft costs (e.g., engineering costs)), and identifying any project not included in its CIP (as shown in Attachment JZW-1) that was completed during the preceding period including final costs (total and a detailed breakdown, including soft costs) (e.g., engineering costs).

C. Termination of Borrowing Authority. Petitioner agrees that any financing authority not used by Petitioner expires twelve (12) months after a Final Order has been issued in this Cause.

D. True-Up. Within thirty (30) days of closing on the Bonds, Bloomington shall file a report with the Commission and serve a copy on the Consumer Parties, explaining the terms of the new loan, including an amortization schedule, the amount of debt service reserve, and all issuance costs (e.g., fee for bond counsel, municipal advisor, rating agency, and all other fees). The report should include a revised tariff and also calculate the rate impact in the same manner as the schedules set forth in Attachment 1 hereto ("Agreed Schedules"). Bloomington's rates should be adjusted to match its actual cost of debt service, whether lower or higher up to an interest rate of six percent (6%) per annum.

i. The Parties agree that the OUCC and any interested intervenor has no less than fourteen (14) days after service of the true-up report to file an objection with the Commission. The Parties agree that Petitioner has fourteen (14) days to file a response to the objection Party or Parties. Thereafter, the Commission should resolve any issue raised through a process it deems appropriate. Any true-up report should state the time frames for objections or responses.

ii. If both parties state in writing that the increase or decrease indicated by the report need not occur because the increase or decrease would be immaterial, the true-up need not be implemented.

E. Smart Meter Contract. To the extent Commission approval is required for the Smart Meter Contract (Attachment JU-1), the OUCC, IU and WTWA agree not to contest the Commission's approval of the Smart Meter Contract and the annual expense associated with the Smart Meter Contract as set forth in the Agreed Schedules.

F. Solar Contracts. To the extent Commission approval is required for the Solar Energy Contract and the Solar Energy Lease Agreement (Attachments JU-3 and JU-4, respectively; the "Solar Contracts"), the OUCC, IU and WTWA agree not to contest the Commission's approval of the Solar Contracts and the annual expense associated with the Solar Contracts as set forth in the Agreed Schedules.

2. **Stipulated Revenues.**

A. Test Year Operating Revenues. The Parties stipulate and agree that Bloomington's adjusted test year operating revenue at present rates is $17,802,751, which is the test year Operating Revenues amount of $17,704,598 plus an adjustment of $98,153 to metered sales as depicted on Schedule 4 to the Agreed Schedules.

B. Revenue Requirement. The Parties stipulate and agree that Bloomington's current rates and charges are inadequate and that, subject to the True-Up provision set forth in Paragraph 1.D. above, Bloomington's rates and charges should be increased as follows:

i. Phase I: Bloomington's rates and charges should be immediately increased upon the issuance of a Commission Order pursuant to the allocations set forth in Section 3 below by 8.39% so as to produce $1,424,754 in additional annual operating revenue.

ii. Phase II: Effective on January 1, 2024, Bloomington's Phase I rates and charges should be increased pursuant to the allocations set forth in Section 3 below by 9.11% so as to produce $1,675,788 in additional annual operating revenue.

The Parties stipulate and agree that the compound increase in revenues for the foregoing Phase I and Phase II increases is 18.26%.

C. Pro Forma Authorized Revenues. After adjustments (including the issuance of the Bonds), subject to the True-Up provision set forth in Paragraph 1D above, the Parties stipulate and agree that Bloomington's pro forma operating revenues (total revenue requirements with additional utility receipts tax) will be $19,227,505 for Phase I, and $20,903,711 for Phase II, as shown in Schedule 3 of the Agreed Schedules. The Parties further stipulate and agree that Bloomington's revenue requirements for the rate increase is depicted on Schedule 3 to the Agreed Schedules. The Parties stipulate and agree that the revenue increases provided herein are just and reasonable and should be approved.

D. Financial Schedules. The Parties stipulate for settlement purposes to the Agreed Schedules, including all adjustments identified therein.

3. **Stipulated Cost Allocation and Rate Design.**

A. Allocations Limited to 1.5 Times System Average Maximum Increase. The Parties agree that in order to resolve their differences on cost of service issues and rate design issues, and guided by principles of gradualism as previously applied by the Commission, the amount of the revenue requirement increase should be allocated as set forth on Attachment 2 hereto, which limits the maximum increase for any rate class, except Irrigation, to 1.5 times the system average increase.

B. Agreed Tariff. The Parties agree that the proposed tariff setting forth Phase I and anticipated Phase II rates attached as Attachment 3 hereto sets forth rates that are reasonable, just and non-discriminatory and that such proposed tariff should be approved.

C. No Approval of Cost of Service Study. The Parties agree that the foregoing allocation of the revenue requirement among the customer classes and resulting rates are based on a compromise of the revenue requirement set forth in this Settlement. The Parties agree that in light of the proposed and agreed upon rate design and allocation among the customer classes, no specific cost of service model was adopted. Commission approval of this Settlement will resolve the cost of service and rate designs issues in this case without the need for Commission determination on the merits of the cost of service study and the Parties request that the Commission make no finding approving any particular cost of service study. Except as expressly stated in this Settlement, no Party, by entering into this Settlement, has acquiesced in or waived any position with respect to the appropriate methodology for determining cost of service, cost allocation or rate design in any other proceeding, including future proceedings initiated by Petitioner. Accordingly, in all future proceedings, including those initiated by Petitioner, no presumption will be given to any prior methodology for determining cost of service or rate design, and the Parties reserve all rights to present evidence and advocate positions with respect to cost of service, cost allocation and rate design issues different from those set forth in this Settlement.

4. **Next Rate Case and Cost of Service Study.**

   A. Next Rate Case Prior to 2029. Petitioner agrees to file a new rate case so that new rates are effective no later than 2029 when debt service is expected to decline as shown on Page 24 of 32 of Attachment JZW-1. If Petitioner files its case-in-chief for the rate case on or before December 31, 2027, it shall be deemed to have satisfied this condition provided that: (1) the case makes provision for the removal of the debt service associated with the 2020B Refunding bonds and any other bonds which have been fully amortized between this rate case and that future rate case; and (2) in the absence of agreement by parties to such a case to extend the schedule, it seeks implementation of those rates on or prior to January 1, 2029.

   B. Cooperation on Future Cost of Service Study. The Parties agree that in Bloomington's next rate case Bloomington will submit a cost of service study and adhere to the protocols set forth on Attachment 4.

5. **Submission of Evidence.** The Parties stipulate to the admission into evidence in this Cause of the testimony each previously filed (each Party's case-in-chief, each Consumer Party's cross-answering testimony, and Bloomington's rebuttal testimony), and any testimony in support of this Settlement offered by the Parties or any of them.

Further, each Party waives cross-examination of the other's witnesses with respect to such testimony. The Parties shall not offer any further testimony or evidence in this proceeding, other than this Settlement and the above-identified testimony and exhibits. If the Commission should request additional evidence to support the Settlement, the Parties shall cooperate to provide such requested additional evidence.

6. **Settlement Fair and Reasonable; Proposed Final Order.** The Parties stipulate and agree that the terms of this Settlement represent a fair, reasonable, and just resolution of all the issues in this Cause, provided they are approved by the Commission in their entirety without material change, except as provided in Paragraph 8 hereof. The Parties agree to cooperate on the preparation and submission to the Commission of a proposed order that reflects the terms of this Settlement and the settlement testimony submitted pursuant to Section 5 hereof.

7. **Sufficiency of Evidence.** The Parties stipulate and agree that the evidentiary material identified immediately above constitutes a sufficient evidentiary basis for the issuance of a final order by the Commission adopting the terms of this Settlement, and granting the relief as requested herein by Bloomington and agreed to by the Parties.

8. **Commission Alteration of Agreement.** The concurrence of the Parties with the terms of this Settlement is expressly predicated upon the Commission's approval of this Settlement. If the Commission alters this Settlement in any material way, unless that alteration is unanimously and explicitly consented to by the Parties, this Settlement shall be deemed withdrawn.

9. **Authorization.** The undersigned represent that they are fully authorized to execute this Settlement on behalf of their respective clients or parties, who will be bound thereby.

10. **Non-Precedential Nature of Settlement.** The Parties stipulate and agree that this Settlement shall not be cited as precedent against any Party in any subsequent proceeding or deemed an admission by any Party in any other proceeding, except as necessary to enforce the terms of this Settlement or the final order to be issued in this Cause before the Commission or any court of competent jurisdiction on these particular issues and in this particular matter. This Settlement is solely the result of compromise in the settlement process and, as provided herein, is without prejudice to

and shall not constitute a waiver of any position that any Party may take with respect to any or all of the items resolved herein in any future regulatory or other proceeding, and, failing approval by the Commission, shall not be admissible in any subsequent proceeding.

11. **Counterparts.** This Settlement may be executed in one or more counterparts (or upon separate signature pages bound together into one or more counterparts), all of which taken together shall constitute one agreement.

[SIGNATURES ON FOLLOWING PAGE]

IN WITNESS WHEREOF, the Parties have executed this Settlement on the dates set forth below.

City of Bloomington, Indiana

By: ~~Philippa M. Guthrie~~ Dated: 10-6-2021
John Hamilton
for Mayor

Indiana Office of the Utility Consumer Counselor

By: ______________________ Dated: ______________
Tiffany Murray
Deputy Consumer Counselor

Trustees of Indiana University on behalf of its Bloomington Campus

By: ______________________ Dated: ______________
Donald S. Lukes
University Treasurer

Washington Township Water Authority

By: ______________________ Dated: ______________
Mark Schmitter
General Manager

IN WITNESS WHEREOF, the Parties have executed this Settlement on the dates set forth below.

City of Bloomington, Indiana

By: ______________________________ Dated: ________________

John Hamilton
Mayor

Indiana Office of the Utility Consumer Counselor

By: Tiffany L Murray Dated: 10/05/2021

Tiffany Murray
Deputy Consumer Counselor

Trustees of Indiana University on behalf of its Bloomington Campus

By: ______________________________ Dated: ________________

Donald S. Lukes
University Treasurer

Washington Township Water Authority

By: ______________________________ Dated: ________________

Mark Schmitter
General Manager

IN WITNESS WHEREOF, the Parties have executed this Settlement on the dates set forth below.

City of Bloomington, Indiana

By: ______________________________ Dated: ________________

John Hamilton
Mayor

Indiana Office of the Utility Consumer Counselor

By: ______________________________ Dated: ________________

Tiffany Murray
Deputy Consumer Counselor

Trustees of Indiana University on behalf of its Bloomington Campus

By: Donald S Lukes Dated: Oct 6, 2021

Donald S. Lukes
University Treasurer

Approved as to legal form by: Joseph Scodro
Joseph Scodro (Oct 6, 2021 13:24 EDT)

Washington Township Water Authority

By: ______________________________ Dated: ________________

Mark Schmitter
General Manager

IN WITNESS WHEREOF, the Parties have executed this Settlement on the dates set forth below.

City of Bloomington, Indiana

By: ________________________ Dated: ______________
John Hamilton
Mayor

Indiana Office of the Utility Consumer Counselor

By: ________________________ Dated: ______________
Tiffany Murray
Deputy Consumer Counselor

Trustees of Indiana University on behalf of its Bloomington Campus

By: ________________________ Dated: ______________
Donald S. Lukes
University Treasurer

Washington Township Water Authority

By: Mark Schmitter Dated: 10/6/2021
Mark Schmitter
General Manager

This 6th Day of October, 2021.

Respectfully submitted,

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Attorney for Intervenor,
Washington Township Water Authority

Cause No. 45533
Joint Stipulation and Settlement Agreement
Attachment 1
Schedule 1

Settlement Amortization Schedule

Date	Principal	Coupon (1)	Interest	Period Total	Fiscal Total
7/1/22			$ 152,234	$ 152,234	
1/1/23			152,234	152,234	$ 304,468
7/1/23			152,234	152,234	
1/1/24			152,234	152,234	304,468
7/1/24	$ 385,000	1.03 %	152,234	537,234	
1/1/25	380,000	1.16	150,251	530,251	1,067,485
7/1/25	385,000	1.16	148,047	533,047	
1/1/26	385,000	1.31	145,814	530,814	1,063,861
7/1/26	390,000	1.31	143,292	533,292	
1/1/27	390,000	1.48	140,738	530,738	1,064,030
7/1/27	400,000	1.48	137,852	537,852	
1/1/28	395,000	1.58	134,892	529,892	1,067,744
7/1/28	400,000	1.58	131,771	531,771	
1/1/29	405,000	1.71	128,611	533,611	1,065,382
7/1/29	410,000	1.71	125,148	535,148	
1/1/30	410,000	1.81	121,643	531,643	1,066,791
7/1/30	420,000	1.81	117,932	537,932	
1/1/31	415,000	1.88	114,131	529,131	1,067,063
7/1/31	425,000	1.88	110,230	535,230	
1/1/32	425,000	1.97	106,235	531,235	1,066,465
7/1/32	430,000	1.97	102,049	532,049	
1/1/33	435,000	2.00	97,814	532,814	1,064,863
7/1/33	445,000	2.00	93,464	538,464	
1/1/34	440,000	2.04	89,014	529,014	1,067,478
7/1/34	450,000	2.04	84,526	534,526	
1/1/35	450,000	2.08	79,936	529,936	1,064,462
7/1/35	460,000	2.08	75,256	535,256	
1/1/36	460,000	2.11	70,472	530,472	1,065,728
7/1/36	465,000	2.11	65,619	530,619	
1/1/37	475,000	2.14	60,713	535,713	1,066,332
7/1/37	480,000	2.14	55,630	535,630	
1/1/38	480,000	2.17	50,494	530,494	1,066,124
7/1/38	490,000	2.17	45,286	535,286	
1/1/39	490,000	2.20	39,970	529,970	1,065,256
7/1/39	505,000	2.20	34,580	539,580	
1/1/40	500,000	2.23	29,025	529,025	1,068,605
7/1/40	510,000	2.23	23,450	533,450	
1/1/41	515,000	2.26	17,763	532,763	1,066,213
7/1/41	525,000	2.26	11,944	536,944	
1/1/42	525,000	2.29	6,011	531,011	1,067,955
Totals	$ 15,950,000		$ 3,850,773	$ 19,800,773	

Average Annual Debt Service (2024-2041) $1,066,213

Net Interest Cost 2.16%

(1) Coupon rates are based on A rates as of July 1, 2021, plus 65 basis points.

Settlement Sources and Uses for Proposed Bonds

Sources of Funds:	
Par Amount	$ 15,950,000
Total Sources of Funds	$ 15,950,000
Uses of Funds:	
Project Fund - Original Petition	14,104,000
Additional Projects to Fund from Settlement	333,000
Debt Service Reserve Fund	1,068,605
Insurance Expense (50 bps)	99,004
Underwriter's Discount (1% of Par)	159,500
IURC Regulatory Fee	39,875
Other Costs of Issuance	146,016
Total Uses of Funds	$ 15,950,000

Settlement Revenue Requirements

	Phase I	Phase II
Adjusted Operation and Maintenance Expense	$ 9,791,599	$ 9,791,599
Adjusted Taxes Other Than Income Taxes	560,814	580,761
Average Annual Debt Service Outstanding Debt (2021-2025)	5,278,299	5,278,299
Estimated Average Annual Debt Service Proposed Bonds	304,468	1,066,213
Average Annual Lease Payment: Equipment for Advance Meter Infrastructure	456,755	456,755
Annual Lease Payment: Solar Lease	79,683	79,683
Average Annual Extensions and Replacements	2,809,000	3,700,000
Less: Revenue Offsets from Settlement	(73,060)	(73,060)
Total Revenue Requirements	19,207,558	20,880,250
Less: Adjusted Operating Revenues	(17,802,751)	(19,227,923)
Deficit	1,404,807	1,652,327
Divide by: Revenue Conversion Factor	0.986	0.986
Revenue Increase Required	1,424,754	1,675,788
Divide by: Adjustable Operating Revenues	16,986,560	18,411,732
Percent Rate Increase Required	8.39%	9.11%
Compounded Rate Increase		18.26%
Total Revenue Requirements with Additional Utility Receipts Tax	$ 19,227,505	$ 20,903,711

Settlement Revenue Requirements with Adjustments from Petition

	Phase I			Phase II		
	Petition	Adjustment	Settlement	Petition	Adjustment	Settlement
Adjusted Operation and Maintenance Expense	$ 9,868,378	$ (76,779) (1)	$ 9,791,599	$ 9,868,378	$ (76,779) (1)	$ 9,791,599
Adjusted Taxes Other Than Income Taxes	560,814		560,814	588,528	(7,767) (6)	580,761
Average Annual Debt Service Outstanding Debt (2021-2025)	5,278,299		5,278,299	5,278,299		5,278,299
Estimated Average Annual Debt Service Proposed Bonds	493,512	(189,044) (2)	304,468	1,181,756	(115,543) (2)	1,066,213
Average Annual Lease Payment: Equipment for AMI	456,755		456,755	456,755		456,755
Annual Lease Payment: Solar Lease	189,646	(109,963) (3)	79,683	189,646	(109,963) (3)	79,683
Average Annual Extensions and Replacements	2,809,000		2,809,000	3,866,500	(166,500) (7)	3,700,000
Less: Revenue Offsets from Settlement		(73,060) (4)	(73,060)	-	(73,060) (4)	(73,060)
Total Revenue Requirements	19,656,404	(448,846)	19,207,558	21,429,862	(549,612)	20,880,250
Less: Adjusted Operating Revenues	(17,704,598)	(98,153) (5)	(17,802,751)	(19,685,608)		(19,227,923)
Deficit	1,951,806		1,404,807	1,744,254		1,652,327
Divide by: Revenue Conversion Factor	0.986		0.986	0.986		0.986
Revenue Increase Required	1,979,519		1,424,754	1,769,020		1,675,788
Divide by: Adjustable Operating Revenues	16,888,407	(98,153) (5)	16,986,560	18,869,417		18,411,732
Percent Rate Increase Required	11.73%		8.39%	9.38%		9.11%
Compounded Rate Increase						18.26%
Total Revenue Requirements with Additional Utility Receipts Tax	$ 19,684,117		$ 19,227,505	$ 21,454,628		$ 20,903,711

(1) Adjustment to include budgeted overtime in lieu of test year overtime and related employee benefits and taxes, system delivery adjustment to account for normalization and growth adjustments (see adjustment 5), and removal of various non-recurring or unallowed invoices.
(2) Adjustment to debt service related to (a) the Parties' mutual agreement to shift a portion of the funding of the Petitioner's Capital Improvement Plan from pay as you go, which is funded through the Extensions and Replacements revenue requirement, to bond financing and (b) an adjustment to the estimated interest rates.
(3) Reduction to the Utility's annual provision for its share of the Solar Lease.
(4) Revenue offsets including interest income and other utility income.
(5) Revenue normalization and customer growth adjustment
(6) Reduction to additional Utility Receipts Tax required due to decrease in Phase I rate increase.
(7) Reduction to the Phase II provision for Average Annual Extensions and Replacements to reflect $333,000 of additional projects financing through the proposed bonds in lieu of pay as you go capital funding.

	Test Year		Phase I Settlement			Increase/Decrease	
	Revenues	Rates	Revenues	Increase	Rates	Revenues	Rates
Meters							
5/8" Meter	$ 463,349 (1)	$ 5.89	$ 485,376	4.75% (1)	$ 6.17	$ 22,027	$ 0.28
3/4" Meter	1,425,945	7.86	1,431,388	0.38%	7.89	5,443	0.03
1" Meter	431,447	10.59	433,077	0.38%	10.63	1,630	0.04
1.5" Meter	106,092	18.39	115,957	9.30%	20.10	9,865	1.71
2" Meter	167,130	26.20	177,400	6.14%	27.81	10,270	1.61
3" Meter	67,392	60.55	67,659	0.40%	60.79	267	0.24
4" Meter	99,968	99.57	100,360	0.39%	99.96	392	0.39
6" Meter	164,801	197.13	165,444	0.39%	197.90	643	0.77
8" Meter	36,542	294.69	36,684	0.39%	295.84	142	1.15
10" Meter	14,121	392.24	14,176	0.39%	393.77	55	1.53
Volumetric Revenue							
Residential / Multi Family	6,041,595 (1)	3.73	6,527,514	8.04% (1)	4.03	485,919	0.30
Comm, Gov, Interdept.	2,491,162	3.16	2,790,733	12.03%	3.54	299,571	0.38
Industrial	148,842	2.92	167,192	12.33%	3.28	18,350	0.36
Wholesale	2,479,465	2.39	2,780,321	12.13%	2.68	300,856	0.29
Indiana University (IU) Usage	840,125	2.37	942,925	12.24%	2.66	102,800	0.29
Irrigation Usage	385,328	3.42	463,070	20.18%	4.11	77,742	0.69
Fire Protection	1,633,005	Various	1,724,031	5.57%	Various	91,026	Various
Total Adjustable Revenues	16,996,309 (1)		18,423,307			1,426,998	
Other Operating Revenues	816,191		816,191			-	
Rounding	(9,749)		(11,993)			(2,244)	
Total Operating Revenues	$17,802,751		$19,227,505			$1,424,754	
			$ 1,424,754				

	Phase II Settlement			Increase/Decrease Over Phase I		Increase/Decrease Combined		
	Revenues	Increase	Rates	Revenues	Rates	Revenues	Increase	Rates
Meters								
5/8" Meter	$ 511,336	5.35% (1)	$ 6.50	$ 25,960	$ 0.33	$ 47,987	10.36% (1)	$ 0.61
3/4" Meter	1,438,645	0.51%	7.93	7,257	0.04	12,700	0.89%	0.07
1" Meter	435,114	0.47%	10.68	2,037	0.05	3,667	0.85%	0.09
1.5" Meter	127,610	10.05%	22.12	11,653	2.02	21,518	20.28%	3.73
2" Meter	189,456	6.80%	29.70	12,056	1.89	22,326	13.36%	3.50
3" Meter	67,960	0.44%	61.06	301	0.27	568	0.84%	0.51
4" Meter	100,812	0.45%	100.41	452	0.45	844	0.84%	0.84
6" Meter	166,197	0.46%	198.80	753	0.90	1,396	0.85%	1.67
8" Meter	36,852	0.46%	297.19	168	1.35	310	0.85%	2.50
10" Meter	14,240	0.45%	395.56	64	1.79	119	0.84%	3.32
Volumetric Revenue								
Residential / Multi Family	7,094,419	8.69% (1)	4.38	566,905	0.35	1,052,824	17.43% (1)	0.65
Comm, Gov, Interdept.	3,137,603	12.43%	3.98	346,870	0.44	646,441	25.95%	0.82
Industrial	189,111	13.11%	3.71	21,919	0.43	40,269	27.05%	0.79
Wholesale	3,143,422	13.06%	3.03	363,101	0.35	663,957	26.78%	0.64
Indiana University (IU) Usage	1,059,904	12.41%	2.99	116,979	0.33	219,779	26.16%	0.62
Irrigation Usage	554,332	19.71%	4.92	91,262	0.81	169,004	43.86%	1.50
Fire Protection	1,829,051	6.09%	Various	105,020	Various	196,046	12.01%	Various
Total Adjustable Revenues	20,096,064			1,672,757		3,099,755		
Other Operating Revenues	816,191			-		-		
Rounding	(8,544)			3,449		1,205		
Total Operating Revenues	$20,903,711			$1,676,206		$3,100,960		
Revenue Increase	$ 1,676,206							

(1) Test Year residential and 5/8 inch meter units adjusted for operating adjustment. Increase reflected is rate increase instead of revenue increase.

BLOOMINGTON MUNICIPAL WATER UTILITY
Bloomington, Indiana

Schedule of Rates and Charges

Monthly usage charge applicable to Residential, Commercial, Governmental, Interdepartmental, Industrial, Indiana University – Master Metered, Indiana University – Non-Master Metered, and Irrigation classes

Category	Phase I Rates Per 1,000 Gallons	Phase II Rates Per 1,000 Gallons
Residential	$ 4.03	$ 4.38
Commercial, Governmental, Interdepartmental	3.54	3.98
Industrial	3.28	3.71
Indiana University – Master Metered	2.66	2.99
Indiana University – Non-Master Metered	3.54	3.98
Irrigation	4.11	4.92

Monthly Service Charge, in Addition to Monthly Usage for the customer categories listed above

Meter Size	Phase I	Phase II
5/8"	$ 6.17	$ 6.50
3/4"	7.89	7.93
1"	10.63	10.68
1 ½"	20.10	22.12
2"	27.81	29.70
3"	60.79	61.06
4"	99.96	100.41
6"	197.90	198.80
8"	295.84	297.19
10"	393.77	395.56

Monthly Surcharges for Fire Protection Service for the customer categories listed above (excluding Indiana University – Master Metered)

	Phase I Charge		Phase II Charge	
Meter Size	Inside City	Outside City	Inside City	Outside City
5/8"	$ 2.07	$ 3.46	$ 2.20	$ 3.67
3/4"	3.09	5.21	3.28	5.52
1"	5.16	8.68	5.48	9.21
1 ½"	10.33	17.33	10.95	18.38
2"	16.52	27.76	17.52	29.44
3"	36.15	60.72	38.34	64.40
4"	61.96	104.05	65.71	110.35
6"	129.12	216.79	136.94	229.92
8"	185.92	312.15	197.19	331.07
10"	299.51	502.94	317.67	533.42

The monthly Fire Protection Charge for Indiana University – Master Metered accounts as a group shall be $1,480 in Phase I and $1,480 in Phase II.

BLOOMINGTON MUNICIPAL WATER UTILITY
Bloomington, Indiana

Schedule of Rates and Charges

Contract Sales for Resale

The rate for contract sales for resale shall be $2.68 per one thousand gallons for Phase I and $3.03 per one thousand gallons for Phase II.

Contract Sales for Resale Monthly Service Charge in Addition to Monthly Usage Charge

Meter Size	Phase I	Phase II
5/8"	$ 6.17	$ 6.50
3/4"	7.89	7.93
1"	10.63	10.68
1 ½"	20.10	22.12
2"	27.81	29.70
3"	60.79	61.06
4"	99.96	100.41
6"	197.90	198.80
8"	295.84	297.19
10"	393.77	395.56

Private fire connections per connection

	Phase I		Phase II	
Line Size	Monthly	Annually	Monthly	Annually
4" and under	$ 10.41	$ 124.92	$ 11.04	$ 132.48
6"	28.93	347.16	30.69	368.28
8"	59.29	711.48	62.89	754.68
10"	103.85	1,246.20	110.14	1,321.68
12"	163.73	1,964.76	173.66	2,083.92

BLOOMINGTON MUNICIPAL WATER UTILITY
Bloomington, Indiana

Non-Recurring Charges

Description of Charge			Charges
1)	5/8" to 1" Connection	- with tap - without tap	$1,533.00 $1,327.00
2)	Greater than 1" Connection		Cost of connection but not less than charge for 5/8" to 1" connection
3)	Service Call	- During hours - After hours	$45.00 $171.00
4)	Bad Check Charge		$25.00
5)	Late Payment Charge		3% of unpaid balance

This charge shall be paid only once and shall be based on the unpaid over-due balance.

6)	Deposit*	- Residential - Commercial	Not to exceed $39.00 Not to exceed 1/6 of estimated annual bill

If a present residential customer has been mailed disconnect notices for two consecutive months or any three months within the preceding twelve-month period or has had service disconnected because of nonpayment within the past four years, a security deposit not to exceed one-sixth of the expected annual billing for the customer at the address at which service is rendered may be required.

7) Meter Testing

The utility shall make a free test of the accuracy of a meter upon written request by a customer and a second free test may be requested twelve months subsequent to the first test. The fee for all meter tests requested within thirty-six months after the preceding test shall be $39.00 if the meter is found not to be at fault.

8) Inspection Charge

All inspections of new mains during normal business hours shall be free of charge. All inspections of new mains during overtime hours shall be based on the amount of time required for the inspection.

9) Temporary Service — $10.00/week

$10.00 minimum plus a deposit equal to the cost of the meter and a charge for the water used.

10) Extension of Service

Free if estimated 3-year revenue is greater than the construction cost. Actual cost if not.

11) Unauthorized Use of Hydrants

Cost of Water billed for up to 8 hours at maximum flow rate of the hydrant for each day the hydrant is used.

*Deposit is not under the jurisdiction of the Indiana Utility Regulatory Commission (IURC).

Protocols for Next Cost of Service Study

1. In its next rate case (expected in late 2024 or early 2025, but Bloomington retains full discretion on when it files its next rate case within the parameters of Section 4.A. of the Settlement), Bloomington will present a new cost of service study ("COSS") utilizing data collected from AMI meters. Bloomington agrees to provide opportunities for WTWA, IU and the OUCC, including their respective consultants, to participate in the preparation of Bloomington's next COSS in good faith collaboration to address areas of concern with any study or related model. That participation will involve, but not be limited to, the sharing of all COSS related data, any COSS related workpapers, the ability to contact/meet (may be electronic meetings) with Bloomington's consultants, and the provision of preliminary and final COSSs that Bloomington intends to present to its Utility Service Board. The sharing of information will be subject to a mutually acceptable confidentiality agreement, where appropriate.

2. Bloomington retains final discretion with respect to the presentation of its cost of service and rate design proposals in its next rate case. In order to facilitate the provision of information set forth in Paragraph 1 above, however, during the course of COSS preparation Bloomington will provide, at least, the following four (4) specific opportunities for the Parties to meet, provide input, suggest changes to, and review COSS materials:
   a. Data Review meeting to go over test year customer billing and AMI data;
   b. Revenue Requirement meeting;
   c. Cost Allocation by Customer Class meeting; and
   d. Rate Design meeting.

   Bloomington agrees to provide 10-days' written notice to WTWA, IU, and the OUCC (email notice is acceptable) of the date, time and location of each meeting. Such meetings may be held by electronic means to facilitate participation. Bloomington may not file its rate case if these four (4) meetings have not been held. In the event these meetings extend the filing of the rate case more than one year after the end of the test year, all Parties to this Settlement agree to waive staleness as an objection to the test year for rate-setting purposes provided the filing is made not more than 18 months following the close of the test year. The Parties, however, retain the right to otherwise raise any challenge to the use and reasonableness of Bloomington's test year, and do not waive their right to challenge any test year cost, or to take any position with respect to revenue, usage, other adjustments to the test year or use of the test year for, and relating to, the COSS. The four (4) meetings identified above are not meant to be exclusive opportunities for pre-filing discussion between Bloomington and any Party, and other meetings, or other communications, may be arranged and held as appropriate. No inferences shall be drawn from a Party's participation, or non-participation, in any pre-filing meeting.

3. Bloomington will take steps to assure that any preliminary or final cost of service models can be fully accessed, operated and manipulated by WTWA, IU and the OUCC, or their respective consultants. For purposes of effectuating this agreement, a fully accessible, operable and manipulatable cost service model shall, at a minimum, meet the following criteria:

a. Be in Excel format with all formulas and inputs intact, unlocked and accessible
b. Not have hidden or otherwise protected cells, tabs or worksheets
c. Not include external links to data which is not also provided
d. Not contain formula errors
e. Be formatted in such a manner as to be legible without extensive re-formatting by users
f. Utilize consistent and readily identifiable units of service (e.g., volumes sold) across testimony, the COSS model, and discovery responses in a manner that is clearly and consistently separated by rate class.
g. Permit users to make modifications to any input that results in clearly updated results
h. Permit users to easily modify any input including the functionalization and allocation of costs.
i. Permit users to save modifications

4. Bloomington agrees to review the appropriateness of a wholesale storage class or sub-class, or other cost of service and rate design proposals for Wholesale contract customers that is supported by the data. Bloomington agrees that WTWA will not be assigned to a customer class consisting only of WTWA unless either 1) Bloomington develops rates unique to each wholesale customer; or 2) WTWA consents to such assignment.

**VERIFIED DIRECT TESTIMONY
OF
EDWARD T. RUTTER
CAUSE NO. 45533**

Q1. Can you please state your name and business address?

A1. My name is Edward T. Rutter. My business address is 1776 North Meridian St., Suite 500, Indianapolis, Indiana.

Q2. By whom are you employed and in what capacity?

A2. I am employed with the firm of LWG CPAs and Advisors ("LWG") as a Manager.

Q3. Please briefly describe your educational and professional background, which you believe is relevant to your testimony here.

A3. I hold a Bachelor of Science degree in Business Administration from Drexel University. I joined LWG in May 2019. Prior to joining LWG, I was employed for more than six (6) years in the Resource Planning and Communications ("RPC") Division and the Natural Gas Division of the Indiana Office of Utility Consumer Counselor ("OUCC"), where I was promoted mid-employment to Chief Technical Advisor. Prior to my time at the OUCC, from 1980 to 2012, I was an independent consultant primarily working with utilities, investors, and regulators. From 1973 until 1980, I was a consultant for Associated Utility Services ("AUS"), primarily providing consulting services to utility regulatory commissions and various utilities generally in Delaware and Maryland. Prior to joining AUS, I was an accountant for South Jersey Industries and its subsidiaries, including South Jersey Gas Company.

Q4. Have you previously testified in any regulatory proceedings?

A4. Yes. I testified frequently before the Indiana Utility Regulatory Commission in my prior role with the OUCC. I have also provided testimony before utility regulatory commissions in Connecticut, Delaware, Florida, Georgia, Maryland, Michigan, New Jersey, New York, North Carolina, Ohio, Oklahoma, Virginia and Wisconsin. The subject of my testimony in these matters varied, including but not limited to: return on common equity; appropriate capital structure for ratemaking purposes; purchased gas adjustment clauses; rate base; operating expenses for ratemaking; tax allowance for ratemaking purposes; valuation of assets and equity; transmission, distribution and storage system improvement charge ("TDSIC") plans; demand side management ("DSM") plans and trackers; and revenue requirement development. I also testified on behalf the Internal Revenue Service ("IRS") on the subject of economic viability in the U.S. Tax Court.

Q5. Who do you represent in this proceeding before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A.5 I represent Washington Township Waters Authority ("WTWA") as a wholesale customer of Bloomington and an intervenor in this proceeding.

Q6. Have you prepared pre-filed direct testimony in this proceeding?

A6. I have prepared pre-filed direct testimony in this proceeding, WTWA Exhibit 1 and an accompanying Exhibit WTWA Exhibit 1A. Accompanying WTWA Exhibit 1A contains Bloomington's responses to certain WTWA Data Requests which I used in preparation of my pre- filed direct testimony

Q7. What have you done to prepare to give testimony in this Cause?

A7. I reviewed The City of Bloomington, Indiana ("Bloomington" or "Petitioner") Petition, filed with the Commission, Petitioner's pre-filed direct testimony and response to data requests prepared WTWA as a wholesale customer of Bloomington and an intervenor in this proceeding, and the response to data requests presented by the other parties in this proceeding, the OUCC and Indiana University ("IU"). My document review is ongoing as additional information from Bloomington is still being received in the form of supplemental responses to previous submitted data requests and additional data requests.

Q8. What is the purpose of your testimony?

A8. On behalf of the WTWA, intervenor I describe my evaluation of Bloomington's proposal and why in my experience much of it should be denied. Specifically, I address:

- Many of the revenue requirement elements in Bloomington's proposal to increase its water rates are not supported by its filing and subsequent responses to the parties' data requests. In many instances Bloomington has failed to show its proposed adjustments are necessary to utility operations and reasonable in mount. In most cases Bloomington's data request responses only confirmed that failure.
- Bloomington has included in its cost recovery, costs associated with both a City of Bloomington solar lease and AMI meter lease but has not provided persuasive documentation of the benefits that would be realized by the water customers most particularly, WTWA.
- Bloomington's cost of service study ("COSS"), included with its Petition and pre-filed direct testimony filed in support of its rate increase and tariff design is seriously flawed in many respects. Further and critically, the COSS does not

recognize the characteristics of WTWA and its available storage which can and will contribute to Bloomington's maximum day and maximum hour impact on the overall cost of service which forms a crucial part of Bloomington's COSS. In fact the filed COSS and subsequent excel filing was so flawed that none of the parties were able to review and analyze various scenarios that would allow their determination of the efficacy of the COSS and its impact on their customers.

- Regardless of whether the Commission determines Bloomington is entitled to some level of rate relief or not, the COSS and its inputs are so seriously flawed, and not conducive to corrective amendment, that it, and the resulting rate design, should not be approved. I recommend that any increase granted be an across the board increase and any future COSS be done correctly, recognize wholesale customer storage capability and employ a full year of AMI water sales data.

Q9. In your professional opinion is the proposal of Bloomington to increase its retail water rates just and reasonable as you understand it?

A9. Municipal utilities, such as Bloomington, are required to charge only "just and reasonable" rates. At the core of government regulation utility rates is the regulatory balancing of consumer and utility interests required to ensure rates are just and reasonable to both. If unjust and unreasonable rates are approved, then the process of utility - price regulation has failed. In my opinion, no rate proposal can be reasonably reviewed without attention to that critical regulatory purpose of balancing competing utility / consumer interests to ensure the rate's result is fair to both. With rate proposals that have multiple facets, the level of one can be adjusted to counter balance another to ensure the end rate result is just and reasonable. If utility rate regulation were to become separated from that core social and economic balancing purpose, then there would not be regulation. Utilities could just download their data into a central government formulaic software system and out would come their approved rates, with no human review or consideration of the impact on consumers or fairness. I am grateful that we have utility regulators who apply that unique human ability to consider all factors and impacts in context and to judge what reasonable balance will be fair to both consumers and utilities. To me, just and reasonableness of rates is the core purpose, the mandate umbrella that covers regulatory rate review. That is why I consider it here.

Q10. What leads to your conclusion that Bloomington's rate proposal in this proceeding is not "just and reasonable"?

A10. First I look to the response of Bloomington to Washington Township Water Authority's Data Request No. 7-1:

> Q-7-1 "Since the (1) year adjustment period following the test year used by Bloomington in this Cause is past and no longer prospective, for each proposed revenue and expense adjustment please provide the actual, current (after March 31, 2021) results for each of these adjustments."
>
> "Response:
>
> This analysis has not been completed.
>
> The Data Request to the extent the Data Request requires a calculation or analysis that Bloomington has not performed and that objects to performing."

While I agree it requests that Bloomington perform an analysis that has not been filed, it demonstrates to me that Bloomington apparently does not care what its results were over the test year period and whether or not they exceeded expectations or underestimated the impact of their adjustments, which may be detrimental to its customers but appears to shift the burden of proof onto the parties and Commission to make that analysis. I object to having the burden put on WTWA to do what is the responsibility, as my experience tells me, of the Petitioner's to bear the burden of proof that their test year results are accurate and appropriate for adoption for setting new rates for the future.

The second point is that in response to several data request relative the AMI lease cost Bloomington responded that the AMI lease was just a financial lease and no prior analysis was done to identify the benefits, if any to the customers. There is no compelling evidence in the record that both the AMI meter purchase and subsequent lease would be beneficial to the water utility customers.

In addition to the fact as explained by Bloomington that the use of the AMI lease was financial in nature and not supported by any independent analysis of the benefits attributed to customers relative to the use of AMI meters. Bloomington appears to have been seriously behind on typical water utility meter replacements and decided on an immediate 100% deployment AMI meters without doing any studies. Typical Things that should have been done prior to proceeding with the purchase of AMI meters is the following:

1. Was the purchase of AMI meters and their subsequent cost for water utility customers justified?

2. What meter alternatives were reviewed and analyzed?
3. Why was a 100% replacement adopted as opposed to a phased in approach/
    a. Was it because the City of Bloomington City contemplated a rate increase filing and they thought they could get customers to pay for the purchase in rates, possibly?
4. Was self-installation of the meters and the corresponding cost considered in reaching the decision to buy AMI meters?
5. What benefits of a Smart City were to be realized by Bloomington water customers' and how did a cost/benefit analysis figure into the decision?
6. Did the benefits of lease funding justify the use of a lease financing option?

The efficacy of the decision to implement is called into question. Without undertaking a reasonable review of the use of AMI meters for a water utility to begin with raises questions but to undertake their purchase without doing any responsible review of their purchase is not fair to the water customers and is unjust and unreasonable.

BLOMINGTON'S COST OF SERVICE STUDY IS FLAWED AND SHOULD NOT BE USED FOR ESTABLISHING RETAIL WATER RATES IN THIS PROCEEDING

Q11. Why in your opinion is the Petitioner's Cost of Service Study flawed and should not be considered in this proceeding?

A11. First the COSS as filed in this proceeding does not allow the parties to be able to use various customer inputs in order to review and analyze the impact certain criteria may have on those parties. I attempted to see what impact storage may have on the end result, again that that effort was not allowed because of the various cell restraints contained within the COSS. Efforts to work with gallons used, various cost undertakings for instance using what the impact might be on rate and class by inputting alternatives to the solar and AMI lease costs and examining potential viable alternative all efforts were thwarted by the inability to work with what was filed. The COSS model as presented and filed was not conducive to analysis and review of certain COSS inputs, for example capacity factors and demand allocators were not allowed to be tested because of the flaws in the COSS model.

The second and more problematic point is that some wholesale customers are being asked to bear the lease cost of the purchased AMI meters but not using more accurate AMI data inputs because of the timing of the COSS.

The third basic problem experienced by WTWA is that nowhere in the COSS has Bloomington recognized that some wholesale customers have storage facilities that would normally impact the usage on the maximum day and maximum hour of the system which may impact the rate charged or the institution of a sub rate recognizing the storage contribution

Q12. Does WTWA have available storage facilities?

A12. Yes, WTWA has several storage facilities available to it and Bloomington if the COSS would have acknowledged its existence. WTWA has available a 200,000 gallon water tower and a 350,000 gallon stand pipe. Usable water storage is approximately 300,000 gallons which was ignored in the preparation of the COSS. Any responsible COSS used to design retail tariff rates for all customers, including wholesale customers would have taken into consideration any available storage facilities

Bloomington has acknowledged that wholesale customer storage was not even looked at in preparing its COSS.

Q13. Did the COSS consider any capital contributions made by wholesale customers to Bloomington's water system?

A13. In response to WTWA data requests, Bloomington stated that such capital contributions should be considered in a COSS, but none were considered because none of Bloomington's wholesale customers made any capital contributions to Bloomington's system. Bloomington's COSS consultant also stated Bloomington provided that information to him.

Q14. Do you believe Bloomington's statements regarding wholesale customer capital contributions to be correct?

A14. No. In discussions with representatives of WTWA they indicate that WTWA made a contribution of $150,000 on March 15, 2000 and on July 7, 1998, they also made a contribution of $30,000. Both of those contributions were ignored in developing the COSS and the wholesale rate proposed to be charged to WTWA.

Q15. Do you know if other of Bloomington's wholesale customers' made capital contributions to Bloomington's water system?

A15. I do not. Given the nature of small water systems such capital contributions by wholesale customers are fairly common but Bloomington denies any capital contributions, including the contributions known to have been made by WTWA.

Q16. Does this conclude your direct testimony?

A16. At this time.

WTWA Exhibit 1

VERIFICATION

I affirm under the Penalties of perjury that the forgoing testimony is to the best of my knowledge true and accurate.

Edward T. Ruttel

Name Edward T. Ruttel

7/30/2021

Date

Bloomington Data Request Response to WTWA No. 1-22

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2

Q-1-22: Did UFS examine the storage capacity of WTWA and verify how the availability
of the WTWA storage capacity impacts WTWA contribution to usage on average
day demands, peak day demands, and peak hour demands?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

The cost of service study identified the cost to serve wholesale customers. All wholesale
customers were combined, and no specific analysis of individual wholesale customers
was performed

Bloomington Data Request Response to WTWA No. 1-31

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2

Q-1-31: In developing your COSS, did you use the AMI meter hourly usage data?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

No. At the time of developing the cost of service study, Bloomington did not have a full
year of AMI meter hourly usage data

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2

Q-1-31: In developing your COSS, did you use the AMI meter hourly usage data?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

No. At the time of developing the cost of service study, Bloomington did not have a full
year of AMI meter hourly usage data

Bloomington Data Request Response to WTWA No. 1-33

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2

Q-1-33: Did any of the wholesale customers make any contribution to the Bloomington system, by payments, the contribution of assets or otherwise, other than payment for water service?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections. Bloomington further objects to this Data Request on the grounds that it is overly broad, unduly burdensome, and seeks the production of irrelevant information not proportional to the needs of this case.

Response:

No.

Bloomington Data Request Response to WTWA No. 1-34

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2

Q-1-34: Did your COSS take into account the contributions, referenced in Data Request
1.33, by each wholesale customer, including WTWA?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections. Bloomington further objects to this Data Request on the grounds that it
is overly broad, unduly burdensome, and seeks the production of irrelevant information not
proportional to the needs of this case.

Response:
Not applicable. As stated in response to Q-1-33, no contributions were made, so no
contributions could be "taken into account."

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 2
May 17, 2021
5
LEGALDOCS\611363\100009\21454263.v2-5/16/21

Q-2-2: On page 3, lines 7 through 9, you indicate that the Smart Meter Contract provides for cost savings and other benefits through the use and installation of the smart meter equipment over the term of the contact for Bloomington's water utility and wastewater utility. Does the Smart Meter Contract provide benefits to the wholesale customers that the Smart Meters do not?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections. Bloomington further objects to this Data Request on the grounds that this request assumes facts not in evidence.

Response:

Yes. The Smart Meter Contract allowed Bloomington to complete the meter changeout more rapidly (approximately within a year), rather than engage in a long, drawn-out process over several years. The faster roll-out allowed Bloomington to quickly realize benefits of the AMI meter program as described in Mr. Underwood's testimony. Moreover, the concentrated efforts to roll out AMI smart meters likely resulted in greater efficiencies in AMI meter deployment through concentrated and focused efforts in contrast to a diluted roll-out taking place over several years.

Bloomington Data Request Response to WTWA No. 2-4

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 2
May 17, 2021
7
LEGALDOCS\611363\100009\21454263.v2-5/16/21

Q-2-4: Is the allocation of AMI meter costs to the wholesale customers supported by
cost savings and benefits to those wholesale customers derived from the installation of AMI meters?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

Bloomington determined that all customers would receive an AMI meter no matter their
customer classification. The cost savings and benefits derived from the installation of the
AMI meters accrue to Bloomington and all of its customers by allowing Bloomington to
accurately measure consumption and overall system efficiency, to improve accuracy from
the newer meters, and to provide additional customer engagement via the customer portal.

Moreover, wholesale customers are not allocated any meter cost in the wholesale
volumetric rate. Wholesale customers are allocated a meter cost based on the number and
size of meters serving them.

A. Please provide any cost benefit analysis to support the answer to the above question.

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

No formal cost benefit analysis was performed for wholesale customers.

Bloomington Data Request Response to WTWA No. 4-13

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 4
May 20, 2021
LEGALDOCS\611363\100009\21459119.v2-5/19/21

Q-4-13: On page 17, lines 21 to 23, and page 18, lines 1 to 5 you discuss the use of AMI meters and that you do not have a full year of AMI data. However, it appears that prior to the close of the record in this Cause you should have one (1) full year of AMI data. Do you have plans to augment or modify your COSS, using updated AMI data, prior to the close of the record in this Cause?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

No.

A. Even if you had no current plans to update your COSS, would you be willing to do so?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

No. Any update would use information that would be outside of the period for fixed, known and measurable adjustments to test year results.

Bloomington Data Request Response to WTWA No. 5-10

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 5 -10
May 24, 2021
21467514.v1

Q-5-10: For Witnesses Kelson and/or Beauchamp. Are AMI meters important to being able to more accurately perform future Cost of Service Studies ("COSS")?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

Yes.

A. Please explain why.

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

AMI meters are important to being able to more accurately perform future cost of service studies because Bloomington will have more data to identify peak demands and variability of demand. The AMI technology would also aid in the collection and validation of data.

Bloomington Data Request Response to WTWA 6-7

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 6
June 21, 2021
21512612.v1

Q-6-8: Mr. Beauchamp responded that none of Bloomington's wholesale customers
made any contributions to the Bloomington system, by payments, the contribution of assets, or otherwise, other than payment for water service. How
does he know this?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

Information was provided by Bloomington.

A. What was done to verify that information?

B. If such contributions had been made by any wholesale customer, should those
contributions have been "taken into account" in the COSS?

C. If so, how?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

A. The information was discussed with Bloomington staff.

B. Yes.

C. Certain asset accounts would change that would affect the allocation of existing
debt service and indirect overhead cost allocations.

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 6
June 21, 2021
21512612.v1

Q-6-7: In developing the COSS, would Mr. Beauchamp have used AMI meter hourly
usage data if it had been available?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

Yes.

A. Why?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

AMI data allows for more accuracy in developing class peaking factors

Bloomington Data Request Response to WTWA 6-24

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 6
June 21, 2021
21512612.v1

Q-6-24: In Response to Data Request 2-11, Bloomington provided the total estimated
purchased power savings in 2020 for the waterworks. What are the savings to the
water utility net of allocated Solar Energy Contract costs?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections. Bloomington further objects to this Data Request as overly broad,
unduly burdensome, compound, vague, ambiguous, and seeks the production of irrelevant
information not proportional to the needs of this case.

Response:

The savings to the water utility are not known at this time. As Bloomington provided in
response to Washington Township DR 2-11, at present all figures are currently estimates.
Accordingly, the actual savings net of allocated costs is unknown at present.

VERIFIED DIRECT TESTIMONY
OF
EDWARD T. RUTTER
CAUSE NO. 45533

Q1. Can you please state your name and business address?

A1. My name is Edward T. Rutter. My business address is 1776 North Meridian St., Suite 500, Indianapolis, Indiana.

Q2. By whom are you employed and in what capacity?

A2. I am employed with the firm of LWG CPAs and Advisors ("LWG") as a Manager.

Q3. Please briefly describe your educational and professional background, which you believe is relevant to your testimony here.

A3. I hold a Bachelor of Science degree in Business Administration from Drexel University. I joined LWG in May 2019. Prior to joining LWG, I was employed for more than six (6) years in the Resource Planning and Communications ("RPC") Division and the Natural Gas Division of the Indiana Office of Utility Consumer Counselor ("OUCC"), where I was promoted mid-employment to Chief Technical Advisor. Prior to my time at the OUCC, from 1980 to 2012, I was an independent consultant primarily working with utilities, investors, and regulators. From 1973 until 1980, I was a consultant for Associated Utility Services ("AUS"), primarily providing consulting services to utility regulatory commissions and various utilities generally in Delaware and Maryland. Prior to joining AUS, I was an accountant for South Jersey Industries and its subsidiaries, including South Jersey Gas Company.

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A.5 I represent Washington Township Waters Authority ("WTWA") as a wholesale customer of Bloomington and an intervenor in this proceeding.

Q6. Have you prepared pre-filed direct testimony in this proceeding?

A6. I have prepared pre-filed direct testimony in this proceeding, WTWA Exhibit 1 and an accompanying Exhibit WTWA Exhibit 1A. Accompanying WTWA Exhibit 1A contains Bloomington's responses to certain WTWA Data Requests which I used in preparation of my pre- filed direct testimony

Q7. What have you done to prepare to give testimony in this Cause?

A7. I reviewed The City of Bloomington, Indiana ("Bloomington" or "Petitioner") Petition, filed with the Commission, Petitioner's pre-filed direct testimony and response to data requests prepared WTWA as a wholesale customer of Bloomington and an intervenor in this proceeding, and the response to data requests presented by the other parties in this proceeding, the OUCC and Indiana University ("IU"). My document review is ongoing as additional information from Bloomington is still being received in the form of supplemental responses to previous submitted data requests and additional data requests.

Q8. What is the purpose of your testimony?

A8. On behalf of the WTWA, intervenor I describe my evaluation of Bloomington's proposal and why in my experience much of it should be denied. Specifically, I address:

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- Bloomington has included in its cost recovery, costs associated with both a City of Bloomington solar lease and AMI meter lease but has not provided persuasive documentation of the benefits that would be realized by the water customers most particularly, WTWA.
- Bloomington's cost of service study ("COSS"), included with its Petition and pre-filed direct testimony filed in support of its rate increase and tariff design is seriously flawed in many respects. Further and critically, the COSS does not

recognize the characteristics of WTWA and its available storage which can and will contribute to Bloomington's maximum day and maximum hour impact on the overall cost of service which forms a crucial part of Bloomington's COSS. In fact the filed COSS and subsequent excel filing was so flawed that none of the parties were able to review and analyze various scenarios that would allow their determination of the efficacy of the COSS and its impact on their customers.

- Regardless of whether the Commission determines Bloomington is entitled to some level of rate relief or not, the COSS and its inputs are so seriously flawed, and not conducive to corrective amendment, that it, and the resulting rate design, should not be approved. I recommend that any increase granted be an across the board increase and any future COSS be done correctly, recognize wholesale customer storage capability and employ a full year of AMI water sales data.

Q9. In your professional opinion is the proposal of Bloomington to increase its retail water rates just and reasonable as you understand it?

A9. Municipal utilities, such as Bloomington, are required to charge only "just and reasonable" rates. At the core of government regulation utility rates is the regulatory balancing of consumer and utility interests required to ensure rates are just and reasonable to both. If unjust and unreasonable rates are approved, then the process of utility - price regulation has failed. In my opinion, no rate proposal can be reasonably reviewed without attention to that critical regulatory purpose of balancing competing utility / consumer interests to ensure the rate's result is fair to both. With rate proposals that have multiple facets, the level of one can be adjusted to counter balance another to ensure the end rate result is just and reasonable. If utility rate regulation were to become separated from that core social and economic balancing purpose, then there would not be regulation. Utilities could just download their data into a central government formulaic software system and out would come their approved rates, with no human review or consideration of the impact on consumers or fairness. I am grateful that we have utility regulators who apply that unique human ability to consider all factors and impacts in context and to judge what reasonable balance will be fair to both consumers and utilities. To me, just and reasonableness of rates is the core purpose, the mandate umbrella that covers regulatory rate review. That is why I consider it here.

Q10. What leads to your conclusion that Bloomington's rate proposal in this proceeding is not "just and reasonable"?

A10. First I look to the response of Bloomington to Washington Township Water Authority's Data Request No. 7-1:

> Q-7-1 "Since the (1) year adjustment period following the test year used by Bloomington in this Cause is past and no longer prospective, for each proposed revenue and expense adjustment please provide the actual, current (after March 31, 2021) results for each of these adjustments."
>
> "Response:
>
> This analysis has not been completed.
>
> The Data Request to the extent the Data Request requires a calculation or analysis that Bloomington has not performed and that objects to performing."

While I agree it requests that Bloomington perform an analysis that has not been filed, it demonstrates to me that Bloomington apparently does not care what its results were over the test year period and whether or not they exceeded expectations or underestimated the impact of their adjustments, which may be detrimental to its customers but appears to shift the burden of proof onto the parties and Commission to make that analysis. I object to having the burden put on WTWA to do what is the responsibility, as my experience tells me, of the Petitioner's to bear the burden of proof that their test year results are accurate and appropriate for adoption for setting new rates for the future.

The second point is that in response to several data request relative the AMI lease cost Bloomington responded that the AMI lease was just a financial lease and no prior analysis was done to identify the benefits, if any to the customers. There is no compelling evidence in the record that both the AMI meter purchase and subsequent lease would be beneficial to the water utility customers.

In addition to the fact as explained by Bloomington that the use of the AMI lease was financial in nature and not supported by any independent analysis of the benefits attributed to customers relative to the use of AMI meters. Bloomington appears to have been seriously behind on typical water utility meter replacements and decided on an immediate 100% deployment AMI meters without doing any studies. Typical Things that should have been done prior to proceeding with the purchase of AMI meters is the following:

1. Was the purchase of AMI meters and their subsequent cost for water utility customers justified?

2. What meter alternatives were reviewed and analyzed?
3. Why was a 100% replacement adopted as opposed to a phased in approach/
    a. Was it because the City of Bloomington City contemplated a rate increase filing and they thought they could get customers to pay for the purchase in rates, possibly?
4. Was self-installation of the meters and the corresponding cost considered in reaching the decision to buy AMI meters?
5. What benefits of a Smart City were to be realized by Bloomington water customers' and how did a cost/benefit analysis figure into the decision?
6. Did the benefits of lease funding justify the use of a lease financing option?

The efficacy of the decision to implement is called into question. Without undertaking a reasonable review of the use of AMI meters for a water utility to begin with raises questions but to undertake their purchase without doing any responsible review of their purchase is not fair to the water customers and is unjust and unreasonable.

BLOMINGTON'S COST OF SERVICE STUDY IS FLAWED AND SHOULD NOT BE USED FOR ESTABLISHING RETAIL WATER RATES IN THIS PROCEEDING

Q11. Why in your opinion is the Petitioner's Cost of Service Study flawed and should not be considered in this proceeding?

A11. First the COSS as filed in this proceeding does not allow the parties to be able to use various customer inputs in order to review and analyze the impact certain criteria may have on those parties. I attempted to see what impact storage may have on the end result, again that that effort was not allowed because of the various cell restraints contained within the COSS. Efforts to work with gallons used, various cost undertakings for instance using what the impact might be on rate and class by inputting alternatives to the solar and AMI lease costs and examining potential viable alternative all efforts were thwarted by the inability to work with what was filed. The COSS model as presented and filed was not conducive to analysis and review of certain COSS inputs, for example capacity factors and demand allocators were not allowed to be tested because of the flaws in the COSS model.

The second and more problematic point is that some wholesale customers are being asked to bear the lease cost of the purchased AMI meters but not using more accurate AMI data inputs because of the timing of the COSS.

The third basic problem experienced by WTWA is that nowhere in the COSS has Bloomington recognized that some wholesale customers have storage facilities that would normally impact the usage on the maximum day and maximum hour of the system which may impact the rate charged or the institution of a sub rate recognizing the storage contribution

Q12. Does WTWA have available storage facilities?

A12. Yes, WTWA has several storage facilities available to it and Bloomington if the COSS would have acknowledged its existence. WTWA has available a 200,000 gallon water tower and a 350,000 gallon stand pipe. Usable water storage is approximately 300,000 gallons which was ignored in the preparation of the COSS. Any responsible COSS used to design retail tariff rates for all customers, including wholesale customers would have taken into consideration any available storage facilities

Bloomington has acknowledged that wholesale customer storage was not even looked at in preparing its COSS.

Q13. Did the COSS consider any capital contributions made by wholesale customers to Bloomington's water system?

A13. In response to WTWA data requests, Bloomington stated that such capital contributions should be considered in a COSS, but none were considered because none of Bloomington's wholesale customers made any capital contributions to Bloomington's system. Bloomington's COSS consultant also stated Bloomington provided that information to him.

Q14. Do you believe Bloomington's statements regarding wholesale customer capital contributions to be correct?

A14. No. In discussions with representatives of WTWA they indicate that WTWA made a contribution of $150,000 on March 15, 2000 and on July 7, 1998, they also made a contribution of $30,000. Both of those contributions were ignored in developing the COSS and the wholesale rate proposed to be charged to WTWA.

Q15. Do you know if other of Bloomington's wholesale customers' made capital contributions to Bloomington's water system?

A15. I do not. Given the nature of small water systems such capital contributions by wholesale customers are fairly common but Bloomington denies any capital contributions, including the contributions known to have been made by WTWA.

Q16. Does this conclude your direct testimony?

A16. At this time.

WTWA Exhibit 1

VERIFICATION

I affirm under the Penalties of perjury that the forgoing testimony is to the best of my knowledge true and accurate.

Edward T. Rutter (signature) 7/30/2021

Name Edward T. Rutter Date

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2

Q-1-22: Did UFS examine the storage capacity of WTWA and verify how the availability
of the WTWA storage capacity impacts WTWA contribution to usage on average
day demands, peak day demands, and peak hour demands?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

The cost of service study identified the cost to serve wholesale customers. All wholesale
customers were combined, and no specific analysis of individual wholesale customers
was performed

Bloomington Data Request Response to WTWA No. 1-31

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2
Q-1-31: In developing your COSS, did you use the AMI meter hourly usage data?
Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.
Response:
No. At the time of developing the cost of service study, Bloomington did not have a full
year of AMI meter hourly usage data

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2
Q-1-31: In developing your COSS, did you use the AMI meter hourly usage data?
Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.
Response:
No. At the time of developing the cost of service study, Bloomington did not have a full
year of AMI meter hourly usage data

Bloomington Data Request Response to WTWA No. 1-33

IURC Cause No. 45533

Bloomington's Responses to Washington Township's DR 1

May 17, 2021

21454261.v2

Q-1-33: Did any of the wholesale customers make any contribution to the Bloomington
system, by payments, the contribution of assets or otherwise, other than payment
for water service?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections. Bloomington further objects to this Data Request on the grounds that it
is overly broad, unduly burdensome, and seeks the production of irrelevant information not
proportional to the needs of this case.

Response:

No.

Bloomington Data Request Response to WTWA No. 1-34

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 1
May 17, 2021
21454261.v2

Q-1-34: Did your COSS take into account the contributions, referenced in Data Request 1.33, by each wholesale customer, including WTWA?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections. Bloomington further objects to this Data Request on the grounds that it is overly broad, unduly burdensome, and seeks the production of irrelevant information not proportional to the needs of this case.

Response:

Not applicable. As stated in response to Q-1-33, no contributions were made, so no contributions could be "taken into account."

Bloomington Data Request Response to WTWA No. 2-2

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 2
May 17, 2021
5
LEGALDOCS\611363\100009\21454263.v2-5/16/21

Q-2-2: On page 3, lines 7 through 9, you indicate that the Smart Meter Contract provides for cost savings and other benefits through the use and installation of the smart meter equipment over the term of the contact for Bloomington's water utility and wastewater utility. Does the Smart Meter Contract provide benefits to the wholesale customers that the Smart Meters do not?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections. Bloomington further objects to this Data Request on the grounds that this request assumes facts not in evidence.

Response:

Yes. The Smart Meter Contract allowed Bloomington to complete the meter changeout more rapidly (approximately within a year), rather than engage in a long, drawn-out process over several years. The faster roll-out allowed Bloomington to quickly realize benefits of the AMI meter program as described in Mr. Underwood's testimony. Moreover, the concentrated efforts to roll out AMI smart meters likely resulted in greater efficiencies in AMI meter deployment through concentrated and focused efforts in contrast to a diluted roll-out taking place over several years.

Bloomington Data Request Response to WTWA No. 2-4

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 2
May 17, 2021
7
LEGALDOCS\611363\100009\21454263.v2-5/16/21

Q-2-4: Is the allocation of AMI meter costs to the wholesale customers supported by
cost savings and benefits to those wholesale customers derived from the installation of AMI meters?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

Bloomington determined that all customers would receive an AMI meter no matter their
customer classification. The cost savings and benefits derived from the installation of the
AMI meters accrue to Bloomington and all of its customers by allowing Bloomington to
accurately measure consumption and overall system efficiency, to improve accuracy from
the newer meters, and to provide additional customer engagement via the customer portal.

Moreover, wholesale customers are not allocated any meter cost in the wholesale
volumetric rate. Wholesale customers are allocated a meter cost based on the number and
size of meters serving them.

A. Please provide any cost benefit analysis to support the answer to the above

question.
Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.
Response:
No formal cost benefit analysis was performed for wholesale customers.

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 4
May 20, 2021
LEGALDOCS\611363\100009\21459119.v2-5/19/21

Q-4-13: On page 17, lines 21 to 23, and page 18, lines 1 to 5 you discuss the use of AMI meters and that you do not have a full year of AMI data. However, it appears that prior to the close of the record in this Cause you should have one (1) full year of AMI data. Do you have plans to augment or modify your COSS, using updated AMI data, prior to the close of the record in this Cause?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

No.

A. Even if you had no current plans to update your COSS, would you be willing to do so?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

No. Any update would use information that would be outside of the period for fixed, known and measurable adjustments to test year results.

Bloomington Data Request Response to WTWA No. 5-10

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 5 -10
May 24, 2021
21467514.v1

Q-5-10: For Witnesses Kelson and/or Beauchamp. Are AMI meters important to being able to more accurately perform future Cost of Service Studies ("COSS")?

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

Yes.

A. Please explain why.

Objection: Bloomington objects to the Data Request on the basis of the foregoing general objections.

Response:

AMI meters are important to being able to more accurately perform future cost of service studies because Bloomington will have more data to identify peak demands and variability of demand. The AMI technology would also aid in the collection and validation of data.

Bloomington Data Request Response to WTWA 6-7

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 6
June 21, 2021
21512612.v1

Q-6-8: Mr. Beauchamp responded that none of Bloomington's wholesale customers
made any contributions to the Bloomington system, by payments, the contribution of assets, or otherwise, other than payment for water service. How
does he know this?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

Information was provided by Bloomington.

A. What was done to verify that information?

B. If such contributions had been made by any wholesale customer, should those
contributions have been "taken into account" in the COSS?

C. If so, how?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

A. The information was discussed with Bloomington staff.

B. Yes.

C. Certain asset accounts would change that would affect the allocation of existing
debt service and indirect overhead cost allocations.

Bloomington Data Request Response to WTWA NO. 6-8

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 6
June 21, 2021
21512612.v1

Q-6-7: In developing the COSS, would Mr. Beauchamp have used AMI meter hourly
usage data if it had been available?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

Yes.

A. Why?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections.

Response:

AMI data allows for more accuracy in developing class peaking factors

Bloomington Data Request Response to WTWA 6-24

IURC Cause No. 45533
Bloomington's Responses to Washington Township's DR 6
June 21, 2021
21512612.v1

Q-6-24: In Response to Data Request 2-11, Bloomington provided the total estimated
purchased power savings in 2020 for the waterworks. What are the savings to the
water utility net of allocated Solar Energy Contract costs?

Objection: Bloomington objects to the Data Request on the basis of the foregoing
general objections. Bloomington further objects to this Data Request as overly broad,
unduly burdensome, compound, vague, ambiguous, and seeks the production of irrelevant
information not proportional to the needs of this case.

Response:

The savings to the water utility are not known at this time. As Bloomington provided in
response to Washington Township DR 2-11, at present all figures are currently estimates.
Accordingly, the actual savings net of allocated costs is unknown at present.

OFFICIAL EXHIBITS

Intervenor WTWA
Exhibit 2

IURC
INTERVENOR'S - WTWA
EXHIBIT NO. 2
10-22-21
DATE
REPORTER

VERIFIED CROSS ANSWERING TESTIMONY
OF
EDWARD T. RUTTER
CAUSE NO. 45533

Q1. Please state your name and business address.

A1. My name is Edward T. Rutter. My business address is 1776 North Meridian Street, Suite 500, Indianapolis, Indiana.

Q2. By whom are you employed and in what capacity?

A2. I am employed with the firm of LWG CPAs and Advisors ("LWG") as a Manager.

Q3. Who do you represent in this proceeding?

A3. Intervenor Washington Township Water Authority ("WTWA").

Q4. Are you the same Edward T. Rutter that filed direct testimony on behalf of WTWA in this proceeding?

A4. Yes.

Q5. What is the purpose of this filing?

A5. I am now offering cross answering testimony on behalf of WTWA.

Q6. What is the purpose of your cross answering testimony?

A6. I have prepared cross answering testimony in response to the direct testimony of the Indiana Office of the Utility Consumer Counselor's ("OUCC") witness Mr. Mierzwa. My position is that the use of the City of Bloomington's flawed cost of service study ("COSS") should be rejected and not used to support any rate design in this Cause. Any use of the COSS will, with virtual certainty, produce a result that is unjust and unreasonable, and would only be otherwise by unlikely happenstance.

Q7. In your professional opinion, is the rate design recommended by Mr. Mierzwa on behalf of the OUCC just and reasonable and beneficial and fair to all customers?

A7. No.

Q8. What is the basis for your opinion on this matter?

A8. I reviewed the direct testimony filed by all parties in this proceeding, particularly the proposed COSS and rate design. My review and analysis of that testimony indicates that the COSS is flawed and should be rejected by the Commission and an across the board rate design be established. Of the consumer parties, only Mr. Mierzwa suggests otherwise.

Q9. Does Mr. Mierzwa find fault with the COSS presented by Mr. Beauchamp on behalf of the City of Bloomington?

A9. Yes. On pages 3 and 4 of Mr. Mierzwa's direct testimony, he raises concerns with the COSS prepared by the City of Bloomington's witness. Yet Mr. Mierzwa goes on, after finding faults with the COSS filed by the City of Bloomington in this proceeding, to attempt to design rates using a flawed COSS. The flawed COSS necessarily results in a flawed rate design which appears to unevenly allocate benefits and costs among the rate classes. In my opinion, Mr. Mierzwa's proposed rate design is unjust and unreasonable.

Q10. Does this conclude your cross answering testimony?

A10. At this time.

VERIFICATION

I affirm under the penalties for perjury that the foregoing cross answering testimony is to the best of my knowledge true and accurate.

9/3/2021

Edward T. Rutter | Date

2

AES Indiana
Petersburg Energy Center
AES Indiana Witness EKM Attachment 5.4.2f

Cause No. 45591

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.2g

Cause No. 45591

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.5

Cause No. 45591

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.5.3

Cause No. 45591

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.6

Cause No. 45591

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.2a

Cause No. 45591

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.2b

Cause No. 45591

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.2c

Cause No. 45591

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.2d

Cause No. 45591

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-5.4.2e

Cause No. 45591

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July 30, 2021
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Cause No. 45591

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July 30, 2021
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Attachment 1.1

ipl an AES company

2019 Integrated Resource Plan (IRP) Non Technical Summary

BACKGROUND

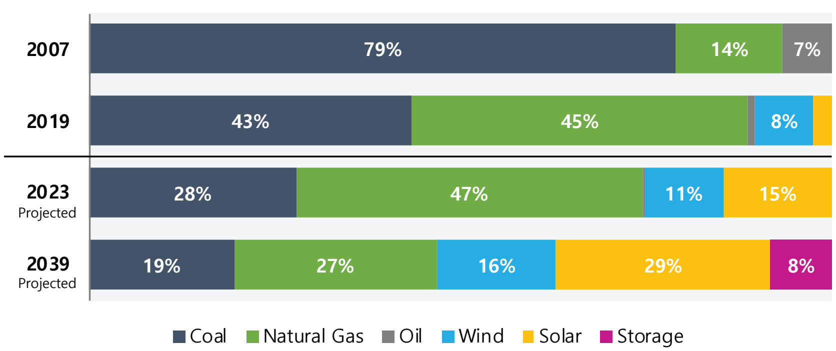
Indianapolis Power & Light Company ("IPL") is engaged primarily in generating, transmitting, distributing and selling electric energy to more than 500,000 retail customers in Indianapolis and neighboring areas; the most distant point being about 40 miles from Indianapolis. IPL's service area covers about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

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

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

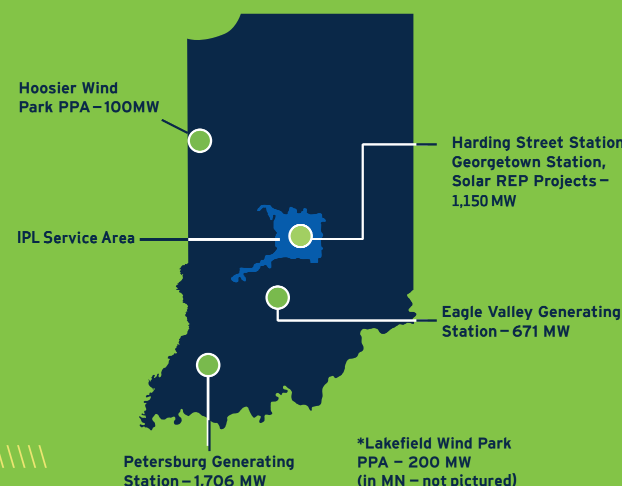
Figure 1 - ***IPL RESOURCE MIX***

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



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

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



IRP OBJECTIVE

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

IRP Process

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

Public Advisory Process

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

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

Public Advisory Meeting #1
January 29, 2019
Topics covered: 2016 IRP review, introduction to the 2019 IRP (timeline, mission, objectives), capacity discussion, 2019 IRP starting point, modeling replacement resources, DSM/EE modeling and load forecast update

Public Advisory Meeting #2
March 26, 2019
Topics covered: stakeholder presentations, detailed load forecast, IPL DSM market potential study and end use results, commodity prices and modeling, assumptions for replacement resources, scenario analysis framework and proposed scenarios

Public Advisory Meeting #3
May 14, 2019
Topics covered: electric vehicle and distributed solar forecast, stakeholder presentation, detailed load forecast, DSM bundles in IRP modeling, modeling and scenario recap

Public Advisory Meeting #4
September 30, 2019
Topics covered: modeling and scenario recap, preliminary model results, optimized portfolios, portfolio metrics

Public Advisory Meeting #5
December 9, 2019
Topics covered: summary of IPL 2019 short term action plan, 2019 IRP modeling insights, analysis of alternatives and preferred resource portfolio

IRP MODELING

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

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

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

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

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

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

PREFERRED RESOURCE PORTFOLIO

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

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

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

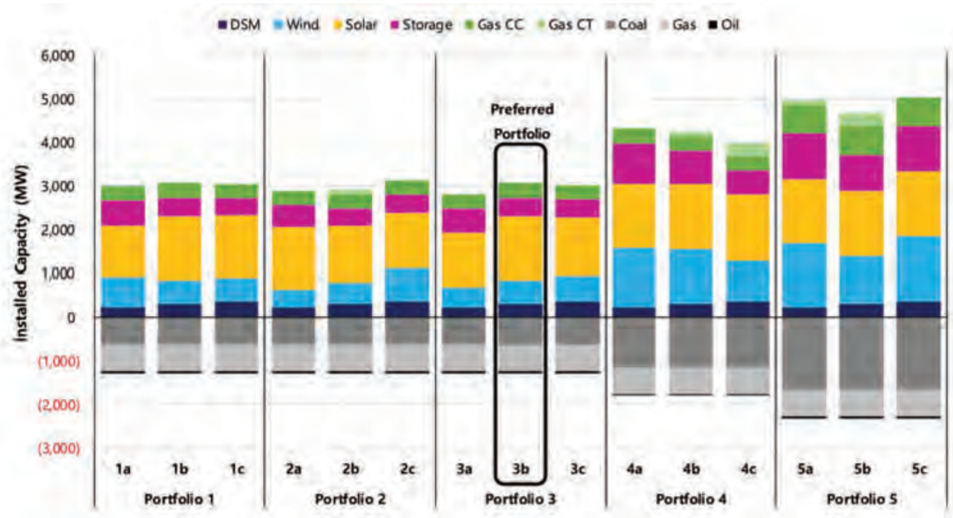
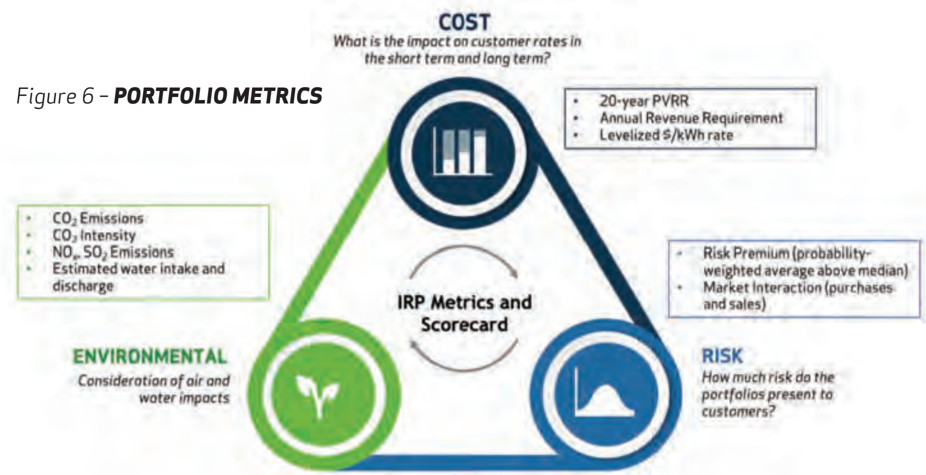


Figure 6 – ***PORTFOLIO METRICS***



SHORT TERM ACTION PLAN

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

Retirement of 630 MW of coal by 2023

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

Competitively bid for 200 MW of replacement capacity

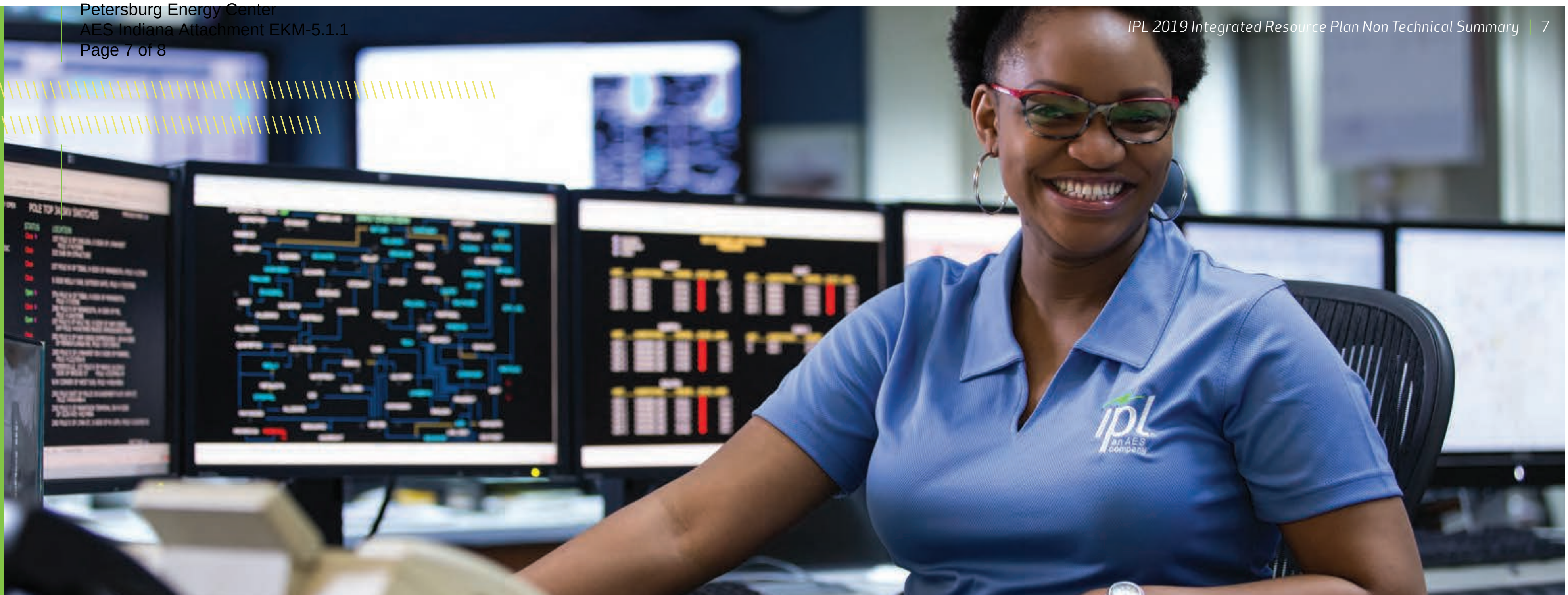
IPL intends to issue an all-source Request for Proposal (“RFP”) to competitively procure replacement capacity by June 1, 2023, which is the first year IPL is expected to have a capacity shortfall. IRP modeling indicates that a combination of wind, solar and storage resources would be the lowest cost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

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

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

Maintain safe, reliable, cost effective generation at Petersburg

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



CONCLUSION

As part of the 2019 IRP, IPL is focused on

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

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

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Maintains generation optionality

Greener Energy Future
Moves the company to more renewables

ipl an AES company

2019 Integrated Resource Plan (IRP) Non Technical Summary

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

Cause No. 45591

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

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

2016 IRP RECAP

Patrick Maguire

Director of Resource Planning

2016 IRP SUMMARY

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

Report Filed on November 1, 2016

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

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

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

2016 IRP: COMMENTS AND IMPROVEMENTS TARGETED

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

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

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

INTRODUCTION TO THE 2019 IRP

Patrick Maguire

Director of Resource Planning

IPL 2019 IRP

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

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

What is a preferred resource portfolio?

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

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

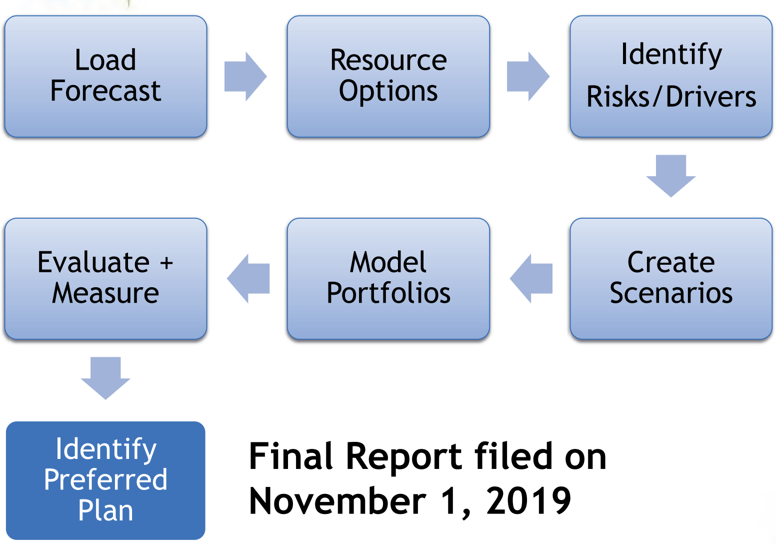
2019 IRP STAKEHOLDER PROCESS

Dates to follow for meetings #3-5

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

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

IRP PROCESS OVERVIEW



Final Report filed on November 1, 2019

2019 IRP PARTNERS AND RESOURCES

Key Partners

Ascend Analytics — Better models. Better decisions.

Itron

GDS Associates, Inc. — Engineers & Consultants

Concentric Energy Advisors

Vanry Associates

Resources

IHS Markit

Wood Mackenzie — Power & Renewables

ABB

S&P Global Market Intelligence — Energy

NREL — National Renewable Energy Laboratory

Bloomberg New Energy Finance

eia — U.S. Energy Information Administration

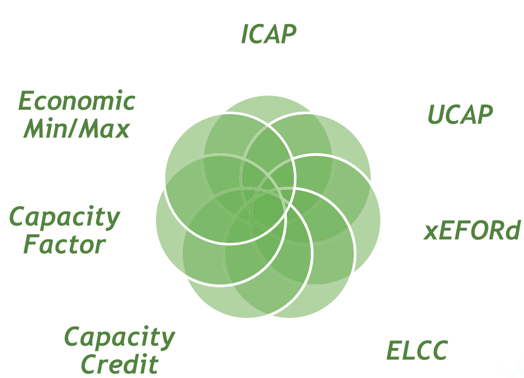
BREAK

CAPACITY: DEFINING COMMON IRP MODELING TERMS

Patrick Maguire
Director of Resource Planning

CAPACITY DEFINITIONS

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



ICAP

ICAP = INSTALLED CAPACITY

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

Examples:

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

XEFORD

xEFORd = Equivalent Demand Forced Outage Rate excluding some outages

Per MISO BPM-011, Section 3.5.4*:

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

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

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

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

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

Link: MISO PY 19/20 Resource Adequacy Documents

ELCC

ELCC = Effective Load Carrying Capability = Capacity Credit

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

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

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

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

UCAP

UCAP = UNFORCED CAPACITY = FIRM CAPACITY = PLANNING CAPACITY

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

THERMAL RESOURCE EXAMPLE

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

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

WIND AND SOLAR EXAMPLES

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

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

ICAP VS UCAP: EXAMPLES

ICAP = Installed Capacity UCAP = Unforced Capacity

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

ICAP VS UCAP: EXAMPLES

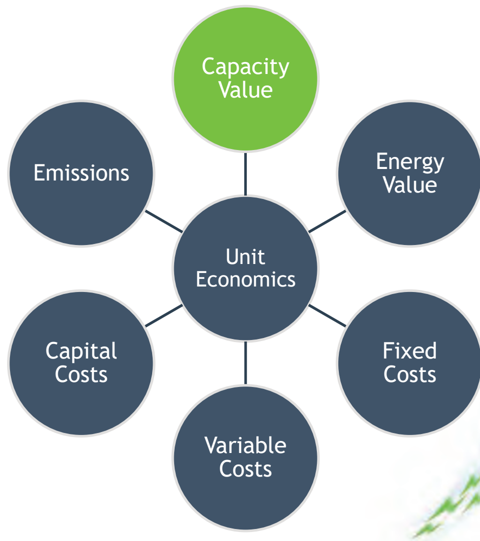
ICAP = Installed Capacity UCAP = Unforced Capacity

To Cover a 1,000 MW UCAP Shortfall:

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

CAPACITY: ONLY ONE PIECE OF RESOURCE VALUATION PUZZLE

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



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

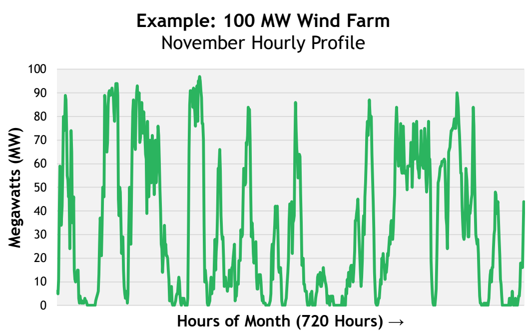
Economic Min/Max: for thermal units, the MW limits used for dispatch modeling in the IRP

- 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



Wind Farm Capacity (ICAP) = 100 MW

Monthly Total Energy = 23,500 MWh

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

Capacity Factor = Actual MWh / Max Potential MWh

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

2019 IRP STARTING POINT: IPL LOAD AND RESOURCES

Patrick Maguire

Director of Resource Planning

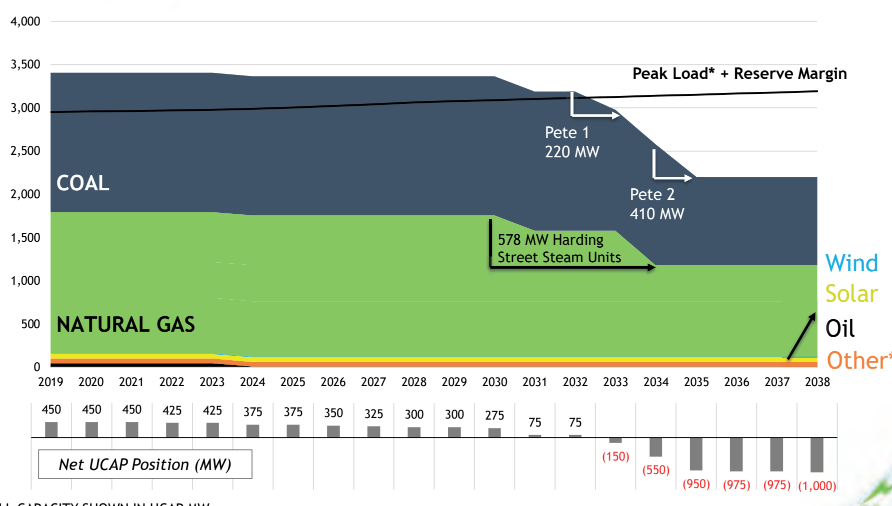
IPL'S CHANGING RESOURCE MIX

2009 - 2018

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

IRP STARTING POINT

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

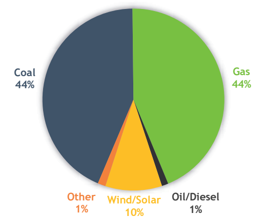


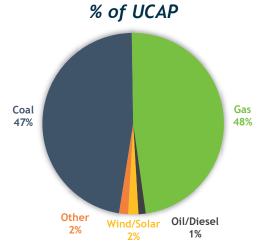
ALL CAPACITY SHOWN IN UCAP MW
* Other: ACLM (37 MW), CVR (17 MW), Rider 17 (1 MW)

* *Preliminary peak load forecast*

IPL RESOURCES: SUMMARY

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





ICAP = Installed Capacity   UCAP = Unforced Capacity

IPL RESOURCES: NATURAL GAS

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

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

Total Natural Gas UCAP: 1,634 MW

IPL RESOURCES: WIND AND SOLAR

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

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

Total Renewable ICAP: 396 MW

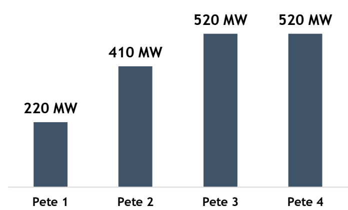
Total Renewable UCAP: 62 MW

IPL RESOURCES: COAL

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

Total Coal ICAP: 1,706 MW

Total Coal UCAP: 1,608 MW



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

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

Ascend Analytics

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

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

Differentiated Value

PowerSimm OPS
OPERATIONAL STRATEGY

1 to 10 days

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

PowerSimm Portfolio Manager
PORTFOLIO MANAGEMENT

1 month to ≈ 5 years

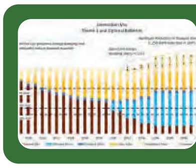
- Budgeted cash flows equal realized cash flows
- Management of retail load risk with volumetric and market price uncertainty
- Impact of hedges on reducing cash flow uncertainty
- Retail management & pricing
- Portfolio management with analytics insight to manage risk (CFaR, GMaR, EaR)
- Track portfolio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

PowerSimm Planner
LONG-TERM PLANNING

5 to 30 years

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

Ascend Analytics expertise in long-term planning

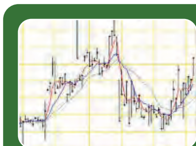


Integrated Resource planning

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

Regulatory and stakeholder support

- Testimony and interrogatory
- Expert witness



Fundamental and Market Analysis

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

Ascend Analytics

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
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PowerSimm Planner
LONG-TERM PLANNING

5 to 30 years

- Resource planning
- Optimal expansion planning
- Renewable integration
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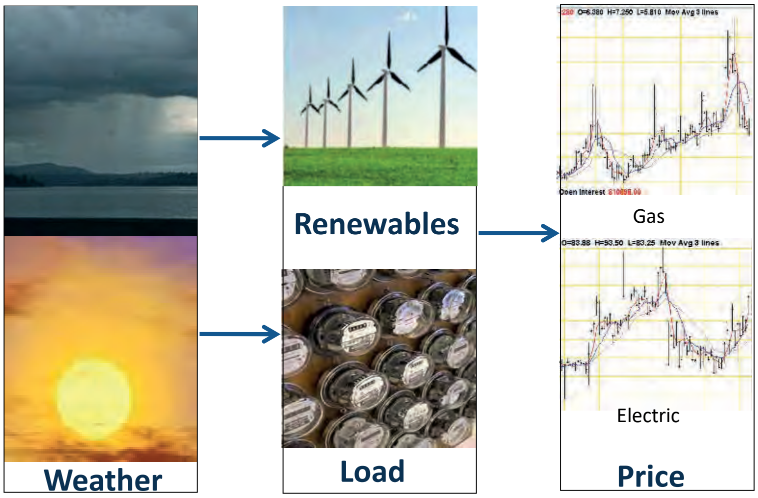
- Financial analysis

Ascend Analytics

Weather → Renewables/Load → Price Simulations



Ascend Analytics

Weather – Load – Delivery – Price Paradigm

Weather

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

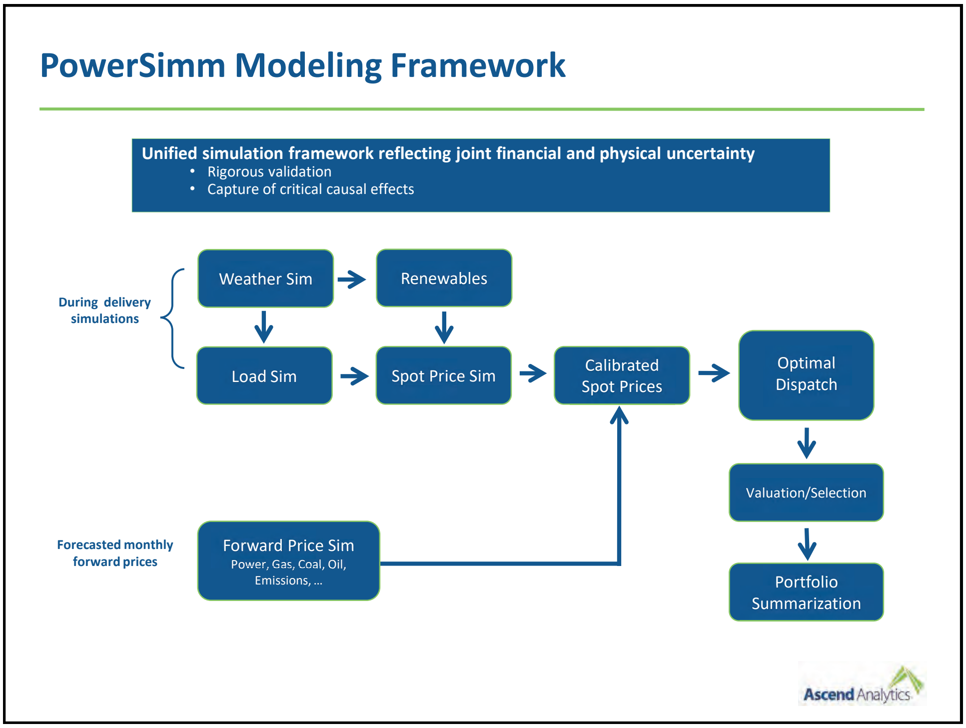
Load

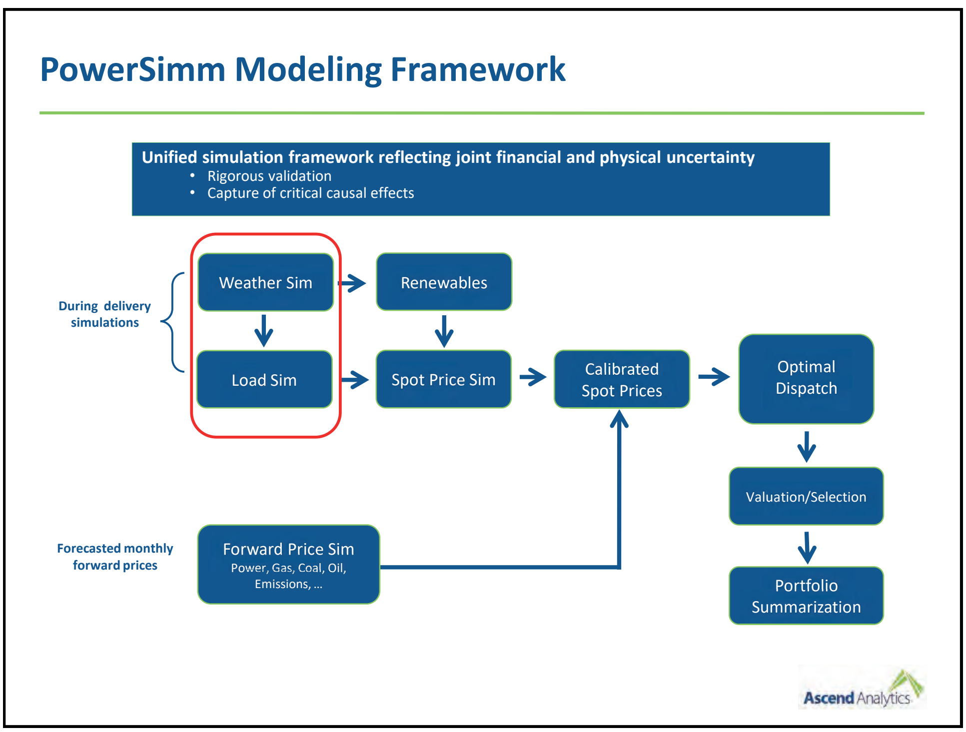
- Load is driven primarily by weather
- Key benefit is analysis of high and low temperatures produce more accurate energy expectations, and hourly demand

Delivery

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

Ascend Analytics


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
Valuation/Selection
Forecasted monthly forward prices
Forward Price Sim
Power, Gas, Coal, Oil, Emissions, ...
Portfolio Summarization
Ascend Analytics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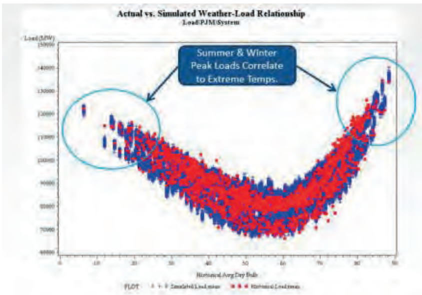
Power, Gas, Coal, Oil, Emissions, ...
Portfolio Summarization
Ascend Analytics

Preserving Relationship and Dependency

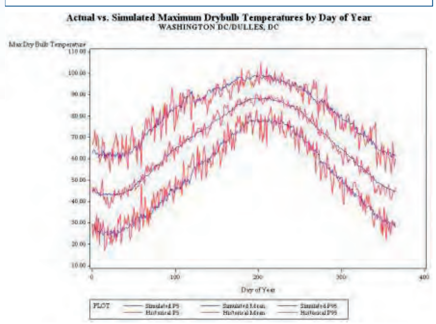


Maintaining Relationships

- 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

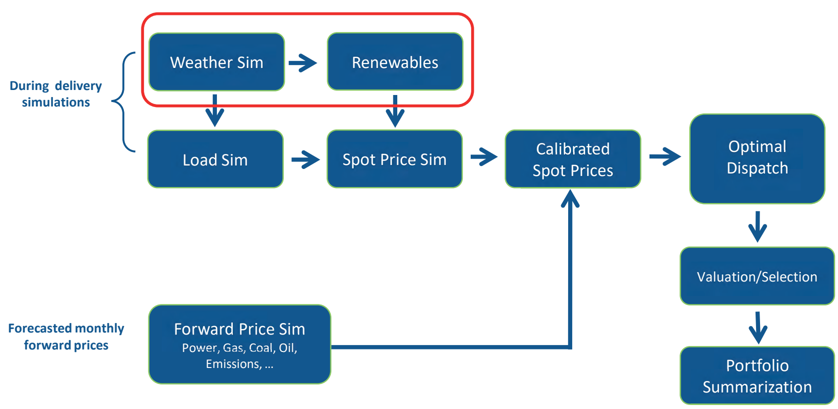


Ascend Analytics

PowerSimm Modeling Framework

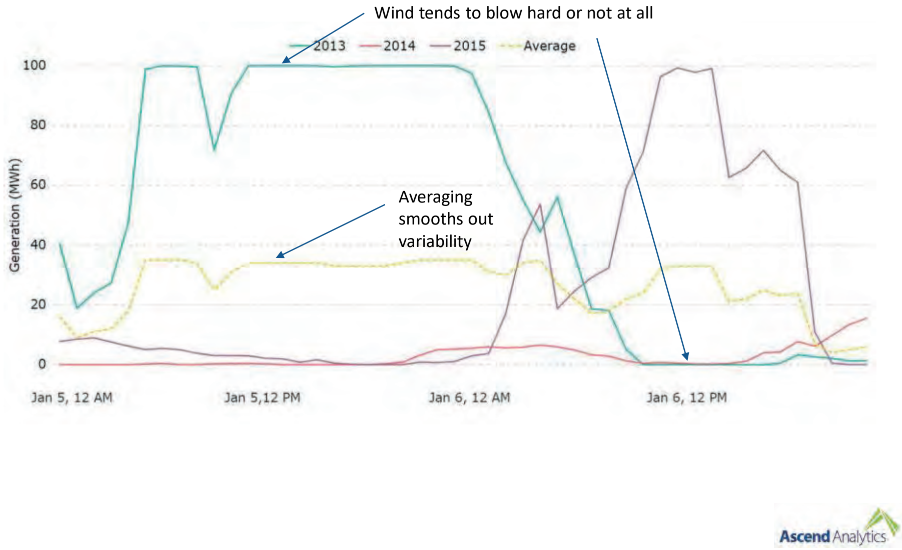
Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Capture of critical causal effects

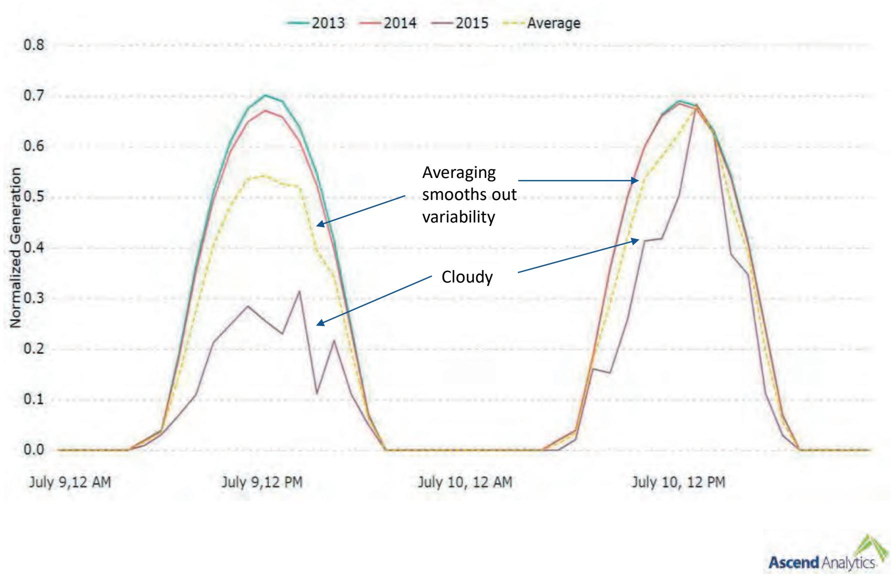


Ascend Analytics

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



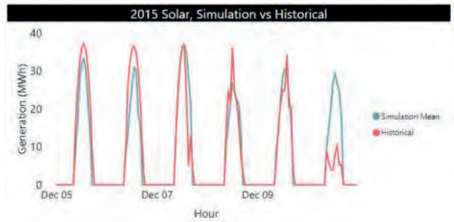
Why You Can't Just Average Renewables: Solar in July

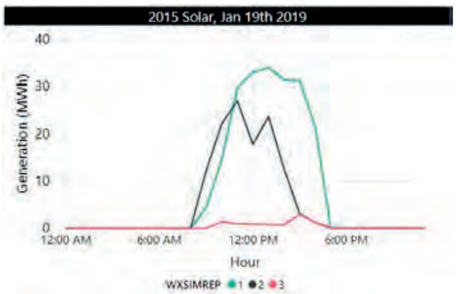


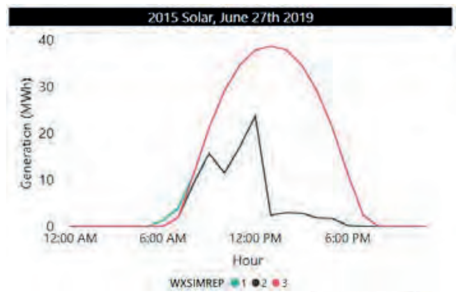
Renewables - Solar

Simulated vs Historical:

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





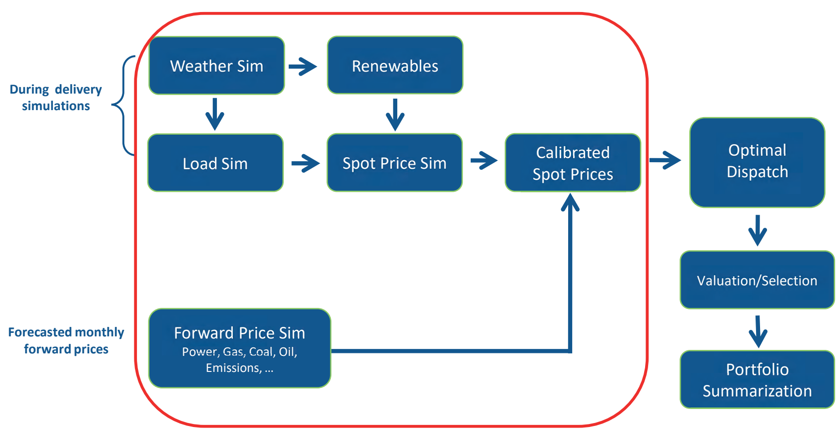


Ascend Analytics

PowerSimm Modeling Framework

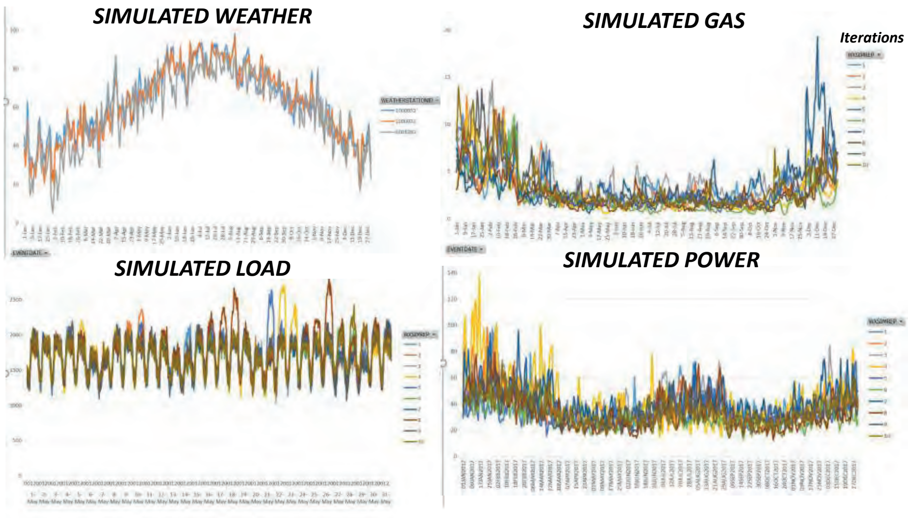
Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Capture of critical causal effects



Ascend Analytics

Example: Simulated Temperature, Load, Gas and Power Prices



Ascend Analytics

PowerSimm Modeling Framework

Unified simulation framework reflecting joint financial and physical uncertainty
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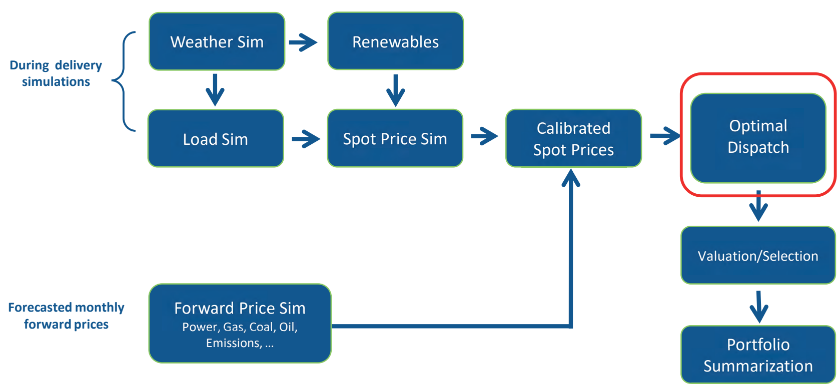


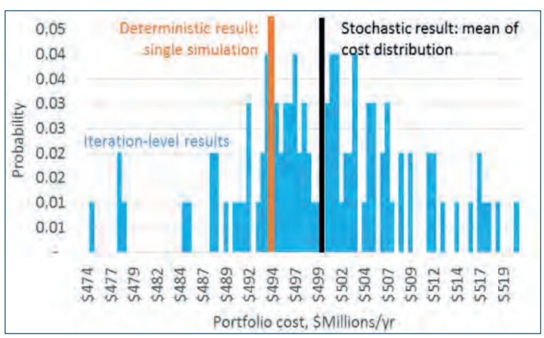
Ascend Analytics

Thermal Asset Modeling

Ascend Analytics

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



Ascend Analytics

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

PowerSimm finds the best plan across hundreds of possible future conditions

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

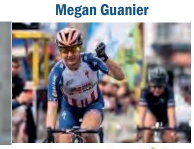
Dave Scott

Best Triathlete

Katie Ledecky

Ryan Hall

Megan Guanier



Ascend Analytics

ipl an AES company

REPLACEMENT RESOURCES IN THE 2019 IRP

Patrick Maguire

Director of Resource Planning

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

NATURAL GAS

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

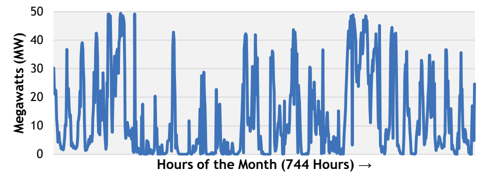
NATURAL GAS
Mature technologies with more certainty around operational parameters and capital costs

WIND

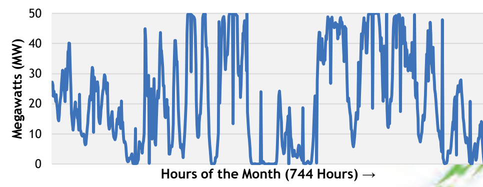
Building Profiles and Capacity Factors

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

Hypothetical 50 MW Wind Farm in Indiana
JULY Hourly Profile



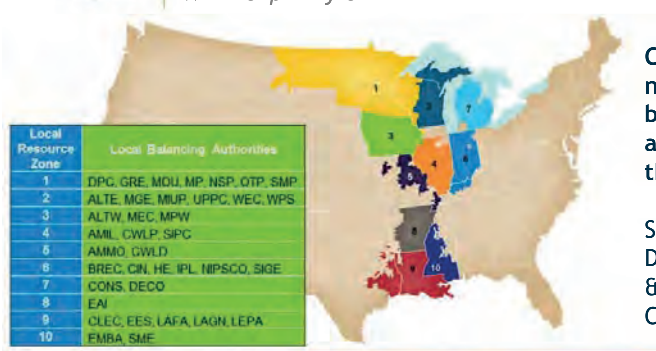
Hypothetical 50 MW Wind Farm in Indiana
JANUARY Hourly Profile



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

WIND (CONT'D)

Wind Capacity Credit



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

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

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

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

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

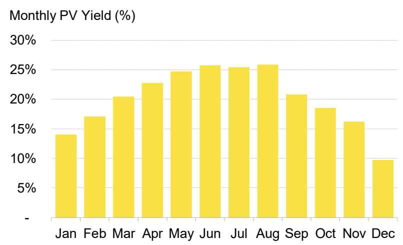
* MISO Wind & Solar Capacity Credit Report, December 2018 (PDF): https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf

SOLAR

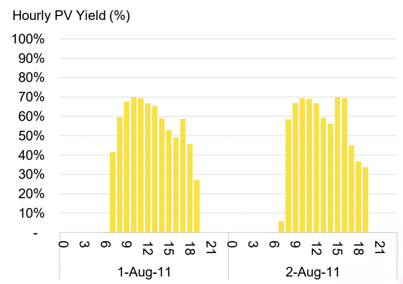
Building Profiles and Capacity Factors

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

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



Source: BloombergNEF & PVGIS.



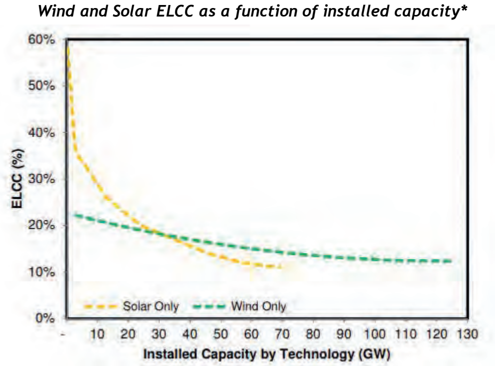
Source: BloombergNEF & PVGIS.

SOLAR (CONT'D)

Solar Capacity Credit

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

Wind and Solar ELCC as a function of installed capacity*



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

STORAGE

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

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

BREAK

DSM/EE AND LOAD FORECAST OVERVIEW

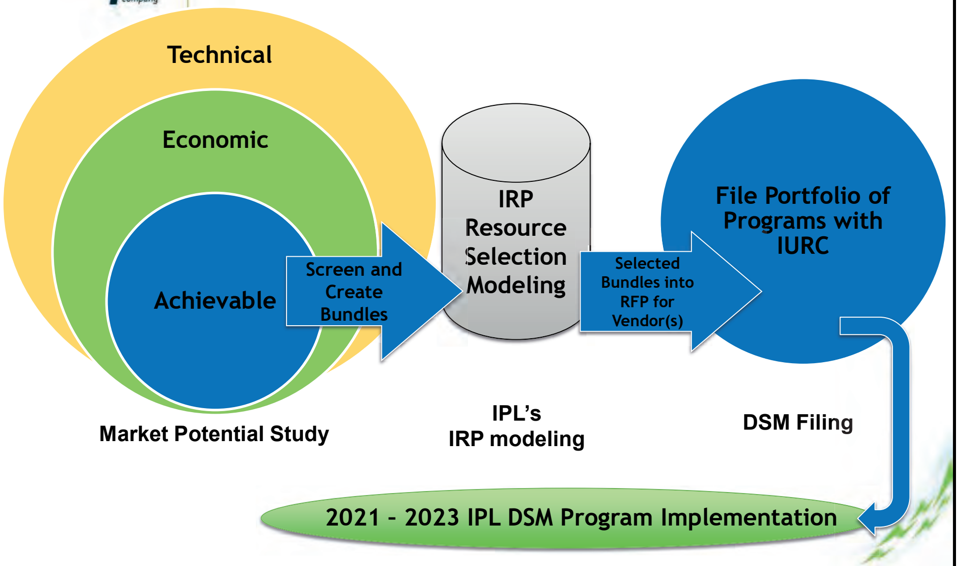
Erik Miller

Senior Research Analyst

DSM UPDATE

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

DSM PROCESS & THE IRP



DSM BUNDLES

Example of Bundles from the IPL 2016 IRP:

Near-term DSM "blocks" developed for 2018 - 2020 (Base Case Selections)			
	Levelized Utility Cost per MWh		
Sector and Technology	(up to $30/MWh)	($30-60/MWh)	($60+ /MWh)
EE Residential HVAC	Selected	Not Selected	Not Selected
EE Residential Lighting	Selected	N/A	N/A
EE Residential Other	Selected	Not Selected	Not Selected
EE C&I HVAC	Selected	Not Selected	Not Selected
EE C&I Lighting	Selected	Not Selected	Not Selected
EE C&I Other	Selected	Not Selected	Not Selected
EE C&I Process	Not Selected	Not Selected	N/A
EE Residential Behavioral	Not Selected		
DR Water Heating DLC	Not Selected		
DR Smart Thermostats	Not Selected		
DR Emerging Tech	Not Selected		
DR Curtail Agreements	Not Selected		
DR Battery Storage	Not Selected		
DR Air Conditioning Load Mgmt	Not Selected		

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

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

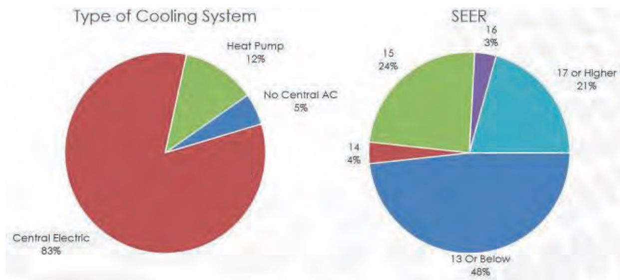
MARKET POTENTIAL STUDY PROCESS

- 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



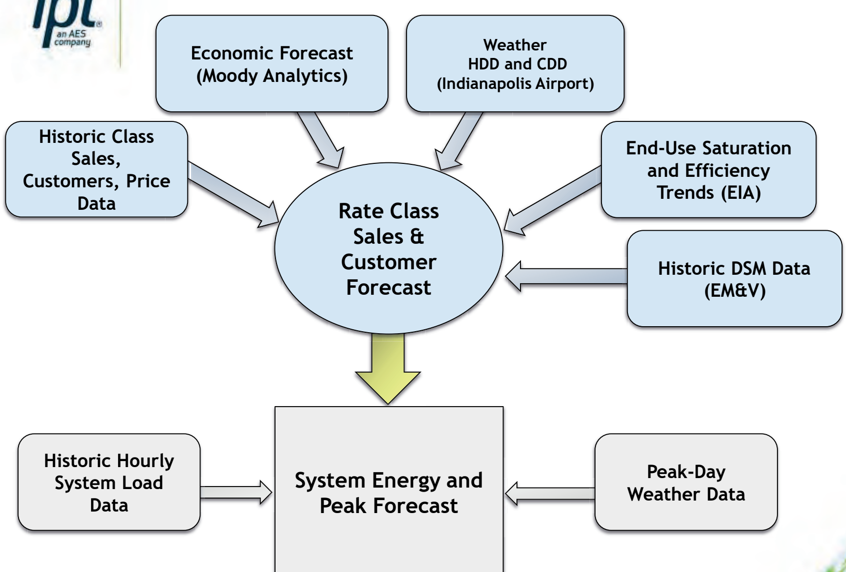
LOAD FORECASTING UPDATE

- 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

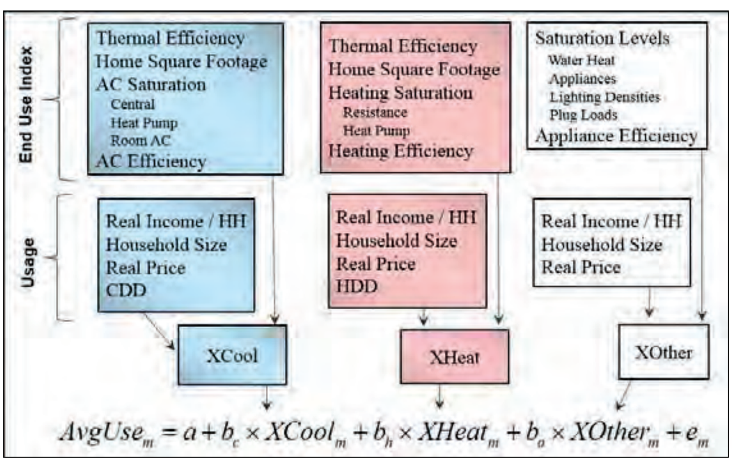
FORECAST MODELING FRAMEWORK



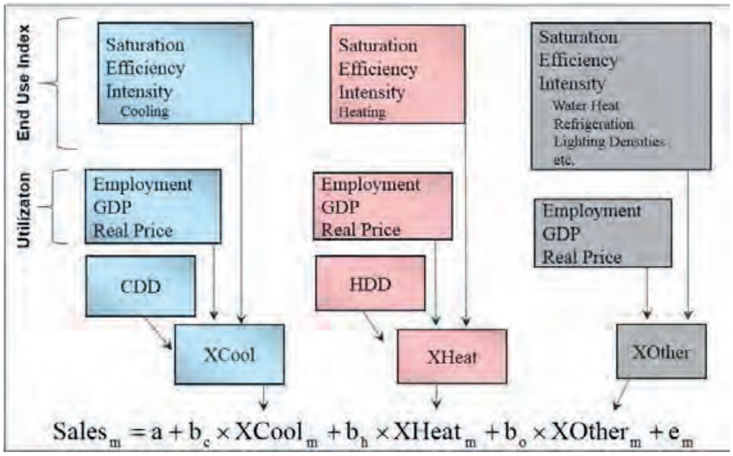
FORECAST MODELS

- 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



COMMERCIAL MODEL FRAMEWORK



INDUSTRIAL MODEL FRAMEWORK

Industrial sales are estimated with a generalized econometric model

Cooling Degree Days

Manufacturing Employment
Manufacturing Output
Price

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

DSM AND LOAD FORECAST SUMMARY

- DSM
  - MPS Results will be presented at the March 13th meeting
    - Introduction to bundles
- Load Forecast
  - 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

ipl an AES company

NEXT STEPS

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

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

IPL 2019 IRP: PUBLIC ADVISORY MEETING #2

March 26, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

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

MEETING 1 RECAP

Patrick Maguire

Director of Resource Planning

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2019 IRP STAKEHOLDER PROCESS

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

6

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

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MODEL INPUTS

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

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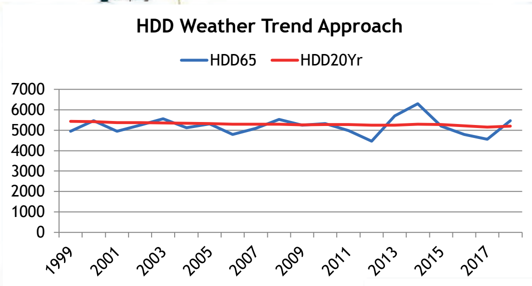
WEATHER 20-YR TRENDED

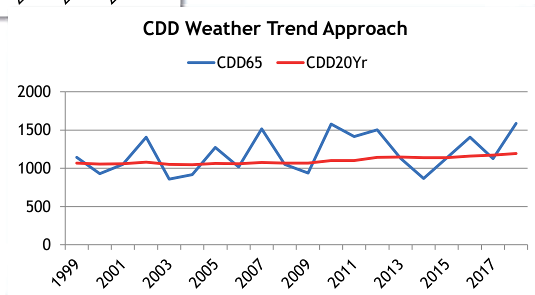


Trend line (red) developed for the 20-yr rolling average HDDs

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

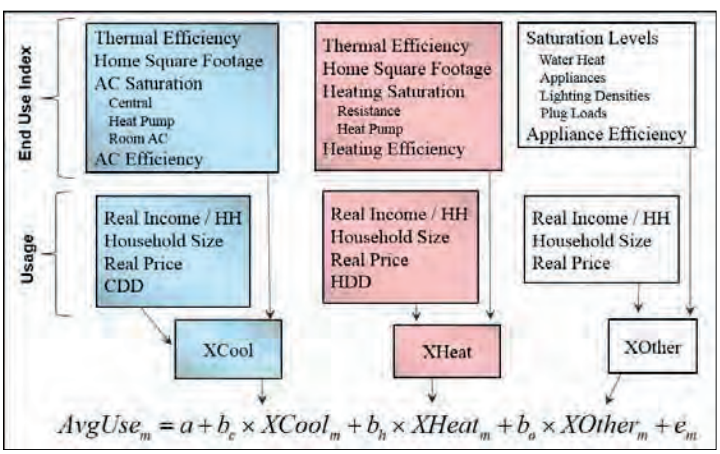
Trend line (red) developed for the 20-yr rolling average CDDs

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

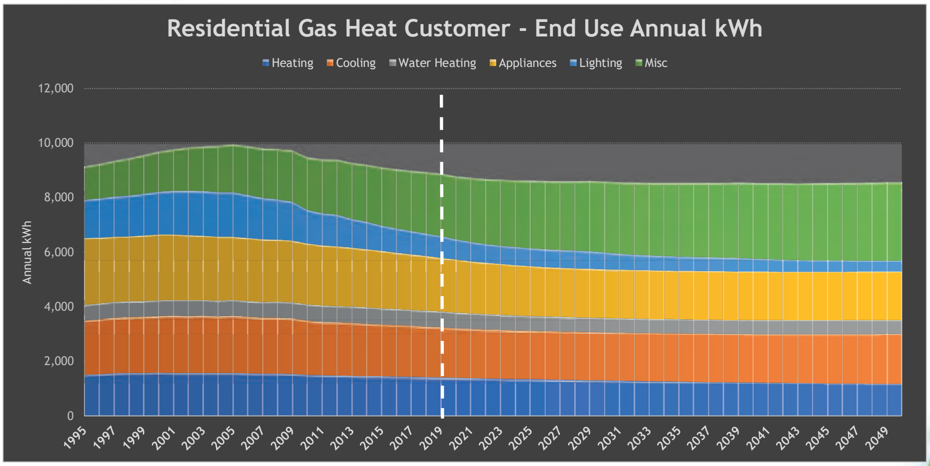


HDD = Heating Degree Day
CDD = Cooling Degree Day

RESIDENTIAL MODEL



RESIDENTIAL END USE TRENDS



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

AAGR = Average Annual Growth Rate

Source: 2018 EIA Annual Energy Outlook

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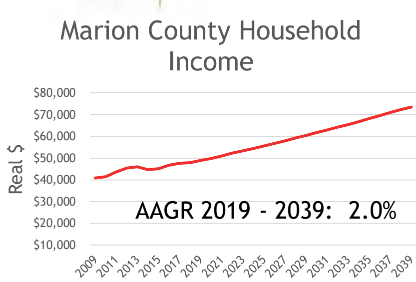
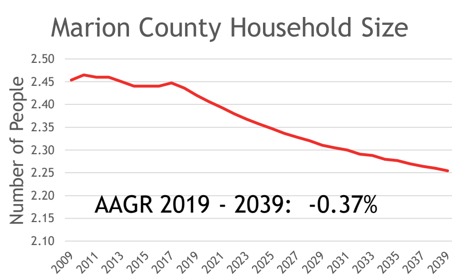
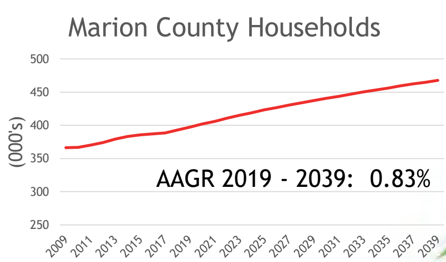
RESIDENTIAL ECONOMIC DRIVERS





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



AAGR = Average Annual Growth Rate

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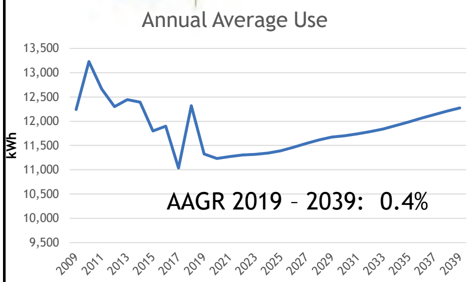
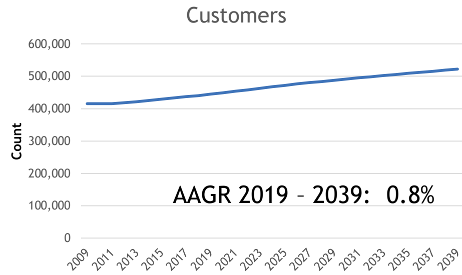
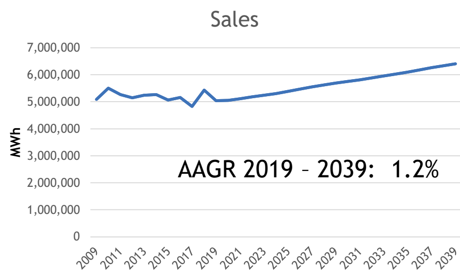
RESIDENTIAL FORECAST







AAGR = Average Annual Growth Rate

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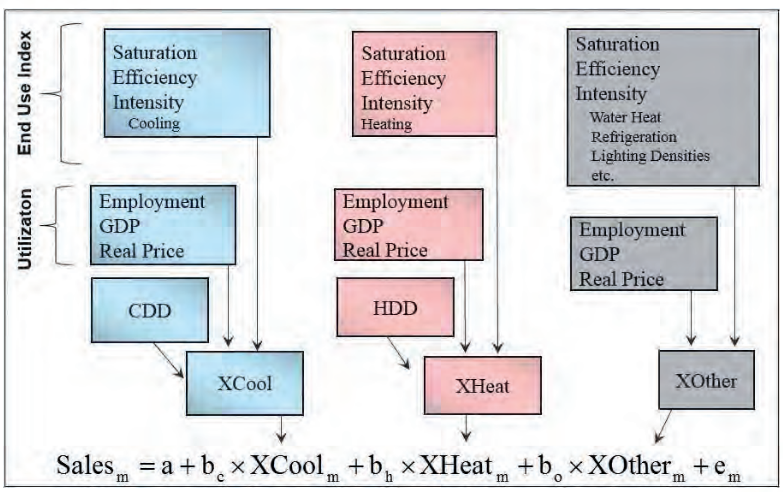
COMMERCIAL MODEL



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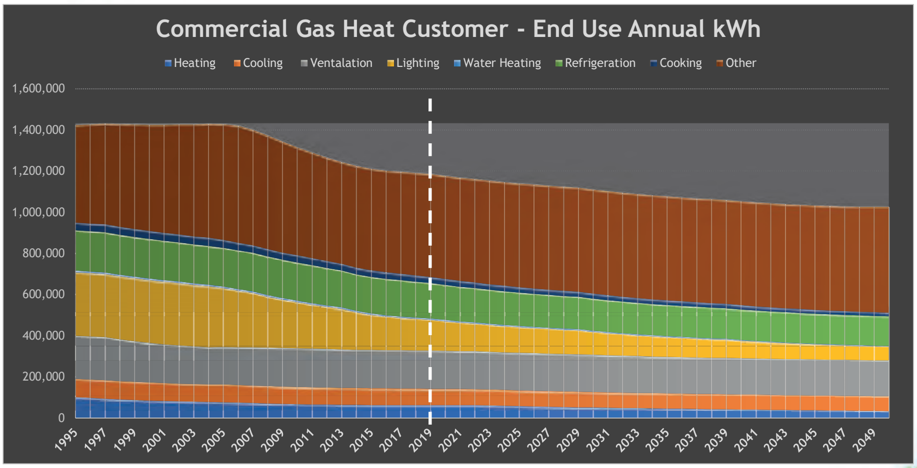
COMMERCIAL END USE TRENDS



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

Source: 2018 EIA Annual Energy Outlook

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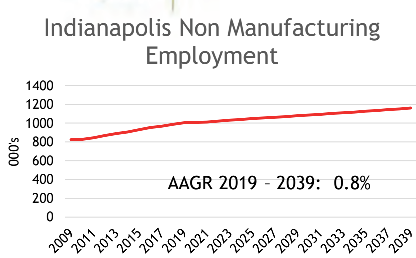
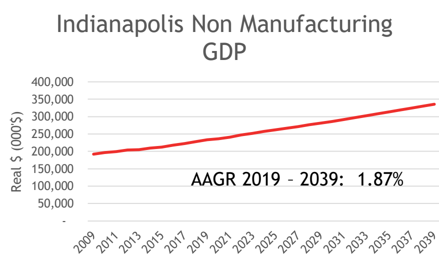
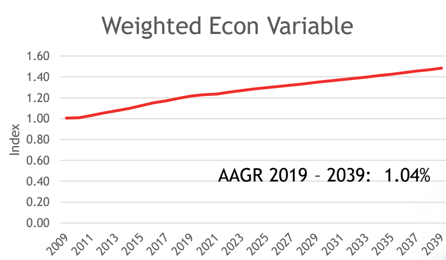
COMMERCIAL ECONOMIC DRIVERS





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



AAGR = Average Annual Growth Rate

18

INDUSTRIAL MODEL

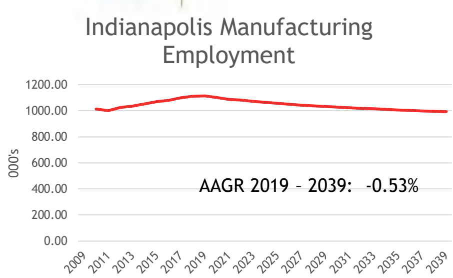
Industrial sales are estimated with a generalized econometric model

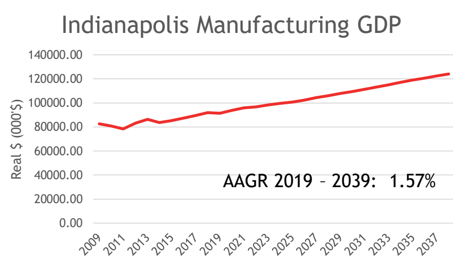
Cooling Degree Days

Manufacturing Employment
Manufacturing Output
Price

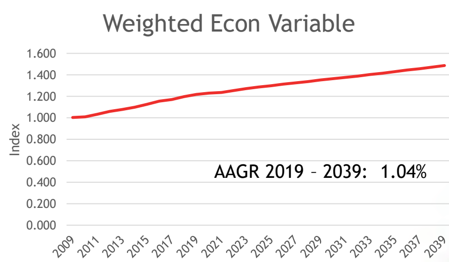
$$Sales_m = a + b_{cdd} \times CDD_m + b_{Econ} \times EconVariable_m + e_m$$

INDUSTRIAL ECONOMIC DRIVERS





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

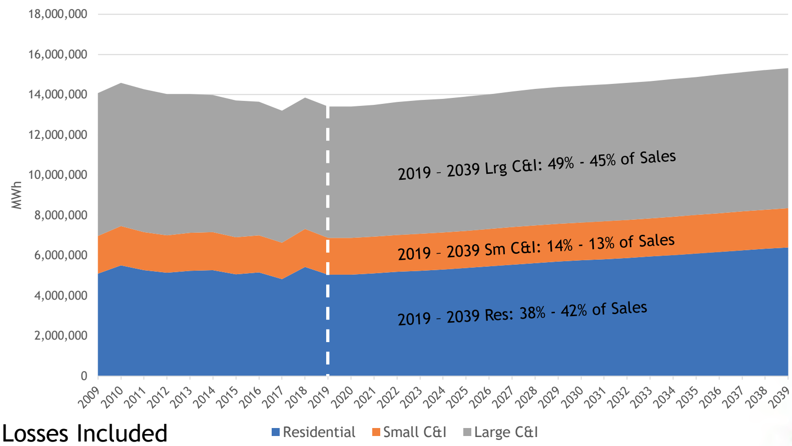


AAGR = Average Annual Growth Rate

CLASS SALES FORECAST

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

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



No Losses Included

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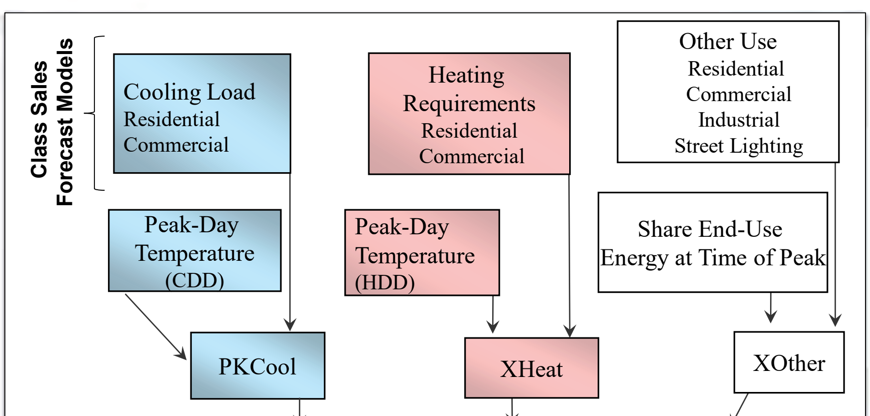
PEAK MODEL



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

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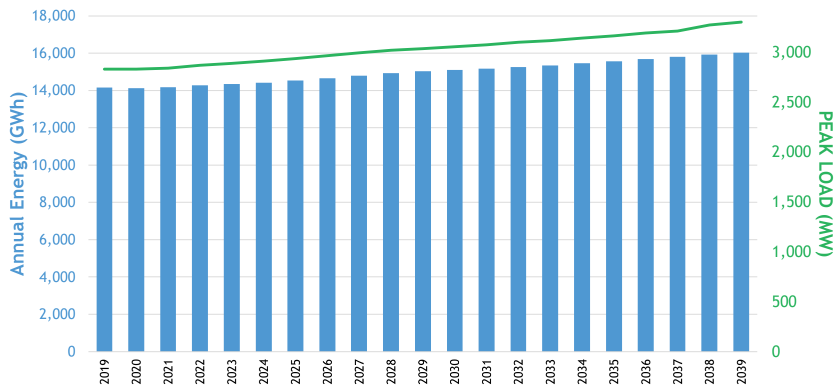
IRP ENERGY & PEAK FORECAST

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

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



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ADDITIONAL LOAD FORECAST ITEMS

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

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BREAK

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

GDS ASSOCIATES

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

MARCH 26, 2019 – IRP Public Advisory Meeting #2

Presented by **THE GDS TEAM**

2018 IPL END USE ANALYSIS RESULTS

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END USE ANALYSIS OBJECTIVES

RESEARCH TO IMPROVE UPON INPUTS TYPICALLY USED IN LOAD FORECAST

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

UNDERSTANDING ENERGY EFFICIENCY BEHAVIOR

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

**commercial building energy consumption survey*

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RESEARCH DESIGN-RESIDENTIAL END USE ANALYSIS

SELF-REPORT SURVEY

- Online/Mail
- 384 responses (95/5)
- Sample stratified by average usage
- Data elements
- End-use saturation
- Miscellaneous end-uses
- Hours of use
- Willingness to participate in a site visit
- Demographics

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

SITE VISITS

- Sub-sample of survey respondents (n=68)
- Verify accurate reporting on survey
- Catalogue of misc. end-uses
- Evaluate willingness to participate in programs

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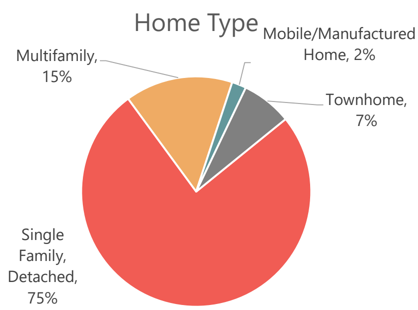
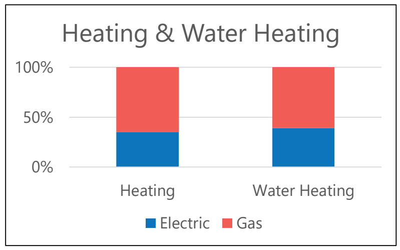
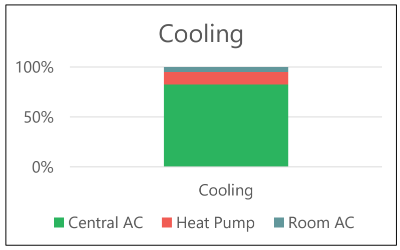
Market Segmentation







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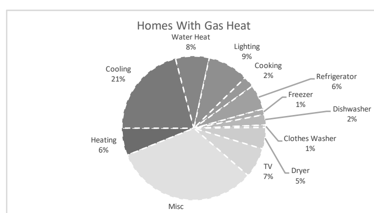
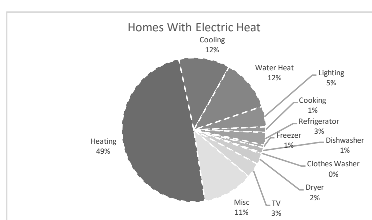
End Use Profiles

average annual kWh per home

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





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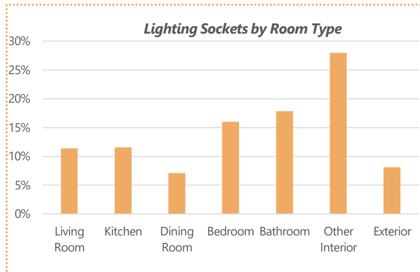
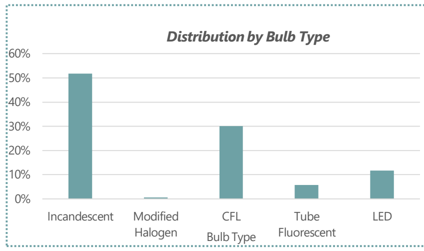
LIGHTING *averages per home*

40.5 *sockets*

5.5 *bulbs in storage*

61% *of storage are incandescent*





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LIGHTING

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

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

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

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RESEARCH DESIGN-SMALL C&I END USE ANALYSIS

ENERGY INTENSITY

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

END-USE SATURATION

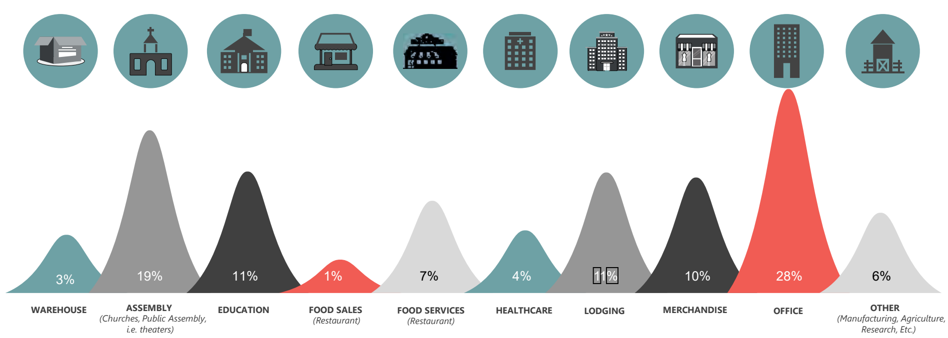
- 70 site visits
- Building type representation
- Compare end-use saturation with CBECS assumptions

BUILDING TYPES

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

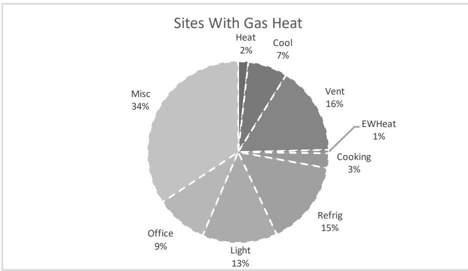
SEGMENTATION *by Electric Consumption*

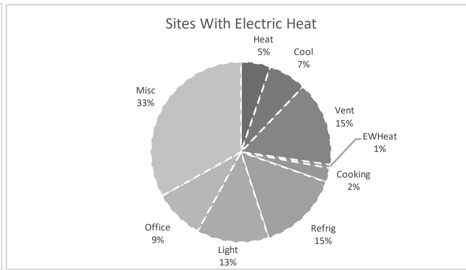
Commercial Segmentation by Commercial Building Type



End Use Profiles

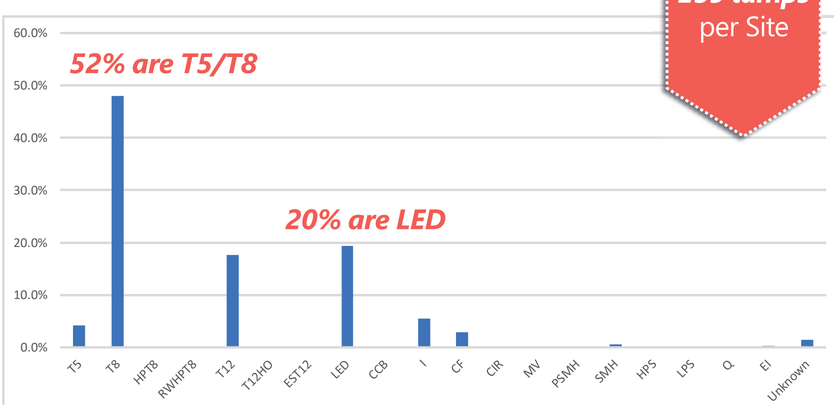
average annual kWh per commercial site





LIGHTING

average
259 lamps
per Site



RESEARCH DESIGN LARGE C&I END-USE ANALYSIS

IDENTIFY POPULATION FRAME

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

RECRUIT PARTICIPANTS *(45 accounts)*

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

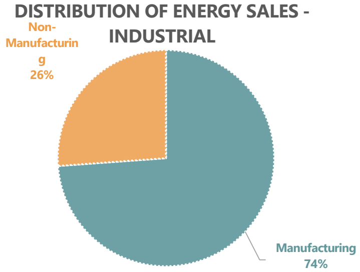
CONDUCT ON-SITE SURVEYS

Collect equipment characteristics
Willingness to participate

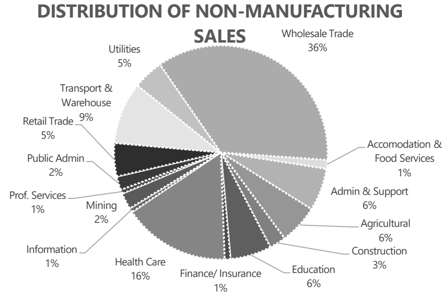
COLLECT INFORMATION ON EFFICIENCY ACTIVITY

INDUSTRY SEGMENTATION

DISTRIBUTION OF ENERGY SALES - INDUSTRIAL

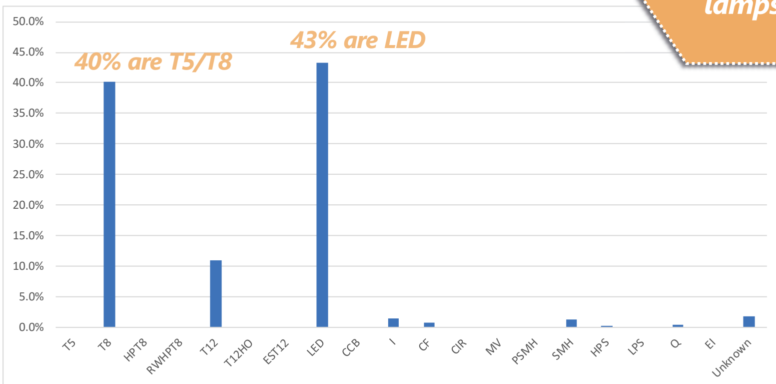


DISTRIBUTION OF NON-MANUFACTURING SALES



LIGHTING

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



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IPL DSM MARKET POTENTIAL STUDY (MPS) PRELIMINARY RESULTS

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

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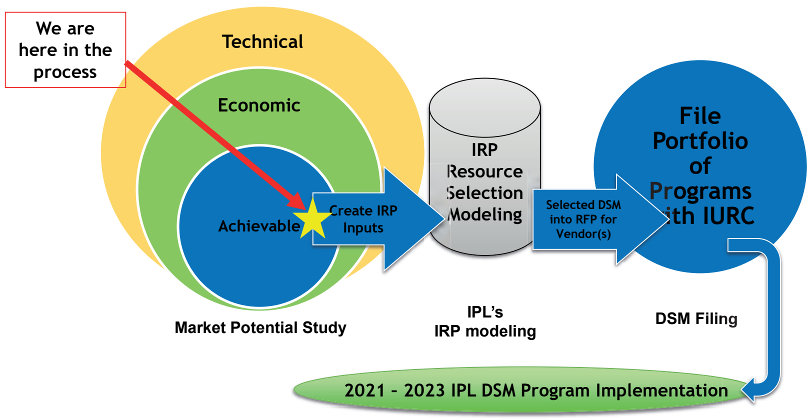
DSM PROCESS & THE IRP



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POTENTIAL STUDY METHODOLOGY

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METHODOLOGY-MEASURE CHARACTERIZATION

Draft Results

01 INCLUDES…

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

02 DATA SOURCES…

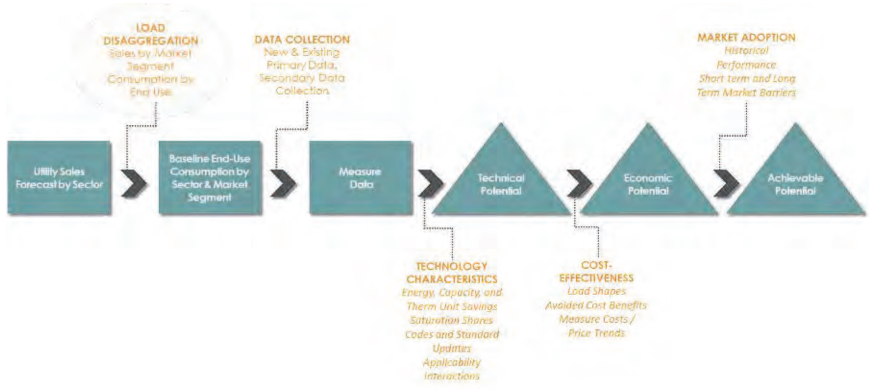
- Current catalog of IPL Measures
- Indiana TRM, Illinois TRM, Michigan Energy Measures Database
- Regional and national costs databases
- Building energy modeling
- IPL market data and survey data

03 ASSUMPTIONS…

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

METHODOLOGY-STUDY APPROACH

Draft Results



METHODOLOGY-TECHNICAL POTENTIAL

Draft Results

Residential Example *(electric)*

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

analysis covers a 20-year timeframe

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

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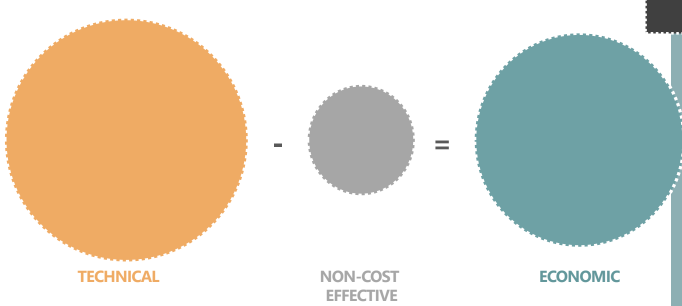
METHODOLOGY-ECONOMIC POTENTIAL

Draft Results

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



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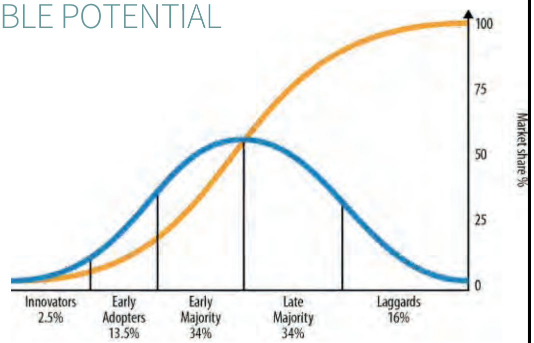
METHODOLOGY-ACHIEVABLE POTENTIAL

Draft Results



ADOPTION RATES

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

METHODOLOGY-ACHIEVABLE POTENTIAL

Draft Results

SHORT TERM ADOPTION RATE

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

LONG TERM ADOPTION RATE

incentive and payback are two primary variables; others considered

IPL willingness to participate research

RESIDENTIAL

ipl an AES company

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RESIDENTIAL POTENTIAL RESULTS

Draft Results

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

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

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

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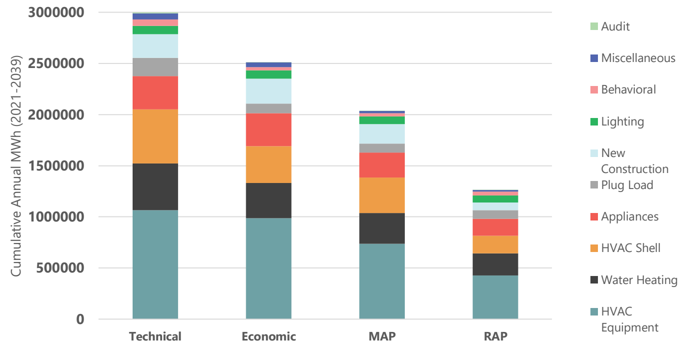
RESIDENTIAL POTENTIAL RESULTS

Draft Results

2021-2039 Cumulative (gross MWh)



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

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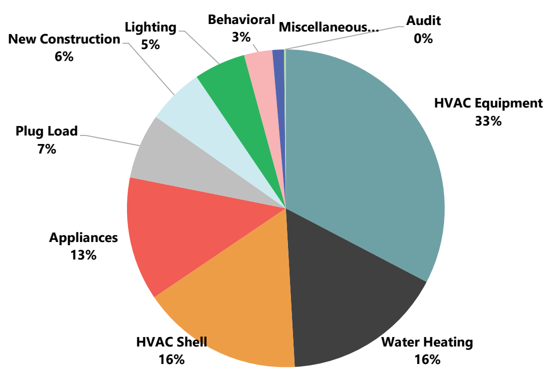
RESIDENTIAL POTENTIAL RESULTS

Draft Results

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



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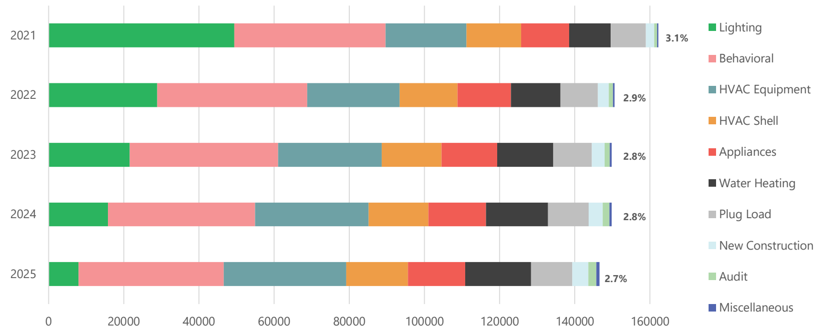
RESIDENTIAL POTENTIAL RESULTS

Draft Results

Annual Incremental RAP 2021-2025 (gross MWh)



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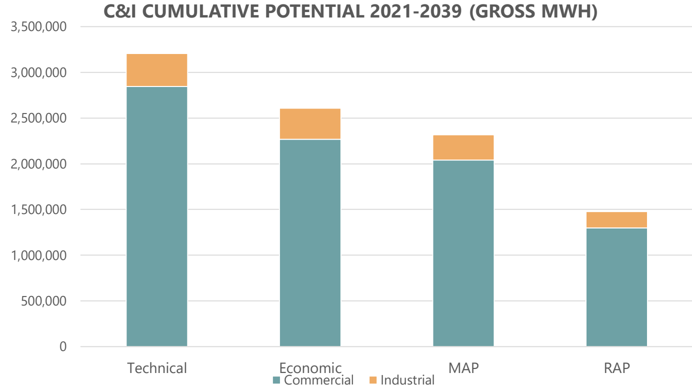
C&I POTENTIAL RESULTS

Draft Results



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

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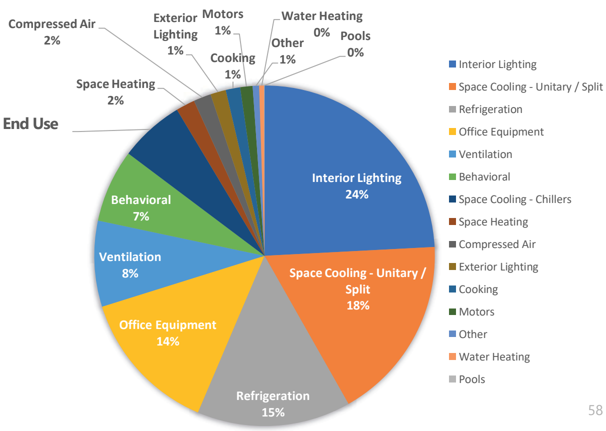
COMMERCIAL POTENTIAL RESULTS

Draft Results

2021-2039

Commercial Cumulative RAP by End Use



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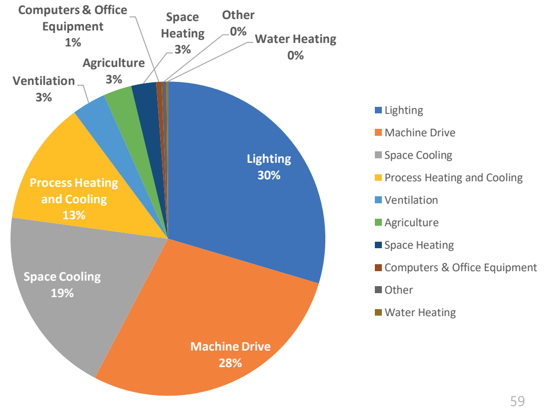
INDUSTRIAL POTENTIAL RESULTS

Draft Results

2021-2039

Industrial Cumulative RAP by End Use



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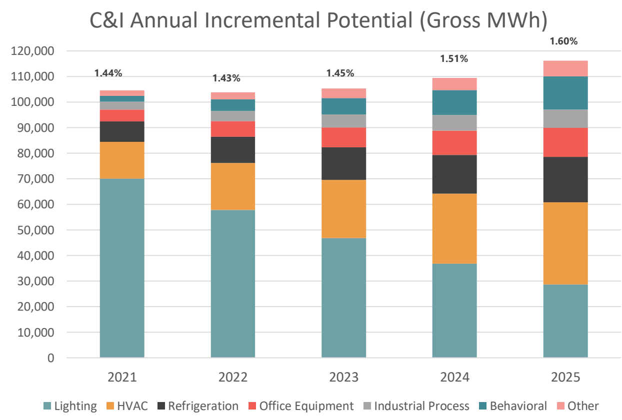
TOTAL C&I 2021-2025 POTENTIAL

Draft Results



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

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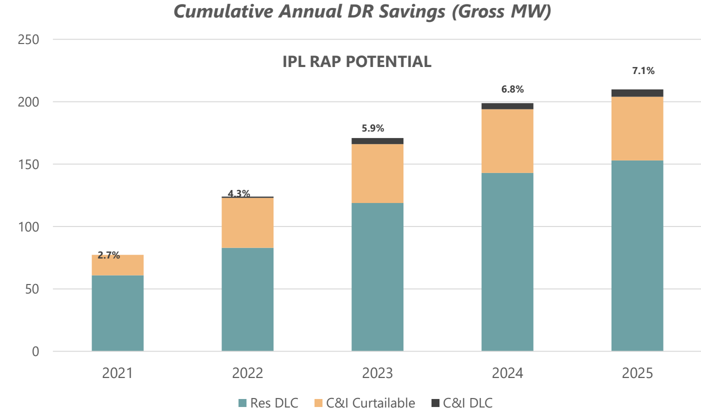
DEMAND RESPONSE

DEMAND RESPONSE

Draft Results

Cumulative Annual DR Savings (Gross MW)



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MPS PRELIMINARY RESULTS NEXT STEPS

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

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LUNCH

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COMMODITY PRICES AND MODELING

Patrick Maguire

Director of Resource Planning

FORWARD CURVES USED IN IRP MODELING

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

FUNDAMENTAL FORECAST VENDOR

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

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FORWARD CURVE NOTES

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

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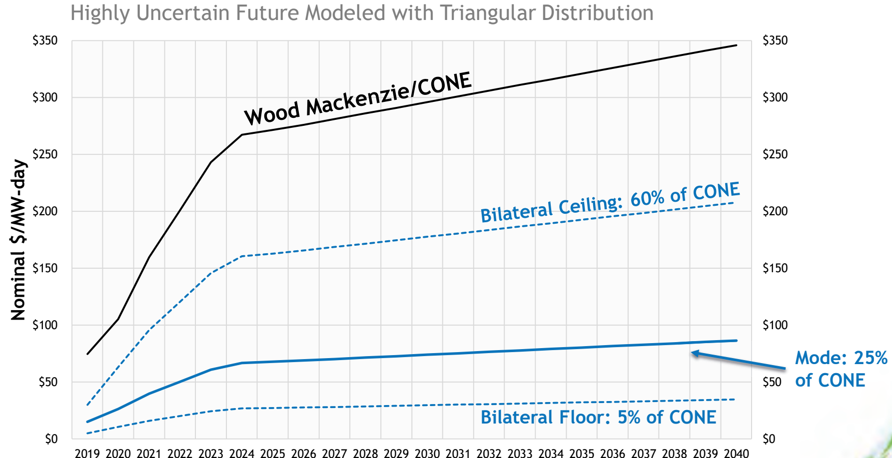
MISO CAPACITY PRICE FORECAST

- MISO Capacity Market is a residual market for balancing prompt year positions
- IPL price construction:
  - "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 CAPACITY PRICE FORECAST (CONT.)

MISO's Residual Capacity Market Results in Low Capacity Prices

Highly Uncertain Future Modeled with Triangular Distribution



ASSUMPTIONS FOR REPLACEMENT RESOURCES

Patrick Maguire

Director of Resource Planning

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JAN 29TH MEETING: REPLACEMENT RESOURCES MODELED

NATURAL GAS
- CCGT
- CT
- Reciprocating Engine/ICE

WIND
- Land-Based Wind

SOLAR
- Utility-Scale
- C&I
- Residential

STORAGE
- Standalone Front-of-meter

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

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KEY ASSUMPTIONS FOR NEW RESOURCES

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

GENERIC RESOURCE COST

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

RESOURCE COST DATA SOURCES

PUBLIC DATA SOURCES

National Renewable Energy Laboratory (NREL)

- 2018 Annual Technology Baseline (ATB)
- https://atb.nrel.gov/electricity/2018/

Lazard

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

NIPSCO RFP Average Bid Prices

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

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

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RESOURCE COST DATA SOURCES (CONT.)

CONFIDENTIAL DATA SOURCES AVAILABLE WITH SIGNED NDA

IHS Markit

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

Bloomberg New Energy Finance (BNEF)

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

Wood Mackenzie

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

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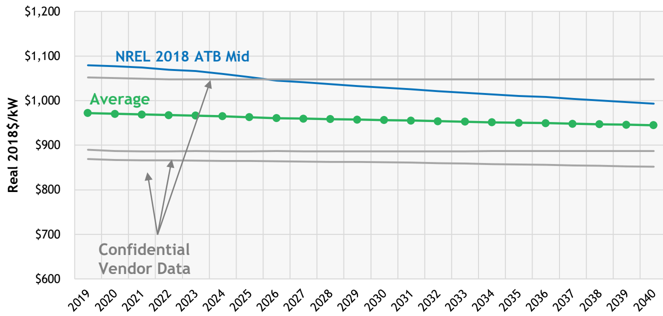
NATURAL GAS TECHNOLOGIES

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

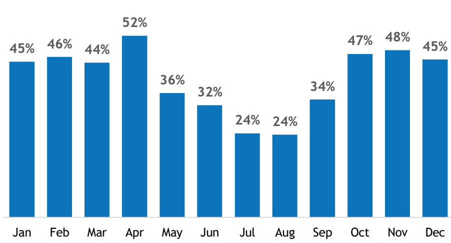
EXAMPLE: Gas Combined Cycle Capital Costs (Real 2018 $/kW)



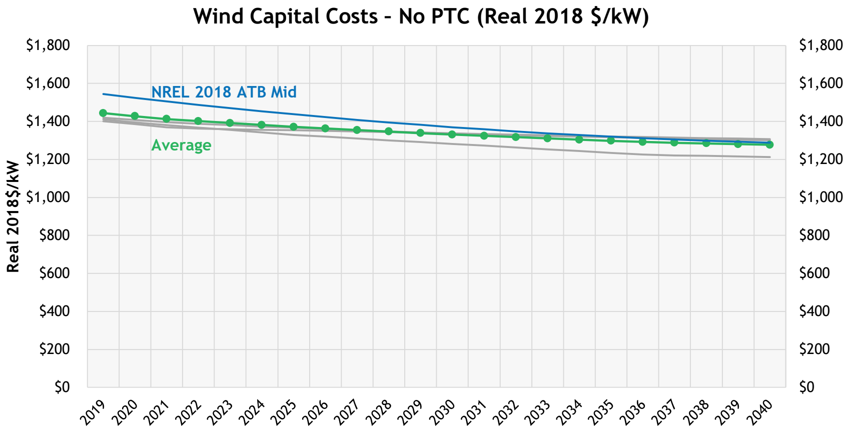
WIND: OPERATIONAL PARAMETERS

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

Generic Wind: Monthly Capacity Factors



WIND: CAPITAL COSTS



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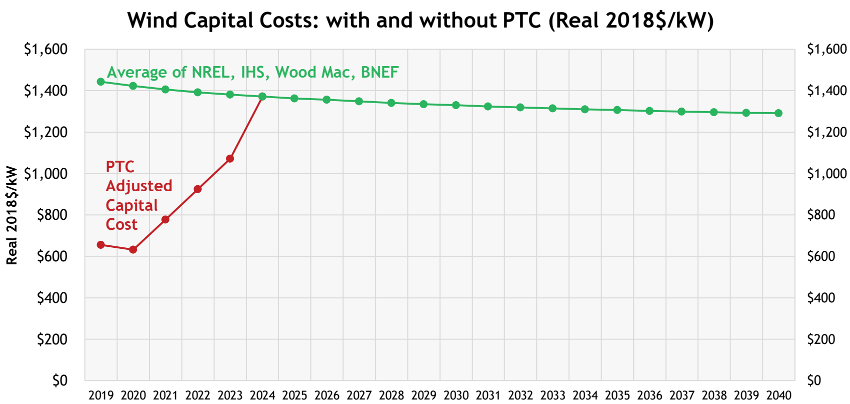
WIND: CAPITAL COSTS (CONT.)

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



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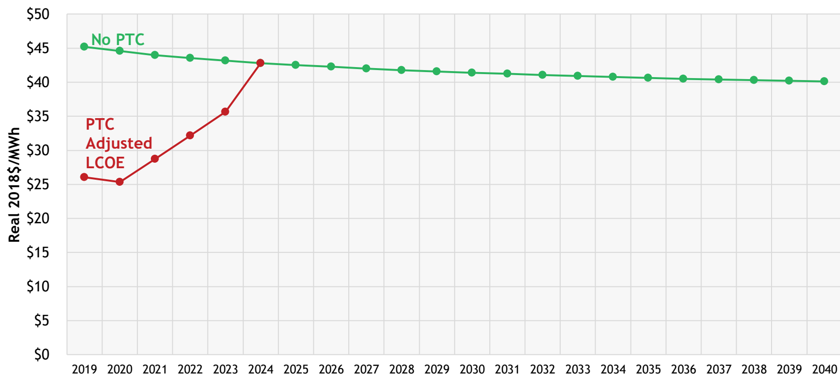
12/11/2019

WIND LCOE

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

Wind LCOE (Real 2018$/MWh)



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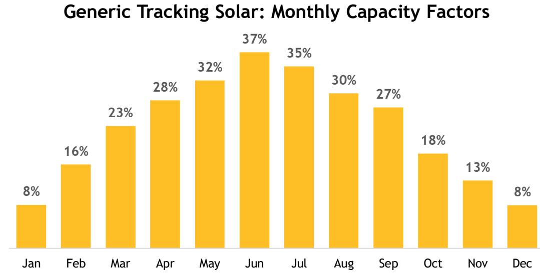
SOLAR: OPERATIONAL PARAMETERS

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

Generic Tracking Solar: Monthly Capacity Factors



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SOLAR: CAPACITY FACTORS

IPL Rate REP Solar: 2016-2018 Monthly Capacity Factors

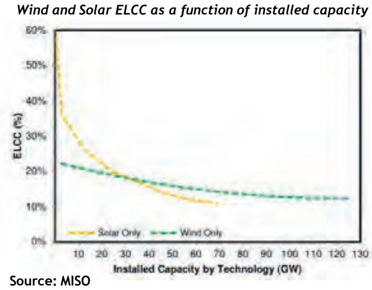
	GROUND FIXED TILT			TRACKING			COMMERCIAL ROOFTOP		
	2016	2017	2018	2016	2017	2018	2016	2017	2018
Jan	9.8%	5.8%	7.0%	9.7%	6.1%	7.1%	6.7%	4.0%	4.7%
Feb	16.5%	15.7%	9.9%	17.3%	16.4%	10.4%	13.2%	12.6%	9.4%
Mar	19.5%	18.6%	15.7%	23.0%	21.6%	19.8%	16.4%	16.7%	15.2%
Apr	19.3%	21.3%	21.8%	27.1%	24.8%	26.2%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

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

SOLAR CAPACITY CREDIT

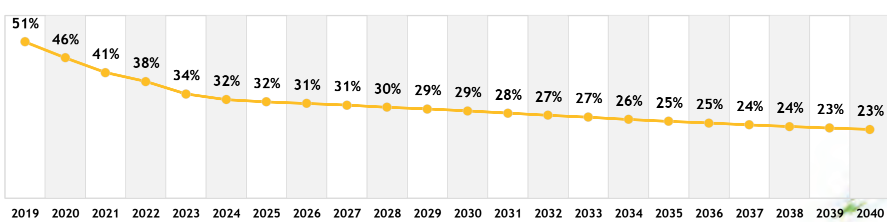
- Solar capacity credit changes as more solar is added to the MISO system
- "Duck curve" phenomenon of shifting net peak load
- Annual capacity credit calculated using forecasted annual installed GW of utility solar in MISO Central
- Installed solar forecast from Wood Mackenzie

Wind and Solar ELCC as a function of installed capacity



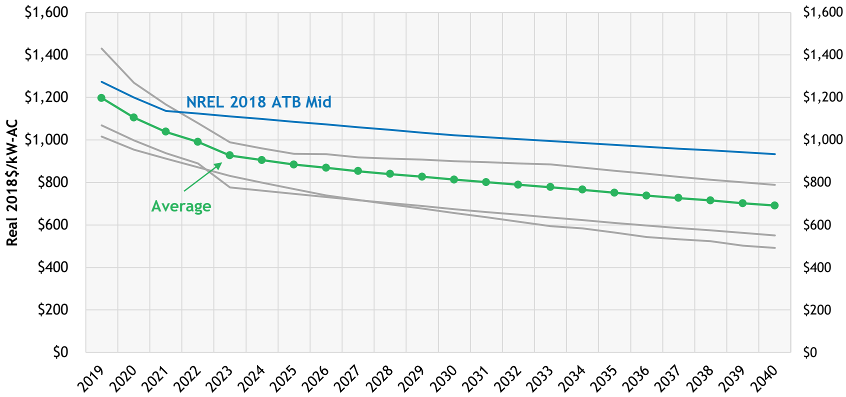
Source: MISO

Annual Solar Capacity Credit



SOLAR: CAPITAL COSTS

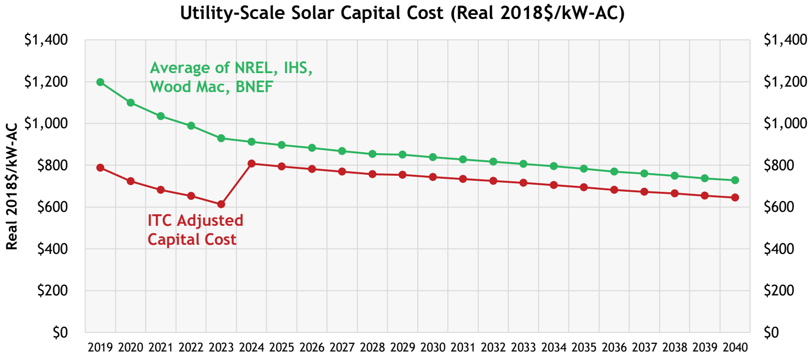
Utility-Scale Solar Capital Costs – No ITC (Real 2018$/kW-AC)



SOLAR: CAPITAL COSTS (CONT.)

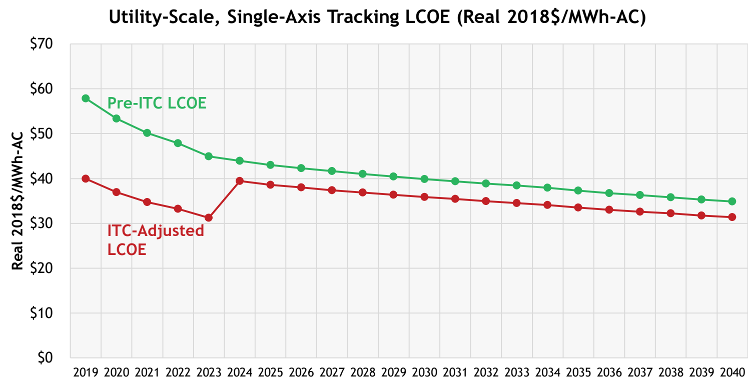
	2020	2021	2022	2023	2024+
ITC Safe Harbor	30%	30%	30%	30%	10%

Utility-Scale Solar Capital Cost (Real 2018$/kW-AC)

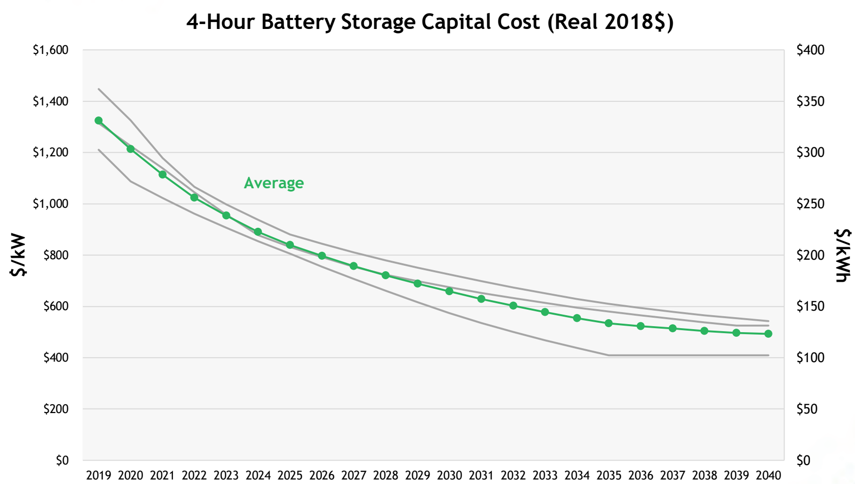


SOLAR: LCOE

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



STORAGE CAPITAL COST



SCENARIO ANALYSIS FRAMEWORK & PROPOSED SCENARIOS

Patrick Maguire

Director of Resource Planning

ROLE OF SCENARIOS IN IPL'S IRP

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

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

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SCENARIO DRIVERS

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

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PROPOSED SCENARIO FRAMEWORK

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

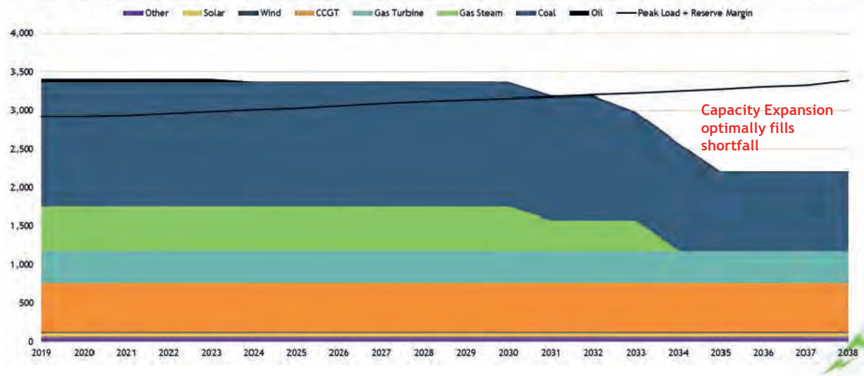
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
No Accelerated Retirements	Portfolio 1	1a	1b	1c	1d
Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	Portfolio 2	2a	2b	2c	2d
Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	Portfolio 3	3a	3b	3c	3d
Pete 1 Retire 2021; Pete 2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

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

IPL STARTING POSITION

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

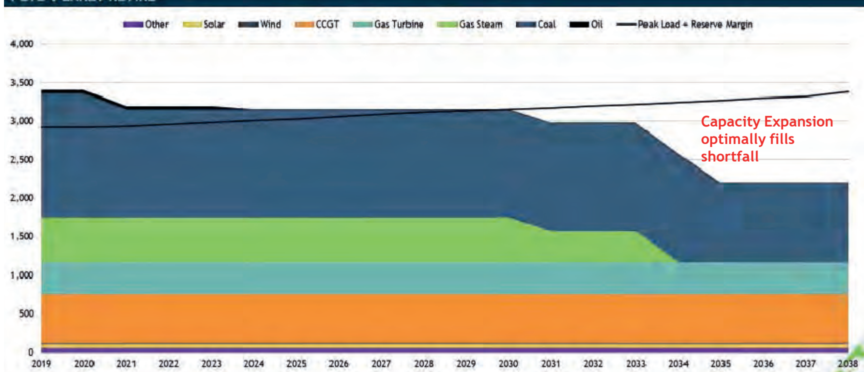
BASE CASE: NO ACCELERATED RETIREMENTS



RETIREMENT PORTFOLIOS (1 OF 4)

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

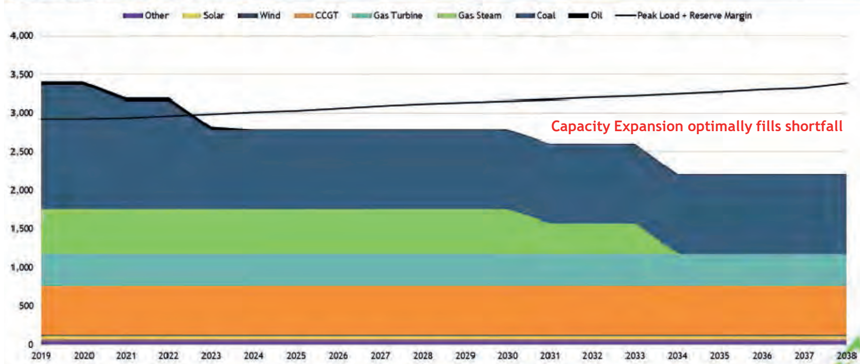
PETE 1 EARLY RETIRE



RETIREMENT PORTFOLIOS (2 OF 4)

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

PETE 1-2 EARLY RETIRE: SHORT IN 2023



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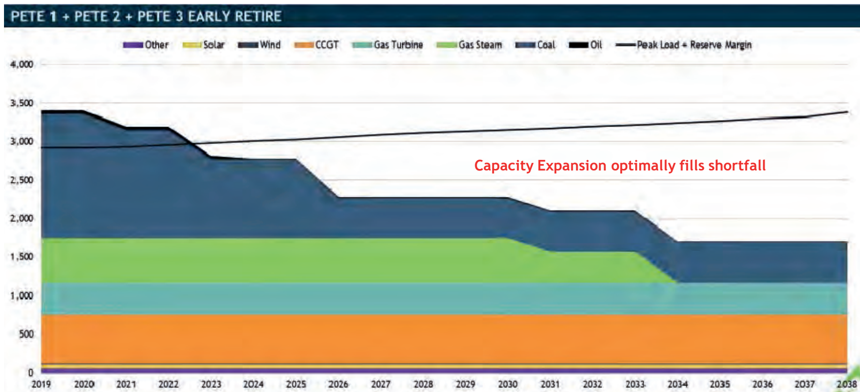
RETIREMENT PORTFOLIOS (3 OF 4)

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

PETE 1 + PETE 2 + PETE 3 EARLY RETIRE



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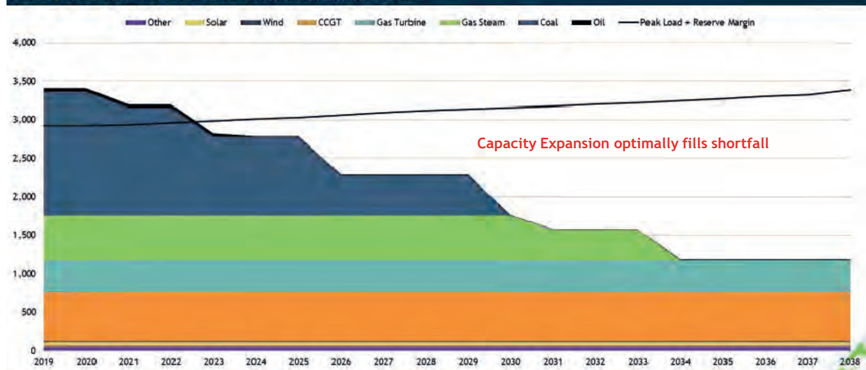
RETIREMENT PORTFOLIOS (4 OF 4)

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

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



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PORTFOLIO COMPARISON

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

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

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

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

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ROLE OF STOCHASTICS

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

FINAL Q&A AND NEXT STEPS

NEXT STEPS

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

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

IPL 2019 IRP: PUBLIC ADVISORY MEETING #3

May 14, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

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MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

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

MEETING 2 RECAP

Patrick Maguire

Director of Resource Planning

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IPL 2019 IRP

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

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

What is a preferred resource portfolio?

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

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

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2019 IRP STAKEHOLDER PROCESS

Dates to follow for Meeting #4 & Meeting #5

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

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

STAKEHOLDER PRESENTATION

Denise Abdul-Rahman

NAACP

STAKEHOLDER PRESENTATION

Ingrid Bjorklund

Advanced Energy Management Alliance (AEMA)

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ELECTRIC VEHICLE (EV) & DISTRIBUTED SOLAR FORECAST

Ed Schmidt

MCR Performance Solutions

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Electric Vehicle and Distributed Solar Forecasts: 2020-2040

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5/14/19

MCR Performance Solutions: Management Consulting to the Utility Industry

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

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

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

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

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

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

MCR Performance Solutions, LLC

Table of Acronyms

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

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

Agenda

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

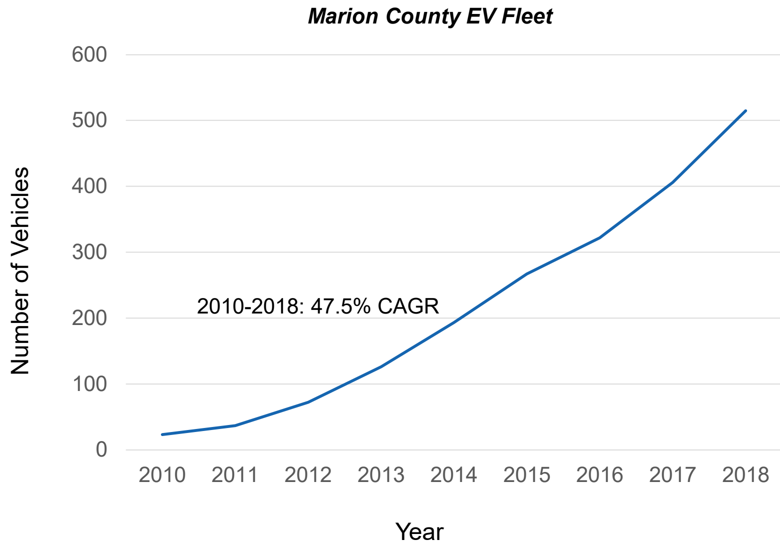
EV Forecast

Light Duty EV (LDEV)

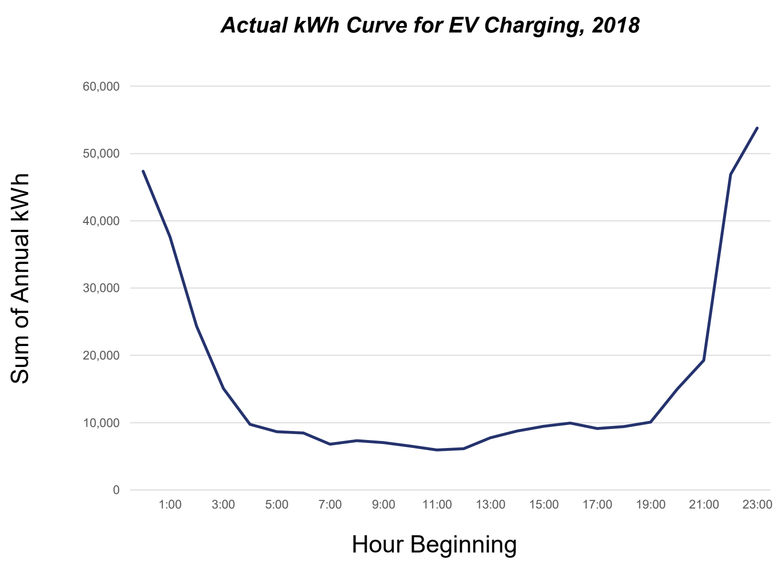
Attribute	Value	Source
Count	515	IPL-provided IHS/Polk
kWh/100 miles	31	www.fueleconomy.gov
Annual miles	11,655	www.carinsurance.com
Annual kWh	3,613	= 31 * (11,655/100)

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

Historical Light Duty EV Fleet Growth



EV Charging Curve – IPL Electric Vehicle Rates



IndyGO Electric Buses

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

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

LDEV Unit Forecasting Methodology

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

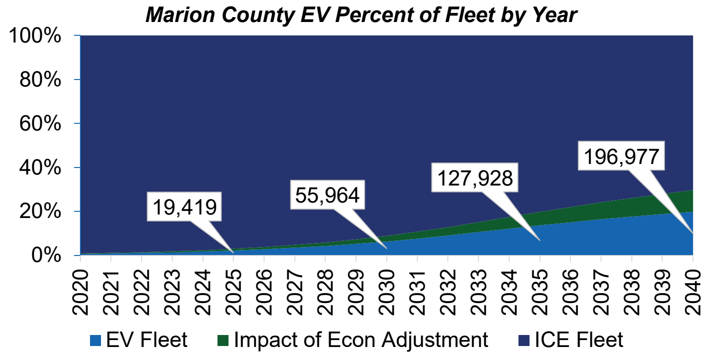
National Forecasts
- Examination of both BNEF and EEI forecasts
- Review of relationship between forecasts to extend EEI from 2030 to 2040

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

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

LDEV Unit Forecast

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



EV MWh Forecasting Methodology

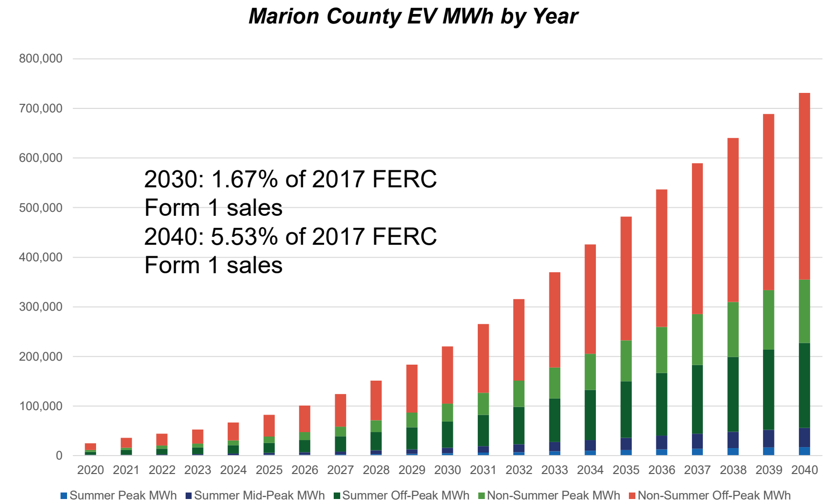
- 3,613 kWh/year used, as discussed above

- 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



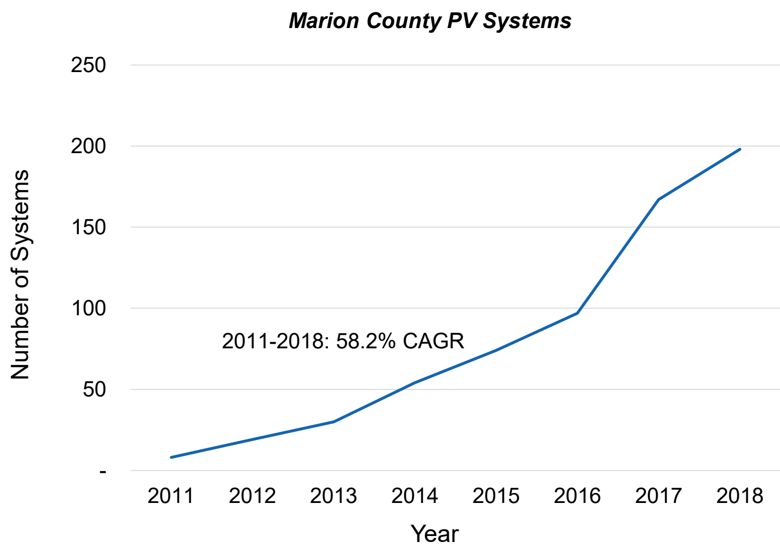
Distributed Solar Forecast

2018 Residential and Commercial Distributed Solar Baseline

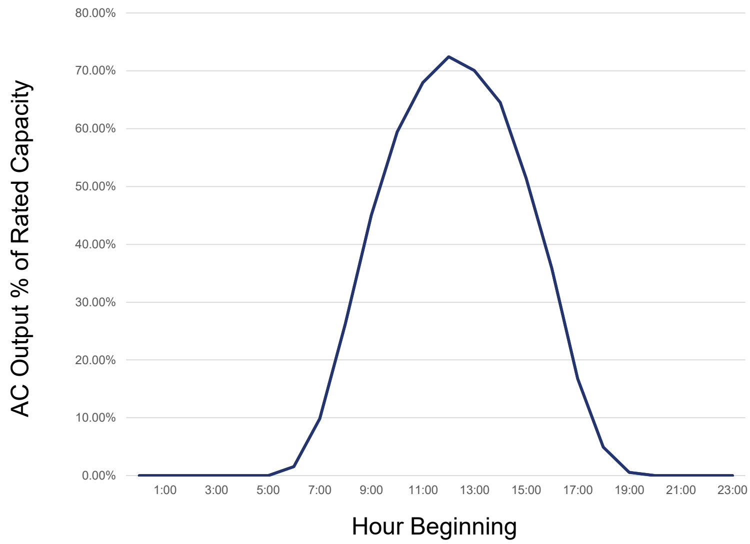
Attribute	Residential	C&I
IPL NEM count (Adjusted EIA counts from IPL 2018 NEM file)	177	21
Size (kW - DC)	8	125
Panel type	Anti-reflective crystalline silicon	Anti-reflective crystalline silicon
Array type	Fixed	Fixed
Capacity factor (AC)	15.8%	15.8%
Production basis	PVWatts – 46241	PVWatts – 46241

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

Historical Distributed Solar System Growth



Distributed Solar Production Curve



Distributed Solar Unit Forecasting Methodology

IPL 2018 NEM Baseline

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

GTM 4Q18 Solar Outlook

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

2019-23 GTM-based CAGR

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

Apply CAGR to IPL NEM Baseline

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

Input Data: GTM-based CAGR

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

Distributed Solar kW and MWh Forecasting Methodology

PVWatts Output

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

IPL Peak/Off-Peak Hours

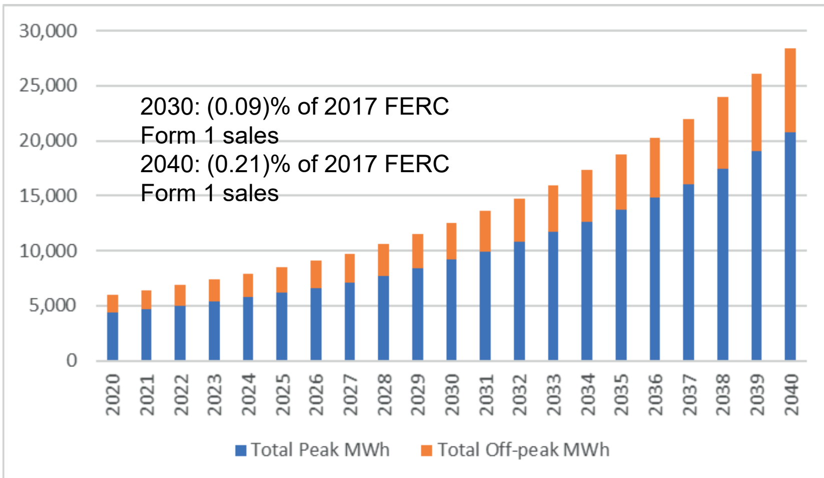
- Rate CGS hours 8-23 are peak
- Rate CGS assigns all weekends to off-peak

Derived kWh per kW

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

Distributed Solar MWh Impacts through 2040

Marion County PV MWh by Year



Summary: EV and Distributed Solar Forecast

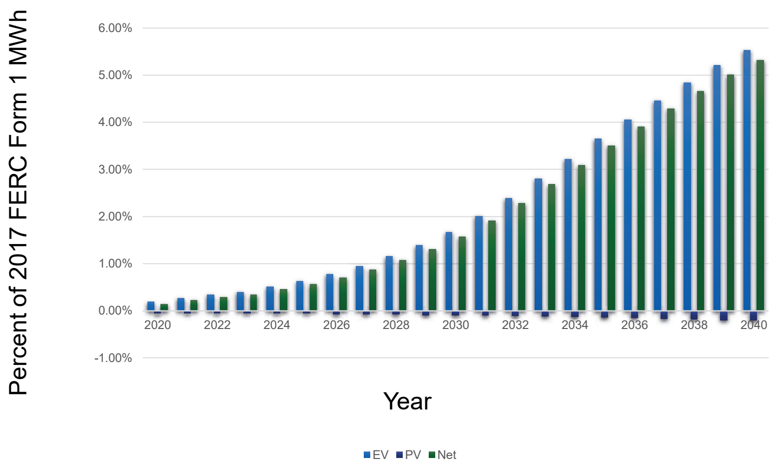
EV and Distributed Solar Forecast Summary: MWh

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

EV and Distributed Solar Forecast Summary: MWh (continued)

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

EV and Distributed Solar as a Percent of 2017 Sales



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MCR Performance Solutions, LLC

BREAK

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LOAD FORECAST – HIGH & LOW RECAP OF CUSTOMER CLASS BREAKOUT

Erik Miller

Senior Research Analyst

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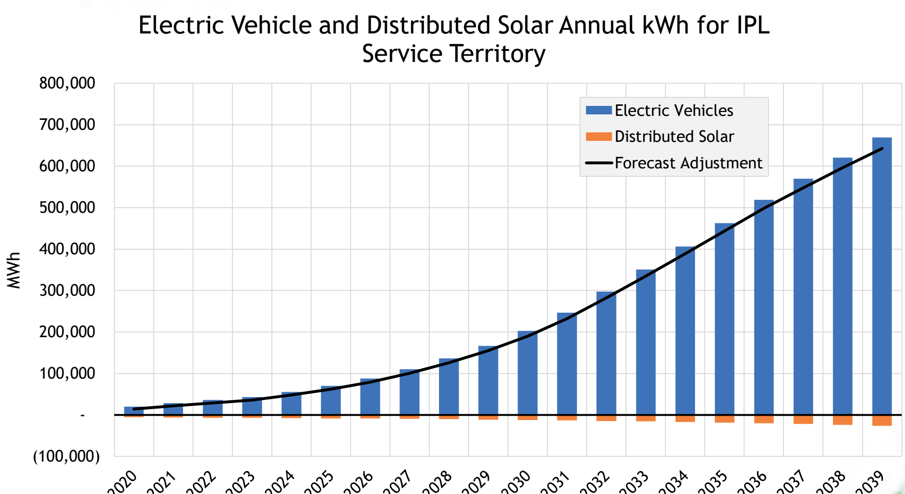
EV & PV ADJUSTMENT



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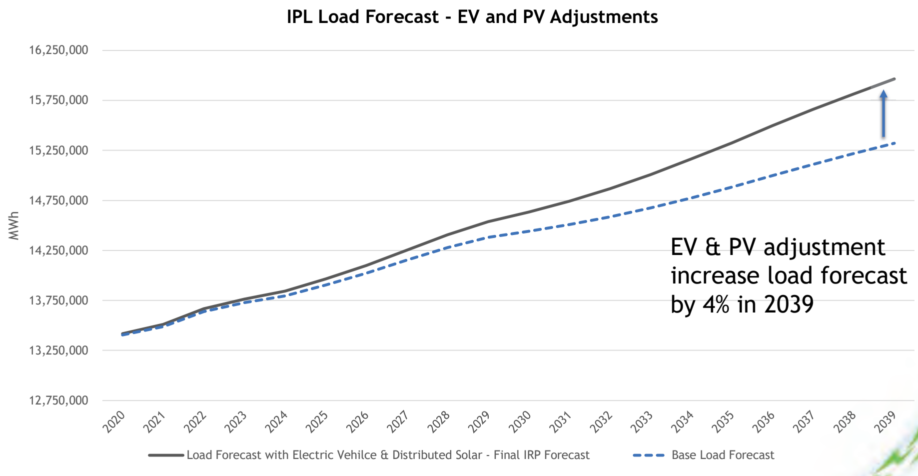
IPL LOAD FORECAST EV & PV ADJUSTMENT



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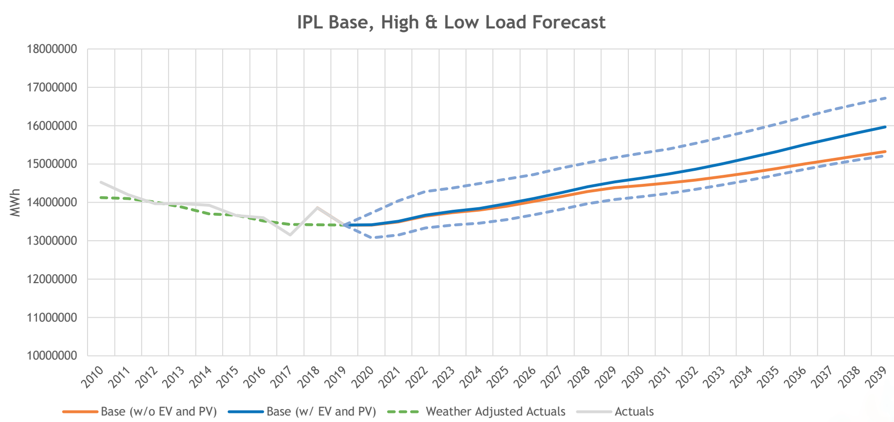
IPL BASE, HIGH & LOW LOAD FORECAST

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

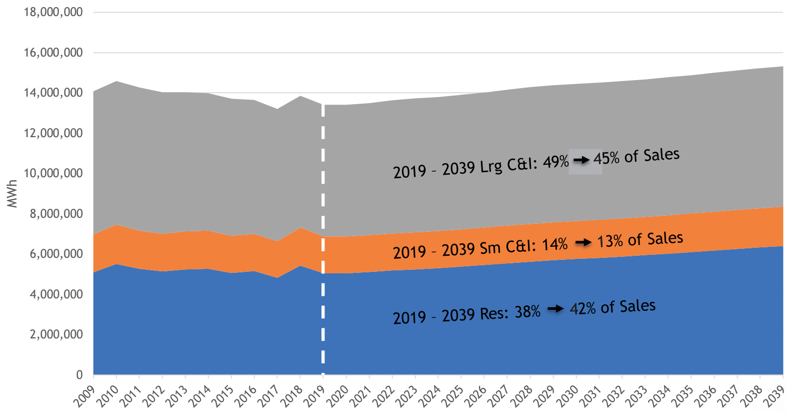


40

CLASS SALES FORECAST

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

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



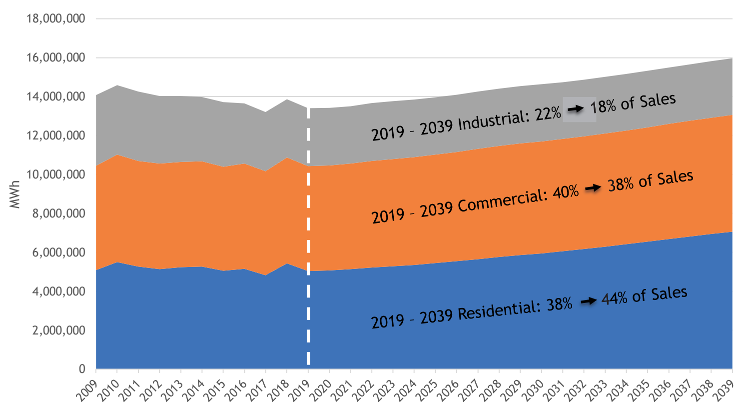
No Losses Included

41

CLASS SALES FORECAST

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

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



No Losses Included

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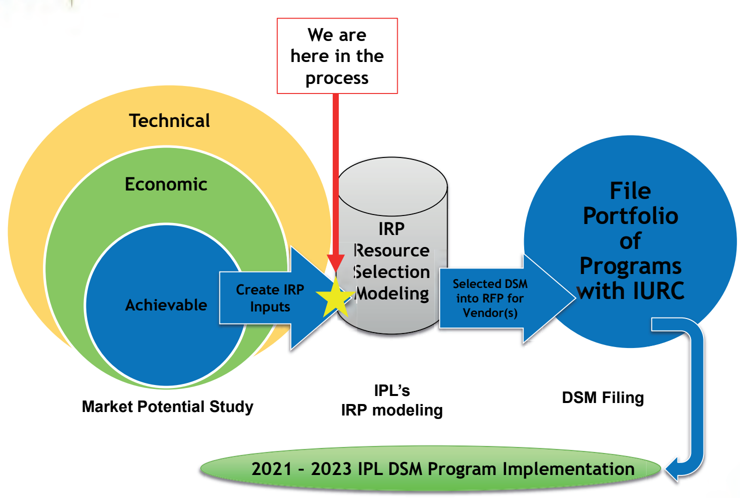
DSM BUNDLES IN IRP MODELING

Erik Miller

Senior Research Analyst

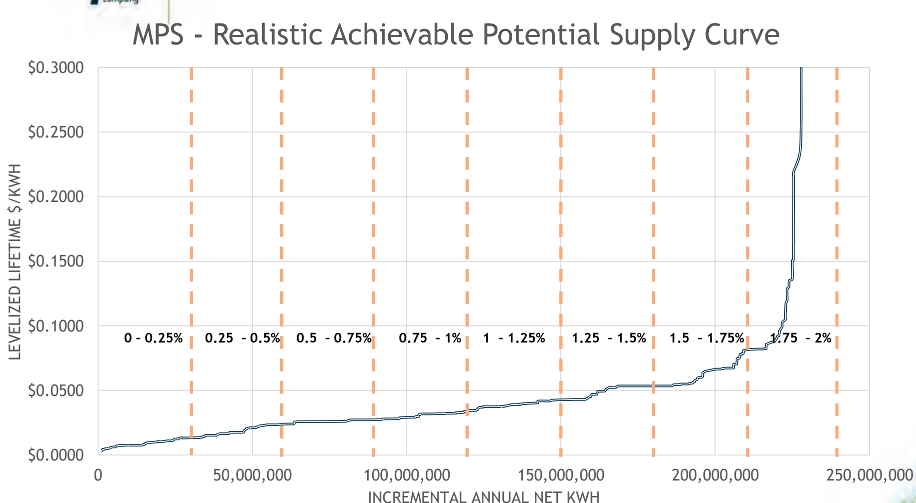
DSM PROCESS & THE IRP



IRP DSM BUNDLING APPROACH

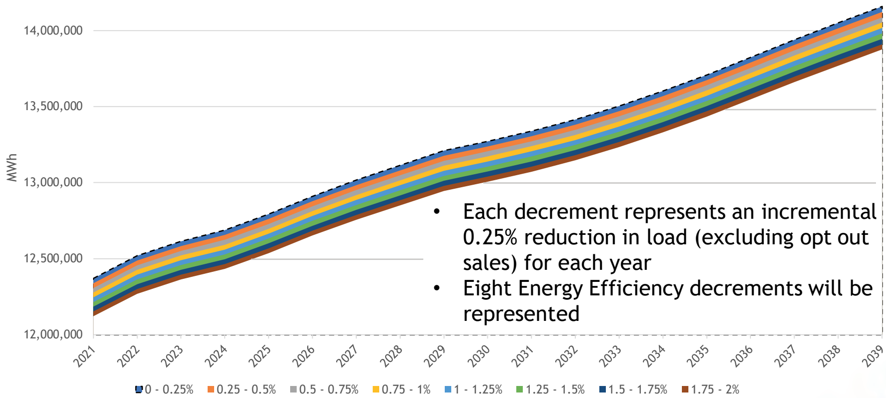
- DSM Bundles are 0.25% “decrements” of annual load excluding Opt Out customers
- Bundles are created from the Market Potential Study’s Realistic Achievable Potential
- Each “decrement” bundle has an associated loadshape and cost/MWh that serves as inputs into the IRP model
- GDS uses loadshapes specific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

DSM DECREMENT BUNDLES



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

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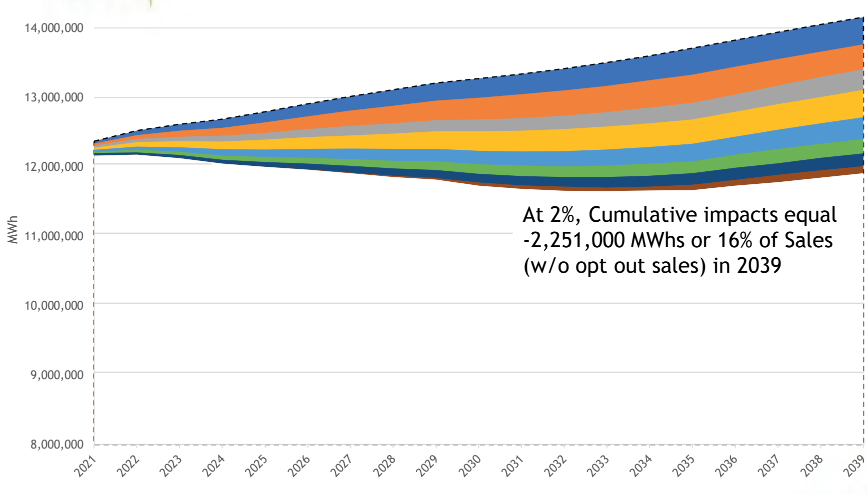
DSM DECREMENT BUNDLES – CUMULATIVE IMPACTS



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

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DSM NEXT STEPS

Next Steps:

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

LUNCH BREAK

MODELING AND SCENARIO RECAP

Patrick Maguire

Director of Resource Planning

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RECAP: SCENARIO DRIVERS

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

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FUNDAMENTAL FORECAST VENDOR

Wood Mackenzie
POWER & RENEWABLES

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

Custom sensitivities completed for IPL - provided to NDA stakeholders

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RECAP: FORWARD CURVES

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

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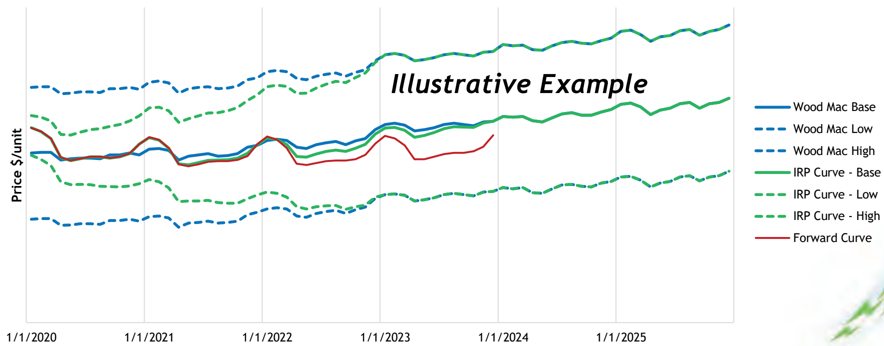
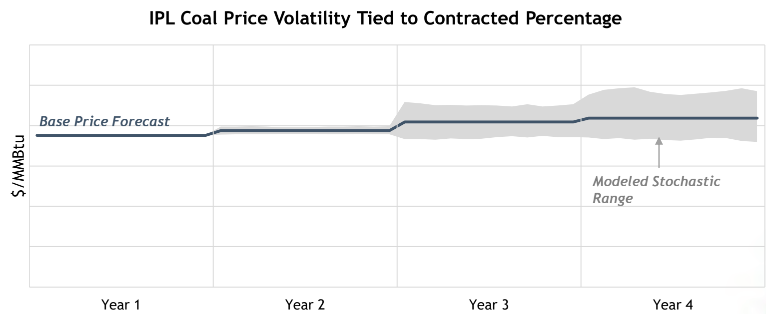
POWER AND NATURAL GAS: BLENDED CURVES FOR YEARS 1-3

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



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



SCENARIO FRAMEWORK

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

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

IRP MODELING: PUTTING THE PIECES TOGETHER

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

Existing Resources
- Age, Type, Primary Fuel, Size

New Resources
- Supply-Side Options
- DSM

Commodity Prices
- Vendor, Key Variables

Scenarios
- Drivers defined
- Modeling Framework

DATA RELEASE SCHEDULE

IPL 2019 IRP Assumptions: Data Release Schedule

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

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Q&A, CONCLUDING REMARKS & NEXT STEPS

Stewart Ramsay
Meeting Facilitator

Patrick Maguire
Director of Resource Planning

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NEXT STEPS

- **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

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

MODELING AND SCENARIO RECAP

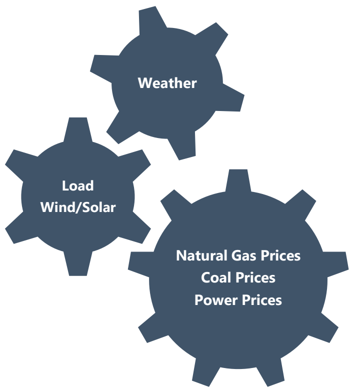
Patrick Maguire
Director of Resource Planning

MODELING ASSUMPTIONS

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

CAPACITY EXPANSION

Stochastic Capacity Expansion



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

KEY HIGHLIGHTS FROM CAPACITY EXPANSION RUNS

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

UNIT RETIREMENTS AND PORTFOLIOS

MODELED COAL RETIREMENTS

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

RETIREMENTS IN ALL PORTFOLIOS

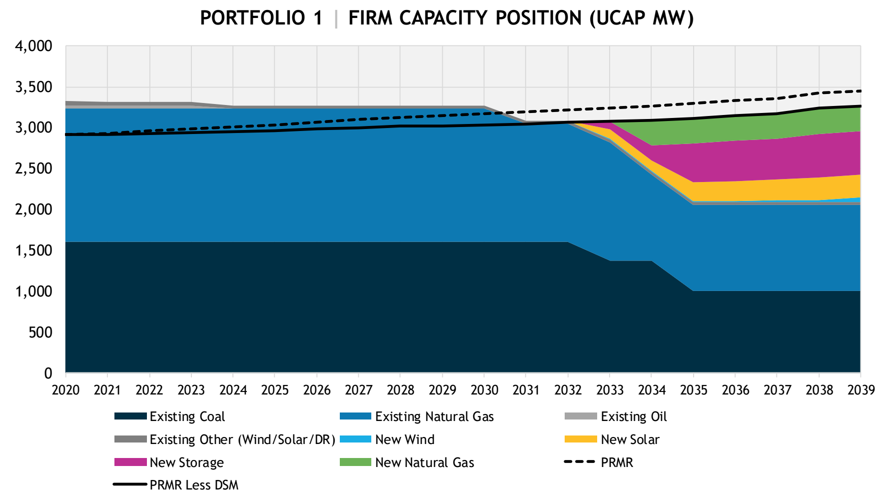
- 2024: Harding Street Oil 1-2 (37 MW)
- 2031: Harding Street ST 5-6 (189 MW)
- 2034: Harding Street ST 7 (394 MW)

PRELIMINARY MODEL RESULTS: OPTIMIZED PORTFOLIOS

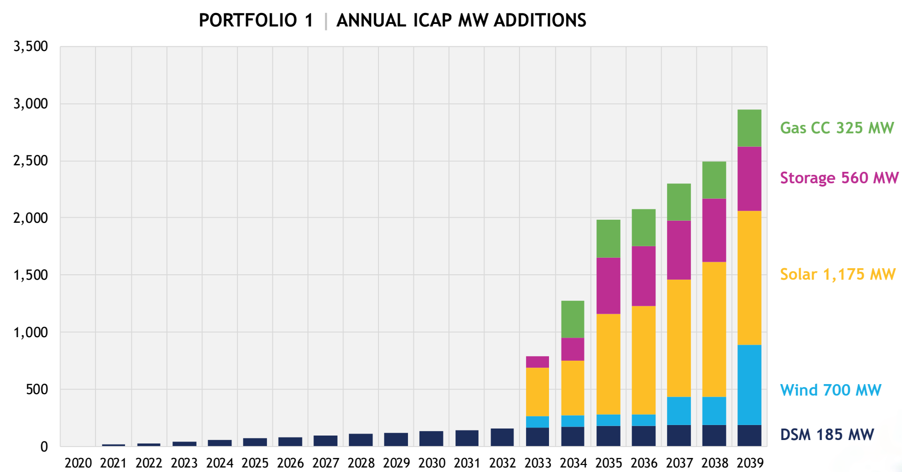
Patrick Maguire

Director of Resource Planning

PORTFOLIO 1: FIRM UCAP POSITION

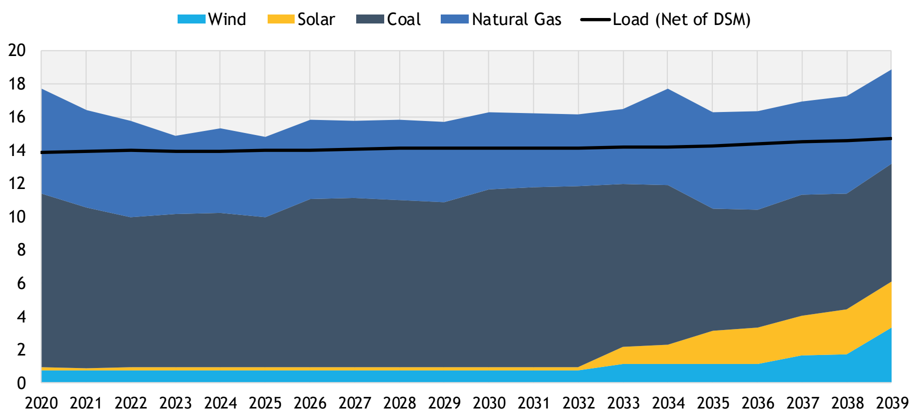


PORTFOLIO 1: ICAP MW ADDITIONS



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

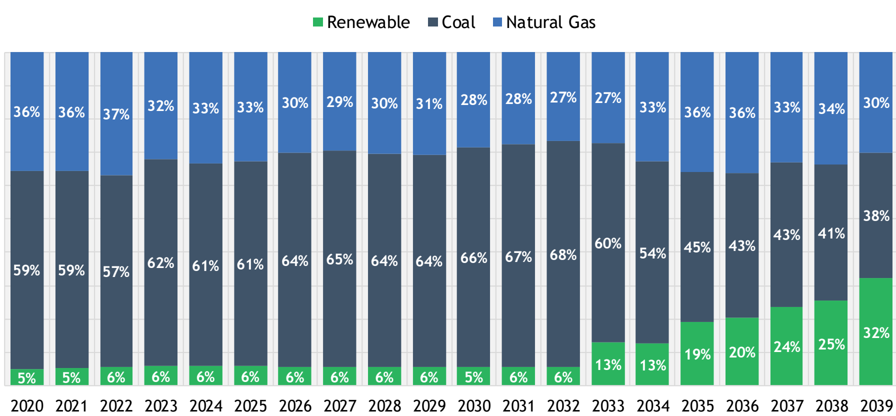
PORTFOLIO 1 | Annual Energy Mix (TWh)



Energy mix for portfolios will vary across scenarios

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

PORTFOLIO 1 | Annual Produced Energy: Percent by Fuel Type



Energy mix for portfolios will vary across scenarios

PORTFOLIO 1 RECAP

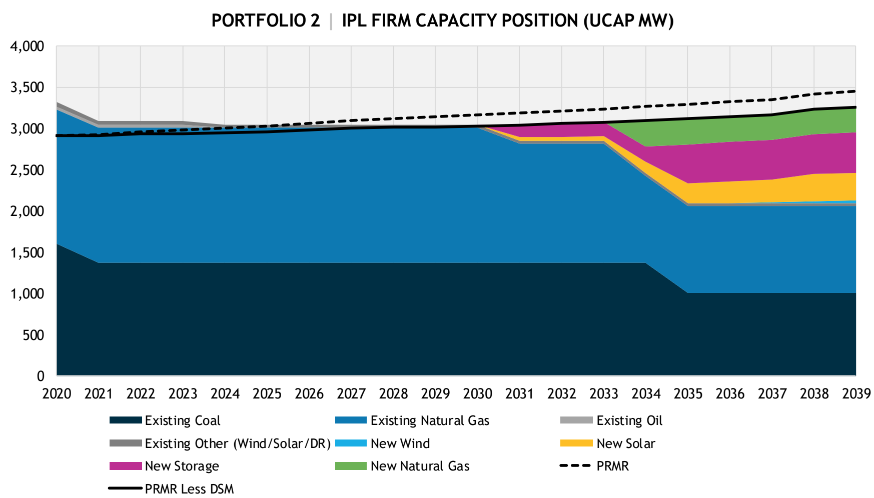
New Build by 2039

- 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

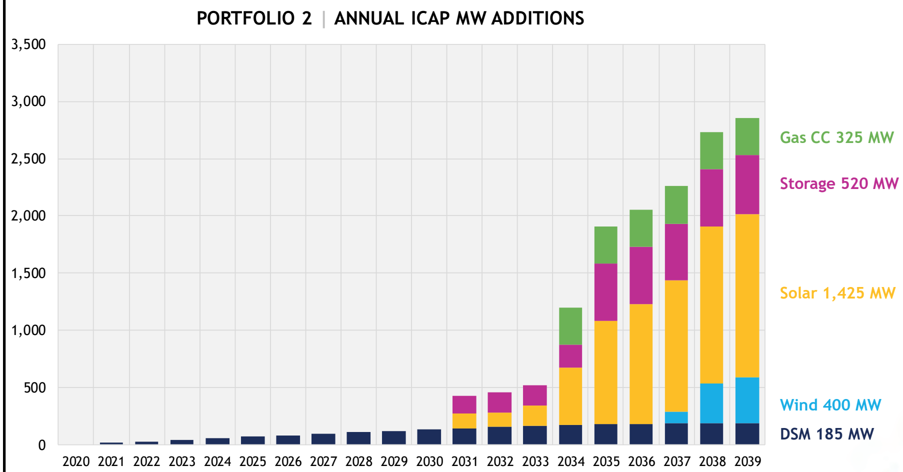
Retirements

- 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

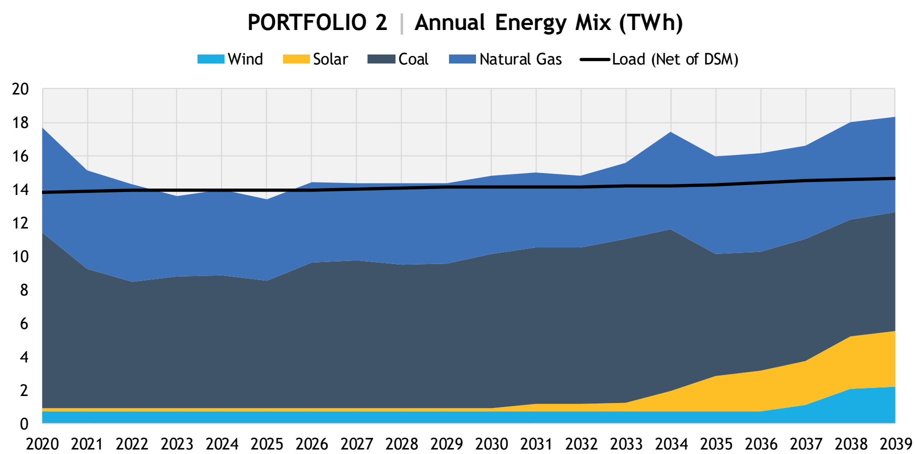
PORTFOLIO 2: FIRM UCAP CAPACITY



PORTFOLIO 2: ICAP MW ADDITIONS



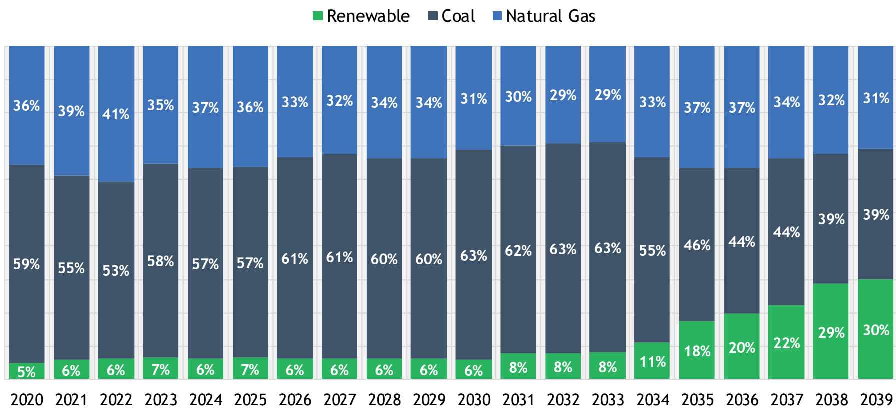
PORTFOLIO 2: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

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

PORTFOLIO 2 | Annual Produced Energy: Percent by Fuel Type



Energy mix for portfolios will vary across scenarios

PORTFOLIO 2 RECAP

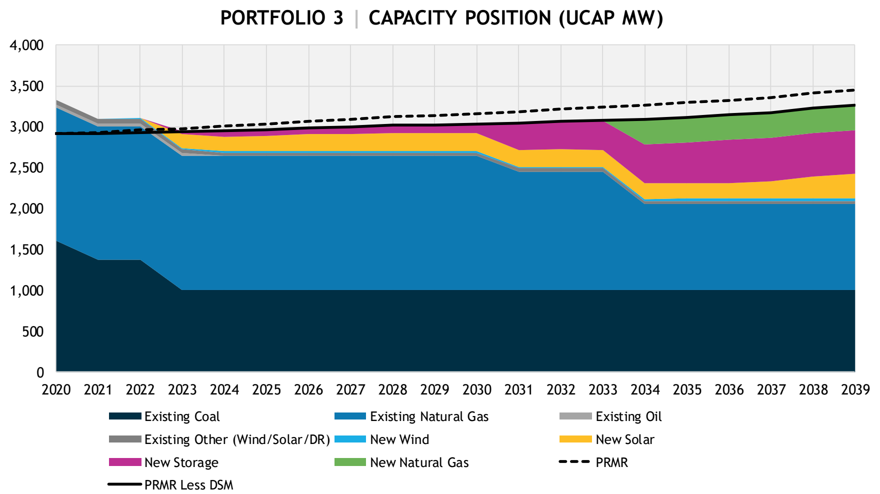
New Build by 2039

- 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

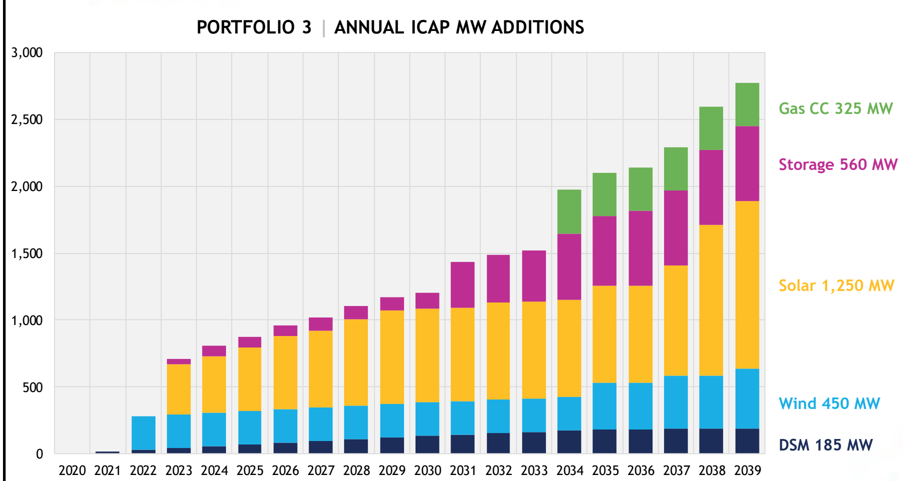
Retirements

- 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

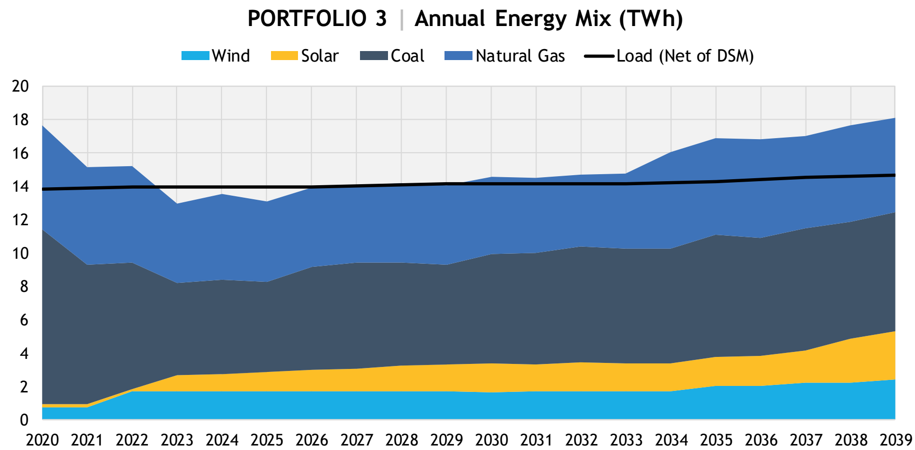
PORTFOLIO 3: FIRM UCAP CAPACITY



PORTFOLIO 3: ICAP MW ADDITIONS

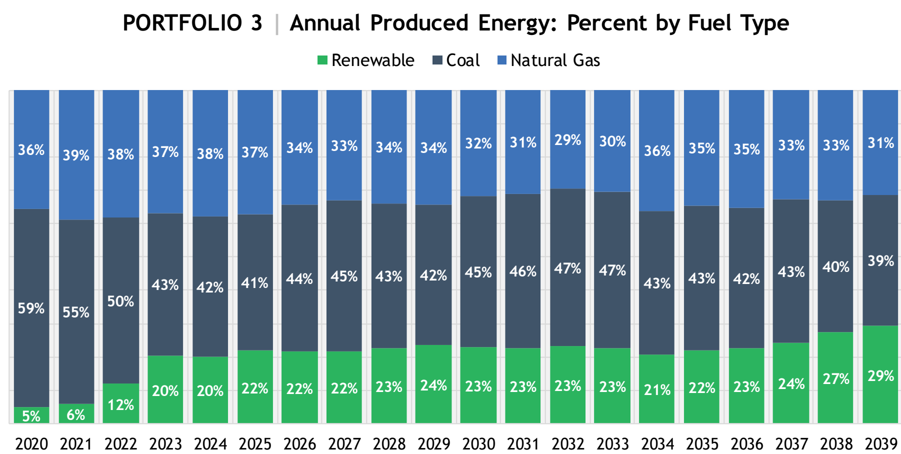


PORTFOLIO 3: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

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



Energy mix for portfolios will vary across scenarios

PORTFOLIO 3 RECAP

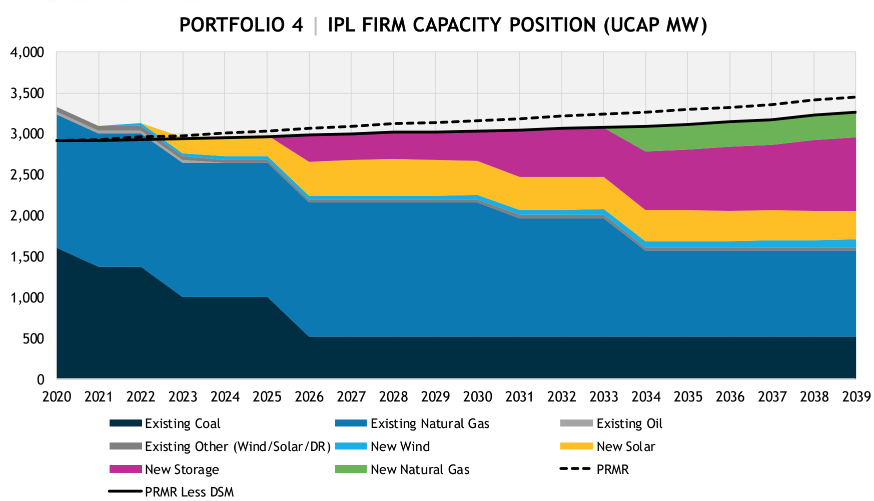
New Build by 2039

- 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

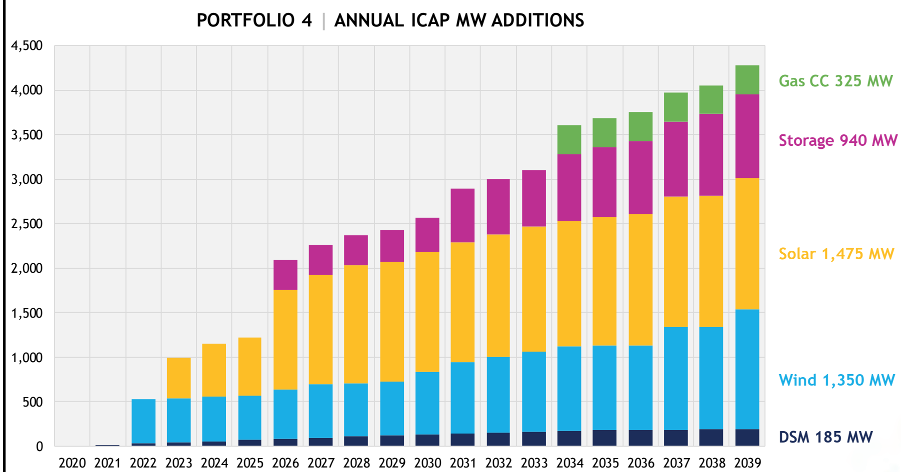
Retirements

- 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

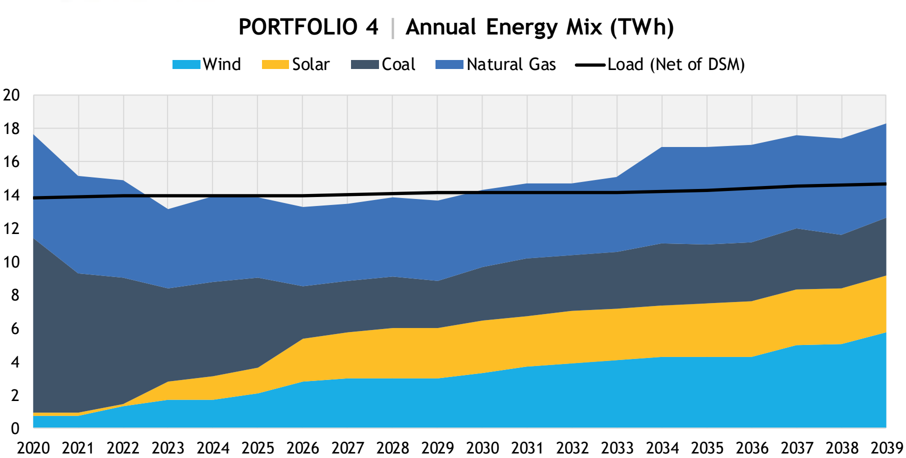
PORTFOLIO 4: FIRM UCAP CAPACITY



PORTFOLIO 4: ICAP MW ADDITIONS



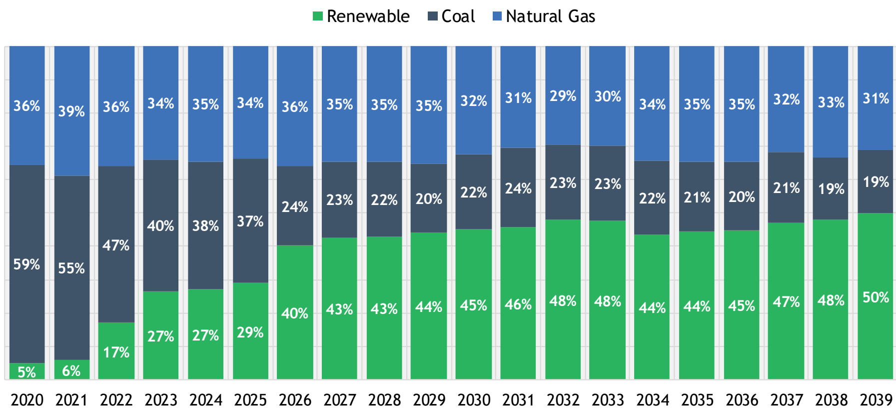
PORTFOLIO 4: REFERENCE CASE ENERGY MIX (1 OF 2)



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



Energy mix for portfolios will vary across scenarios

PORTFOLIO 4 RECAP

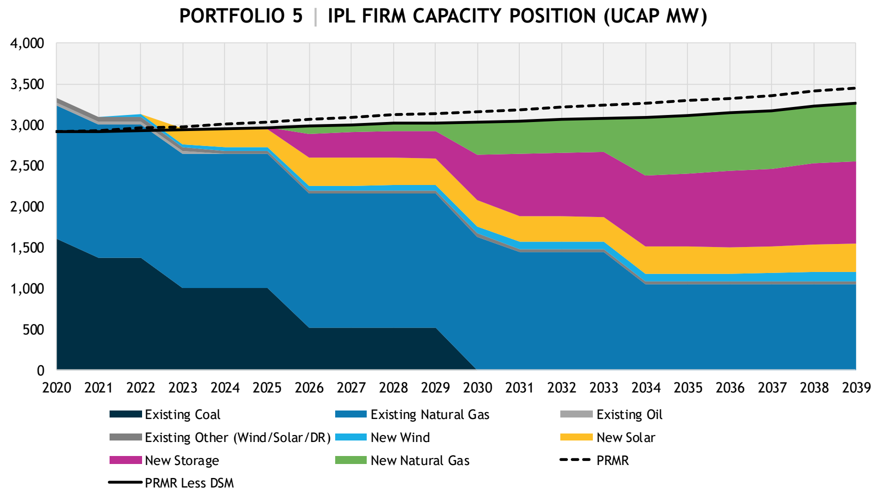
New Build by 2039

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

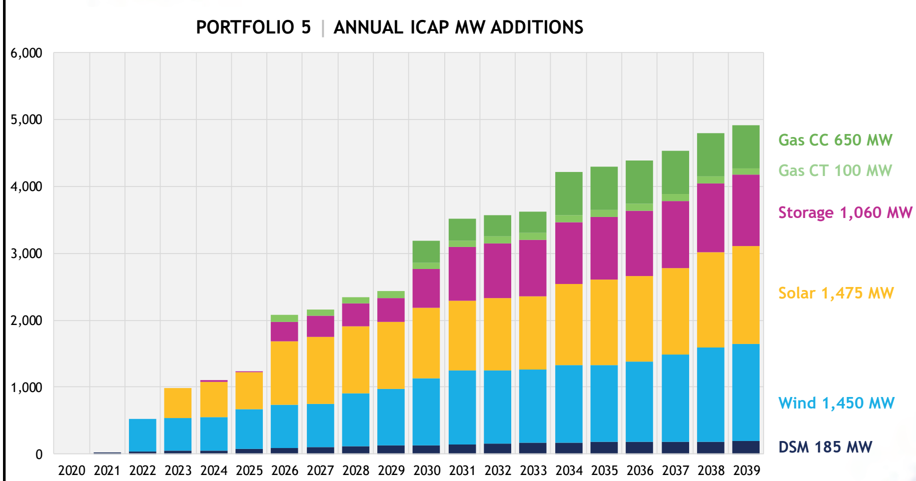
Retirements

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

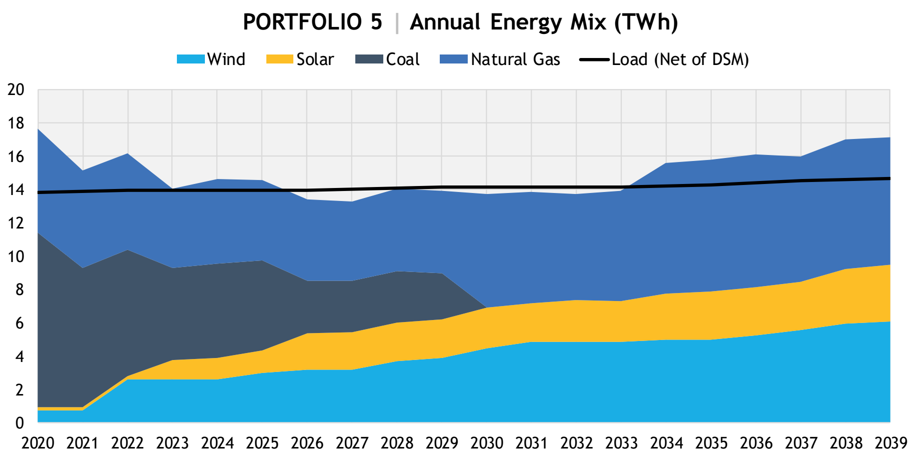
PORTFOLIO 5: FIRM UCAP CAPACITY



PORTFOLIO 5: ICAP MW ADDITIONS

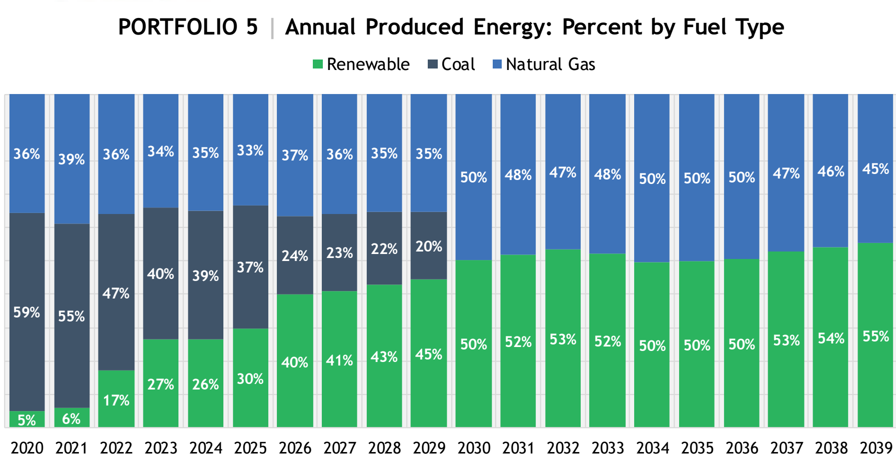


PORTFOLIO 5: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

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



Energy mix for portfolios will vary across scenarios

PORTFOLIO 5 RECAP

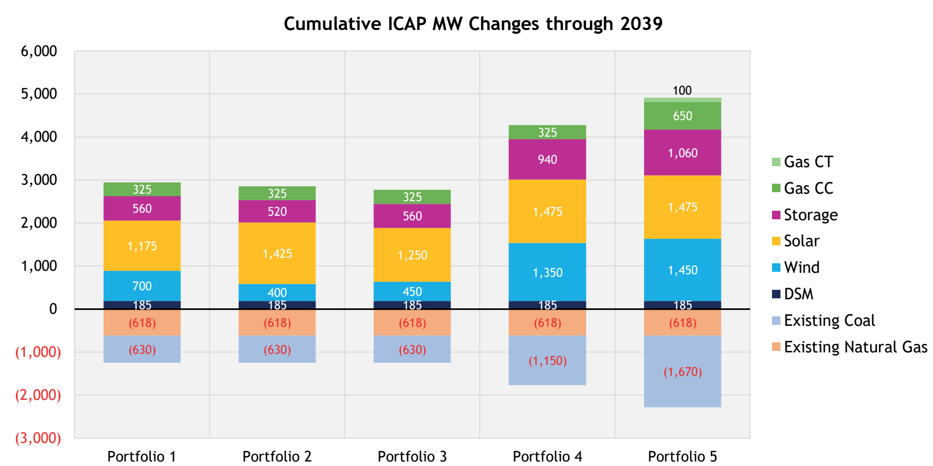
New Build by 2039

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

Retirements

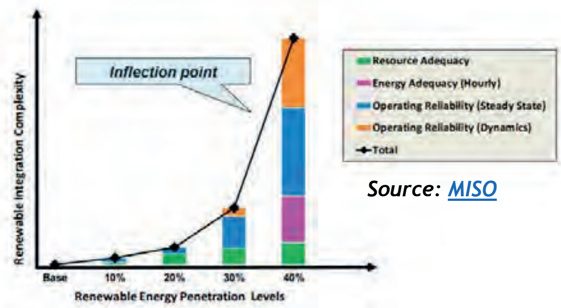
- Petersburg
  - Pete 1: 2021
  - Pete 2: 2023
  - Pete 3: 2026
  - Pete 4: 2030
  - Total UCAP: 1,600 MW
- Harding Street:
  - HS ST5: 2031
  - HS ST6: 2031
  - HS ST7: 2034
  - Total UCAP MW: 583

PORTFOLIO SUMMARIES



OBSERVATIONS AND TAKEAWAYS

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



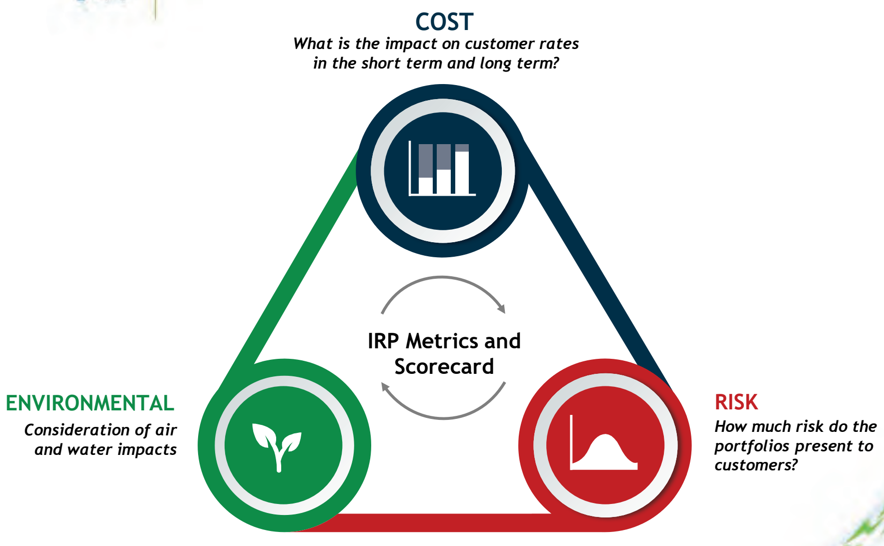
Source: MISO

PORTFOLIO METRICS

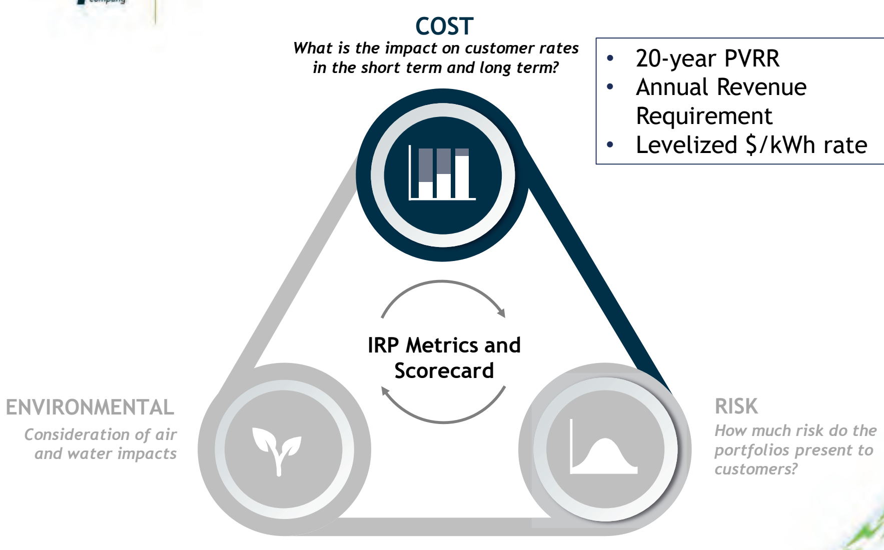
Patrick Maguire

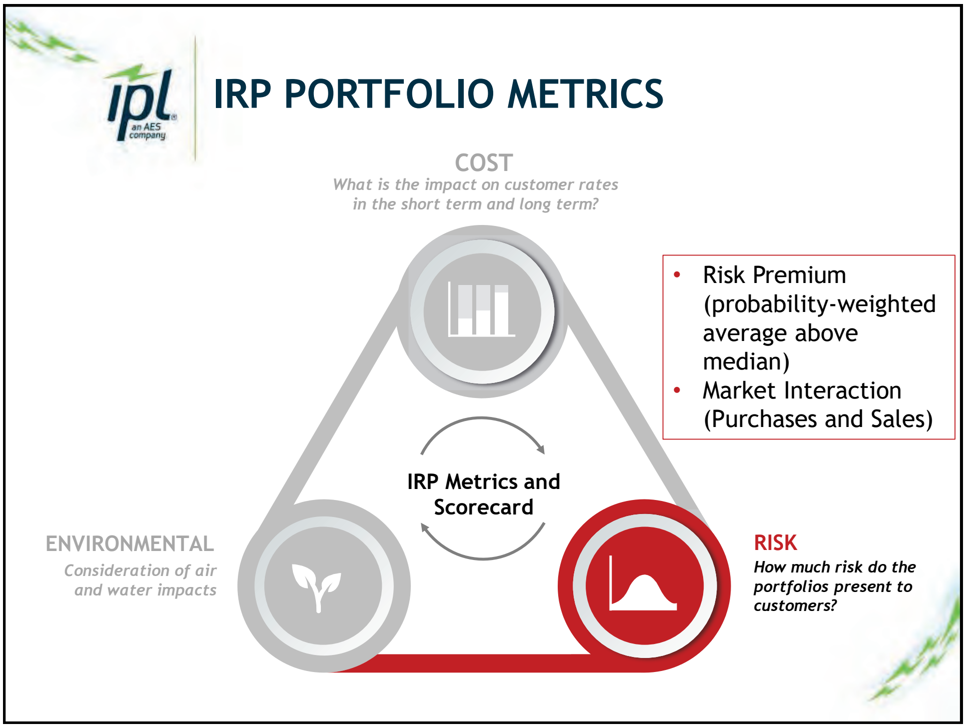
Director of Resource Planning

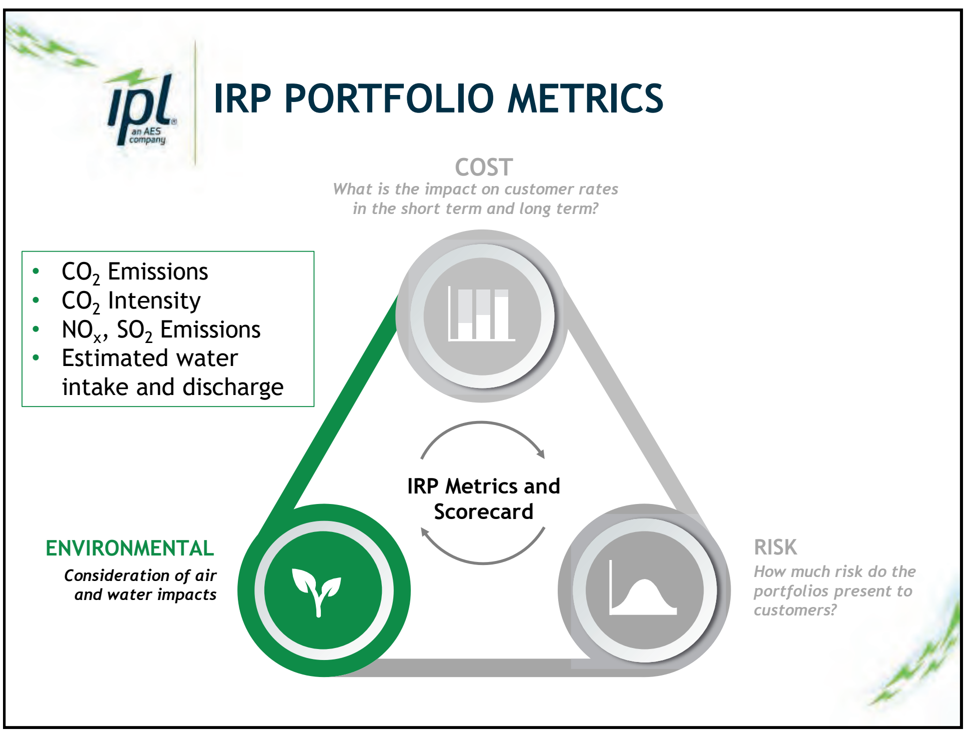
IRP PORTFOLIO METRICS



IRP PORTFOLIO METRICS




ipl an AES company
IRP PORTFOLIO METRICS
COST
What is the impact on customer rates in the short term and long term?
Risk Premium (probability-weighted average above median)
Market Interaction (Purchases and Sales)
IRP Metrics and Scorecard
ENVIRONMENTAL
Consideration of air and water impacts
RISK
How much risk do the portfolios present to customers?


ipl an AES company
IRP PORTFOLIO METRICS
COST
What is the impact on customer rates in the short term and long term?
CO_2 Emissions
CO_2 Intensity
NO_x, SO_2 Emissions
Estimated water intake and discharge
IRP Metrics and Scorecard
ENVIRONMENTAL
Consideration of air and water impacts
RISK
How much risk do the portfolios present to customers?

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

APPENDIX

ACRONYM LIST

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

INDIANAPOLIS POWER & LIGHT COMPANY

IPL 2019 IRP: PUBLIC ADVISORY MEETING #5

DECEMBER 9, 2019

ipl an AES company

INTRODUCTIONS & SAFETY MESSAGE

Shelby Houston

Regulatory Analyst, IPL

MEETING OBJECTIVES & AGENDA

Stewart Ramsey

Meeting Facilitator, Vanry & Associates

AGENDA

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

EXECUTIVE SUMMARY OF SHORT TERM ACTION PLAN

Vince Parisi,

President and CEO, IPL

IPL 2019 IRP

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

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

What is a preferred resource portfolio?

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

170 IAC 4-7-1(cc)

2019 IRP STAKEHOLDER PROCESS

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

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

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

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

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

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

IPL PORTFOLIO DIVERSIFICATION: 2009 - 2018






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

2011
Signed 200 MW PPA at Lakefield Wind Farm in Minnesota

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

2016
Retired 260 MW of coal at Eagle Valley

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

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

IPL PREFERRED PORTFOLIO & SHORT-TERM ACTION PLAN

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

BENEFITS OF PREFERRED RESOURCE PORTFOLIO

IPL Preferred Portfolio: Areas of Focus

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Measured approach maintaining optionality

Greener Energy Future
Moves the company to more renewables

CUSTOMER CENTRICITY

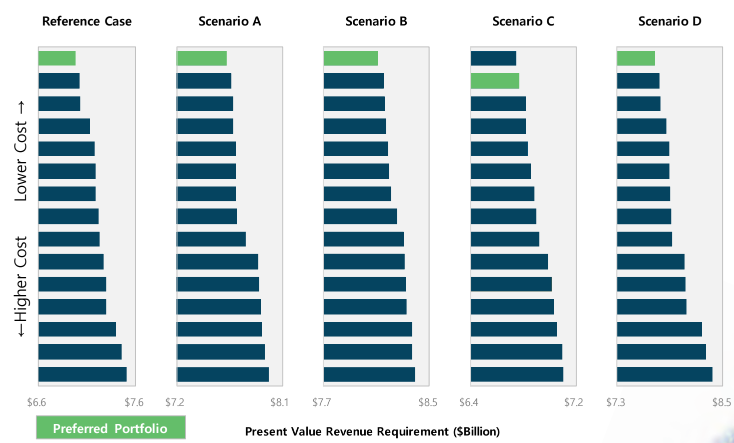
Focus on customer needs and wants

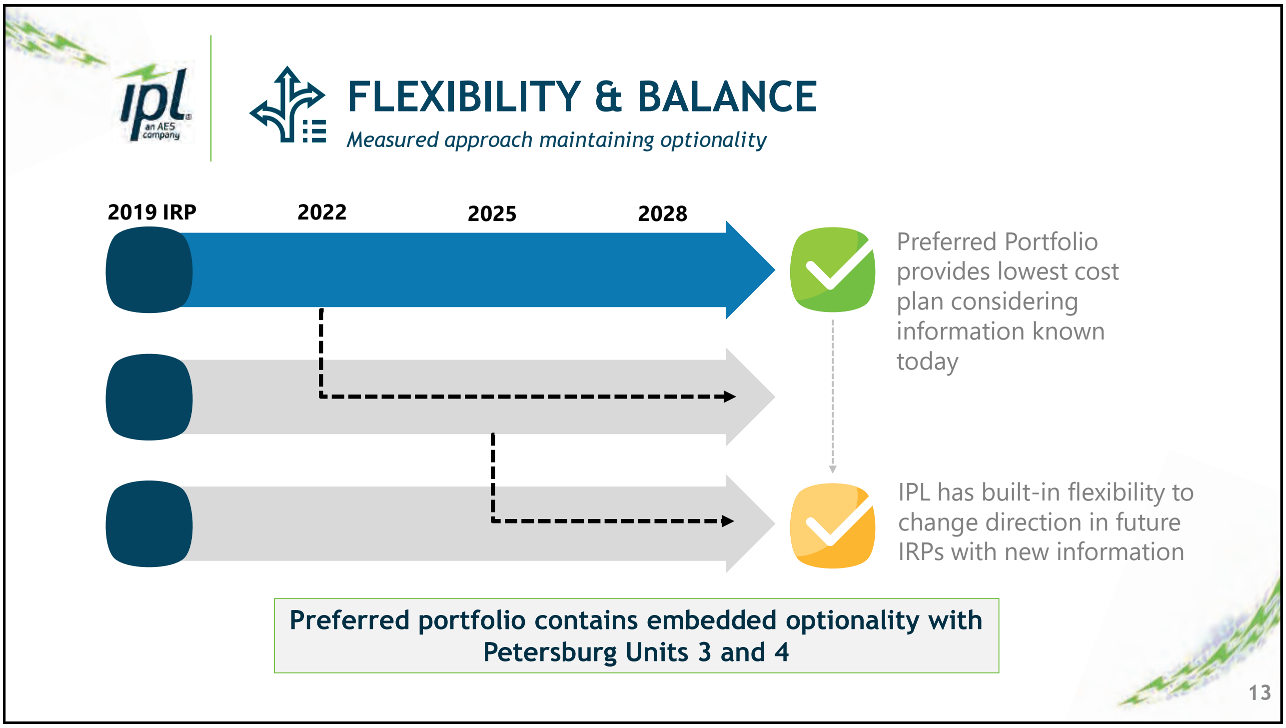
- IPL' s Preferred Resource Portfolio delivers safe, reliable, and economic electricity to customers at just and reasonable rates
- The preferred resource portfolio best serves IPL customers today and into the future, contemplates customers' evolving energy needs, and relies on data-driven models

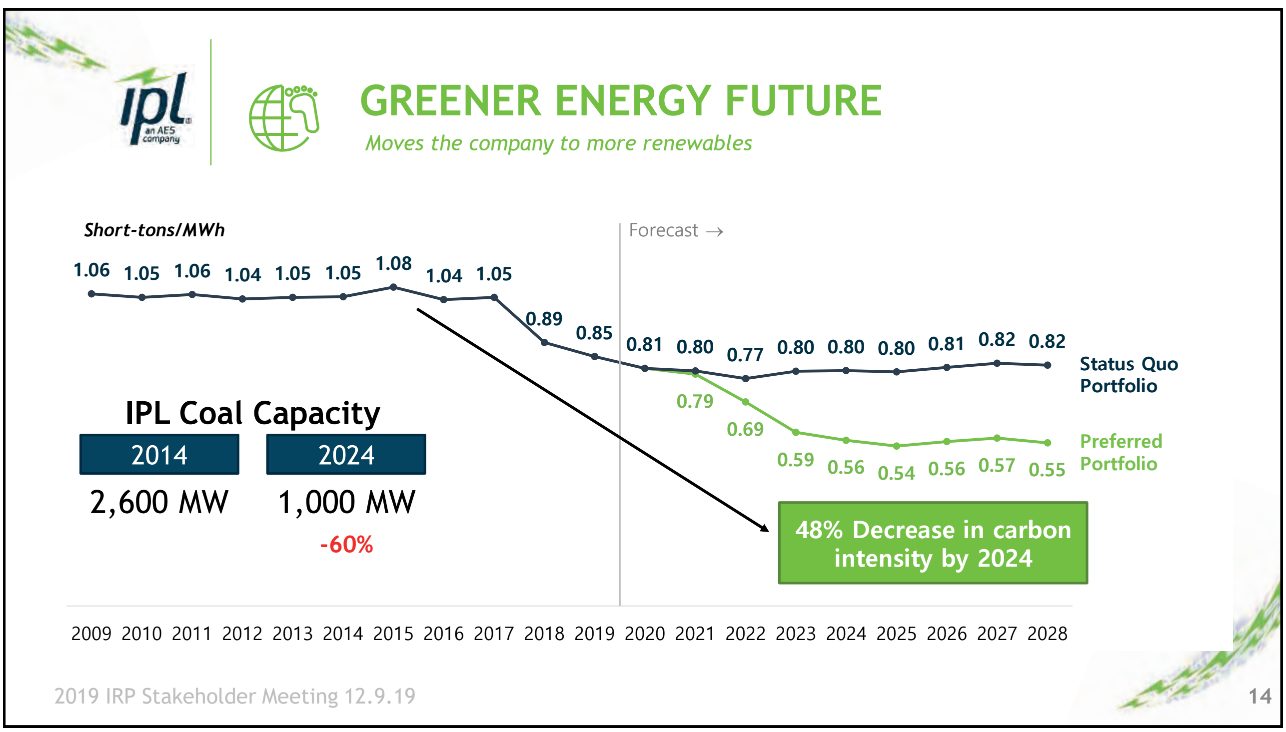
LEAST COST

Minimizes total portfolio cost

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




FLEXIBILITY & BALANCE
Measured approach maintaining optionality
2019 IRP
2022
2025
2028
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
13


GREENER ENERGY FUTURE
Moves the company to more renewables
Short-tons/MWh
Forecast →
1.06 1.05 1.06 1.04 1.05 1.05 1.08 1.04 1.05 0.89 0.85 0.81 0.80 0.77 0.80 0.80 0.80 0.81 0.82 0.82
Status Quo Portfolio
0.79 0.69 0.59 0.56 0.54 0.56 0.57 0.55
Preferred Portfolio
IPL Coal Capacity
2014
2024
2,600 MW
1,000 MW
-60%
48% Decrease in carbon intensity by 2024
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028
2019 IRP Stakeholder Meeting 12.9.19
14

BENEFITS OF PREFERRED RESOURCE PORTFOLIO

IPL Preferred Portfolio: Areas of Focus

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Measured approach maintaining optionality

Greener Energy Future
Moves the company to more renewables

2019 IRP: MODELING INSIGHTS

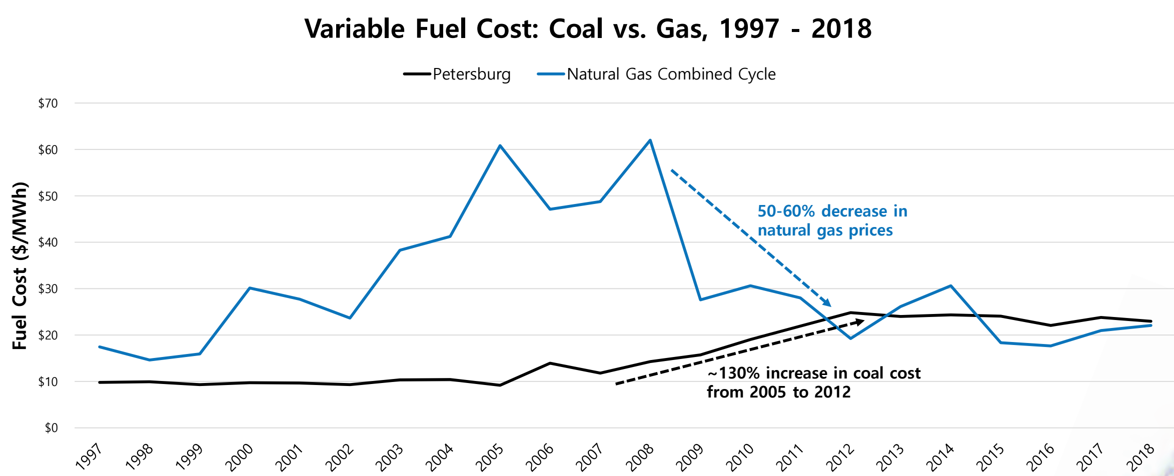
Patrick Maguire

Director of Resource Planning, IPL

HIGH IMPACT MARKET FORCES

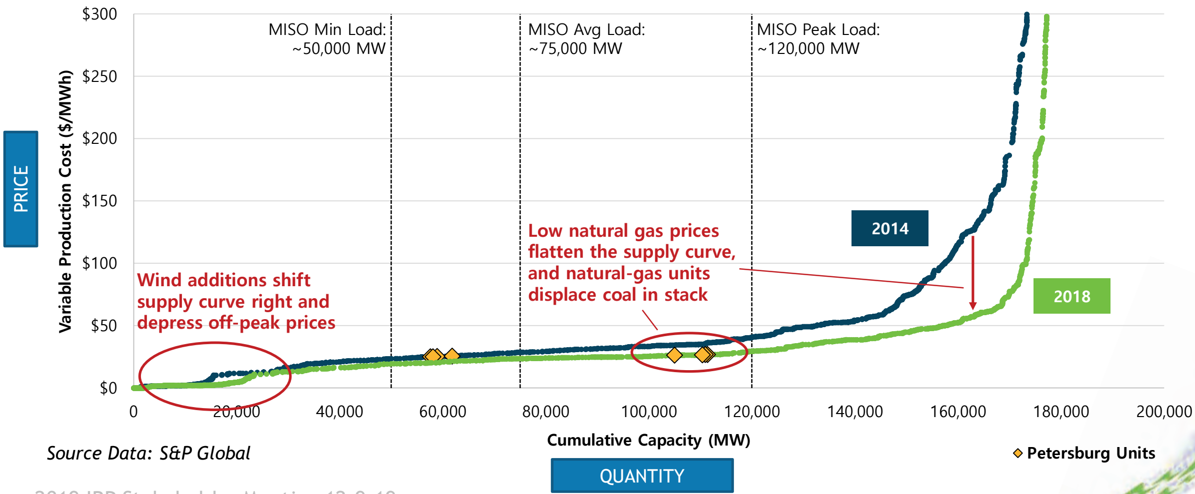
- Significant market changes over the past 10 years have impacted IPL's existing resources
- Opportunities and risk associated with alternative resources
- Present Value Revenue Requirement (PVRR) is key cost metric that is impacted by relative economics of resource technologies
  - Look at underlying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

COAL ECONOMICS (1 OF 3)



COAL ECONOMICS (2 OF 3)

MISO Generation Supply Stack



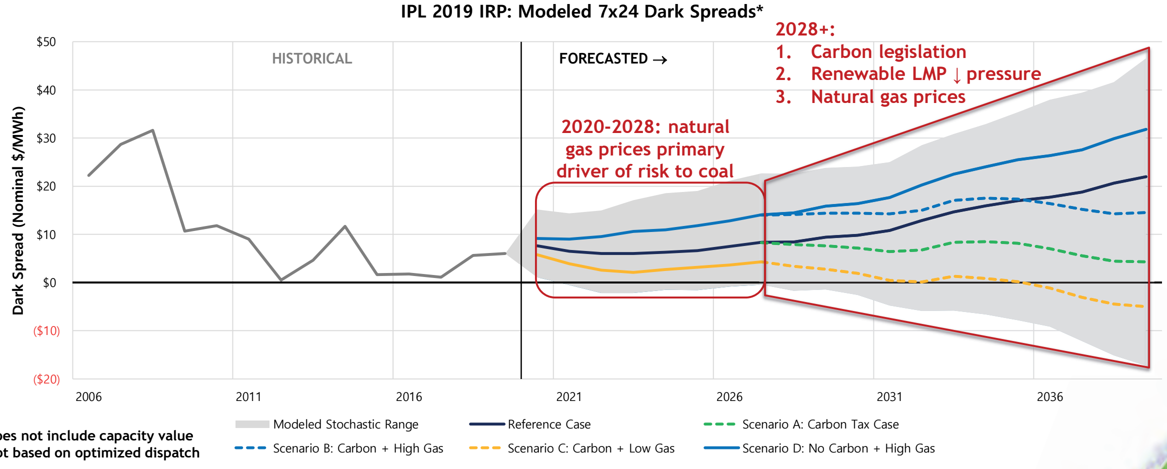
Source Data: S&P Global

COAL ECONOMICS (3 OF 3)

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

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

IPL 2019 IRP: Modeled 7x24 Dark Spreads*



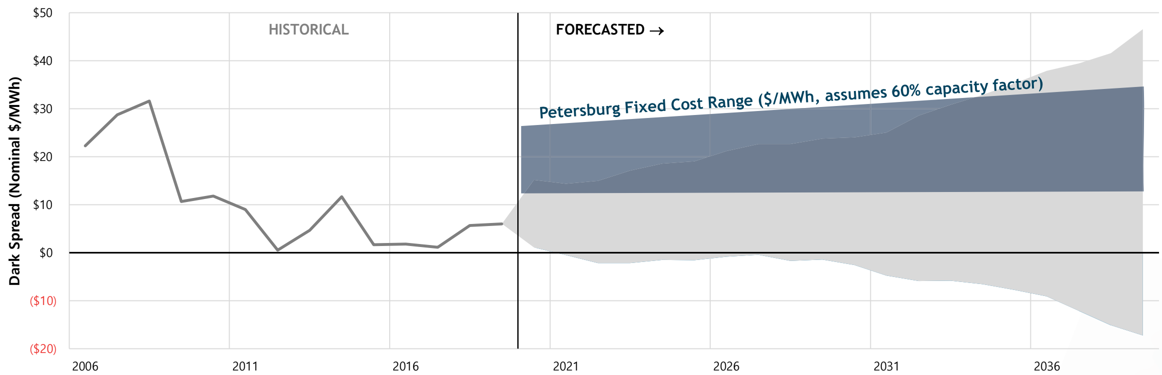
* Does not include capacity value
* Not based on optimized dispatch

COAL ECONOMICS (3 OF 3)

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

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

IPL 2019 IRP: Modeled 7x24 Dark Spreads*

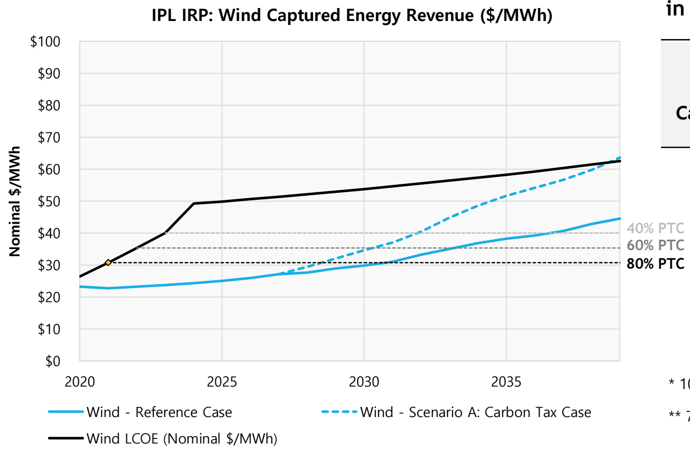


* Does not include capacity value
* Not based on optimized dispatch

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

WIND ECONOMICS: HEADWINDS AND UPSIDE POTENTIAL

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



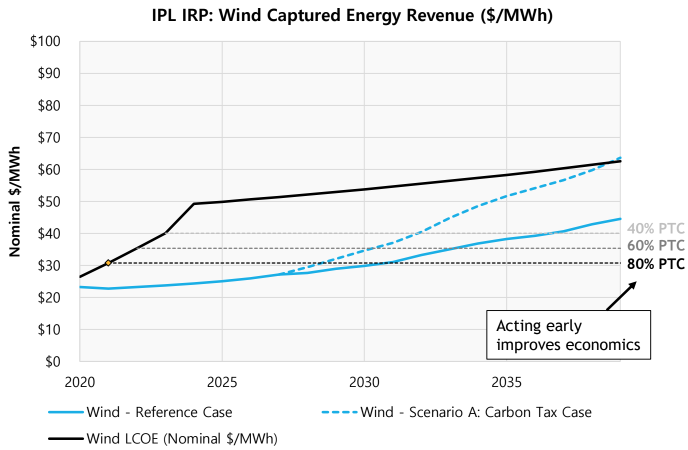
Carbon tax increases wholesale prices via increase in variable cost of fossil units on the margin

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

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

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

WIND ECONOMICS: HEADWINDS AND UPSIDE POTENTIAL



Challenging wind economics with PTC phaseout

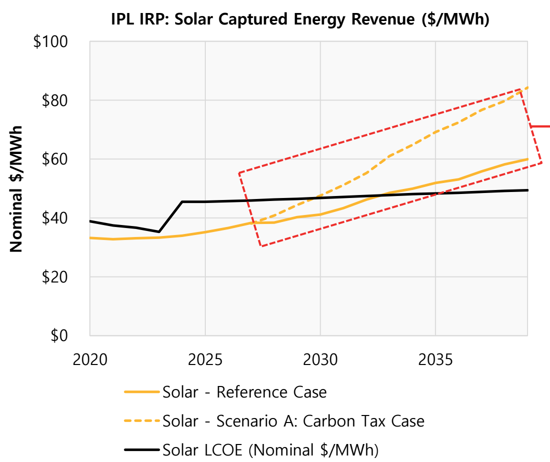
Headwinds:

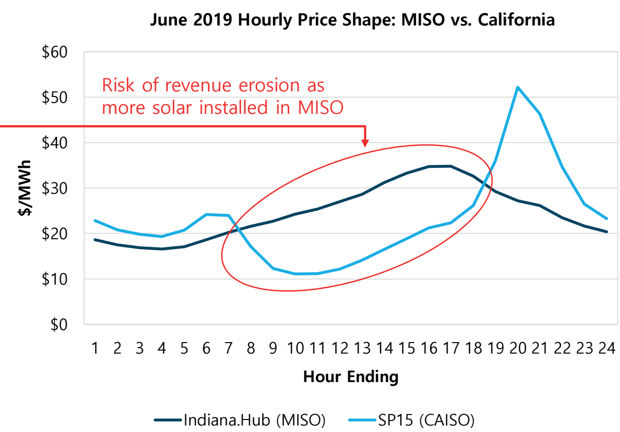
- Each 20% reduction in PTC increases LCOE by $3-$5/MWh
- Captured revenue remains hampered by production shapes, congestion

Upside potential:

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

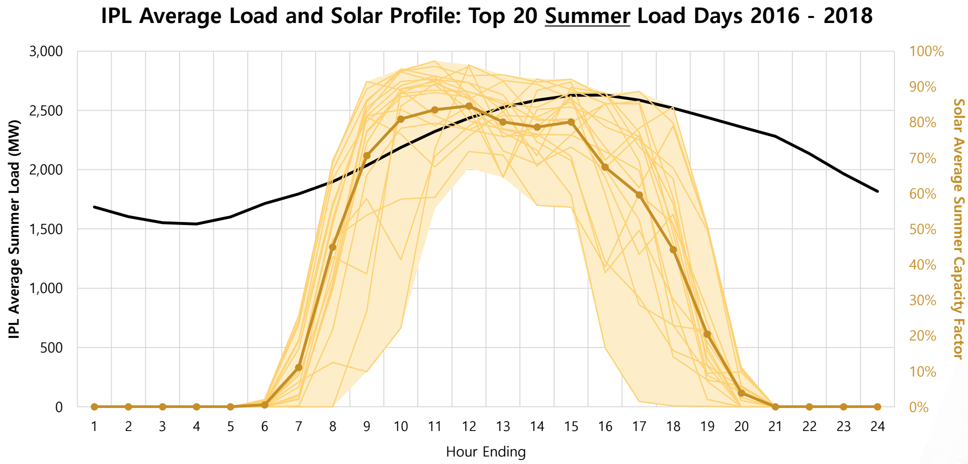
SOLAR ECONOMICS: FAVORABLE IN SHORT TERM, LONG TERM RISKS



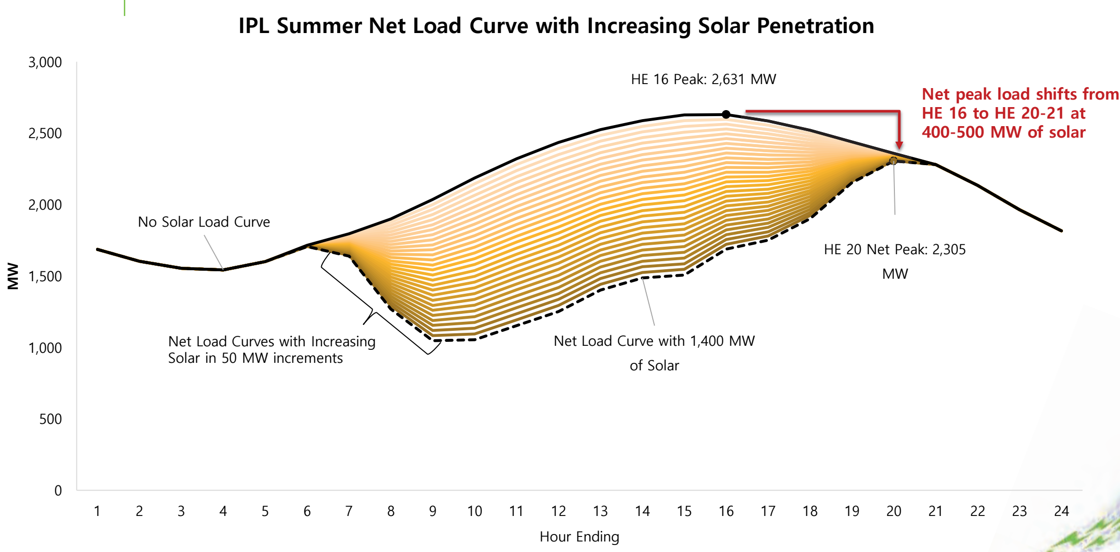


SOLAR CAPACITY CREDIT: SUMMER

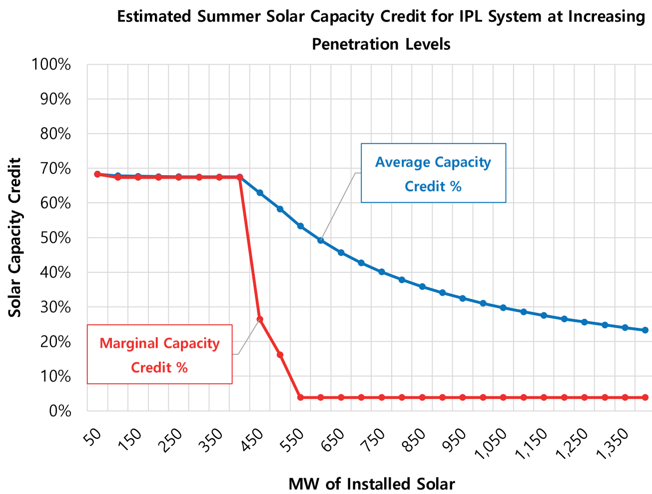
Summer capacity credit for single-axis tracking solar is 60-70% at low penetration levels



SUMMER NET LOAD CURVE



SOLAR CAPACITY CREDIT



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

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

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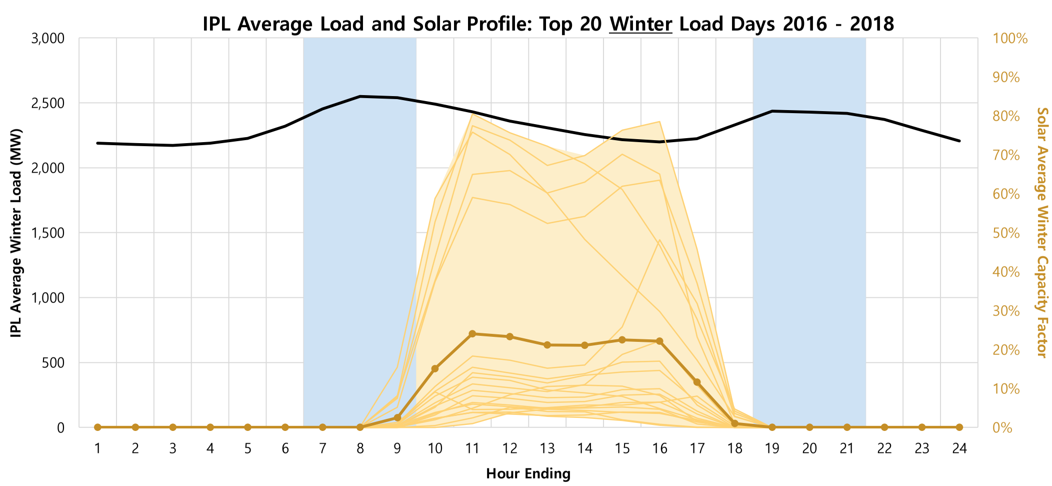
SOLAR CAPACITY CREDIT: WINTER

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



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BREAK

ANALYSIS OF ALTERNATIVES: 2019 IRP MODELING

Patrick Maguire

Director of Resource Planning, IPL

2019 IRP MODELING FRAMEWORK

SCENARIOS

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

IRP Modeling Framework:

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

TESTING FOR COST EFFECTIVENESS OF INCREMENTAL DSM

Presented at Sep. 30th Meeting ↓ New portfolios

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

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

MODELING SUMMARY

- **Final modeling framework:**
  - 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

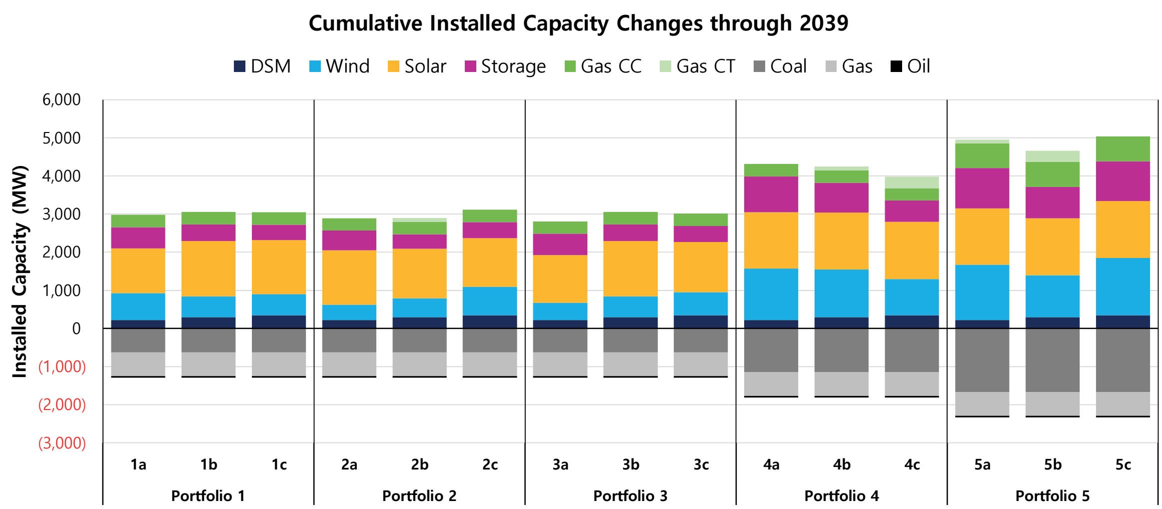
Modeling Tools and Analysis

- 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

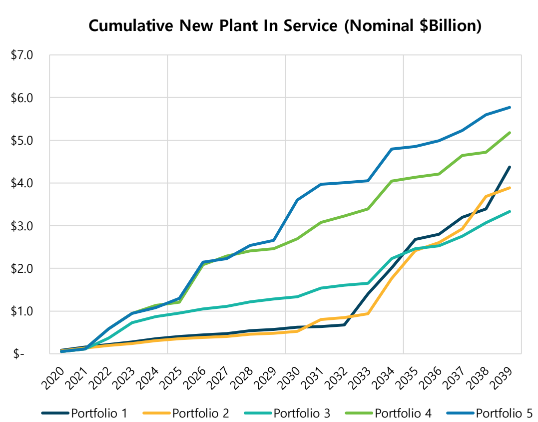
Renewable Modeling

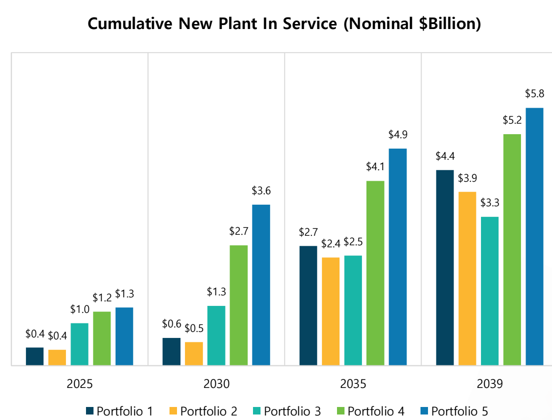
- Robust development of wind and solar profiles
- Solar ELCC and net price shape analysis
- Capital costs: transparent, multi-source cost estimates benchmarked to market bids
- Improved storage modeling

CANDIDATE RESOURCE PORTFOLIOS

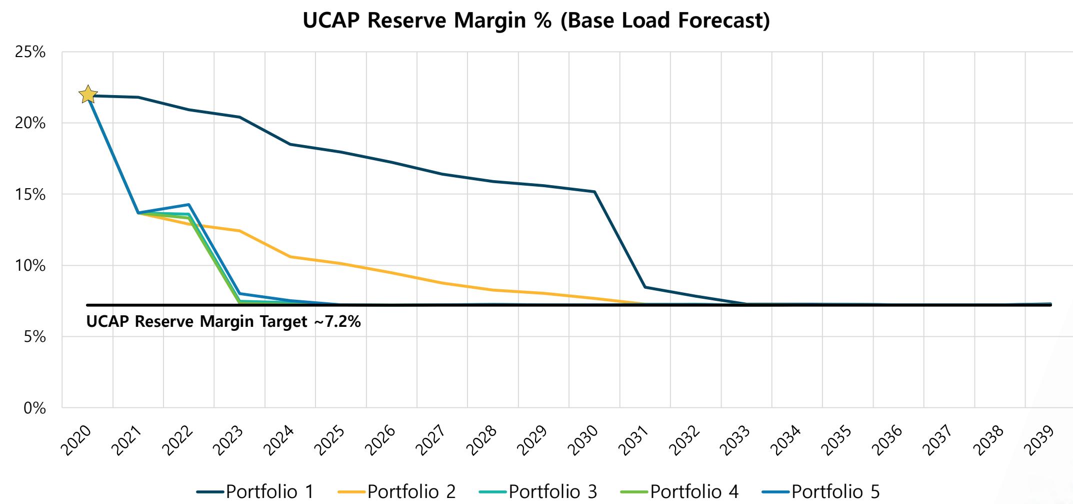


CAPEX REQUIREMENTS BY PORTFOLIO

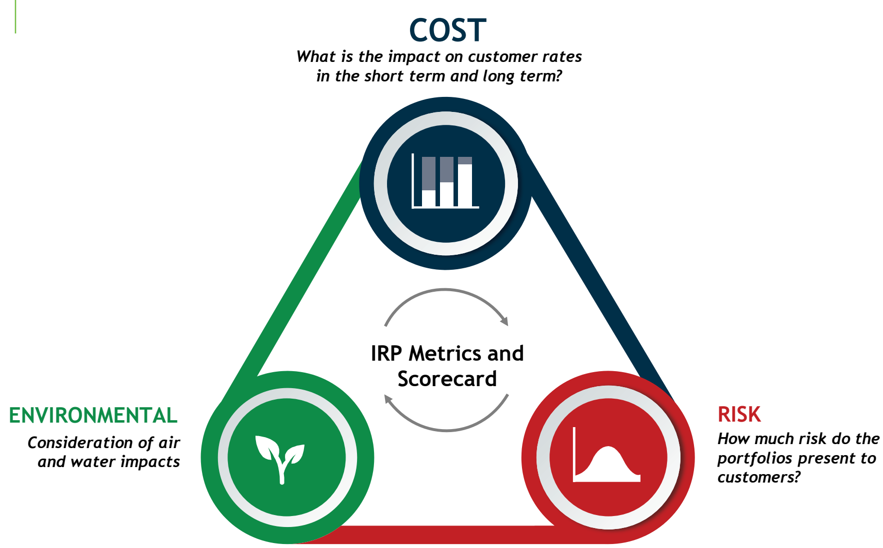




RESERVE MARGIN



PORTFOLIO METRICS

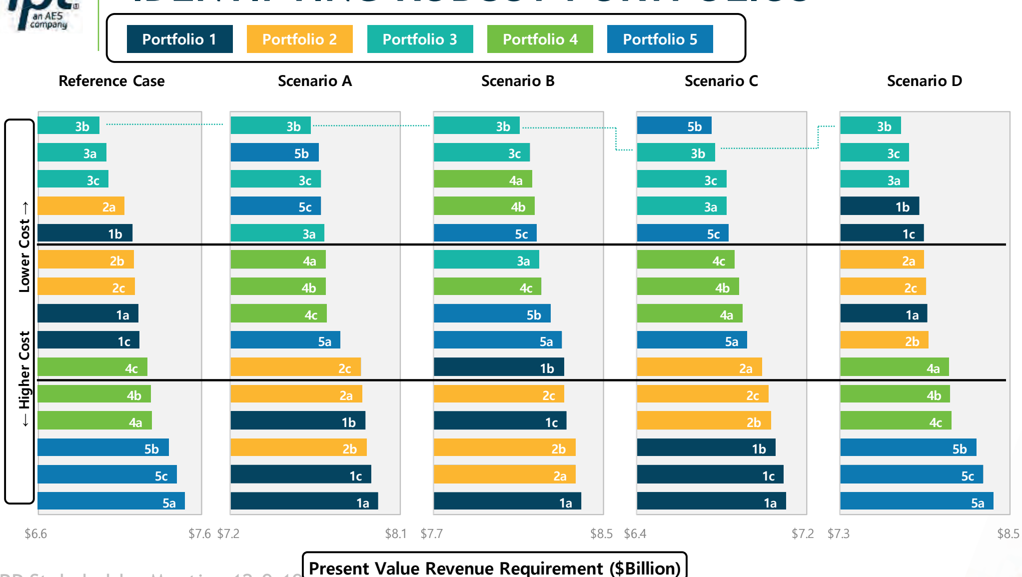


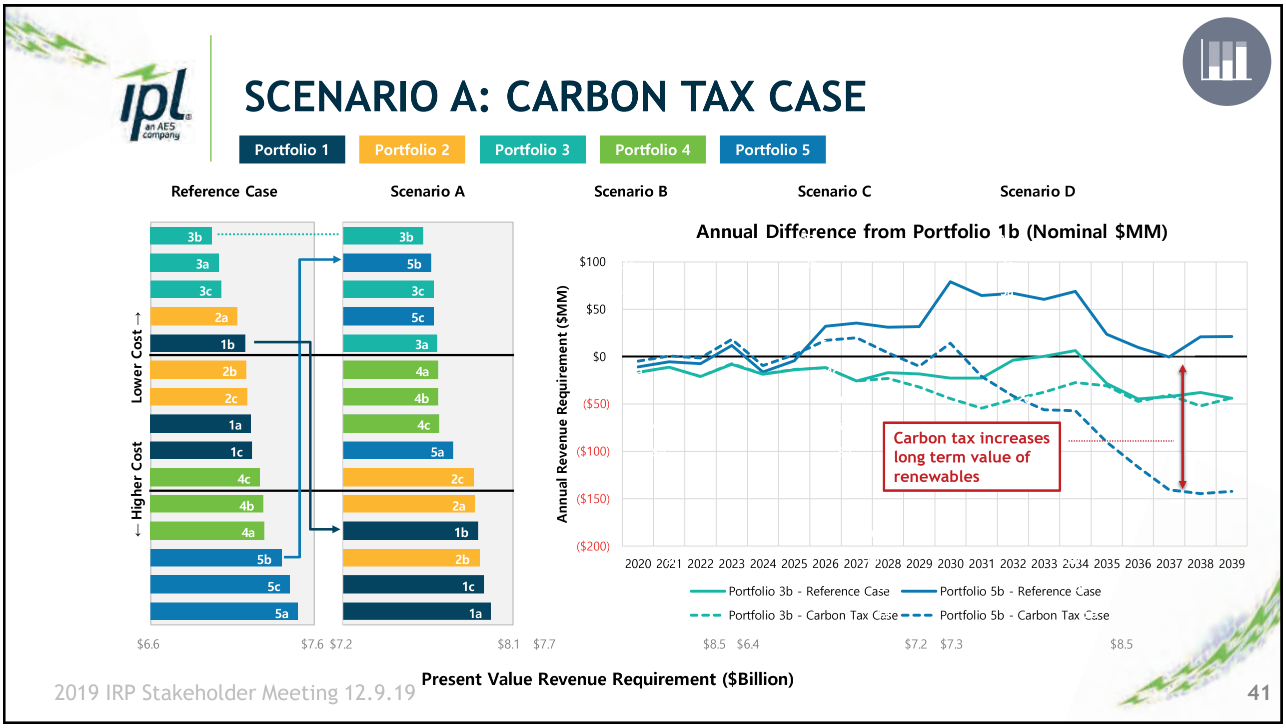
PVRR SUMMARY TABLE BY SCENARIO

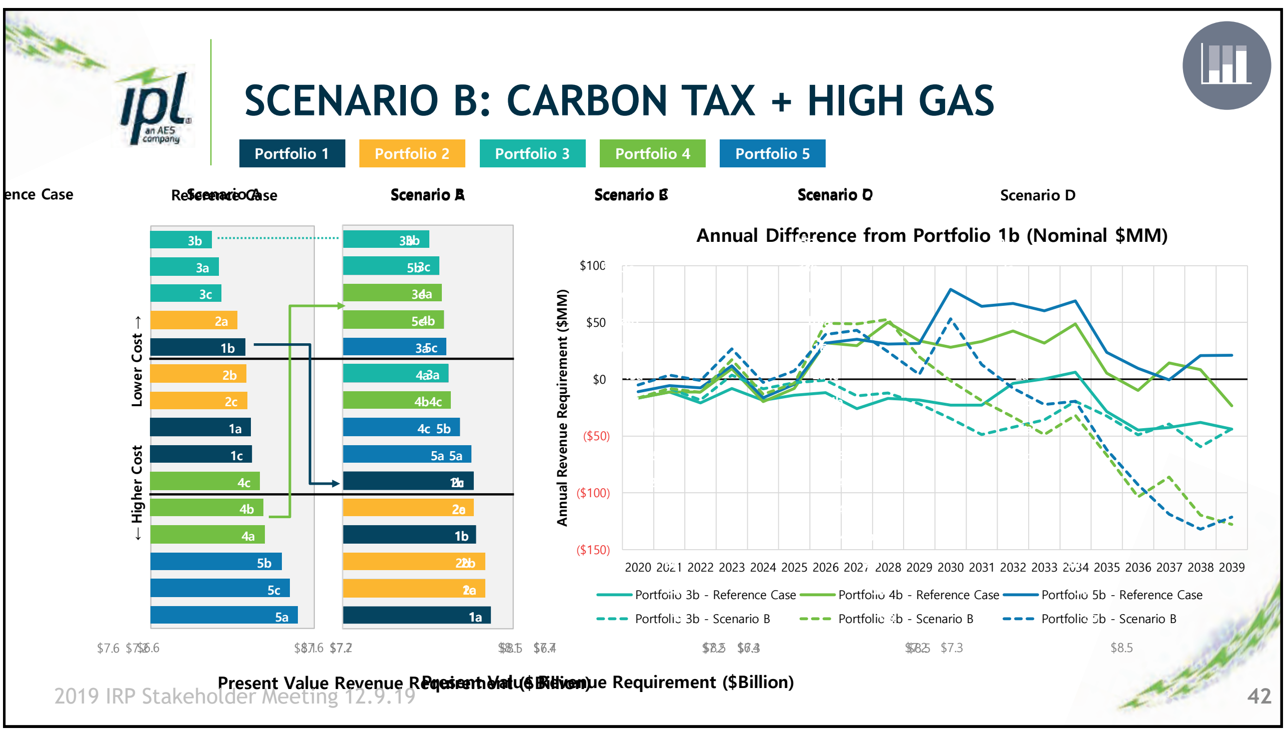
20-Year PVRR ($MM)

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

IDENTIFYING ROBUST PORTFOLIOS

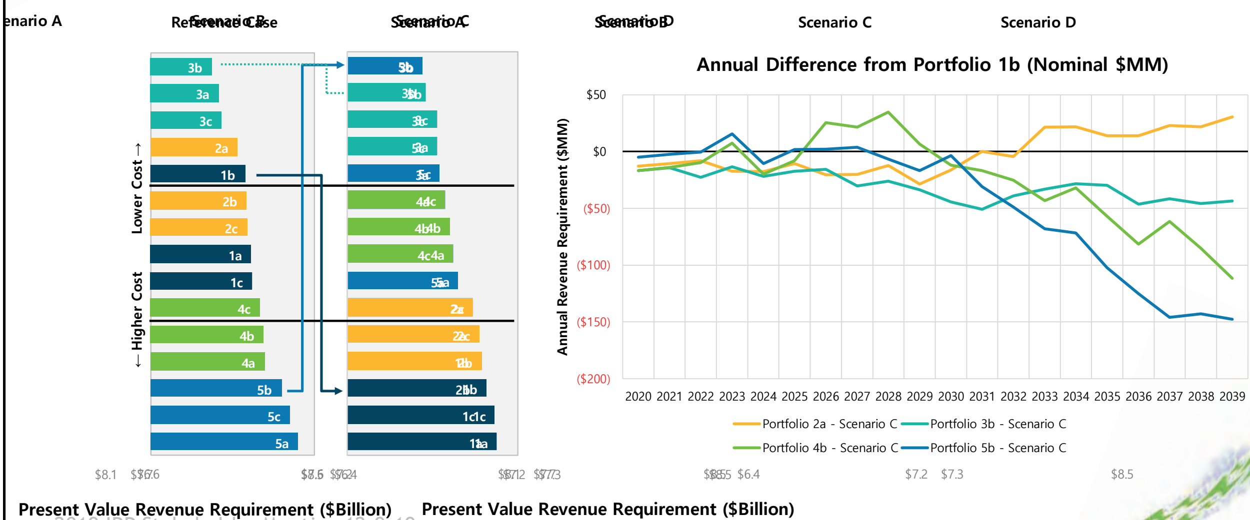



SCENARIO A: CARBON TAX CASE
Portfolio 1
Portfolio 2
Portfolio 3
Portfolio 4
Portfolio 5
Reference Case
Scenario A
Scenario B
Scenario C
Scenario D
Lower Cost
Higher Cost
Annual Difference from Portfolio 1b (Nominal $MM)
Annual Revenue Requirement ($MM)
$100
$50
$0
($50)
($100)
($150)
($200)
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039
Carbon tax increases long term value of renewables
Portfolio 3b - Reference Case
Portfolio 5b - Reference Case
Portfolio 3b - Carbon Tax Case
Portfolio 5b - Carbon Tax Case
$6.6
$7.6
$7.2
$8.1
$7.7
$8.5
$6.4
$7.2
$7.3
$8.5
Present Value Revenue Requirement ($Billion)
2019 IRP Stakeholder Meeting 12.9.19
41


SCENARIO B: CARBON TAX + HIGH GAS
Portfolio 1
Portfolio 2
Portfolio 3
Portfolio 4
Portfolio 5
Reference Case
Scenario B
Scenario C
Scenario D
Lower Cost
Higher Cost
Annual Difference from Portfolio 1b (Nominal $MM)
Annual Revenue Requirement ($MM)
$100
$50
$0
($50)
($100)
($150)
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039
Portfolio 3b - Reference Case
Portfolio 4b - Reference Case
Portfolio 5b - Reference Case
Portfolio 3b - Scenario B
Portfolio 4b - Scenario B
Portfolio 5b - Scenario B
Present Value Revenue Requirement ($Billion)
2019 IRP Stakeholder Meeting 12.9.19
42

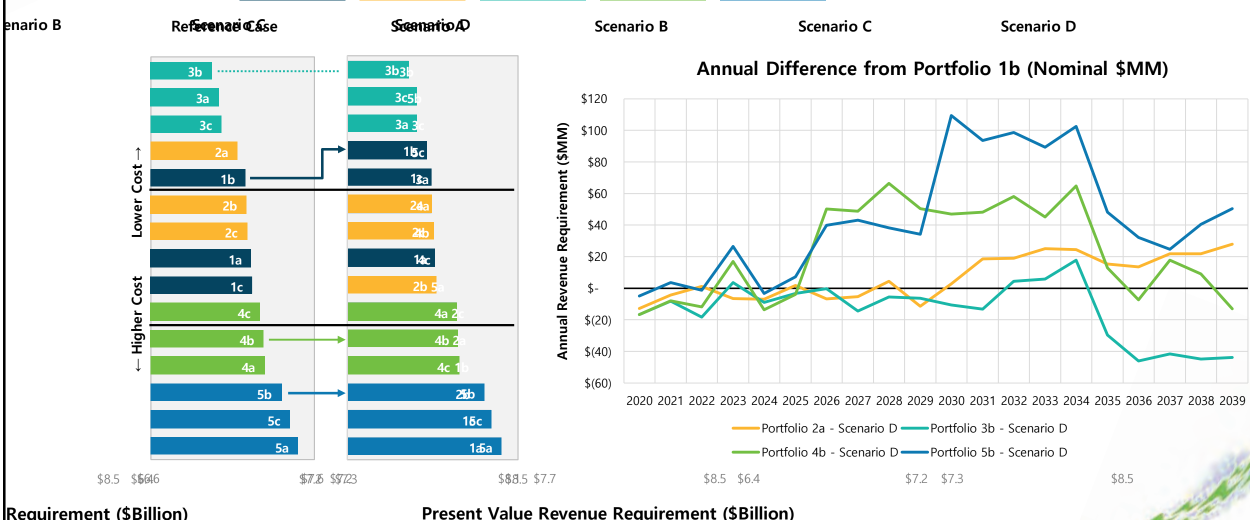
SCENARIO C: CARBON TAX + LOW GAS + LOW LOAD

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



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

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



PVRR TAKEAWAYS

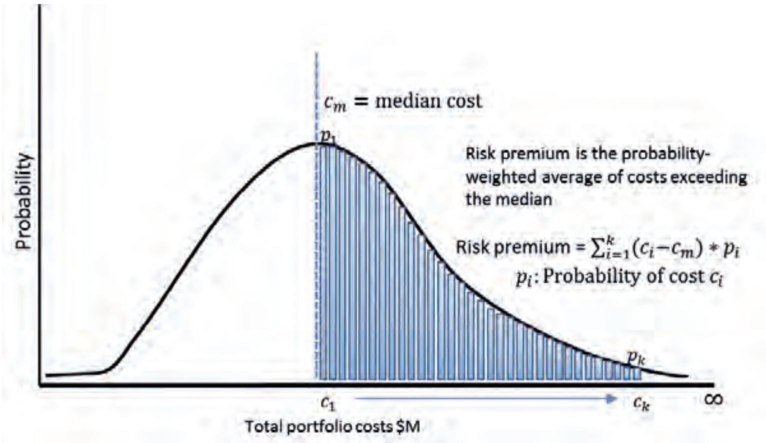
- **Carbon tax single largest driver of changes in PVRR**
  - Coal margins 40-50% lower with carbon tax
  - Renewable captured revenue 30-40% higher because of higher wholesale power prices
  - Reducing exposure to future carbon legislation important
- Natural gas will continue to be a high impact variable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

RATE IMPACTS

Levelized Rate $/kWh

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

RISK PREMIUM METRIC



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

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

RISK PREMIUM ($MM)

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

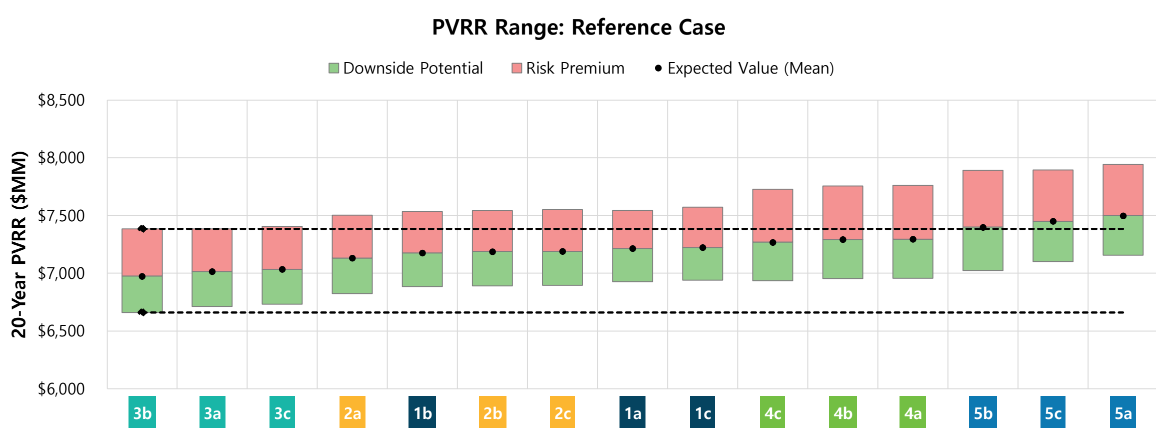
- Risk premiums are 4-7% of total cost
- Risk premium lowest for Portfolios 1 and 2
- Coal prices relatively stable, dispatchability improves economics
- High renewable portfolios can create mismatch between load and generation

RISK-ADJUSTED PVRR ($MM)

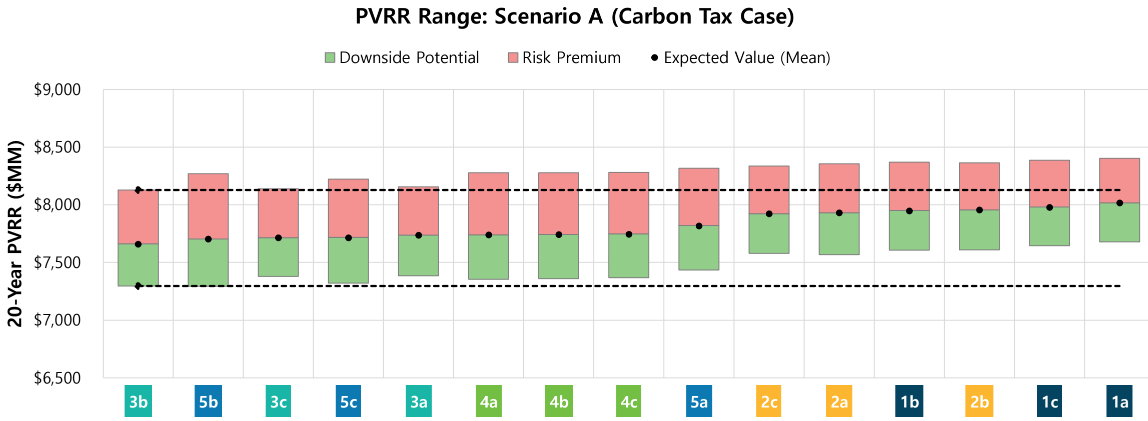
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1a	$7,544	$8,401	$8,833	$7,489	$8,324
Portfolio 2a	$7,502	$8,356	$8,865	$7,401	$8,351
Portfolio 3a	$7,383	$8,156	$8,676	$7,213	$8,246
Portfolio 4a	$7,761	$8,278	$8,784	$7,388	$8,623
Portfolio 5a	$7,941	$8,317	$8,904	$7,379	$8,915
Portfolio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

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

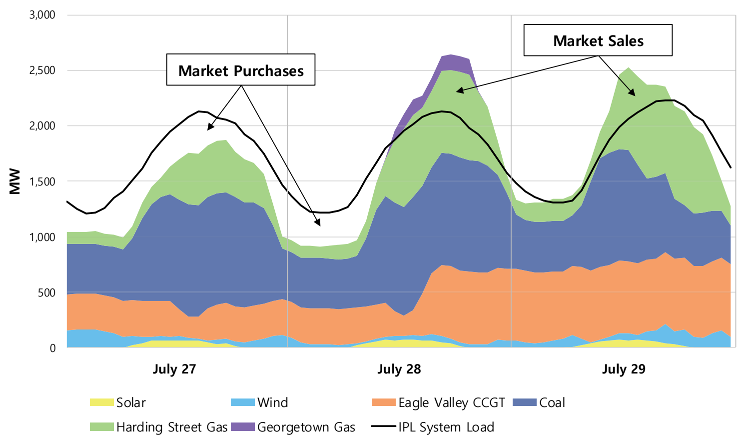
PVRR WITH RISK DISTRIBUTIONS: REFERENCE CASE



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



RISK METRIC: MARKET INTERACTION

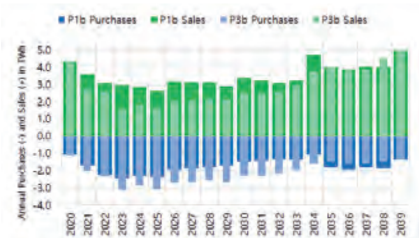


- Looking only at annual energy misses the actual market interaction that will occur hourly
- Market purchases and sales occur in all portfolios
- Relying too heavily on market purchases introduces risk
- Relying on value from market sales is equally risky

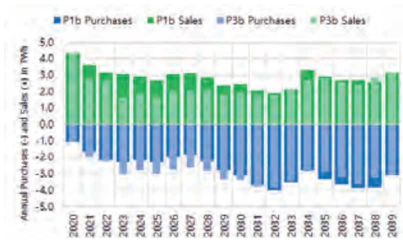
RELIANCE ON THE MARKET: BALANCED APPROACH

Portfolio 1 vs. Portfolio 3

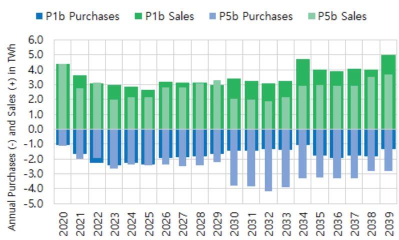
Reference Case

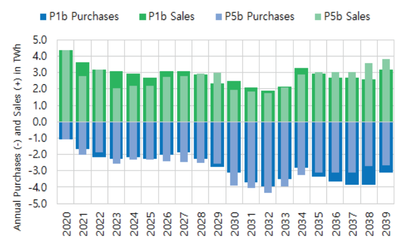


Scenario A: Carbon Case



Portfolio 1 vs. Portfolio 5





Market Interaction

(in Millions of MWh)
|Purchases| + |Sales|

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

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

ENVIRONMENTAL: AIR EMISSIONS

Reference Case

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

Scenario A: Carbon Tax Case

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

ENVIRONMENTAL: NON-AIR IMPACTS

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

PORTFOLIO METRICS SUMMARY

Cost	Risk	Environmental
• Portfolio 3b is the lowest cost portfolio across wide range scenarios • O&M and Capex savings from retirements mitigates rate impacts of cost of new capacity	• Portfolio 3b lowest cost on risk-adjusted basis • Portfolio 3b resource mix provides balanced energy and load profile and reduction total market interaction	• Portfolio 3b benefits: • Near term reductions in CO2, NOx, SO2 • 60-70% reduction in water intake flow at the plant

LUNCH BREAK

SENSITIVITY ANALYSIS

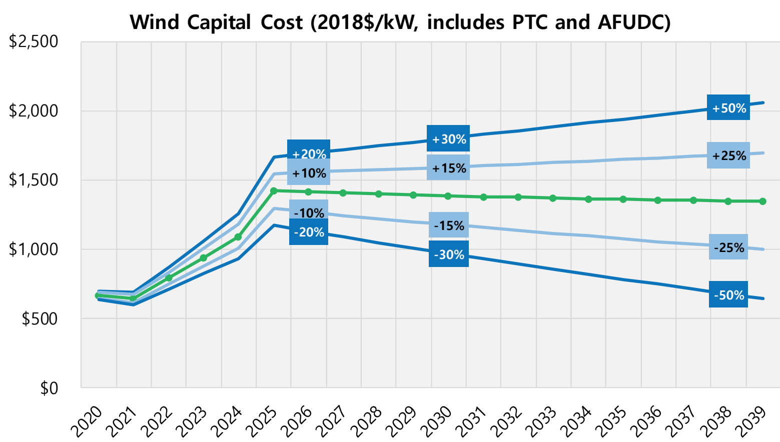
Patrick Maguire

Director of Resource Planning, IPL

SENSITIVITY ANALYSIS

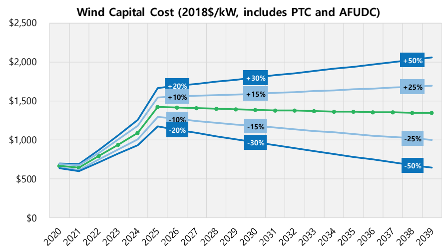
- **Sensitivity: change of a single variable to isolate the impact of future uncertainty**
- Four deterministic analyses conducted:
  1. Capital Costs for wind, solar, and storage
  2. MISO Capacity Prices
  3. Wind Capacity Factor
  4. Wind LMP Basis

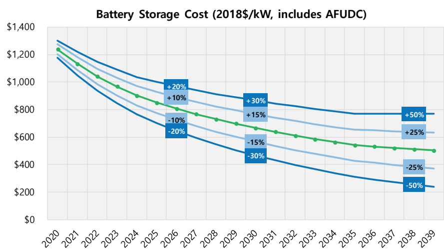
CAPITAL COST SENSITIVITY (1 OF 4)

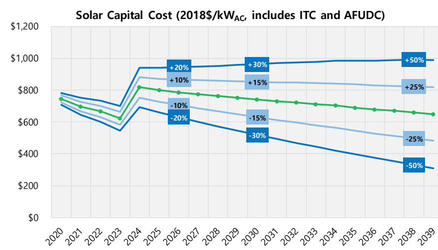


High and low capital cost ranges established for wind, solar, and storage

CAPITAL COST SENSITIVITY (2 OF 4)







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

CAPITAL COST SENSITIVITY (3 OF 4)

Reference Case PVRR ($MM)

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

Takeaways:

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

CAPITAL COST SENSITIVITY (4 OF 4)

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

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

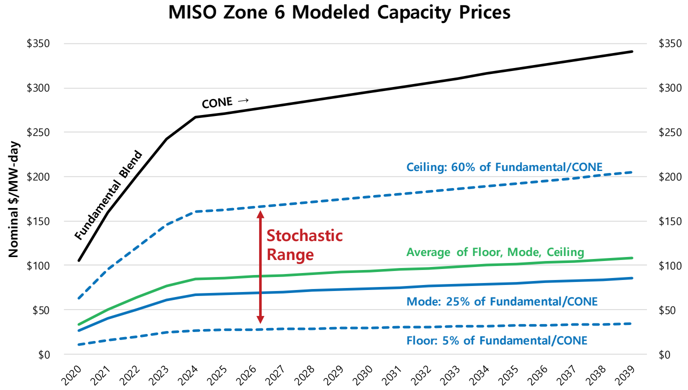
Carbon Tax Case Results:

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

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

MISO CAPACITY PRICE SENSITIVITY (1 OF 3)

MISO Zone 6 Modeled Capacity Prices



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

MISO CAPACITY PRICE SENSITIVITY (2 OF 2)

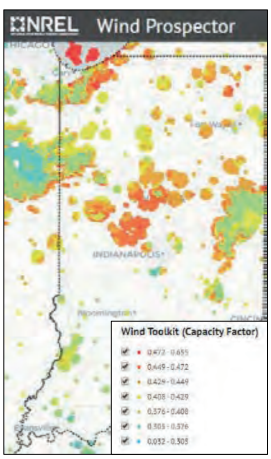
Reference Case PVRR ($MM)

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

Reference Case Results:

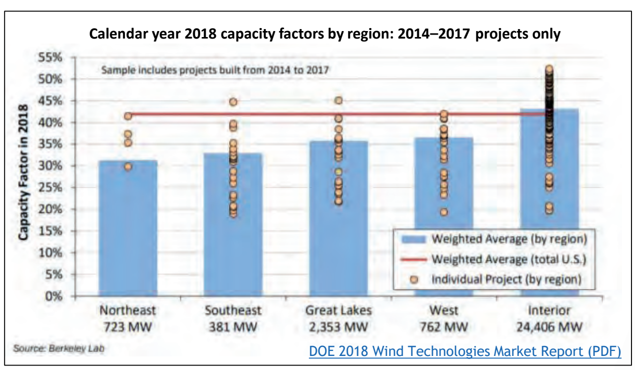
1. Portfolio 3b lowest cost even with applying CONE capacity price to capacity length in Portfolios 1 and 2
2. Sustained low capacity prices increases value of Portfolio 3 relative to Portfolios 1 and 2

WIND CAPACITY FACTOR (1 OF 3)



Source: NREL

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



DOE 2018 Wind Technologies Market Report (PDF)

WIND CAPACITY FACTOR (2 OF 3)

Wind annual capacity factor →

Reference Case PVRR ($MM)

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

Reference Case Results:

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

WIND CAPACITY FACTOR (3 OF 3)

Wind annual capacity factor →

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

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

Carbon Tax Case Results:

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

WIND LMP BASIS/CAPTURED REVENUE (1 OF 3)

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

WIND LMP BASIS/CAPTURED REVENUE (2 OF 3)

Reference Case PVRR ($MM)

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

Reference Case Results:

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

WIND LMP BASIS/CAPTURED REVENUE (3 OF 3)

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

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

1

Carbon Tax Case Results:

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

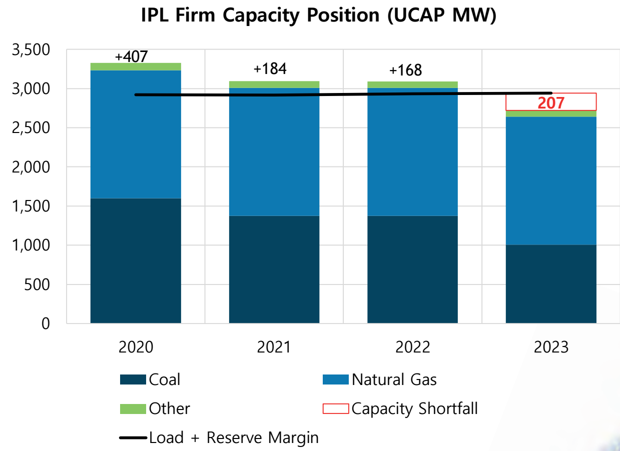
PREFERRED RESOURCE PORTFOLIO & SHORT TERM ACTION PLAN

Patrick Maguire

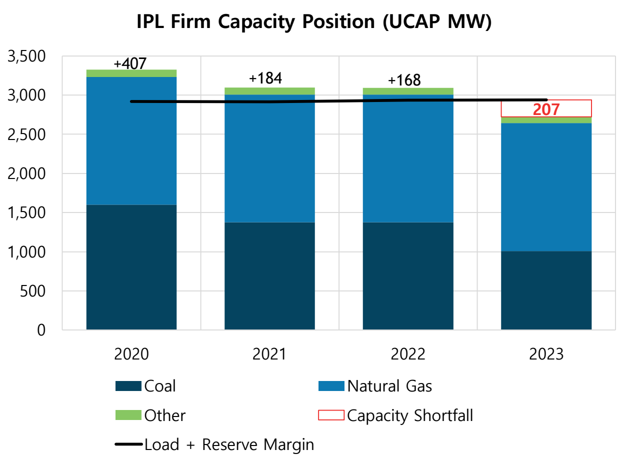
Director of Resource Planning, IPL

PREFERRED PORTFOLIO

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



PREFERRED PORTFOLIO



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

~200 MW of firm capacity =

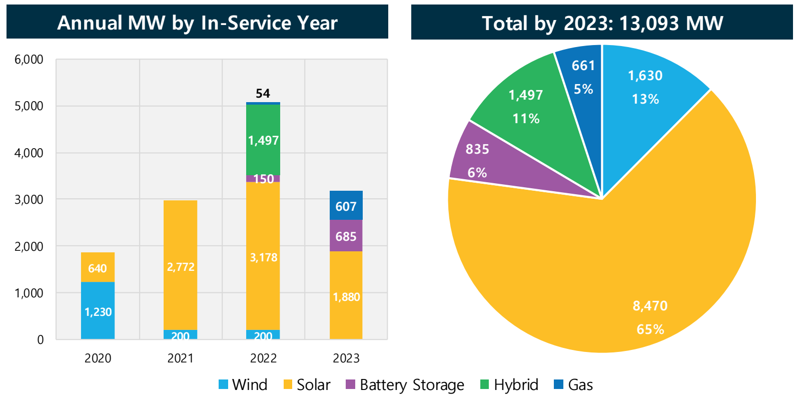
	Portfolio 3a	Portfolio 3b	Portfolio 3c
Wind	250	100	150
Solar	375	450	400
Storage	40	0	20
Total ICAP MW	**665**	**550**	**570**

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

ALL-SOURCE RFP

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

MISO Generation Interconnection Queue: Indiana Projects



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

DSM ACTION PLAN 2021 - 2023

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

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

FUTURE MODELING ENHANCEMENTS

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

Previous IPL IRPs

- 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

ACRONYM LIST

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

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

PORTFOLIO 1 ICAP CHANGES

Portfolio 1a: Includes Decrements 1-3

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

Portfolio 1b: Includes Decrements 1-4

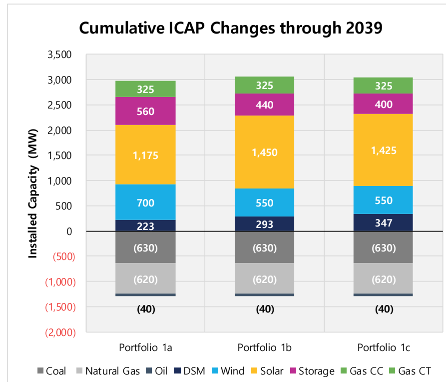
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	550
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	500	900	1,375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

Portfolio 1c: Includes Decrements 1-5

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

Retirements in All Portfolio 1 Runs

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



PORTFOLIO 2 ICAP CHANGES

Portfolio 2a: Includes Decrements 1-3

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

Portfolio 2b: Includes Decrements 1-4

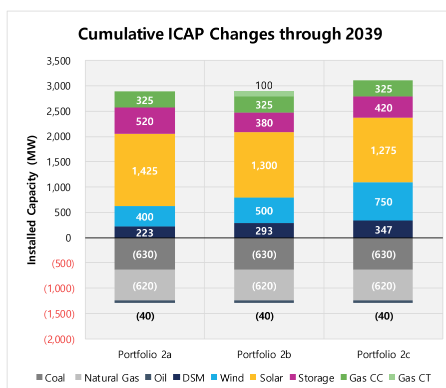
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	450	500	500
New Solar	0	0	0	0	0	0	0	0	0	0	0	350	350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

Portfolio 2c: Includes Decrements 1-5

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

Retirements in All Portfolio 1 Runs

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



PORTFOLIO 3 ICAP CHANGES

Portfolio 3a: Includes DSM Decrements 1-3

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

Portfolio 3b: Includes DSM Decrements 1-4

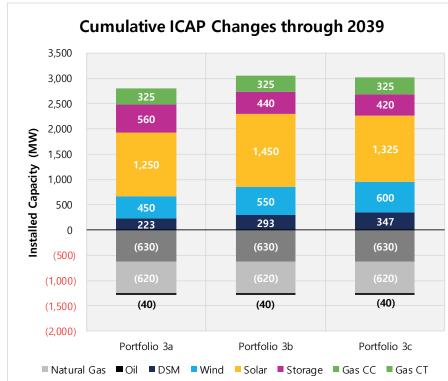
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	100	100	100	100	100	100	150	150	150	150	150	250	250	250	250	300	450	550
Solar	0	0	0	450	600	650	725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

Portfolio 3c: Includes DSM Decrements 1-5

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

Retirements in All Portfolio 3 Runs:

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



PORTFOLIO 4 ICAP CHANGES

Portfolio 4a: Includes Decrements 1-3

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

Portfolio 4b: Includes Decrements 1-4

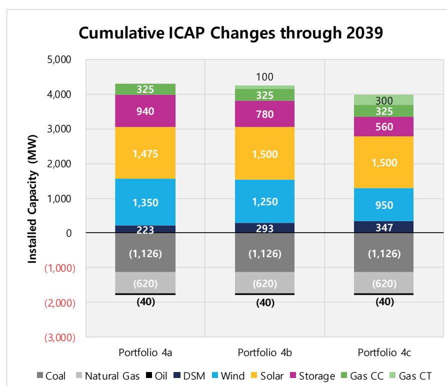
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	400	400	400	400	400	400	550	550	600	600	700	800	800	850	950	1,100	1,250	1,250
Solar	0	0	0	425	550	600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

Portfolio 4c: Includes Decrements 1-5

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

Retirements in All Portfolio 3 Runs:

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



PORTFOLIO 5 ICAP CHANGES

Portfolio 5a: Includes Decrements 1-3

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

Portfolio 5b: Includes Decrements 1-4

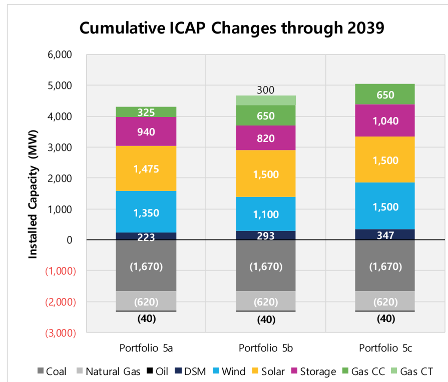
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	350	350	350	350	350	350	400	450	450	450	450	550	550	600	600	800	1,000	1,100
Solar	0	0	0	425	550	600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

Portfolio 5c: Includes Decrements 1-5

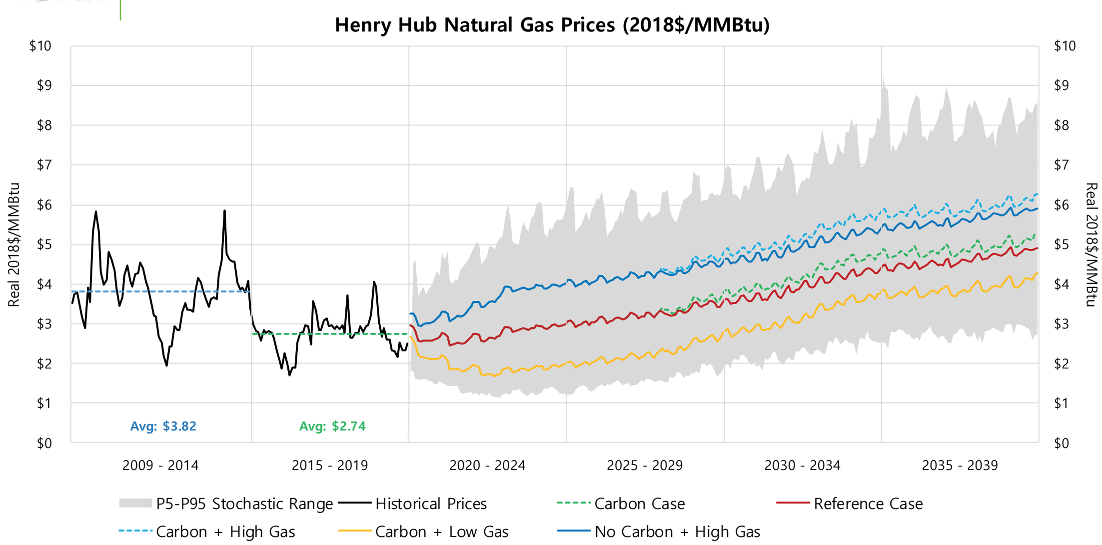
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	500	500	500	500	500	550	550	750	950	1,150	1,150	1,200	1,200	1,300	1,300	1,300	1,500	1,500
Solar	0	0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

Retirements in All Portfolio 3 Runs:

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

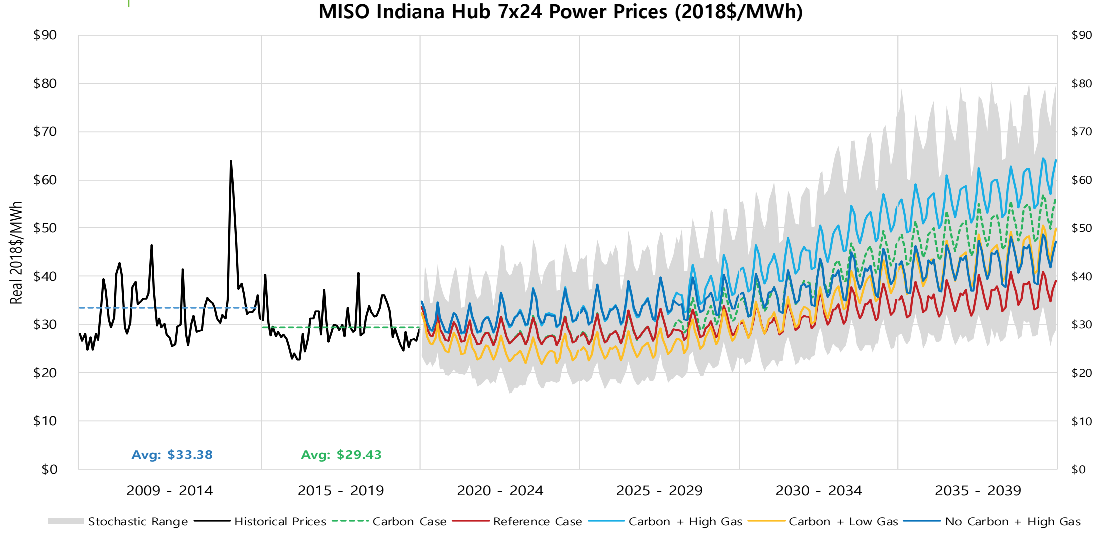


NATURAL GAS PRICES

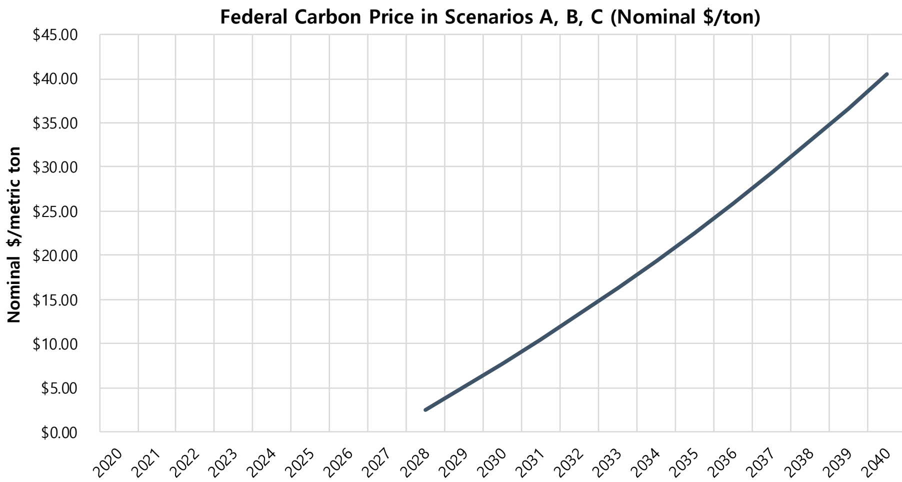


12/11/2019

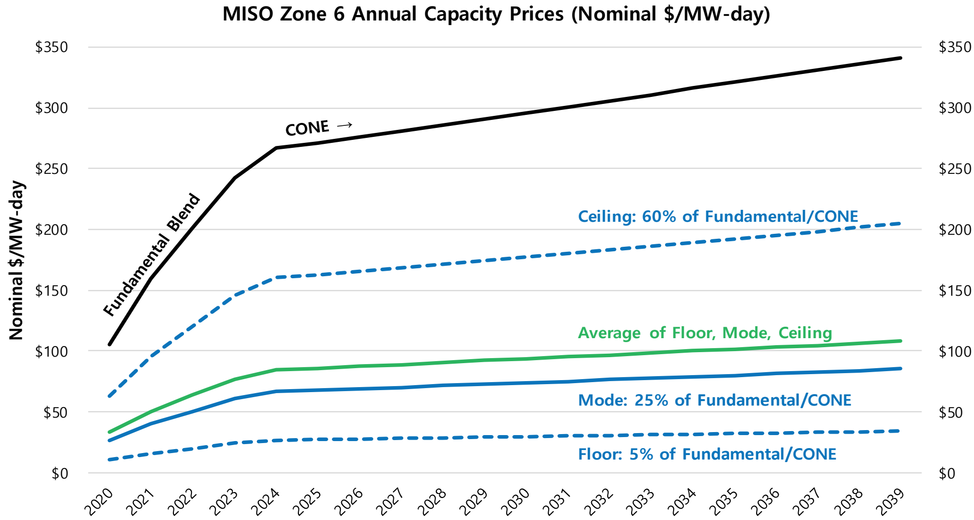
POWER PRICES



CARBON PRICE

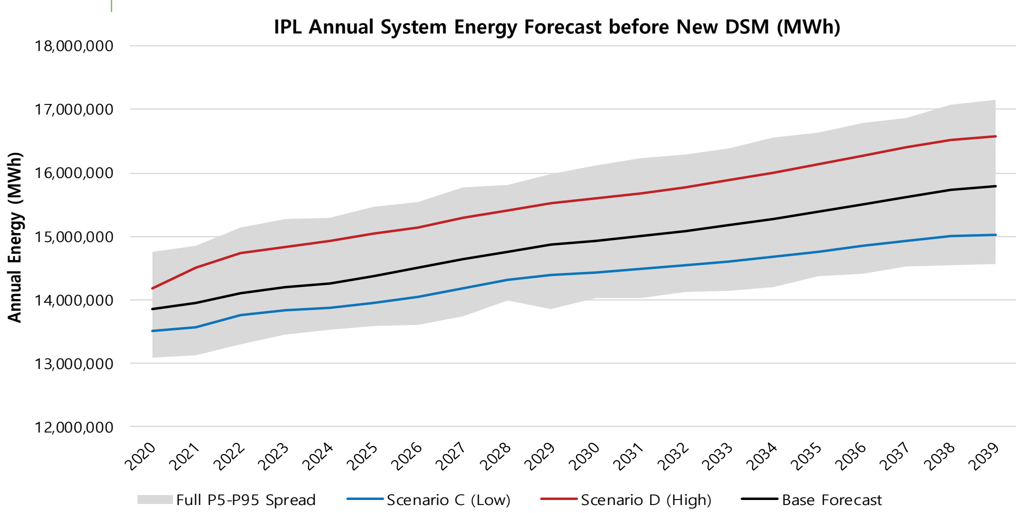


CAPACITY PRICES



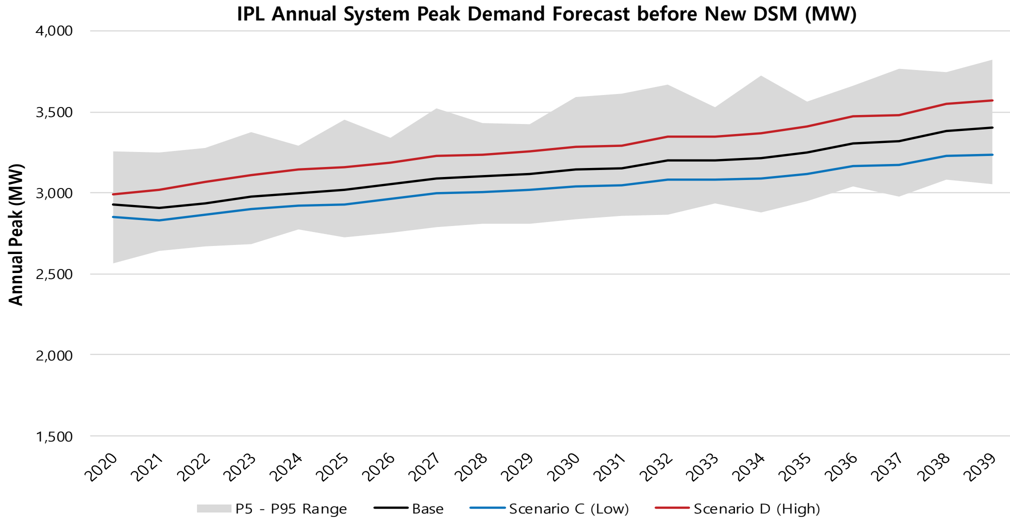
89

LOAD FORECAST (ENERGY)



90

LOAD FORECAST (PEAK)



Cause No. 45591

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

<u>SUBMISSION OF COMPLIANCE FILING</u>

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

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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 2017, via electronic mail, on the following:

Randall Helmen
Tiffany Murray
Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor
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Citizens Action Coalition
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Indianapolis, Indiana 46202
jwashburn@citact.org

Jeffrey M. Peabody

DMS 4569304v1

THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM ANNUAL REPORT

DECEMBER 31, 2017

GENERAL UPDATE

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

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

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

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

PROFIT SHARE RECEIVED

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

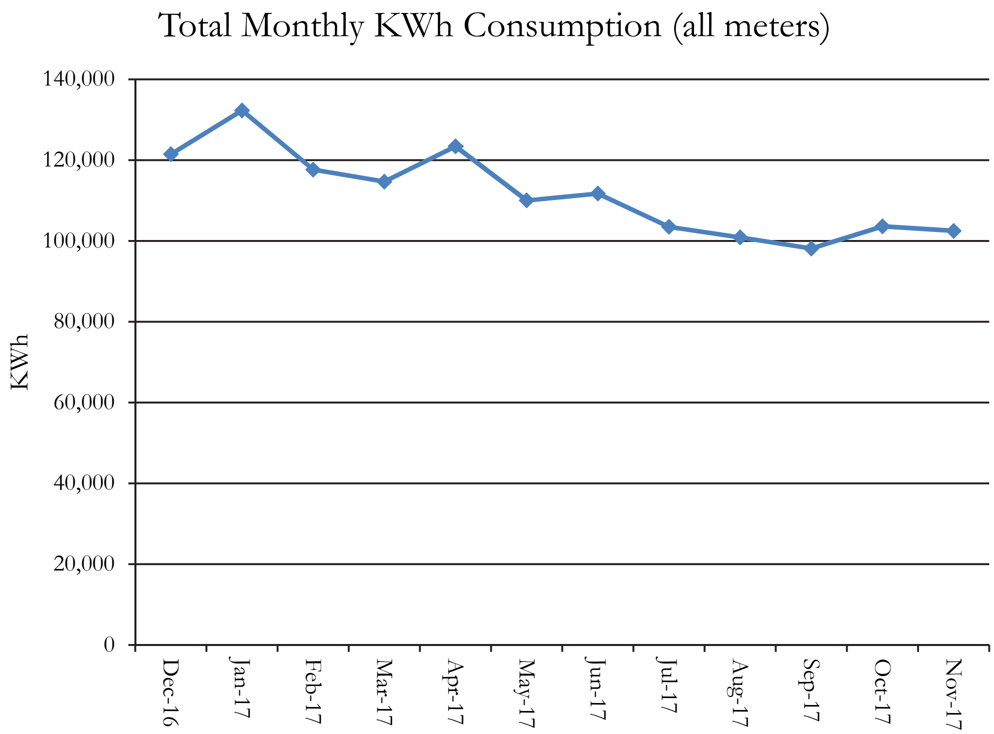
DATA GATHERED

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

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

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

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



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

Photos of BlueIndy Local Use

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

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

<u>SUBMISSION OF COMPLIANCE FILING</u>

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: ______________________________

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Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY

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

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Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY
DMS 13718691v1

THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM FINAL REPORT

DECEMBER 31, 2018

GENERAL UPDATE

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

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

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

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

PROFIT SHARE RECEIVED

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

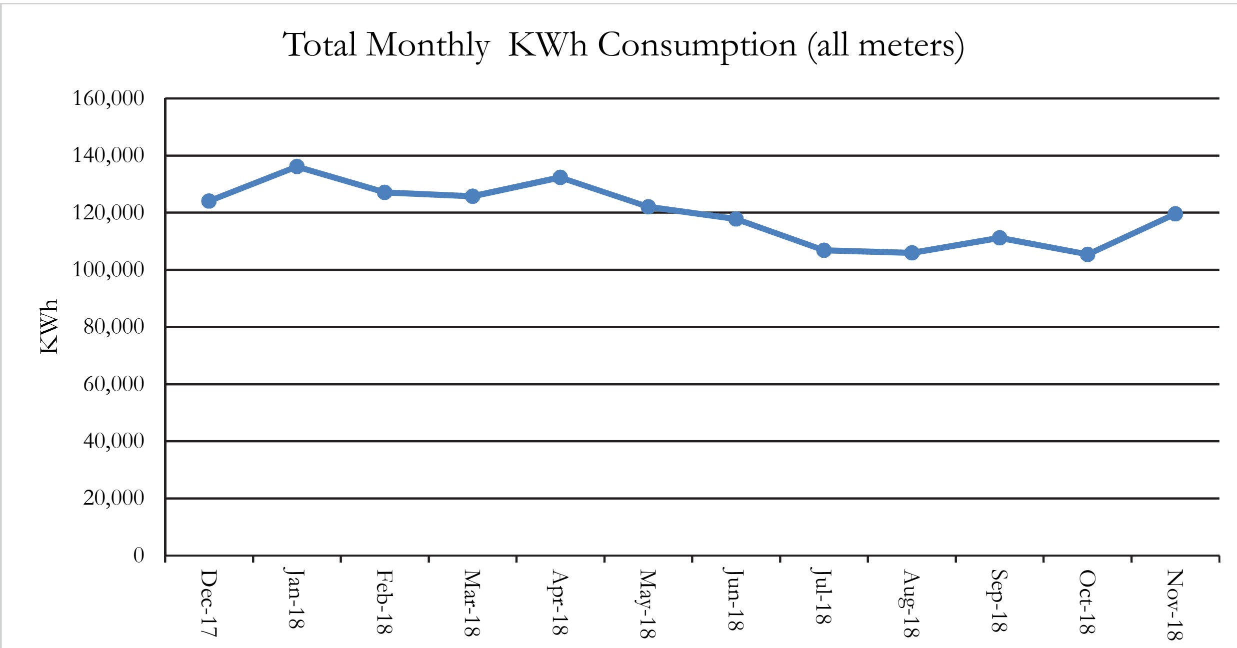
DATA GATHERED

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

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

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

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



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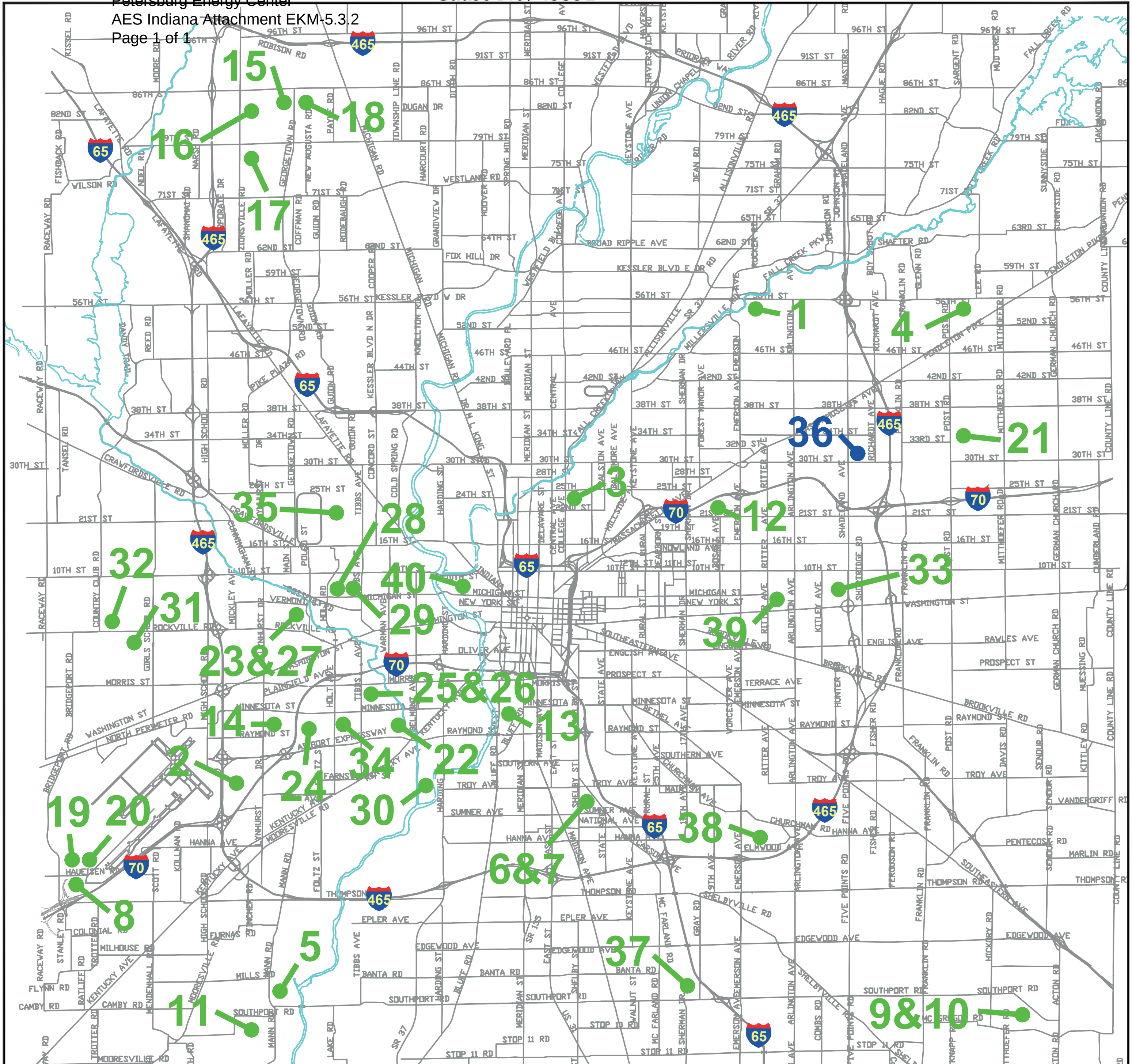
BlueIndy Station downtown Indianapolis showing Bluecars, Reservation Kiosk and Meter Pedestal.

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



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

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

LEGEND

\# - OPERATING

\# - UNDER CONSTRUCTION

\# - IN DEVELOPMENT

ipl an AES company

INDIANAPOLIS POWER & LIGHT CO.

SOLAR FACILITIES

DRAWN BY: RLW
5-18-15

solar-REP-GIS-map

REV. 11-1-19 WJK

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

Residential SAE Modeling Framework

Cause No. 45591

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,

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

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

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

$XHeat_m$, $XCool_m$, 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,

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

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:

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

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

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \tag{5}$$

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

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

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

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \tag{7}$$

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

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

Table 1: Electric Space Heating Equipment Weights

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

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

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

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

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

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

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

Where:

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

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

Constructing XCool

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

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

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

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

Where

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

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

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

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

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

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

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

Table 2: Space Cooling Equipment Weights

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

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

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

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m}\right)^{\gamma} \quad (13)$$

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

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

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

Where:

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

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

Constructing XOther

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

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

The explanatory variable for other uses is defined as follows:

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

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

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

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

Where:

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

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

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

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

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

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

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{18}$$

Commercial Statistically Adjusted End-Use Model

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

There are several advantages to this approach.

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

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

1.2 Commercial Statistically Adjusted End-Use Model Framework

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

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

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

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

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

Constructing XHeat

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Constructing XCool

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

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

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

$$\mathrm{XCool}_{\mathrm{y,m}} = \mathrm{CoolIndex}_{\mathrm{y}} \times \mathrm{CoolUse}_{\mathrm{y,m}} \tag{7}$$

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

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

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

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

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh/Sqft_e}\right) \qquad (9)$$

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

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

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

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

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

Constructing XOther

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

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

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The explanatory variable for other uses is defined as follows:

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

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

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

where, *Weight* is the weight for each equipment type,

Share represents the fraction of floor stock with an equipment type, and

Eff is the average operating efficiency.

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

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_{e} kWh \big/ Sqft_{e}} \right) \tag{13}$$

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

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

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

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GDS Associates, Inc.
ENGINEERS & CONSULTANTS

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Thorpe Energy Services

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FINAL REPORT

prepared by

GDS ASSOCIATES INC
DEMAND SIDE ANALYTICS
THORPE ENERGY SERVICES

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VOLUME II *Appendices*

EXECUTIVE SUMMARY

2018 IPL DEMAND SIDE MANAGEMENT Market Potential Study

prepared for

AUGUST 2019

1 Executive Summary

1.1 OBJECTIVES & SCOPE

This project included a demand-side management (DSM) Market Potential Study and End Use Analysis for Indianapolis Power & Light Company (IPL). The study included assessments of electric energy efficiency and demand response potential. This report provides the results of the electric energy efficiency and demand response potential analysis for the 2021-2039 (19-year) timeframe.[1]

The energy efficiency potential study assessed potential by customer segment (residential, commercial, and industrial – with and without opt-out customers[2]). The effort included several preliminary tasks to assess the IPL market and develop foundational assumptions about the customer base, sales forecasts, and savings opportunities to order to then assess the overall energy efficiency potential in the IPL services territories.

1.2 APPROACH SUMMARY

The GDS team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial (C&I) sectors, GDS utilized the bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load. The demand response potential assessment was conducted in a similar manner as the energy efficiency potential assessment. Below is the summary of the Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP). More detail can be found in Section 1 of Volume I, Market Potential Study.

- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate (WTP) in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***MAP*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***RAP*** estimates achievable potential with IPL paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

The 2019 Market Potential Study included a detailed End Use Analysis that utilized primary market research at residential dwellings, as well as commercial and industrial facilities, to better understand the mix of customers, building characteristics, and efficiency trends for each customer segment. Historically, IPL's Market Potential Studies and load forecasts have been driven by the Energy Information Administration's regional end use saturation and intensity baselines and forecasts. The End Use Analysis served to create more IPL-specific saturation and efficiency profiles for both the 2019 Market Potential Study, but for future load forecasting efforts as well.

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[1] The study period is for 2021-2039 to align with the 2019 Integrated Resource Plan (IRP) timeline. In addition, the GDS Team assessed the electric energy efficiency potential in 2020 as part of an analysis to determine whether current planned DSM levels in 2020 addressed the identified potential. Results of this analysis are included as an appendix to this report.

[2] In Indiana, a combined energy efficiency resource standard repeal and opt-out bill became law in 2014. The opt-out placed eligibility at 1 MegaWatt (MW) – any customer that has a peak demand of at least 1MW can opt-out of paying the charge levied to support the utility-run energy efficiency program.

1.3 RESULTS

Table ES-1 summarizes the electric energy-efficiency savings for all measures at the different levels of potential relative to the baseline forecast. This provides cumulative annual technical, economic, MAP and RAP potential energy savings, in total MWh and as a percentage of the sector-level sales forecast for the first three years of the analysis, as well as in the 10th and 19th year of the analysis. The cumulative RAP increases to 4.8% cumulative annual savings over the next three years. The RAP savings estimates have a large residential sector low-income component.[3] Approximately 58% of the residential sector budget addresses the low-income market segment, with about 25% of the RAP savings are attributable to this segment. Forecasted sales are total sales including commercial and industrial opt-out customers.

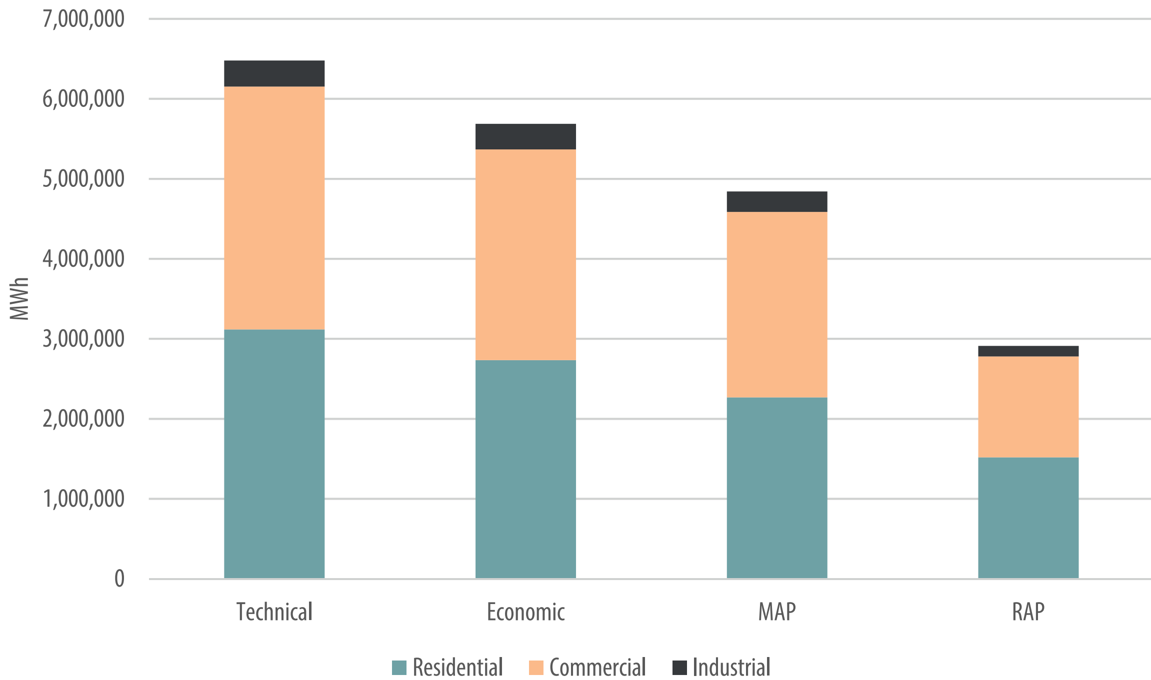
TABLE ES-1 CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY (NET OF LARGE CUSTOMER OPT-OUT LOAD)

	2021	2022	2023	2030	2039
MWh					
Technical	777,115	1,495,812	2,222,444	5,480,409	6,479,384
Economic	699,639	1,316,546	1,938,817	4,773,845	5,687,312
MAP	463,542	879,184	1,325,103	3,712,615	4,841,953
RAP	273,942	462,015	656,209	2,006,568	2,911,537
Forecasted Sales	13,543,498	13,708,234	13,809,273	14,490,281	15,411,542
Energy Savings (as % of Forecast)					
Technical	5.7%	10.9%	16.1%	37.8%	42.0%
Economic	5.2%	9.6%	14.0%	32.9%	36.9%
MAP	3.4%	6.4%	9.6%	25.6%	31.4%
RAP	2.0%	3.4%	4.8%	13.8%	18.9%

Figure ES-1 provides the electric technical, economic, and achievable potential, by sector, by the end of the 19-year timeframe for the study (2021-2039). The residential sector contributes about half of the overall RAP.

[3] Low income households were characterized as homes that have household incomes at or below 200% of federal poverty guidelines. Based on data from the American Community 5-Year Public Use Microdata Set (PUMS), GDS used household income and number of people per household to identify the percent of the population at or below 200% of federal poverty guidelines for the IPL service area. 30.6% of single-family households and 52.7% of multifamily households were identified to meet the criteria.

FIGURE ES-1 NINETEEN (19)-YEAR CUMULATIVE ANNUAL ELECTRIC ENERGY EFFICIENCY POTENTIAL – ALL SECTORS COMBINED (NET OF LARGE CUSTOMER OPT-OUT LOAD)



1.3.1 Measure-Level Realistic Achievable Potential (Net of Opt-Outs)

Table ES-2 provides the incremental RAP for each year by sector. The incremental annual savings potential ranges from 274 GWh to nearly 350 GWh. These results exclude savings attributed to large customers that have opted out of energy efficiency programs.

TABLE ES-2 INCREMENTAL ELECTRIC MEASURE LEVEL RAP – BY SECTOR (2021-2023, 2030, AND 2039)

Incremental Annual MWh	2021	2022	2023	2030	2039
Sector					
Residential	175,436	164,092	164,881	171,594	164,489
Commercial	87,433	87,790	88,538	128,764	163,720
Industrial	11,073	12,149	13,001	15,566	21,577
Total	273,942	264,031	266,420	315,924	349,786
Forecasted Sales	13,543,498	13,708,234	13,809,273	14,490,281	15,411,542
Incremental Annual Savings %					
Sector					
Residential	1.3%	1.2%	1.2%	1.2%	1.1%
Commercial	0.6%	0.6%	0.6%	0.9%	1.1%
Industrial	0.1%	0.1%	0.1%	0.1%	0.1%
% of Forecasted Sales	2.0%	1.9%	1.9%	2.2%	2.3%

Table ES-3 provides the cumulative RAP for each year across the 2021-2023 timeframe, as well as for 2030 and 2039.[4] The cumulative annual savings potential ranges from 274 GWh to nearly 2,912 GWh. These results assume that opt-out C&I customers do not provide any savings potential.

TABLE ES-3 CUMULATIVE ELECTRIC MEASURE LEVEL RAP – BY SECTOR (2021-2023, 2030, AND 2039)

Cumulative Annual MWh	2021	2022	2023	2030	2039
Sector					
Residential	175,436	266,884	365,671	1,079,971	1,518,517
Commercial	87,433	172,729	256,487	824,507	1,259,861
Industrial	11,073	22,402	34,051	102,090	133,159
Total	273,942	462,015	656,209	2,006,568	2,911,537
Forecasted Sales	13,543,498	13,708,234	13,809,273	14,490,281	15,411,542
Cumulative Annual Savings %					
Sector					
Residential	1.3%	1.9%	2.6%	7.5%	9.9%
Commercial	0.6%	1.3%	1.9%	5.7%	8.2%
Industrial	0.1%	0.2%	0.2%	0.7%	0.9%
% of Forecasted Sales	2.0%	3.4%	4.8%	13.8%	18.9%

Table ES-4 provides the annual budgets in the RAP scenario. The total RAP budgets across all sectors ranges from $91 million to $121 million during the 2020-2023 timeframe.

TABLE ES-4 ANNUAL BUDGETS (2021-2023, 2030, AND 2039) IN THE RAP SCENARIO ($ IN MILLIONS)

RAP Budgets	2021	2022	2023	2030	2039
Energy Efficiency					
Incentives	$60.5	$68.9	$75.3	$77.7	$59.6
Admin	$24.8	$27.9	$30.7	$41.6	$51.0
Energy Efficiency Sub-Total	$85.3	$96.8	$106.0	$119.4	$110.6
Demand Response					
Incentives	$2.0	$3.4	$4.9	$7.3	$8.9
Admin	$4.2	$6.9	$10.0	$3.8	$4.9
Demand Response Sub-Total	$6.1	$10.3	$14.9	$11.1	$13.8
Total					
Total Costs	$91.4	$107.1	$120.9	$130.5	$124.4

1.4 DEMAND SAVINGS

The study also included an assessment of peak demand savings potential. Table ES-5 below provides the overall peak demand savings from energy efficiency and demand response potential. The demand response potential assumes the energy efficiency peak demand reductions take precedent, and thereby reduce the baseline peak demand which can be further reduced by demand response.

[4] Cumulative annual savings refers to the overall savings occurring in a given year from both new participants and savings continuing to result from past participation with measures that are still in place. Cumulative annual does not always equal to the sum of all prior year incremental values as some measures have relatively short measure lives, and a result, their savings drop off over time.

TABLE ES-5 CUMULATIVE PEAK DEMAND SAVINGS POTENTIAL – MAP AND RAP (2021-2023, 2030, AND 2039)

MW	2021	2022	2023	2030	2039
MAP					
Energy Efficiency	79	156	239	684	896
Demand Response	91	161	228	331	397
Total	171	317	467	1,015	1,293
RAP					
Energy Efficiency	48	86	124	385	546
Demand Response	73	114	155	218	253
Total	121	200	279	603	799

VOLUME I

2018 IPL Demand Side Management Market Potential Study

prepared for

JUNE 2019

1 Introduction

1.1 BACKGROUND & STUDY SCOPE

This Market Potential Study was conducted to support the Integrated Resource Plan (IRP) and DSM planning for IPL. The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential. Separate estimates of electric energy efficiency and demand response potential were developed. The effort was highly collaborative, as the GDS Team worked closely alongside IPL, as well as the IPL Oversight Board, to produce reliable estimates of future saving potential, using the best available information and best practices for developing market potential saving estimates.

The 2019 Market Potential Study included a detailed End Use Analysis that utilized primary market research at residential dwellings, as well as commercial and industrial facilities, to better understand the mix of customers, building characteristics, and efficiency trends for each customer segment. Historically, IPL's Market Potential Studies and load forecasts have been driven by the Energy Information Administration's regional end use saturation and intensity baselines and forecasts. The End Use Analysis served to create more IPL-specific saturation and efficiency profiles for both the 2019 Market Potential Study, but for future load forecasting efforts as well.

1.2 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- ***Technical Potential*** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
- ***Economic Potential*** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. This study uses the Utility Cost Test (UCT) to assess cost-effectiveness.
- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and WTP in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***MAP*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***RAP*** estimates achievable potential with IPL paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

1.3 STUDY LIMITATIONS

As with any assessment of energy efficiency potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs
- Projected penetration rates for energy efficiency measures

- Projections of electric avoided costs
- Future known changes to codes and standards
- IPL load forecasts and assumptions on their disaggregation by sector, segment, and end use
- End-use saturations and fuel shares

While the GDS team has sought to use the best and most current available data, there are often reasonable alternative assumptions which would yield slightly different results.

1.4 ORGANIZATION OF REPORT

The remainder of this report is organized in seven sections as follows:

Section 2 MPS End-Use Analysis details the primary market research studies completed in conjunction with the market potential analysis, and a summary of the end-use analysis results by sector.

Section 3 MPS Methodology details the methodology used to develop the estimates of technical, economic, and achievable energy efficiency and demand response potential savings.

Section 4 MPS Market Characterization provides an overview of the IPL service areas and a brief discussion of the forecasted energy sales by sector.

Section 5 Residential Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the residential sector.

Section 6 Commercial Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the commercial sector.

Section 7 Industrial Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the industrial sector.

Section 8 Demand Response Potential provides a breakdown of the technical, economic, and achievable potential demand response by program type.

Appendices for the DSM Market Potential are included in Volume II of this report. MPS appendices include a discussion of sources used for the analysis, detailed measure level assumptions by customer segment, nonresidential sector potential savings (including opt-out customers), and detailed demand response results. A discussion of the 2020 Refresh analysis is also included as an appendix.

2 Market Potential Study End Use Analysis

In 2018 and 2019, IPL and the GDS team performed multiple market research studies targeting the residential, commercial, and industrial sectors. The goal of the research was to collect primary data from IPL customers to inform the market potential study and to improve upon assumptions built into IPL's load forecasting system. This chapter will describe the methods employed by the GDS team to collect primary research data for the end-use analysis and provide summary results.

2.1 RESIDENTIAL SECTOR

There were three objectives of the end use analysis specific to the residential sector:

- Collect market share information of electric end uses specific to IPL's residential class of customers,
- Perform a demographic survey to collect key demographic information,
- Update Unit Energy Consumption assumptions, representing the amount of electricity used by typical major appliances in homes.

To meet these objectives, the GDS team performed research activities through four tasks in 2018 and 2019. A self-report study conducted via internet and the mail was conducted to collect initial market saturation and demographic data. From the pool of respondents, participants were recruited to participate in on-site visits conducted by trained technicians to collect detailed home and end-use characteristic data. Independent of that process, an online survey of a separate population frame of residences was conducted to understand WTP in energy efficiency programs. Finally, GDS developed building energy simulation models.

2.1.1 Self-Report Survey

The self-report study was conducted via a mailed questionnaire to selected representative homes in the IPL service territory. The recruitment population frame was drawn using a structured stratified sampling approach using annual energy consumption to stratify the population. Homeowners were asked to complete the questionnaire either by filling out a form mailed to them or by visiting a web-based survey instrument online. A total of 30 questions were included in the survey, seeking to collect information about ownership of electric appliances; the type, fuel, and age of heating, ventilation, and air conditioning (HVAC) and water heating equipment in the home; the types of energy improvements that may have been made to the home; demographic information; and if the homeowner had interest in participating in the onsite survey.

The research objective was to collect at least 384 survey responses, representing a design with 95% confidence and +/- 5% precision. The survey was initially mailed to 1,400 residences drawn from IPL's billing database. After the first mailing, only 94 responses were collected by mail and 32 by internet, representing only 126 responses. A reminder email was sent to those customers in the original recruitment frame for whom IPL had a valid email address and who had not yet responded to the survey, which generated an additional 27 responses. Finally, a second recruitment frame of 1,375 new residences was developed. For the new frame, an email campaign was launched asking customers to respond online. The second wave garnered an additional 72 responses. In total, the self-report study solicited 231 responses, representing 95% confidence with +/- 6.45% precision.[5]

[5] Although the goal was to achieve 5% precision, this result is acceptable, especially given the additional site-specific research conducted for the residential sector. It was concluded by GDS and IPL that the costs of additional efforts to improve precision outweighed the value achieving such additional precision would provide.

FIGURE 2-1 SELF-REPORT SURVEY RETURNS BY MEDIUM

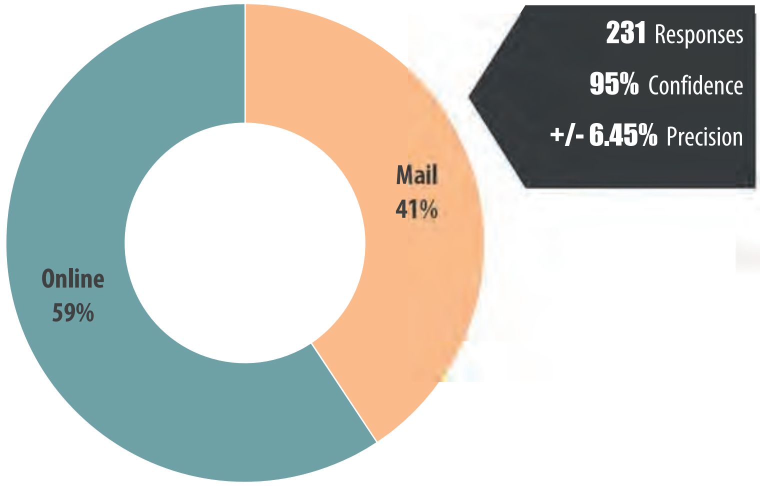
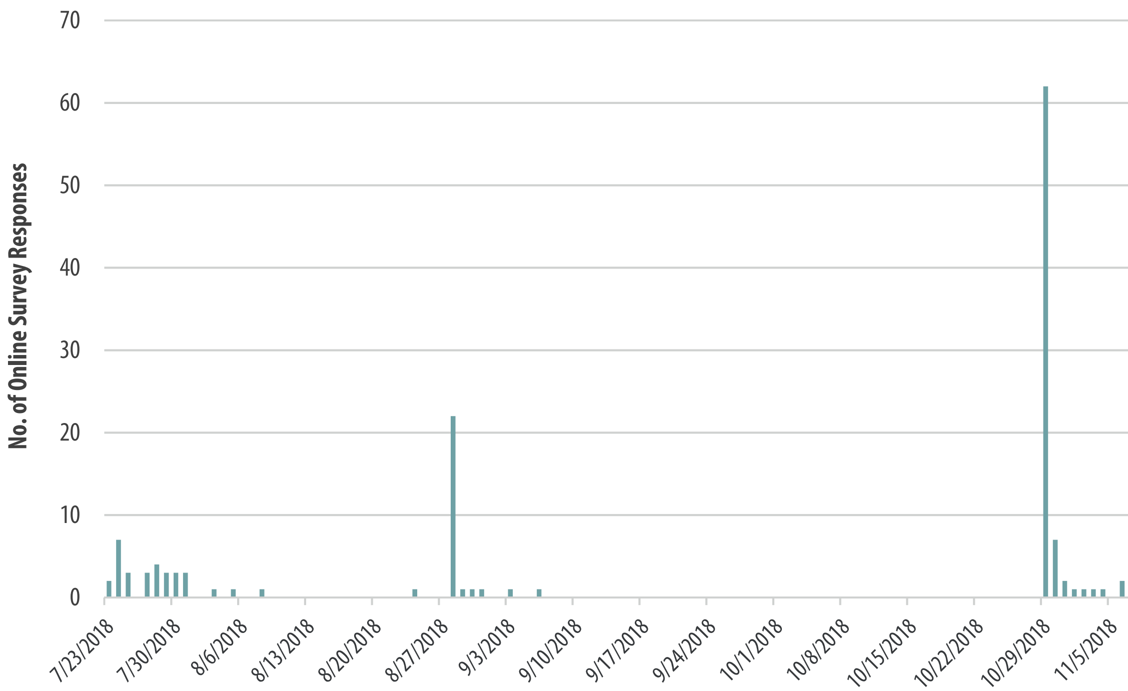


FIGURE 2-2 SELF-REPORT SURVEY, TIMING OF ONLINE RESPONSES



2.1.2 On-Site Survey

Following the self-report survey, the GDS team conducted a series of residential on-site visits. The purpose of the site-visits was to collect more detailed end-use and housing characteristics that are difficult to collect in a self-report survey. The goal was to recruit 68 homes to participate in site visits, using the self-report survey as the first recruitment tool. Interest in participating in a site visit was high from survey respondents, with 67% (156) respondents indicating interest in finding out more about the visits. To ensure a representative sample of homes in the study, GDS developed 68 recruitment bins sorted by average usage. Nearly 40 of the recruitment bins were successfully filled from the 156 homes that indicated initial interest in the study, with attrition associated with fulfilling recruitment bins from other homes and loss of interest once homeowners understood in more detail the nature of the site visits. Therefore, the GDS team supplemented the study by recruiting additional homes to agree to participate in site visits by contacting homes from the initial recruitment frames of the self-report survey group.

2.1.3 Willingness to Participate

IPL and the GDS team worked together to develop a series of questions designed to understand residential WTP in various energy efficiency programs given varying incentive levels. Such research was valuable to helping identify participation levels that can be assumed in various scenarios within the market potential study. The original goal was to collect WTP information during the residential site visits. However, the WTP questionnaire was still being developed by the GDS team while technicians were conducting site visits. The site visits therefore did not collect a statistically significant number of WTP survey responses. Therefore, GDS created a supplemental online WTP survey. Fifteen thousand (15,000) residential accounts were selected to receive an email asking for participation in the online WTP survey. These accounts had not yet been contacted by IPL and GDS for any aspect of survey work prior to this email. GDS collected 875 WTP survey responses.

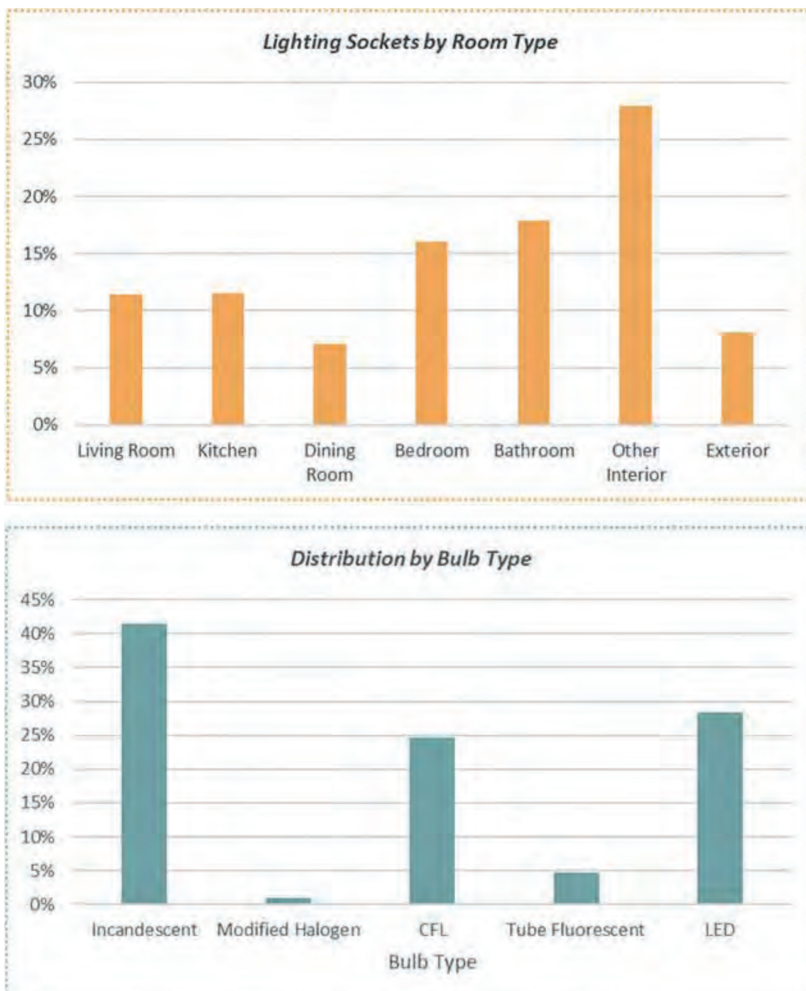
2.1.4 Building Energy Simulation Modeling

The final phase of end use analysis for the residential sector consisted of constructing building energy simulation models using BEopt™ (Building Energy Optimization)[6] software. The building simulations involve developing end-use energy profiles based on assigned housing characteristics. The housing characteristics (e.g., size of home, type of end use equipment, etc.) were developed from the primary market research conducted by the GDS team.

2.1.5 Summary Results of Residential End Use Analysis

Although detailed information was collected for many end-uses in the residential sector, this section provides an overview of the data collection for lighting and space heating equipment. The end use databases developed through the primary research methods were used by the GDS to inform potential study and load forecast inputs for many end uses.

FIGURE 2-3 LIGHTING END USE RESULTS - RESIDENTIAL SECTOR



Lighting. In self-response surveys, homeowners tend to underestimate the number of lighting sockets in the home, which was the case with IPL as well. The IPL self-responders indicated they had an average of 20 bulbs per home, whereas the site visits indicated the average exceeds 40 bulbs per home. This was the biggest discrepancy between self-reported information and information collected from onsite technicians. The GDS team considered the site visits data to be more accurate since onsite technicians take the time to record every lighting socket in the home and collect information on the type and wattage of the bulbs installed in those sockets.

As part of the onsite visits, technicians also collect the number of bulbs in storage to provide an indication of the potential lighting efficiency in

[6] BEopt can be used to analyze both new construction and existing home retrofits, as well as single-family detached and multi-family buildings, through evaluation of single building designs, parametric sweeps, and cost-based optimizations.

the near future when bulbs are replaced. The study indicated that the average home had 5.5 bulbs in storage, and that 48% of those bulbs were incandescent bulbs, which is higher than the share of incandescent bulbs (42%) in service in homes.

Space Heating. Other than the lighting counts, the only other major appliance that had a market penetration differential between self-reporting and the site visits was the share of electric primary space heating equipment. The self-report survey indicated that 45% of homes had electric heat while the site visits found 21% of homes with electric heat. With such a discrepancy, a third source of information was consulted. IPL's retail rate codes are designed such that homes with electric heat can be identified. In theory, the homes had electric heat when they signed up for service, although if they have since switched to non-electric heat, they could possibly still be on the electric heat service code. The IPL billing database shows approximately 35% of homes having electric heat. For purposes of the market potential study, the 35% market share was assumed.

Load Forecast Disaggregation. Figure 2-4 and Figure 2-5 summarize the end-use disaggregation for residential energy sales as a result of the end use analysis.

FIGURE 2-4 SHARE OF ANNUAL HOUSEHOLD ENERGY CONSUMPTION BY END USE - RESIDENTIAL SECTOR

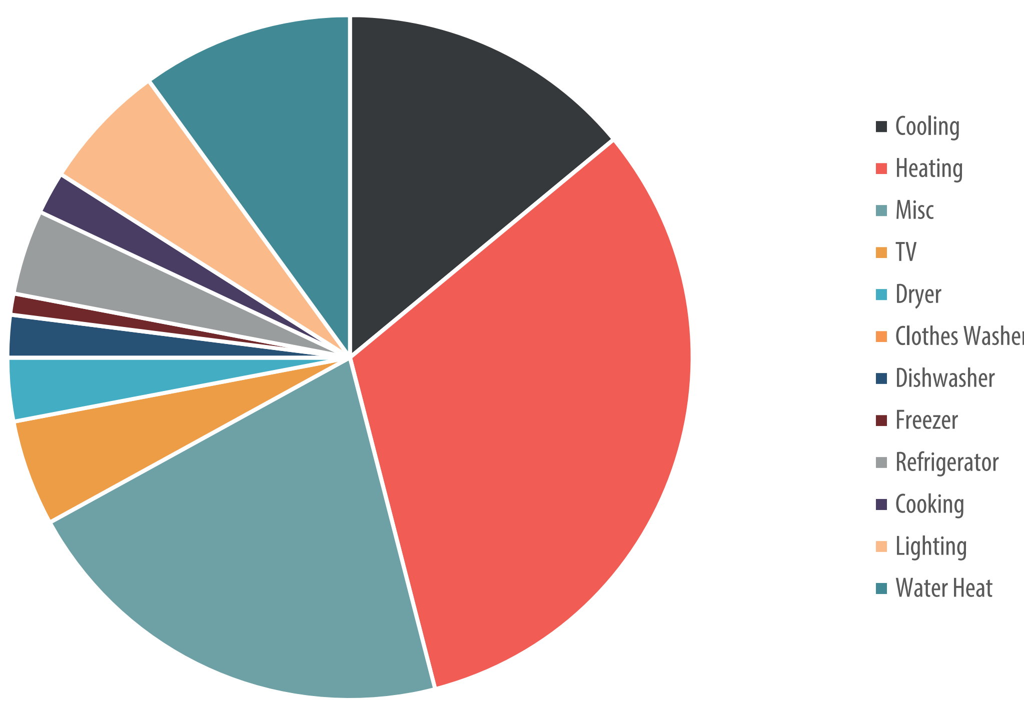
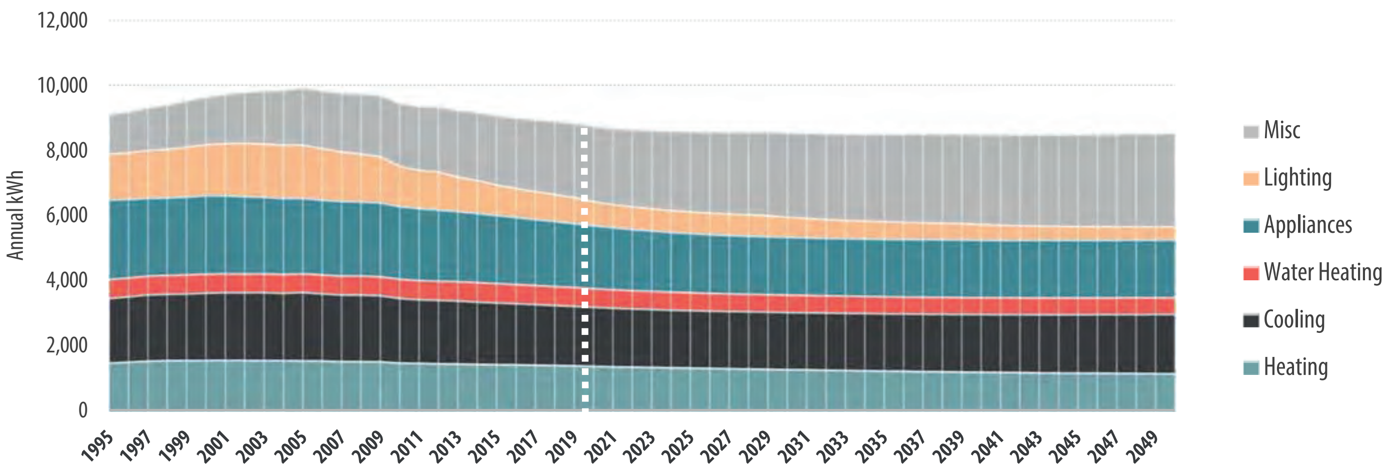


FIGURE 2-5 RESIDENTIAL LOAD FORECAST BY END USE



2.2 COMMERCIAL SECTOR

In the commercial sector, the GDS Team conducted a series of site visits to collect end use information. The first step was to segment the commercial class by building type to determine the recruitment frame for site visits. Then, sites were recruited from bins segmented by building type to recruit a total of 68 sites. A detailed end use survey was then completed by technicians to collect detailed research data and WTP information from site representatives.

2.2.1 Segmentation by Building Type

The GDS Team segmented commercial energy sales by building type using several analytical techniques. The first step was to assign an industry code (NAICS[7] and/or SIC[8]) to as many customers in IPL's commercial billing database as possible. Then, the codes were mapped to building types consistent with the types used in IPL's forecasting models and in the Commercial Building Energy Consumption Survey (CBECS) conducted by the US Department of Energy.

A multi-step process was used to assign industry codes to commercial accounts. First, codes that were available from IPL's databases were used. Then, a secondary database was used to supplement the IPL designations. The second data source was InfoUSA, which contains a business listing for Indianapolis and includes industry codes for those businesses.

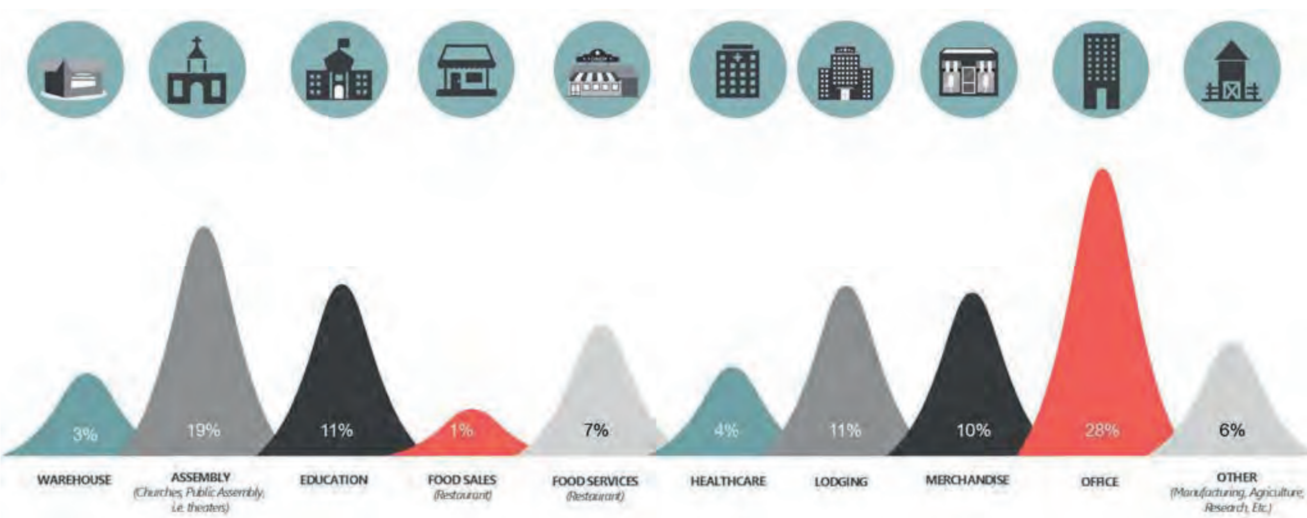
[7] North American Industry Classification System
[8] Standard Industrial Classification

FIGURE 2-6 HEURISTIC WORDS ASSIGNED TO SPECIFIC BUILDING TYPES

CHURCH	GRILL
HOSPITAL	OFFICE
AUTO	OFFICES
BANK	MOTEL
APARTMENTS	HOTEL
UNIVERSITY	WENDY'S
INVESTMENTS	MCDONALDS
REALTY	BURGER
PIZZA	RETAIL
RESTAURANT	SCHOOL
INSURANCE	COLLEGE
FITNESS	BAKERY
SALON	KOHLS
MEDICAL	SUBWAY
DENTAL	PUB
STUDIO	EATERY
BAPTIST	HOSPITALITY
DEPT OF TRANS	SPEEDWAY LLC

One challenge GDS had was matching InfoUSA information to IPL's customer billing database. A three-step process was employed to achieve the matching. First, we included the industry codes in InfoUSA if there was an exact match between the billing database and InfoUSA database for address, zip code, and phone number of the business. Next, GDS used a Levenshtein matching distance scoring algorithm[9] to compare business name, address, zip code, and phone number between the two data sources. The Levenshtein score determines how many textual changes have to be made between two strings of text to make them equivalent. Although some fuzzy logic is deployed in selecting a score that is considered a match and one that is not, GDS used observational evidence to set a score setpoint that would tend to reject more matches than accept. For example, if one database had "Arby's Restaurant #5852" as the business name and the other database simply had "Arby's", the Levenshtein score was 500 and considered a match if addresses also matched. However, "Beech Grove Community School" and "Beech Grove Aquatic" would have a score of 600 and would not be considered a match. Finally, the supplement the number of industry codes identified, GDS performed a heuristic approach by calculating a frequency of the number of times specific words appeared in business names and identified building types associated with certain key words. For instance, the word "Hotel" in a company name that was not otherwise identified with an industry code was assigned to the Lodging building type.

FIGURE 2-7 SALES SEGMENTATION BY BUILDING TYPE



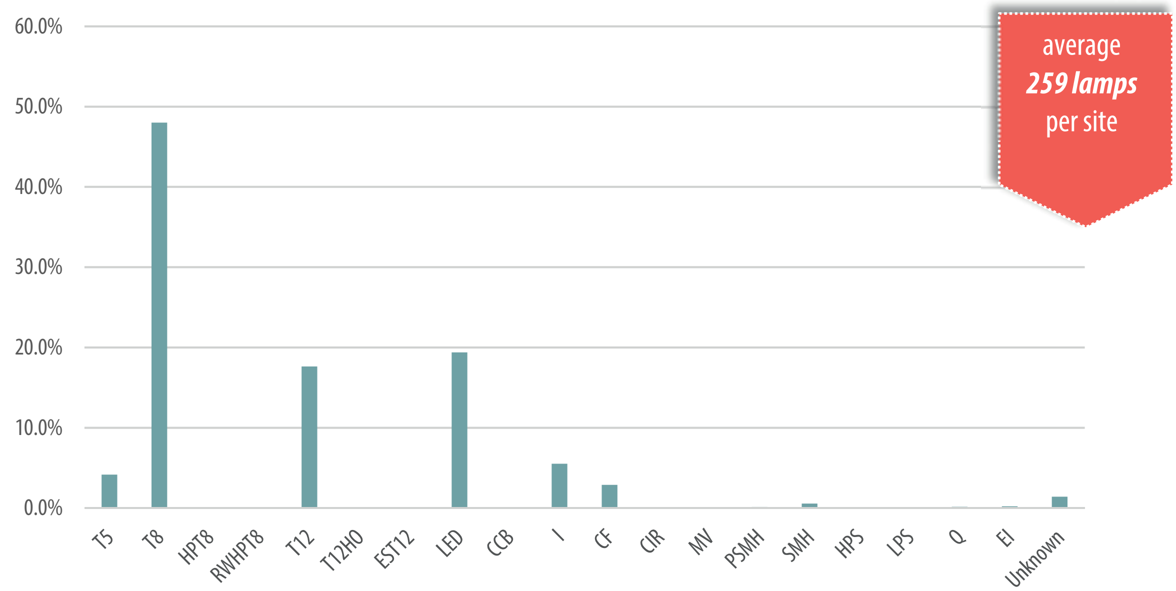
2.2.2 Site Visits

A total of 68 site visits were completed, with representation from the major building types shown in Figure 2-7 above. Technicians collected data on building characteristics, heating and cooling behaviors, and detailed end-use equipment at each site, including information on HVAC, water heating, ventilation, cooking, refrigeration, air pressure, and other equipment.

[9] In information theory, the Levenshtein distance is as string metric for measuring the distance between two sequences. Informally, it is the minimum number of single-character edits (insertions, deletions, or substitutions) required to change one string of text into the other.

As an example of the information collected, an average of 259 lamps per site were found during the site visits. Of those, 52% were T5/T8 bulbs and 20% were light emitting diode (LED).

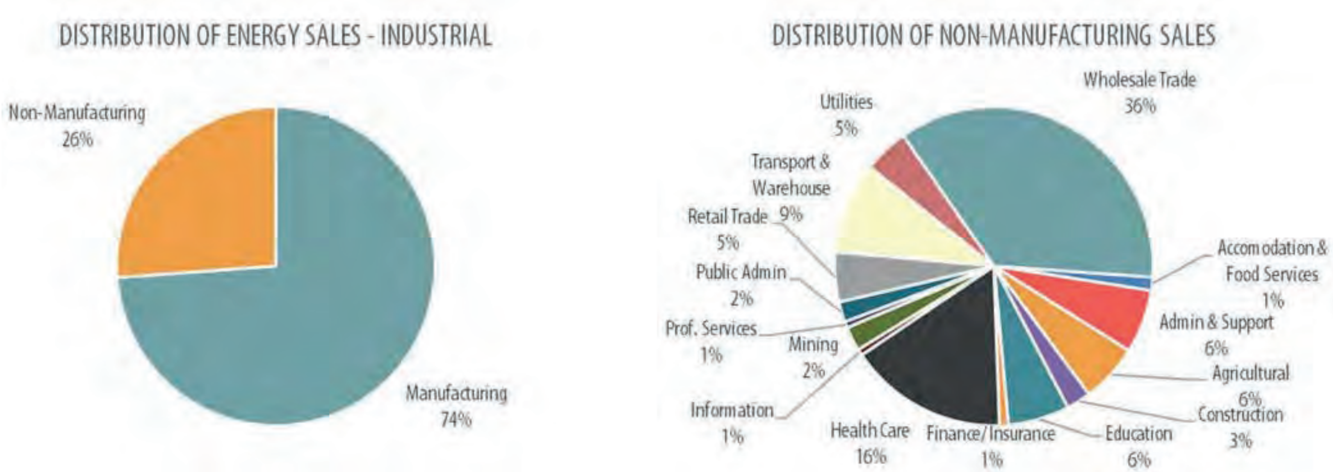
FIGURE 2-8 LIGHTING RESULTS FROM ONSITE SURVEYS - COMMERCIAL SECTOR



2.3 INDUSTRIAL SECTOR

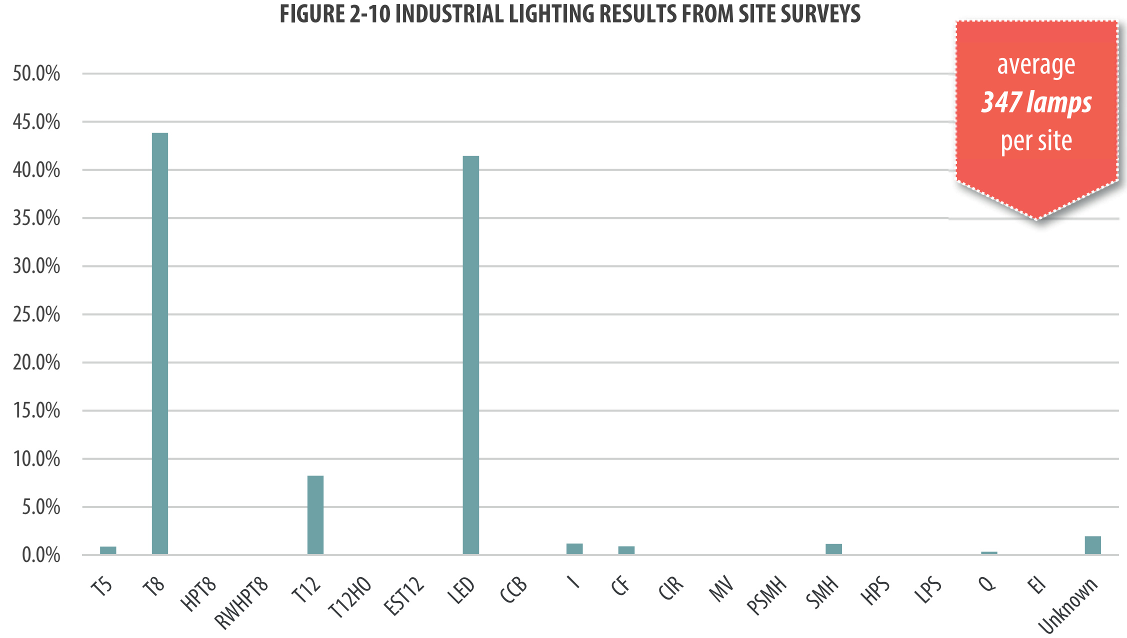
Much like in the commercial sector, end use analysis for the industrial sector involved market segmentation and onsite visits. Market segmentation was conducted using industry codes as described in the Commercial Sector section above. The segmentation analysis indicates that three quarters of industrial energy sales are to manufacturing industries. Of the quarter of non-manufacturing accounts, 50% of energy sales are in wholesale trade and health care industries with transportation and warehousing accounting for an additional nearly 10%.

FIGURE 2-9 INDUSTRIAL SEGMENTATION



A total of 40 site visits were conducted for the industrial sector, in which WTP and detailed end-use information was collected. One goal of the research was to recruit multiple opt-out accounts for onsite surveys. However, only 1 opt-out site agreed to participate in a site visit even though the GDS recruitment frame was designed with a significant number of opt-out accounts in it. Lighting information is provided in Figure 2-10 below as an example of summary information collected for the industrial sector.

FIGURE 2-10 INDUSTRIAL LIGHTING RESULTS FROM SITE SURVEYS



3 Market Potential Study Methodology

This section describes the overall methodology utilized to assess the electric energy efficiency and demand response potential in the IPL service area. The main objectives of this Market Potential Study were to estimate the technical, economic, MAP and RAP of energy efficiency and demand response in the IPL service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency and demand response potential.

3.1 OVERVIEW OF APPROACH

For the residential sector, GDS took a bottom-up approach to the modeling, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential. For the C&I sectors, GDS took a bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load.

Further details of the market research and modeling techniques utilized in this assessment are provided in the following sections.

3.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments in the IPL service area. The GDS team coordinated with IPL to gather utility sales and customer data and existing market research to define appropriate market sectors, market segments, vintages, saturation data and end uses. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and nonresidential sectors.

3.2.1 Forecast Disaggregation

In the residential sector, GDS calibrated its building energy modeling simulations with IPL's sales forecasts.[10] This process began with the construction of building energy models, using the BEopt™ (Building Energy Optimization) software, which were specified in accordance with the most currently available data describing the residential building stock in the IPL service area. Models were constructed for both single-family and multifamily homes, as well as various types of heating and cooling equipment and fuel types. Key characteristics defining these models include conditioned square footage, typical building envelope conditions such as insulation levels and representative appliance and HVAC efficiency levels. The simulations yielded estimated energy consumption for each building prototype, including estimates of each key end use. These end use estimates were then multiplied by the estimated proportion of customers that applied to each end use, to calculate an estimated service territory total consumption for each end use. For example, when completing this process for the IPL potential analysis, the simulated heat pump electric heating consumption was multiplied by the proportion of homes that rely on heat pumps for their electric heating needs, to calculate the total heat pump electric heating load in the IPL service territory.

The simulation process required several iterations. GDS collaborated with IPL to verify and modify certain assumptions about the market characteristics, such as the heating fuel and equipment types. GDS adjusted its assumptions about key market characteristics and revised its BEopt models to calibrate its building energy models to within 4% of forecasted sales in 2021.

[10] IPL's sales forecast in all sectors excludes the impact of future DSM savings. Excluding future DSM savings prevents under-estimating energy efficiency savings potential.

In the C&I sectors, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS disaggregated the nonresidential sector for IPL into building or industry types using IPL's C&I customer database and 2017 monthly sales data. GDS supplemented the IPL customer database with a third-party dataset (purchased from InfoUSA) that provided additional SIC/NAICS code data by business.[11] This disaggregation involved two steps. First, the GDS team used rate codes to determine whether the customer was captured in either IPL's commercial or industrial load forecast. Next, GDS determined the appropriate industry for industrial customers and the building type for commercial customers. We used the following information, either from IPL's customer data or third-party dataset, to determine the appropriate building or industry type. Using these fields, GDS assigned customers IPL's non-residential data sets to one of the commercial or industrial segments listed in Table 3-1.

TABLE 3-1 NON-RESIDENTIAL SEGMENTS

COMMERCIAL	INDUSTRIAL	
Education	Chemicals	Paper
Food Sales	Fabricated Metals	Plastics & Rubber
Food Service	Food & Agriculture	Primary Metals
Health Care	Machinery	Transportation Equipment
Hospital	Mining	Wood
Lodging	Nonmetallic Mineral	
Office		
Public Assembly		
Retail		
Warehouse		

GDS further disaggregated sales for each of the segments into end uses. For commercial segments, GDS primarily used IPL's 2019 end-use forecast planning models supplemented with updated Energy Information Administration (EIA) 2012 CBECS data. This information was used to determine energy use intensities, expressed in kWh per square foot, for each end use within each segment.[12] We then used data compiled from metering studies, evaluation, measurement and verification (EM&V), and engineering algorithms to further disaggregate energy intensities into more granular end uses and technologies. For the industrial sector, the analysis relied on the EIA's Manufacturing Energy Consumption survey to disaggregate industry-specific estimates of consumption into end uses.[13]

Table 3-2 lists the electric end-uses considered in the forecast disaggregation and subsequent potential assessment.

TABLE 3-2 ELECTRIC END USES

Residential	Commercial	Industrial
Behavioral	Cooking	Agriculture
Clothes Washer/Dryer	Space Cooling	Computers & Office Equipment
Dishwasher	Lighting	CHP
Electronics	Office Equipment	Lighting
Hot Water	Refrigeration	Machine Drive
HVAC Equipment	Space Heating	Process Heating
HVAC Shell	Ventilation	Process Cooling
Lighting	Water Heating	Space Cooling
Pools		Space Heating

[11] The IPL dataset classifies businesses by Standard Industrial Classification (SIC) code, a four-digit standardized code, that has largely been replaced by the North American Industry Classification System (NAICS) code. The GDS Team converted the IPL SIC codes to NAICS codes, then mapped NAICS/SIC codes to building and industry types considered in this study.
[12] U.S. Energy Information Agency. *Commercial Buildings Energy Consumption Survey*. May 20, 2016.
[13] U.S. EIA. *Manufacturing Energy Consumption Survey 2010.* March 2013.

Residential	Commercial	Industrial
		Ventilation Water Heating

3.2.2 Eligible Opt-Out Customers

In Indiana, commercial or industrial customers with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. In the IPL service area, approximately 6.5% of commercial sales have opted out of utility-funded electric energy efficiency programs, while nearly 45% of industrial sales have opted out. [14]

FIGURE 3-1 OPT-OUT SALES BY C&I SECTOR

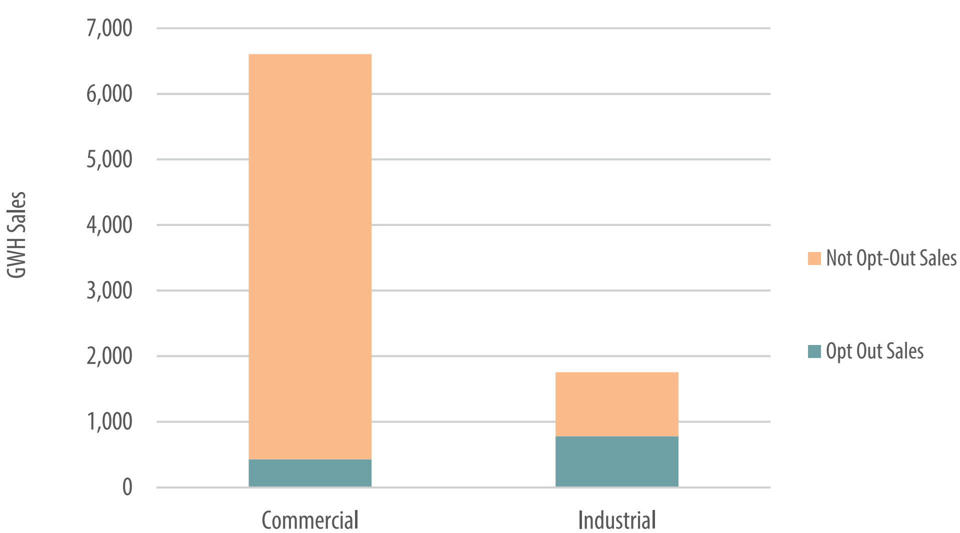


Figure 3-1 shows the total sales for the C&I sectors, as well as the sales, by sector, that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e. does not meet the 1 MW monthly peak requirement) as well as eligible load that has not yet opted out.

The main body of this report focuses on the electric energy efficiency potential savings in the C&I sectors excluding sales from opt-out customers. Results of C&I sector potential in a scenario that includes savings from IPL's opt-out customers are provided in an appendix to this report.

3.2.3 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

3.2.3.1 Residential Sector

For the residential sector, GDS relied on several primary research efforts. The most important effort was a 2018 online survey of IPL customers conducted by the GDS Team as part of the study. More than 200 responses provided a strong basis for many of the IPL measure baseline and efficient saturation estimates. GDS also relied on an onsite survey of IPL customers conducted by the GDS Team in 2018. This study helped fill in data gaps and confirm the results of the online survey.

Other data sources included ENERGY STAR unit shipment data, IPL evaluation reports, EIA Residential Energy Consumption Survey data from 2015 and baseline studies from other states. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

[14] These percentages were calculated based on the 2017 IPL non-residential customer data and 2017 billing history. Note, the total C&I sales were adjusted to shift select industrial sales into the commercial sector based on the identified building type and more applicable mapping to the commercial sector models for the MPS.

3.2.3.2 Commercial Sector

For the commercial sector, data collected through on-site visits as part of this study was leveraged to develop remaining factors for many of the measures. GDS coordinated with IPL and the Oversight Board to develop a research plan, sampling plan, and a survey questionnaire used to collect data. The on-site data collection included facility operation schedules and building characteristics, HVAC equipment type and efficiency levels, lighting fixture inventories, control systems and strategies, and related electric consuming equipment characteristics.

The survey data was used to inform two main assumptions for the potential study, the Base Case factor and saturation of efficient equipment. The Base Case Factor is the fraction of the end use energy that is applicable for the efficient technology in given market segment. Survey data was used to determine fractional energy use for most measures in the study. The survey data provided counts for equipment and energy usage levels for the lighting, heating, cooling, water heating, motors and refrigeration end-uses. For example, T12 and T8 lighting used 84% of the energy for interior fluorescent lamps and fixtures for the surveyed buildings. The remaining usage was a combination of compact fluorescent lights (CFLs), T5s and LED linear tube lighting.

In total, 63% of the base case allocations came directly from the survey data and the other 37% came from regional potential study data from other Indiana Utilities or from GDS estimates based upon past study experience.

In addition to base equipment saturation data, the commercial survey data was used to determine the efficient saturations for 60% of all measures in the study. For example, the survey found that 14% of commercial building lighting has already been concerted to LEDs. The latest ENERGY STAR shipment data report was also used to determine efficient equipment saturation estimates. Emerging technologies typically assumed no significant market saturation levels.

3.2.3.3 Industrial Sector

As in the commercial sector, data collected in industrial facilities through on-site visits as part of this study was leveraged to develop remaining factors for many of the measures. The on-site data collection included facility operation schedules and building characteristics, HVAC equipment type and efficiency levels, lighting fixture inventories, control systems and strategies, and related process electric consuming equipment characteristics.

Survey data was used to determine fractional energy use for most measures in the study. The survey data provided counts for equipment and energy usage levels for the lighting, heating, cooling, water heating, motors and refrigeration end-uses. For example, 56% of lighting energy was found to be associated with high bay and low bay light fixtures, while 33% was found to be associated with other interior tube lighting (T8, T12, LED). 11% was associated with exterior lighting and other interior bulbs such as CFLs and incandescent bulbs.

Base factor assumptions for industrial lighting, process motors, and space cooling came directly from the survey data and the other base factor information came from regional potential study data from other Indiana Utilities or from GDS estimates based upon past study experience.

In addition to base case factor, the survey data was also utilized, where possible, to estimate the saturation of efficient equipment, primarily lighting. GDS relied on secondary research, including the EIA Manufacturing Energy Consumption Survey for assessing the efficiency saturation of the remaining measures for industrial lighting, process motors and variable frequency drives, space cooling equipment, and air compressors. Like the commercial sector, emerging technologies were assumed to have little to no significant market saturation.

3.2.4 Remaining Factor

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. It is the inverse of the saturation of an energy efficient measure, prior to any adjustments. For this study we made two key adjustments to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation. In other words, while a percentage of installed measures may already be efficient, this does not preclude customers from backsliding, or reverting to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences (e.g. historically, some customers have disliked CFL light quality, and have reverted to incandescent and halogen bulbs after the CFLs burn out).

For measures categorized as market opportunity (i.e. replace-on-burnout), we assumed that 50% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. Essentially this adjustment implies that we are assuming that 50% of the market is transformed, and no future savings potential exists, whereas the remaining 50% of the market is not transformed and could backslide without the intervention of an IPL program and an incentive. Similarly, for retrofit measures, we assumed that only 10% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. We recognize the uncertainty in these assumptions, but we believe these are appropriate assumptions, as they recognize a key component of the nature of customer decision making.

3.3 MEASURE CHARACTERIZATION

3.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Indiana TRM, current IPL program offerings, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with IPL and stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS analyzed 554 measure types for IPL. Many measures were included in the study as multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. GDS developed a total of 4,708 measure permutations for this study. Each permutation was, screened for cost-effectiveness according to the UCT. The parameters for cost-effectiveness under the UCT are discussed in detail later in Section 3.4.3.

TABLE 3-3 NUMBER OF MEASURES EVALUATED

	# of Measures	Total # of Measure Permutations	# with UCT ≥ 1
IPL – Electric			
Residential	187	648	420
Commercial	237	2370	2160
Industrial	130	1690	1482
Total	***554***	***4708***	***4062***

3.3.2 Emerging Technologies

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart technologies, including smart appliances, smart water heater (WH) tank controls, smart window coverings, smart ceiling fans, heat pump dryers and home automation/home energy management systems. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include strategic energy management, advance lighting controls, advanced rooftop controls, cloud-based energy information systems (EIS), high performance elevators, and escalator motor controls. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the 19-year study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

3.3.3 Assumptions & Sources

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to IPL when it was available and current. GDS used the most recent IPL evaluation report findings (as well as IPL program planning documents), 2015 Indiana Technical Reference Manual (TRM), the Illinois TRM, and the Michigan Energy Measures Database (MEMD) to a large amount of the data requirements. Evaluation report findings and the Indiana TRM were leveraged to the extent feasible – additional data sources were only used if these first two sources either did not address a certain measure or contained outdated information. The BEopt simulation modeling results formed the basis for most heating and cooling end use measure savings. The National Renewable Energy Laboratory (NREL) Energy Measures Database also served as a key data source in developing measure cost estimates. Additional source documents included American Council for an Energy-Efficient Economy (ACEEE) research reports covering topics like emerging technologies.

Measure Savings: GDS relied on existing IPL evaluation report findings[15] and the 2015 IN TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the IN TRM, GDS estimated savings from a variety of sources, including:

- Illinois TRM, MEMD, and other regional/state TRMs
- Building energy simulation software (BEopt) and engineering analyses
- Secondary sources such as the ACEEE, Department of Energy (DOE), EIA, ENERGY STAR©, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.[16] One exception is an assumed decrease in costs for LED bulbs over the study horizon. LED bulb consumer costs have been declining rapidly over the last several years and future cost projections indicate a continued decrease in bulb costs.[17] GDS' treatment of LED bulb costs, LED lighting efficacy, and the impacts of the Energy Independence and Security Act (EISA) are discussed in greater detail in Section 3.3.5, "Review of LED Lighting Assumptions."

GDS obtained measure cost estimates primarily from the IPL program planning databases, and the 2015 IN TRM. GDS used the following data sources to supplement the IN TRM:

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[15] 2016 EM&V (Cause No. 44497) and 2017 EM&V (Cause No. 44792)

[16] GDS reviewed the deemed measure cost assumptions included in the Illinois TRM from 2012 (v1) through 2018 (v7). Where a direct comparison of cost was applicable, GDS found no change in measure cost across 80% of residential and nonresidential measures. In a similar search of the MEMD from 2011 to 2018, GDS again found that most of incremental measure costs in 2018 were either the same or higher than the recorded incremental measure cost in 2011.

[17] LED Incremental Cost Study Overall Final Report. The Cadmus Group. February 2016

- Illinois TRM, MEMD, and other regional/state TRMs
- Secondary sources such as the ACEEE, ENERGY STAR, and NREL
- Program evaluation and market assessment reports completed for utilities in other states

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the 2015 IN TRM and IPL program planning databases, and used the following data sources for measures not in the IN TRM:

- Illinois TRM, MEMD, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in Appendices B-D.

3.3.4 Treatment of Codes & Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does attempt to reflect the latest legislated improvements to federal codes and standards. Where possible, improvements to baseline equipment standards can typically be met with incremental improvements to efficient equipment standards. However, in select case, such as screw-in lighting (discussed further below), improvements to the baseline standard effectively will be expected to eliminate the efficient technology from future consideration.

3.3.5 Review of LED Lighting Assumptions

Recognizing that there remains significant uncertainty regarding the future potential of residential screw-in lighting, GDS reviewed the latest lighting-specific program designs and consulted with industry peers to develop critical assumptions regarding the future assumed baselines for LED screw base omnidirectional, specialty/decorative, and reflector/directional lamps over the study timeframe.

EISA Impacts. LED screw base omnidirectional and decorative lamps are impacted by the EISA 2007 regulation backstop provision, which requires all non-exempt lamps to be 45 lumens/watt, beginning in 2020. Based on this current legislation, the federal baseline in 2020 will be roughly equivalent to a CFL bulb. However, in January 2017, the Department of Energy expanded the scope of the standard to include directional and specialty bulb but stated that they may delay enforcement based on ongoing dialog with industry stakeholders. Although there is uncertainty surrounding EISA and the backstop provision, the Market Potential Study assumes the backstop provision for standard (A-lamp) screw-in bulbs will take effect beginning in 2022. The analysis assumes the expanded definition of general service lamps to include specialty and reflector sockets will impact those sockets beginning in 2023. Last, the analysis assumes a limited opportunity for direct install of LED bulbs replacing halogen bulbs through 2024 in both low-income and non-low-income households.

TABLE 3-4 ASSUMED LIGHTING BASELINE TECHNOLOGY BY YEAR

Delivery Approach/Bulb Type	2021	2022	2023	2024
Buydown				
Standard LED	Halogen	CFL	CFL	CFL
Specialty LED	Incandescent	Incandescent	CFL	CFL
Reflector LED	Incandescent	Incandescent	CFL	CFL
Direct Install				
Standard LED	Halogen	Halogen	Halogen	CFL
Specialty LED	Incandescent	Incandescent	Incandescent	CFL
Reflector LED	Incandescent	Incandescent	Incandescent	CFL

LED Bulb Costs. Based on EIA Technology Forecast Report, LED bulb costs were assumed to decrease over the analysis period. LED bulb costs ranged between $2.95 (standard) and $5.45 (reflector) in 2021, decreasing to

$2-$3 by 2039. Incentives were modeled as a % of incremental cost, resulting in decreasing incentives over the analysis timeframe as well.

LED Lighting Efficacy. Using the same EIA Technical Forecast Report, LED efficacy was also assumed to improve over the analysis timeframe. By 2040, the LED wattage of a bulb equivalent to a 60W incandescent will improve from 8W (today's typical LED) down to 4W.

3.3.6 Net to Gross (NTG)

All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive) were considered in the development of DSM Inputs into IPL's upcoming IRP.

3.4 ENERGY EFFICIENCY POTENTIAL

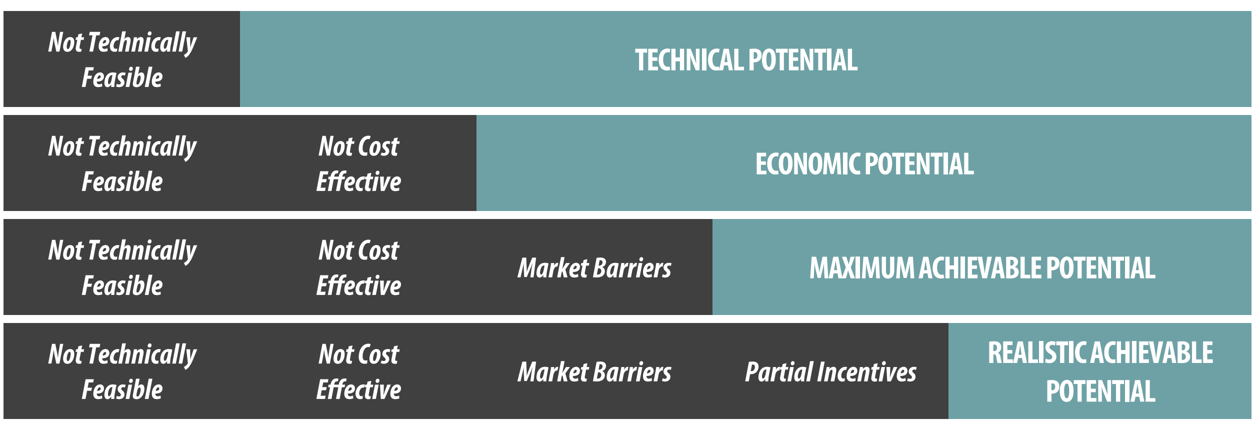
This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

3.4.1 Types of Potential

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 3-2 illustrates the types of energy efficiency potential considered in this analysis.

FIGURE 3-2 TYPE OF ENERGY EFFICIENCY POTENTIAL



3.4.2 TECHNICAL POTENTIAL

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 15 years.

3.4.2.1 Competing Measures & Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares may be factored into the baseline saturation estimates. For example, nearly all homes can receive insulation, but the analysis has created multiple measure permutations to account for varying impacts of different heating/cooling combinations and have applied baseline saturations to reflect proportions of households with each heating/cooling combination.

Applicability Factor Adjustment. Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat are adjusted down to reflect the efficiency gains of installing an efficient air source heat pump. The analysis also prioritizes efficiency measures relative to conservation (behavioral) measures.

3.4.3 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the UCT) as compared to conventional supply-side energy resources.

3.4.3.1 Utility Cost Test & Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the UCT at the measure level. In the IPL territory, the UCT considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness.[18]

Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective; all low-income specific measures are included in the economic and achievable potential estimates.

For both the calculation of the measure-level UCT, as well as the determination of RAP, historical incentive levels (as a % of incremental measure cost) were calculated for current measure offerings. Figure 3-3 describes the incentive levels by key market segment within the residential and nonresidential sectors.

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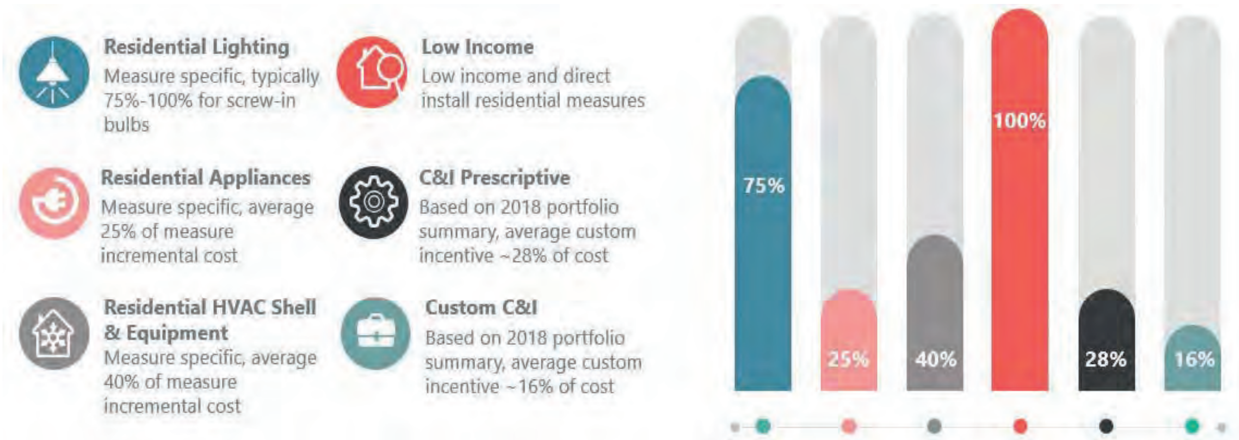
[18] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. *Note: Non-incentive delivery costs are included in the assessment of achievable potential.*

FIGURE 3-3 INCENTIVES BY SECTOR AND MARKET SEGMENT



GDS relied on IPL's DSM Portfolio Summary to map current measure offerings to their historical incentive levels. For study measures that did not map directly to a current offering, GDS calculated the weighted average incentive level (based on 2017 participation) by sector and/or program and applied these "typical" incentive levels to the new measures.

- In the residential sector, lighting incentive levels were assumed to represent 75-100% of the measure cost. Overall, residential appliance incentive levels averaged 25% of the incremental measure cost, while HVAC Shell and Equipment incentives averaged roughly 4-% of the measure cost.
- Low income and direct install measures received incentives equal to 100% of the measure cost.
- In the non-residential sector, prescriptive incentives were approximately 28% of the measure cost, and custom measures received incentives equal to 16% of the measure cost.
- In the MAP scenario, all incentives were set to 100% of the incremental measure cost.

3.4.3.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided T&D were provided by IPL as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

3.4.4 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and WTP in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- ***MAP*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***RAP*** estimates achievable potential with IPL paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

3.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

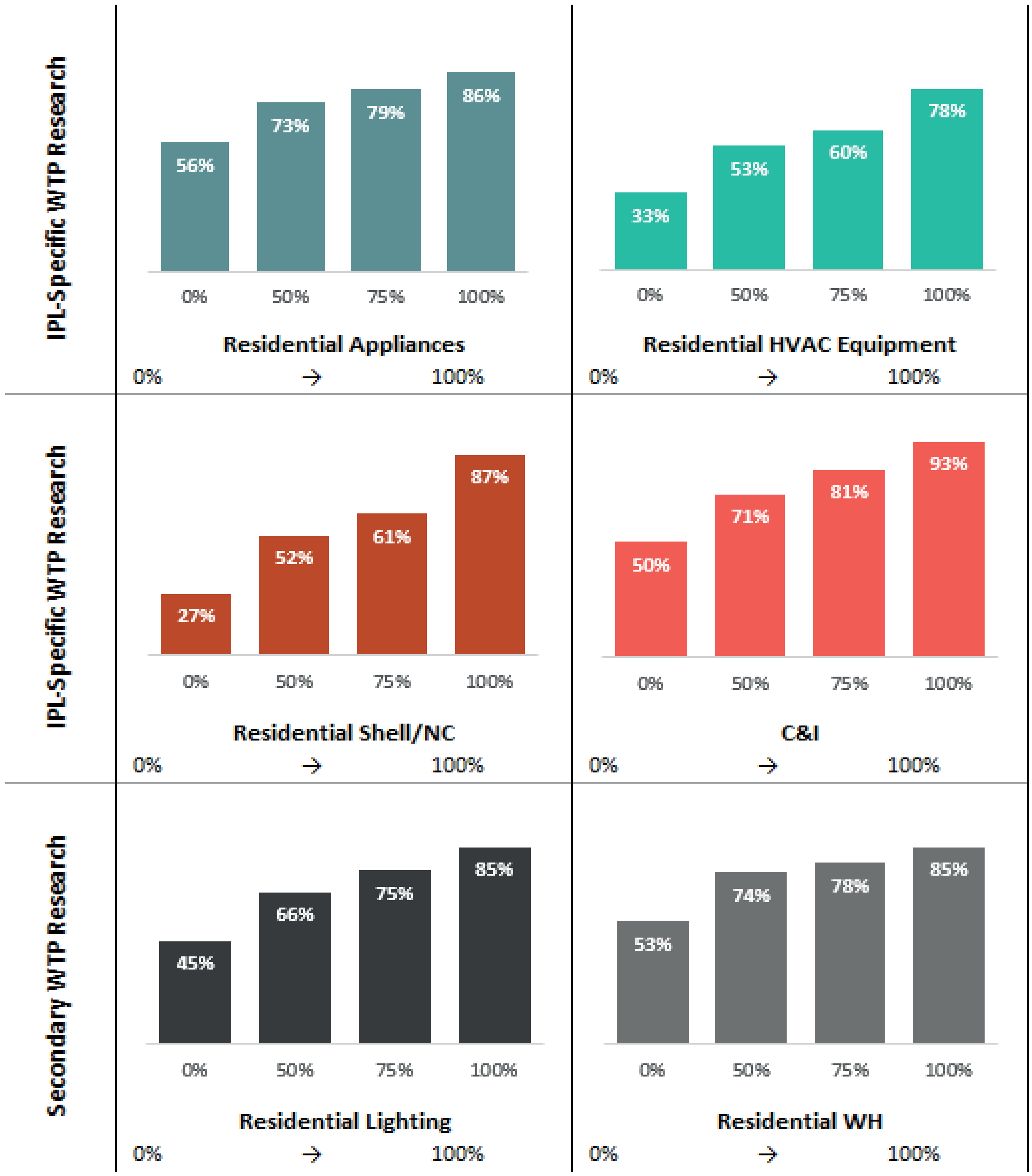
The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on either IPL-specific WTP market research or publicly available DSM research including market adoption rate surveys and other utility program benchmarking. These surveys included questions to residential homeowners and nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive levels.

GDS utilized likelihood and willingness-to-participate data to estimate the long-term market adoption potential for both the maximum and realistic achievable scenarios.[19] Table 3-5 presents the long-term market adoption rates at varied incentive levels used for both the residential and nonresidential sectors. When incentives are assumed to represent 100% of the measure cost (maximum achievable), the long-term market adoption typically ranged by sector and end-use from 78% to 93%. For the RAP scenario, the incentive levels also varied by measure resulting in measure-specific market adoption rates.

[19] For the MAP Scenario, the long-term adoption rate was reached by Year15 (or earlier) and annual participation remained flat in the final five years of the analysis. In the RAP scenario, the analysis assumes the maximum adoption rate is reached over a period of 20-years or less.

TABLE 3-5 LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

(based on Willingness-to-Participate Survey Results)



GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2020 annual potential to recent historical levels achieved by IPL's current DSM portfolio. This calibration effort ensures that the forecasted achievable potential in 2020 is realistic and attainable. GDS then assumed a non-linear ramp rate from the initial year market adoption rate to the various long-term market adoption rates for each specific end-use.

One caveat to this approach is that the ultimate long-term adoption rate is generally a simple function of incentive levels and payback. There are other factors that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. Other benefits, such as increased comfort or safety and reduced maintenance costs could also factor into a customer's decision to purchase and install energy efficiency measures. To acknowledge these impacts, GDS reviewed the stated adoption levels depending on whether cost was named as the primary barrier towards adoption. For respondents who did not select cost as the primary barrier, stated adoption levels were typically higher than those where cost was the primary barrier. To reflect the opportunity for increased education, marketing, and awareness to impact future long-term adoption levels, GDS ultimately utilized the adoption rates from respondents where cost was not the primary barrier. Although we recognize this approach does not capture every possible factor in determining appropriate long-term adoption levels, it does assign some weight to non-financial considerations in the assessment of long-term energy efficiency potential.

3.4.4.2 Non-Incentive Costs

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[20], utility non-incentive costs were included in the overall assessment of cost-effectiveness at the RAP scenario. 2021 direct measure/program non-incentive costs were calibrated to recent projected levels (using the 2019 portfolio summary) and set at:

- $0.31 per Home Energy Report
- $1.5-$2.5 per bulb for residential LEDs
- $0.05-$.10 per first year kWh saved for most residential appliance, electronics, and water heating retrofit measures;
- $0.16 per first year kWh saved for residential appliance recycling;
- $0.28 per first year kWh saved for residential heating and cooling equipment;
- 0.20-$0.23 per first year kWh saved for the remaining residential measures,
- $0.25-.28 per first year kWh saved for prescriptive C&I measures
- $0.06 per first year kWh saved for custom C&I measures; and
- $0.08 per first year kWh saved for C&I emerging technology measures.

Non-incentive costs were then escalated annually at the rate of inflation. [21]

3.5 DEMAND RESPONSE POTENTIAL

This section provides an overview of the demand response potential methodology. Summary results of the demand response analysis are provided in Section 8. Additional results details are provided in Appendix G.

3.5.1 Demand Response Program Options

Table 3-6 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study. This includes direct load control (DLC) and rate design options.

TABLE 3-6 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

Demand Response Program Option	Program Description	Eligible Markets
DLC AC (Switch)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). GDS looked at both the one-way communicating Cannon switches and two-way communicating L+G switches. Both switch options were assumed to be phased out as customers switch to thermostats over time.	Residential and Non-Residential Customers

[20] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.
[21] As noted earlier in the report, measure costs and utility incentives were not escalated over the 20-year analysis timeframe to keep those costs constant in nominal dollars.

Demand Response Program Option	Program Description	Eligible Markets
DLC AC (Thermostat)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load. GDS looked at the three options IPL currently has: a customer is given a free thermostat to participate along with an annual incentive, a customer is given a rebate through the marketplace or a storefront along with an annual incentive, or the customer brings an existing thermostat and is only given an annual incentive.	Residential and Non-Residential Customers
DLC Space Heating	The system operator can remotely lower the HVAC's thermostat set point during winter peak load conditions, lowering the heating load. This program is an add-on to the DLC AC Thermostat program. Only participants in the AC Thermostat program would be allowed to participate in the Space Heating program.	Residential and Non-Residential Customers
DLC Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and Non-Residential Customers
Ice Storage Cooling Rate	The use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods.	Large Non-Residential Customers
DLC Lighting	Part of the lighting load is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Non-Residential Customers
Curtailable Rate (Day of)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers
Curtailable Rate (Day Ahead)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control (DLC) program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. However, in this study, none of the programs interacted with each other. All residential programs considered were direct load control. Only small non-residential customers were eligible for direct load control programs, and large non-residential customers were eligible for the Ice Storage Cooling Rate and Curtailable Rate.

3.5.2 Demand Response Potential Assessment Approach Overview

The analysis of demand response, where possible, closely followed the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[22] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[23] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits.

Direct load control demand response analysis was conducted using the GDS Demand Response Model. Demand response via rate programs (specifically, curtailable rates) were analyzed by Demand Side Analytics (DSA). GDS and DSA determine the estimated savings for each demand response program by performing a review of all benefits and cost associated with each program. Both firms a modeling approach that considers numerous required inputs for each program including: expected life, coincident peak (CP) kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses.

The UCT was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

The demand response analysis includes estimates of technical, economic, and achievable potential. Achievable potential is broken into maximum and RAP in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 19-year study period. For this study, this is defined as customer participation in demand response program options that reflect a “best practices” estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 19-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or “average” industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

3.5.3 Avoided Costs

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by IPL. The primary benefit of demand responses is avoided generation capacity, resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered “load shifting”, such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. If the program is not considered to be “load shifting” the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

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[22] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.

[23] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

3.5.4 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources used to complete the demand response potential analysis. Appendix G provides additional detail by program and sector related to load reduction, program costs, and projected participation.

3.5.4.1 Direct Load Control Program Assumptions

Load Reduction: Demand reductions were based on load reductions found in IPL's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies. DLC and thermostat-based demand response options were typically calculated based on a per-unit kW demand reduction whereas rate-based demand response options were typically assumed to reduce a percentage of the total facility peak load.

Useful Life: The useful life of a smart thermostat is assumed to be 12 years . Load control switches have a useful life of 12 years. This life was used for all direct load control measures in this study.

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost, with evaluation cost for existing programs already being included in the administration costs. It was assumed that there would be a cost of $50[24] per new participant for marketing for the DLC programs. Marketing costs are assumed to be 33.3% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

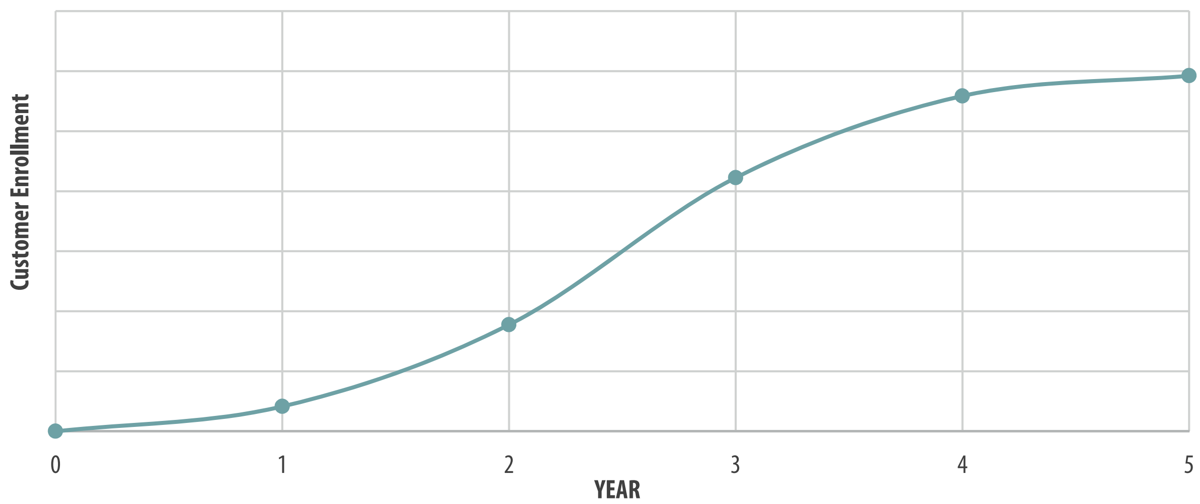
Saturation: The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.055 thermostats.

Program Adoption Levels: Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS reviewed industry data and program adoption levels from several utility demand response programs. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Appendix G. As noted earlier in this section, for direct load control programs, MAP participation rates rely on industry best adoption rates and RAP participation rates are based on industry average adoption levels. For the rate programs, the MAP steady-state participation rates assumed programs were opt-out based and RAP participation assumed opt-in status.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 3-4). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

[24] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

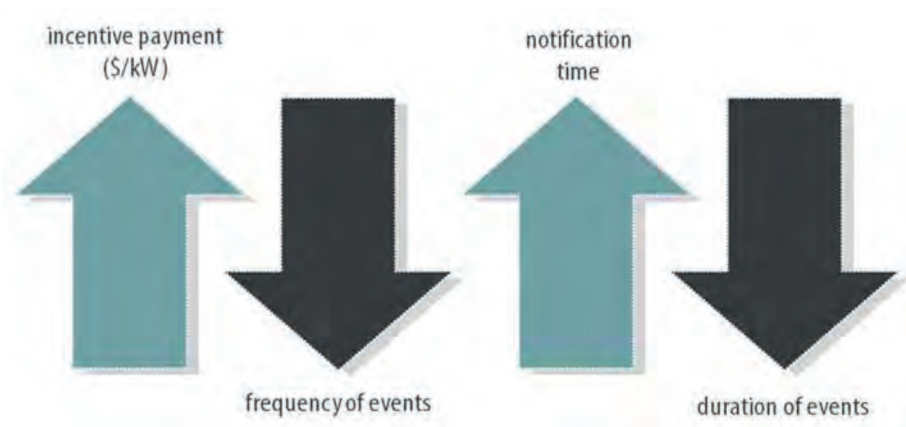
FIGURE 3-4 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE



3.5.4.2 C&I Curtailment Load Program Assumptions

One of the most prominent forms of demand response among non-residential customers is load curtailment agreements where the utility, or an aggregator on the utility's behalf, enters financial agreements with businesses to reduce load when dispatched. Load curtailment potential is driven by a few key factors – incentive payments, the frequency of events, the duration of events, and the level of notification participants are given about pending events. The directional effect these factors have on demand response potential is shown in Figure 3-5.

FIGURE 3-5 DRIVERS OF DR POTENTIAL



Several different estimates of Curtailment Load potential can be produced by turning levers related to these four inputs. Rather than producing several different scenario-based estimates, the research team made several simplifying assumptions regarding program design. Components of program design include how many demand response events will be called, how long the demand response events will last, how far in advance participants are notified of the upcoming demand response event, and the incentive payment participants receive (the amount and how it is distributed – annually, monthly, per event, etc.).

Program Design: Previous Indiana research suggests relatively short demand response events would serve the region better than relatively long events, as summer peaks are concentrated between 2:00 PM and 6:00 PM. Thus, our estimates of potential assume a four-hour event duration. We're also assuming that there will be an average of seven summer events will be called (28 total event hours for the summer).

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

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

For MAP, the goal of the simulation was not to optimize net benefits. Instead, we used the simulation to determine the greatest possible incentive level that would produce a cost-effective program (e.g., largest incentive value such that the UCT ratio does not fall below 1). The results indicated an incentive level of $39/kW-year should be used in estimating MAP for summer 2020.

In both cases, the incentive level is escalated annually at a rate that matches the growth rate of avoided costs. This growth rate is largely driven by the generation component (avoided cost of generation capacity was provided by IPL).

Price Elasticity of Demand Coefficients: The price elasticity of demand coefficients used in this research were derived from two years of demand response performance data for C&I demand response participants in Pennsylvania. Information about sector (small/large), incentive levels, and the peak load share of each participant was used in the development of the elasticity coefficients. Traditional elasticity formulas were used.

Leveraging the inputs discussed above, C&I Curtailable load potential estimates were developed via a "top-down" approach. At a high level, the approach entails disaggregating the peak load forecast into peak load forecasts by sector, and then combining these forecasts with the price elasticity of demand coefficients to estimate potential. Price elasticity of demand can be thought of as the percentage change in the quantity of electricity demanded divided by the percentage change in the price (including an incentive) of demand response:

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price}$$

Rearranging the terms in the elasticity equation yields the following:

$$\%\ change\ in\ Quantity = (Elasticity) \times (\%\ change\ in\ Price)$$

Note that "% change in Quantity" can also be expressed as:

$$\%\ change\ in\ Quantity = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

Combing these two "% change in Quantity" equations yields:

$$(Elasticity) \times (\%\ change\ in\ Price) = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

By making assumptions about price elasticity, the percentage change in price (related to electric retail rates and the incentive level), and the summer peak load, it is possible to estimate how much demand response potential exists in each market segment by solving for "demand response potential". It is important to note that the estimates of C&I Curtailable Load demand response potential discussed in this section are not incremental to existing IPL programs. That is, we are not estimating how much Curtailable Load demand response potential exists beyond the existing IPL resources. It is also important to note that this top-down methodology produces estimates of Curtailable Load demand response potential at the system-level (inclusive of line losses).

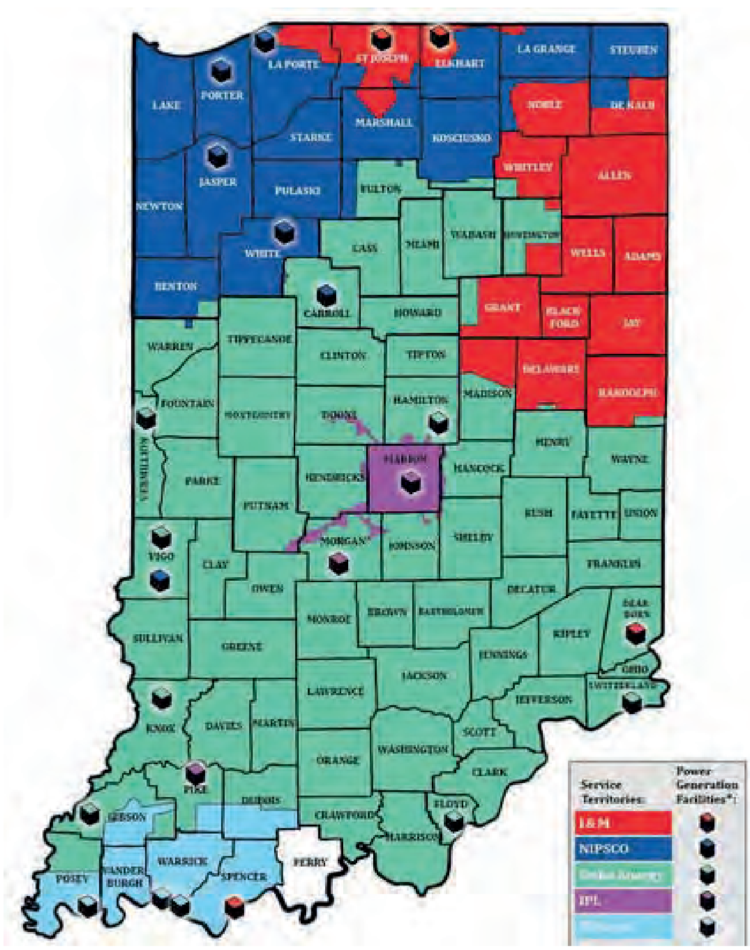
4 Market Characterization

Developing a market characterization in the context of utility electric consumption among each sector is a key foundational element to market potential studies. A market characterization describes how energy is used among the various end-uses and building types that are the subject of the potential study. This section provides a brief overview of the sales and customer forecasts for IPL's electric customers. It also includes a more detailed breakdown of the end-use and building type consumption, along with an overview of how these segmentations were developed.

4.1 INDIANAPOLIS POWER & LIGHT COMPANY SERVICE AREA

This study assessed the electric energy efficiency potential for IPL. Figure 4-1 identifies the overall IPL territory relative to the geographic area of Indiana.

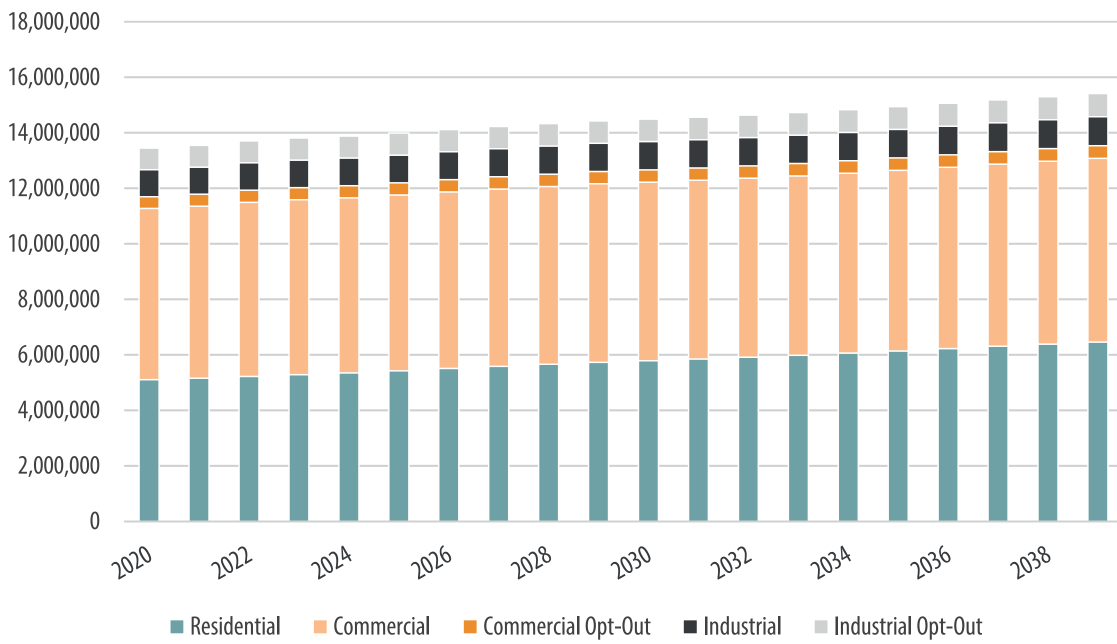
FIGURE 4-1 IPL SERVICE TERRITORY MAP



4.2 LOAD FORECASTS

Figure 4-2 provides the electric sales by sector across the 2020-2039 timeframe. Sales are forecasted to gradually increase from 13.4 million MWh to 15.4 million MWh from 2020 to 2039. The sales figure shows C&I sales break outs of the sales projections for opt-out customers.

FIGURE 4-2 20-YEAR ELECTRIC SALES (MWH) FORECAST BY SECTOR

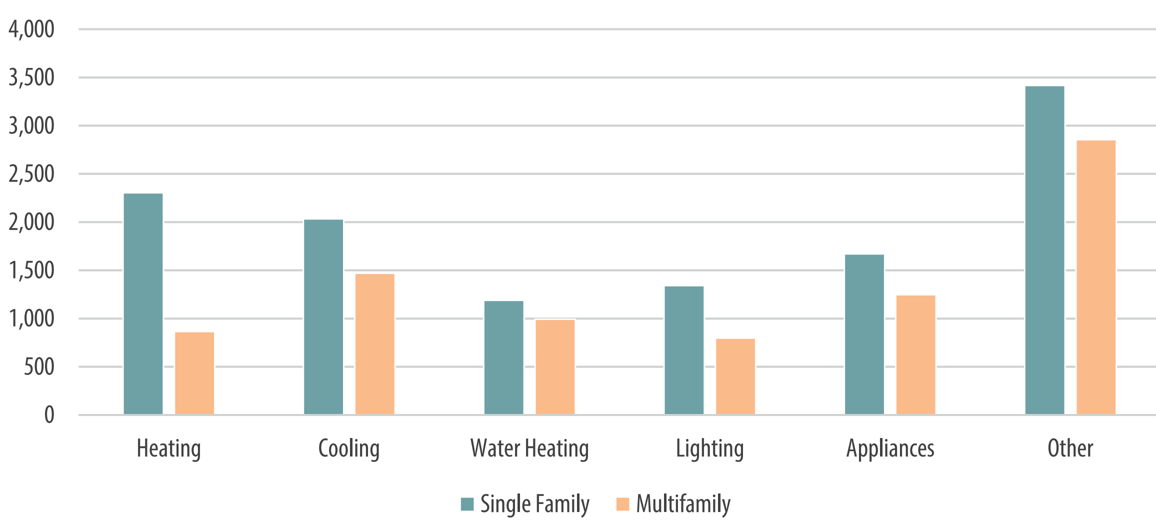


4.3 SECTOR LOAD DETAIL

4.3.1 Residential Sector

The residential electric calibration effort led to a housing-type specific end-use intensity breakdown as shown below in Figure 4-3. Overall, we estimated single-family consumption to be just shy of 12,000 kWh per year, and multifamily homes to be about 8,200 kWh per year. The "Other" end use is the leading end-use among both housing types. This reflects the increasing prominence of electronics and other plug in load devices.

FIGURE 4-3 RESIDENTIAL ELECTRIC END-USE BREAKDOWN BY HOUSING TYPE



4.3.2 Commercial Sector

Figure 4-4 provides a breakdown of commercial electric sales by building type. Mercantile (25%) and Office (20%) are the leading contributors of stand-alone building types to the total commercial electric sales.[25]

FIGURE 4-4 COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

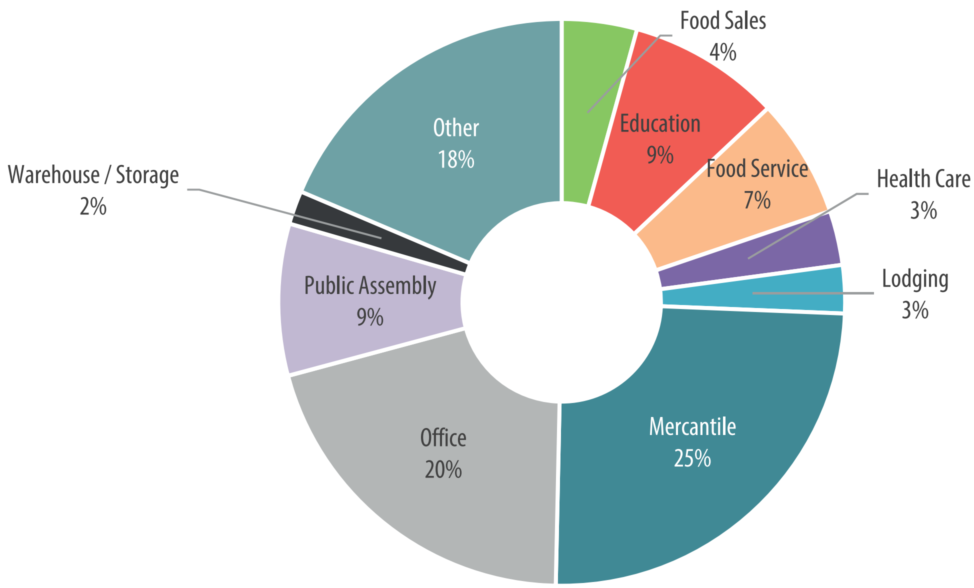
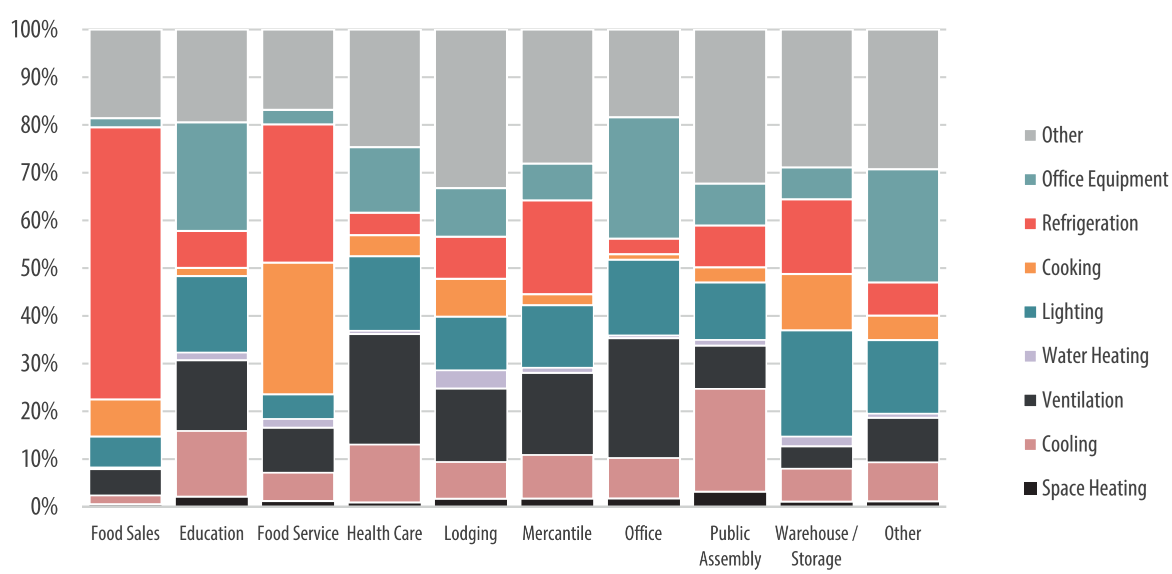


Figure 4-5 provides an illustration of the leading end-uses across all building types in the commercial sector. Ventilation, lighting, and refrigeration are prominent across most of the building types.

FIGURE 4-5 COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE



[25] "Other" building types include buildings that engage in several different activities, a majority of which are commercial (e.g. retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

4.3.3 Industrial Sector

Figure 4-6 provides a breakdown of industrial electric sales by industry type. Food (24%), Chemicals (8%), Paper (8%), Fabricated Metals (8%), and Miscellaneous (44%) are the leading industry types contributing to industrial electric sales.

FIGURE 4-6 INDUSTRIAL ELECTRIC INDUSTRY TYPE BREAKDOWN

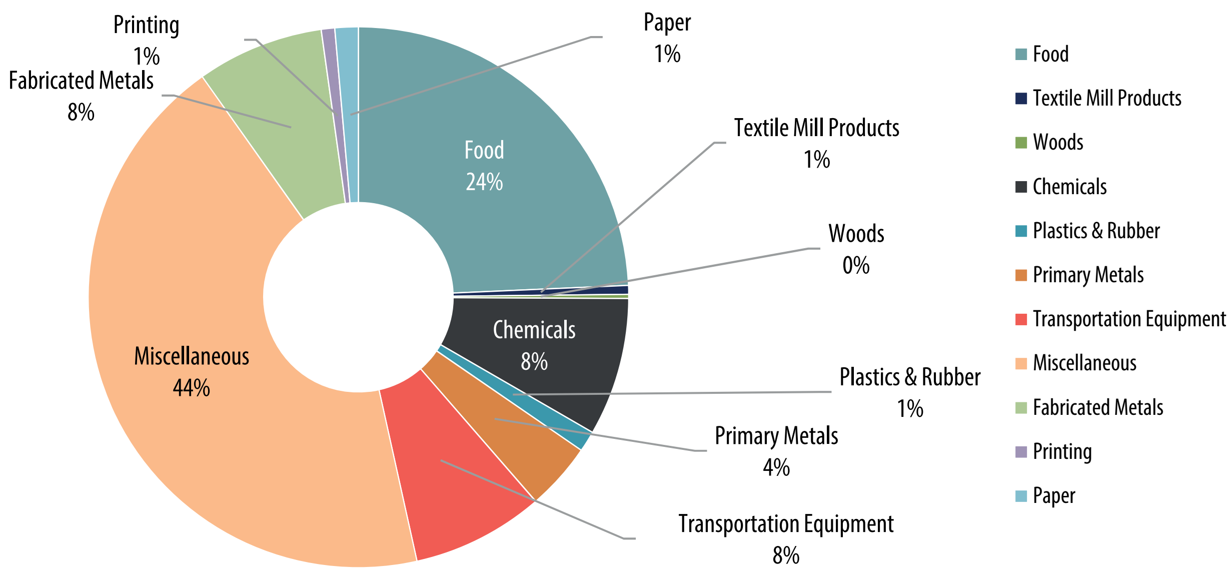
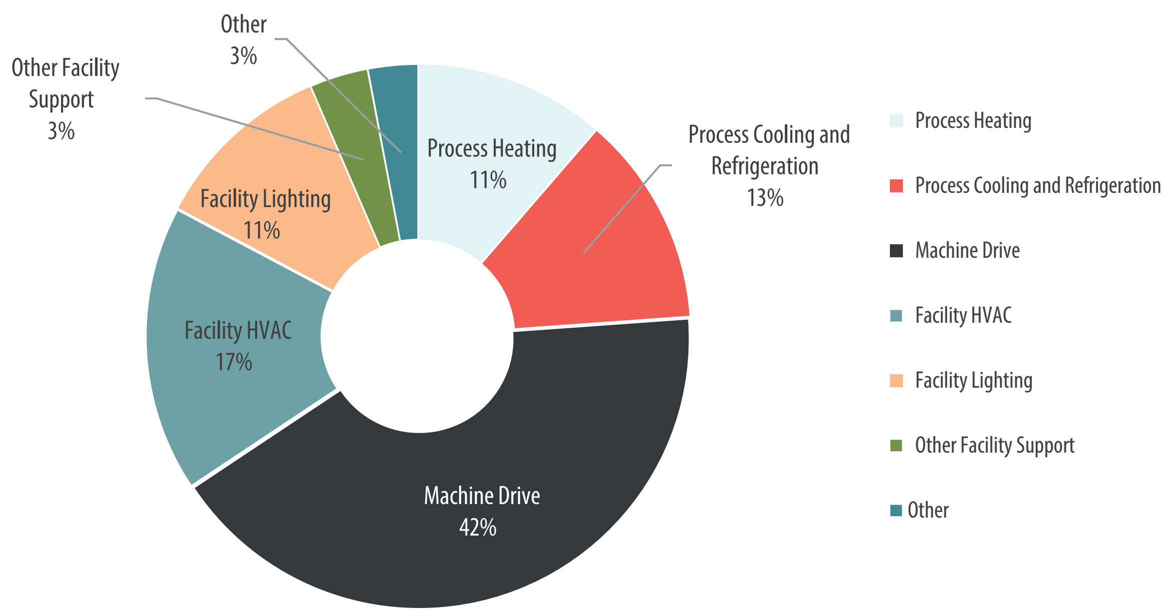


Figure 4-7 provides a breakdown of the industrial electric sales end use. Machine Drive (42%) and Facility HVAC (17%) are the leading end-uses.

FIGURE 4-7 INDUSTRIAL ELECTRIC END-USE BREAKDOWN



5 Residential Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. The cost-effectiveness results and budgets for the RAP scenario are also provided.

5.1 SCOPE OF MEASURES & END USES ANALYZED

There were 187 total unique electric measures included in the analysis. Table 5-1 provides the number of measures by end-use and fuel type (the full list of residential measures is provided in Appendix B). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 5-1 RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Appliances	28
Audit	3
Behavioral	6
HVAC Equipment	45
Lighting	15
Miscellaneous	6
New Construction	4
Plug Loads	9
HVAC Shell	55
Water Heating	16

5.2 RESIDENTIAL ELECTRIC POTENTIAL

Figure 5-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 3-year technical potential is 22.4% of forecasted sales, and the economic potential is 19.0% of forecasted sales. The 3-year MAP is 11.3% and the RAP is 6.9%.

FIGURE 5-1 RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF RESIDENTIAL SALES)

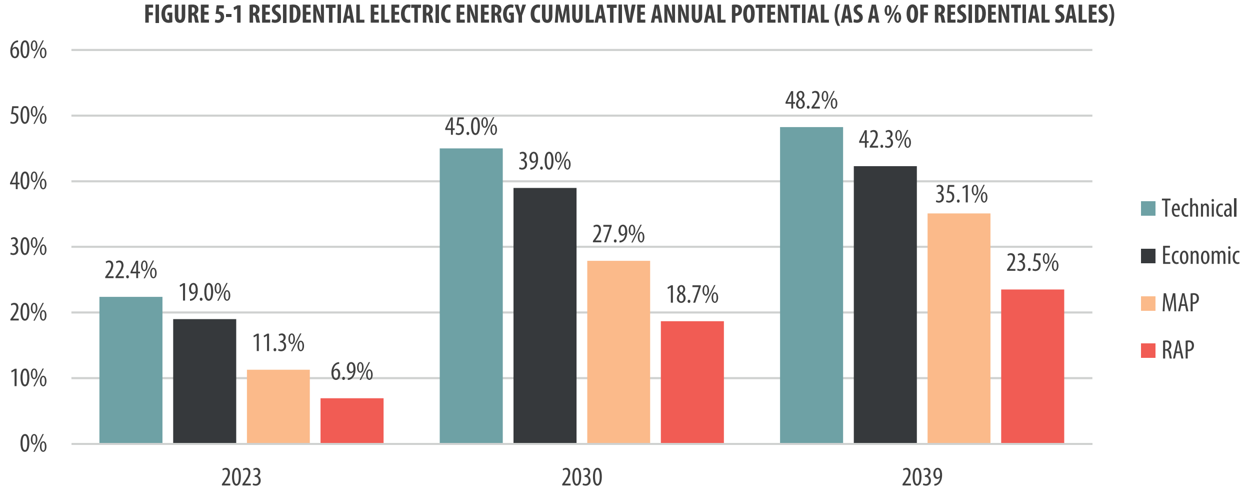


Table 5-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP increases to nearly 7% cumulative annual savings over the next three years.

TABLE 5-2 RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	443,322	818,857	1,182,808	2,604,874	3,116,819
Economic	401,929	706,729	1,003,079	2,255,197	2,732,750
MAP	244,657	414,183	595,903	1,612,643	2,267,253
RAP	175,436	266,884	365,671	1,079,971	1,518,517
Forecasted Sales	5,157,382	5,223,774	5,284,520	5,788,077	6,462,180
Energy Savings (as % of Forecast)					
Technical	8.6%	15.7%	22.4%	45.0%	48.2%
Economic	7.8%	13.5%	19.0%	39.0%	42.3%
MAP	4.7%	7.9%	11.3%	27.9%	35.1%
RAP	3.4%	5.1%	6.9%	18.7%	23.5%

Table 5-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 3.1% to 3.4% per year over the next three years.

TABLE 5-3 RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	443,322	426,679	416,391	247,610	270,960
Economic	401,929	377,942	365,341	214,307	233,397
MAP	244,657	244,314	251,929	190,090	222,905
RAP	175,436	164,092	164,881	171,594	164,489
Forecasted Sales	5,157,382	5,223,774	5,284,520	5,788,077	6,462,180
Energy Savings (as % of Forecast)					
Technical	8.6%	8.2%	7.9%	4.3%	4.2%
Economic	7.8%	7.2%	6.9%	3.7%	3.6%
MAP	4.7%	4.7%	4.8%	3.3%	3.4%
RAP	3.4%	3.1%	3.1%	3.0%	2.5%

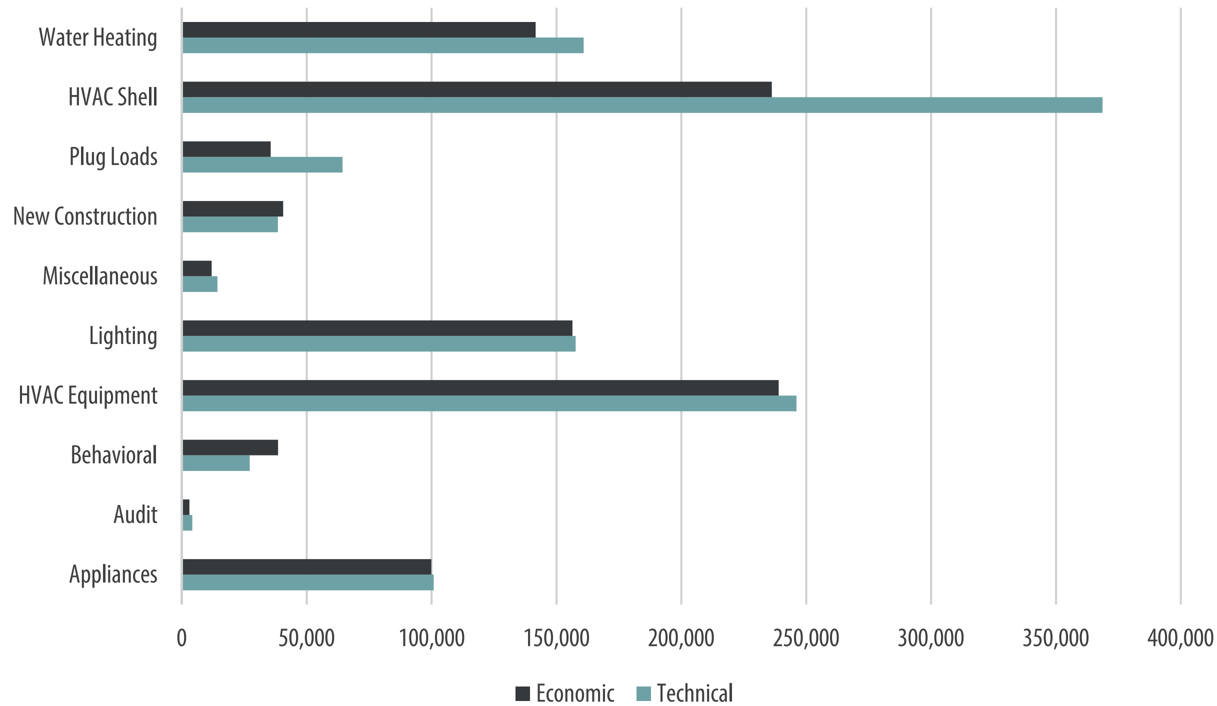
Technical & Economic Potential

Table 5-4 provides cumulative annual technical and economic potential results across the 2021-2023 timeframe, as well as for 2030 and 2039. Figure 5-2 shows a comparison of the technical and economic potential (3-year) by end use. The HVAC Shell and HVAC Equipment are by far the leading end-uses among technical and economic potential.

TABLE 5-4 TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	443,322	818,857	1,182,808	2,604,874	3,116,819
Economic	401,929	706,729	1,003,079	2,255,197	2,732,750
Peak Demand (MW)					
Technical	85	167	247	563	686
Economic	72	135	196	466	575

FIGURE 5-2 3-YEAR TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 5-3 illustrates the cumulative annual MAP results by end use across the 2021-2023 timeframe. Like technical and economic potential, HVAC Shell and HVAC Equipment are the leading end uses. Water Heating, Lighting, and Appliances also have significant MAP.

FIGURE 5-3 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

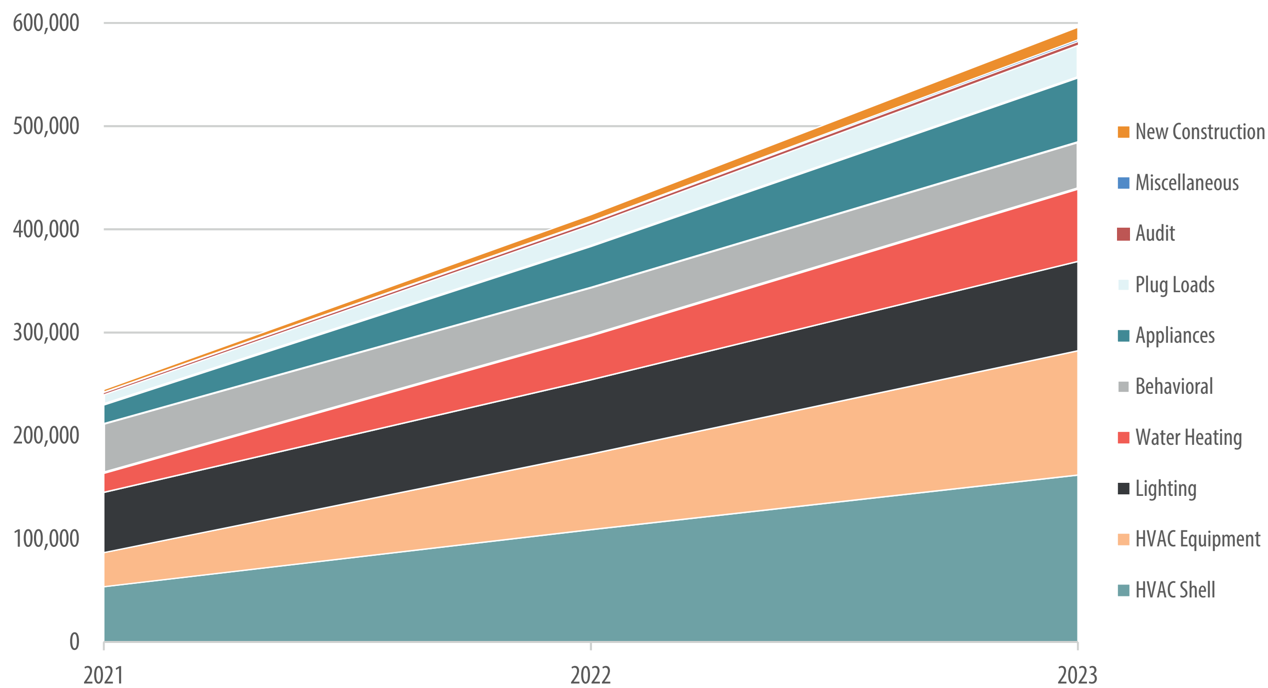


Table 5-5 provides the incremental and cumulative annual MAP across the 2021-2023 timeframe, as well as for 2030 and 2039. HVAC Shell, HVAC Equipment, Lighting, and the Behavioral end uses provide the greatest incremental annual MAP over the next three years.

TABLE 5-5 RESIDENTIAL ELECTRIC MAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Appliances	18,656	21,543	22,839	17,977	20,341
Audit	1,537	2,221	3,066	3,570	1,806
Behavioral[26]	47,718	46,600	45,238	40,186	38,538
HVAC Equipment	33,084	40,516	48,038	39,687	56,260
Lighting	58,384	37,015	30,062	4,374	10,397
Miscellaneous[27]	414	619	884	2,160	2,477
New Construction	2,477	3,971	5,511	12,490	10,973
Plug Loads	9,878	10,652	11,096	13,775	16,956
HVAC Shell	53,561	56,619	55,922	16,992	21,388
Water Heating	18,946	24,558	29,273	38,880	43,768
Total	244,657	244,314	251,929	190,090	222,905
% of Forecasted Sales	4.7%	4.7%	4.8%	3.3%	3.4%
Incremental Annual MW					
Total	44.7	46.9	48.5	33.2	43.8
% of Forecasted Demand	4.0%	4.2%	4.3%	2.8%	3.4%
Cumulative Annual MWh[28]					
Appliances	18,656	40,188	62,543	181,163	234,853
Audit	1,537	2,221	3,066	3,570	1,806
Behavioral	47,718	46,600	45,238	42,069	43,846
HVAC Equipment	33,084	73,223	120,515	468,563	766,806
Lighting	58,384	71,944	86,589	116,397	73,591
Miscellaneous	414	1,033	1,918	14,859	26,877
New Construction	2,477	6,517	12,066	83,992	189,730
Plug Loads	9,878	20,531	31,627	74,682	90,447
HVAC Shell	53,561	108,912	161,775	334,152	380,447
Water Heating	18,946	43,015	70,567	293,198	458,849
Total	244,657	414,183	595,903	1,612,643	2,267,253
% of Forecasted Sales	4.7%	7.9%	11.3%	27.9%	35.1%
Cumulative Annual MW					
Total	44.7	81.3	118.9	318.4	464.4
% of Forecasted Demand	4.0%	7.2%	10.5%	26.9%	36.2%

[26] The behavioral end-use includes home energy reports and home energy management systems (HEMs).
[27] Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.
[28] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.

Realistic Achievable Potential

Figure 5-4 illustrates the cumulative annual RAP results by end use across the 2021-2023 timeframe. HVAC Equipment and Lighting are the leading end uses over the first three years. The HVAC Shell, Behavioral, and Water Heating end uses also have significant potential in the RAP scenario of this timeframe.

FIGURE 5-4 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

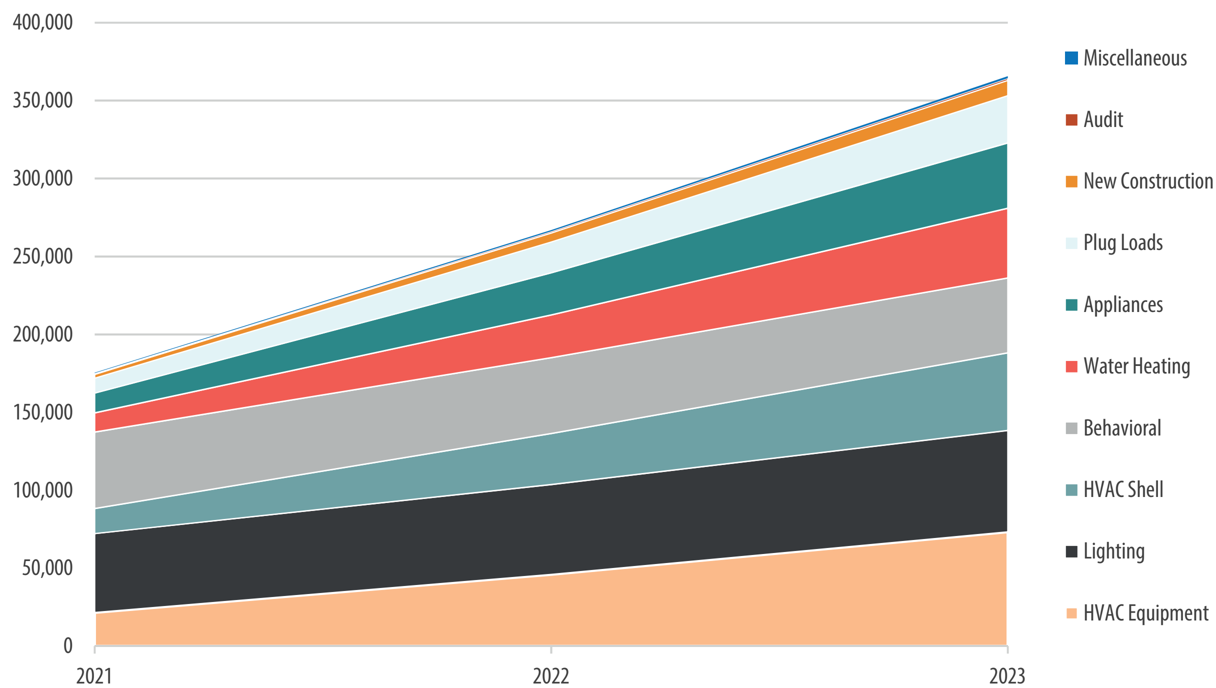


Table 5-6 provides the incremental and cumulative annual RAP across the 2021-2023 timeframe, as well as for 2030 and 2039. HVAC Shell, HVAC Equipment, Lighting, and the Behavioral end uses provide the greatest incremental annual MAP over the next three years.

TABLE 5-6 RESIDENTIAL ELECTRIC RAP BY END-USE

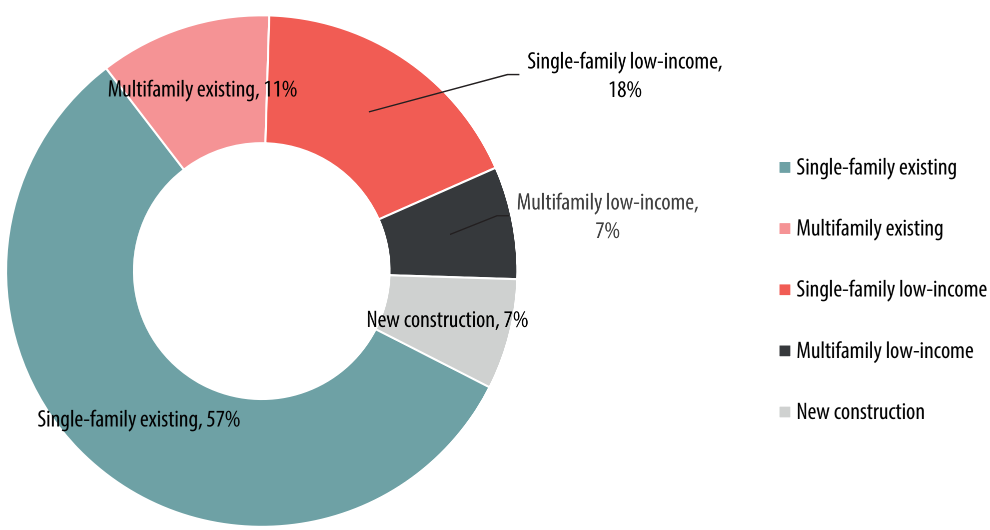
End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Appliances	12,718	14,299	15,192	14,736	15,642
Audit	781	1,035	1,354	4,041	2,302
Behavioral[29]	49,063	48,657	48,057	44,940	45,323
HVAC Equipment	21,534	24,526	27,485	33,577	25,174
Lighting	50,665	29,513	22,359	5,108	9,745
Miscellaneous[30]	328	438	572	1,683	1,889
New Construction	2,424	3,291	3,917	6,016	5,363
Plug Loads	9,546	10,217	10,633	13,558	16,927
HVAC Shell	16,070	16,901	17,574	14,698	8,515
Water Heating	12,306	15,217	17,740	33,238	33,611
Total	175,436	164,092	164,881	171,594	164,489

[29] The behavioral end-use includes home energy reports and home energy management systems (HEMs).
[30] Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.

End Use	2021	2022	2023	2030	2039
% of Forecasted Sales	3.4%	3.1%	3.1%	3.0%	2.5%
Incremental Annual MW					
Total	30.0	30.4	31.0	29.5	28.8
% of Forecasted Demand	2.7%	2.7%	2.7%	2.5%	2.2%
Cumulative Annual MWh[31]					
Appliances	12,718	27,015	41,890	136,801	174,298
Audit	781	1,035	1,354	4,041	2,302
Behavioral	49,063	48,657	48,057	45,878	50,641
HVAC Equipment	21,534	45,977	73,258	298,296	460,561
Lighting	50,665	57,643	65,110	93,649	75,854
Miscellaneous	328	766	1,338	10,062	20,789
New Construction	2,424	5,796	9,767	47,187	98,778
Plug Loads	9,546	19,763	30,395	73,679	89,992
HVAC Shell	16,070	32,741	49,796	158,391	225,785
Water Heating	12,306	27,491	44,706	211,988	319,517
Total	175,436	266,884	365,671	1,079,971	1,518,517
% of Forecasted Sales	3.4%	5.1%	6.9%	18.7%	23.5%
Cumulative Annual MW					
Total	30.0	50.5	71.3	215.6	301.6
% of Forecasted Demand	2.7%	4.5%	6.3%	18.2%	23.5%

Figure 5-5 illustrates a market segmentation of the RAP in the residential sector by 2023. More than half of the RAP is associated with single-family existing homes that are not low-income, whereas the total low-income potential is about 25% of the RAP.[32]

FIGURE 5-5 2023 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT



[31] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.
[32] The low-income measures in the RAP analysis did not have to pass the UCT.

RAP Benefits & Costs

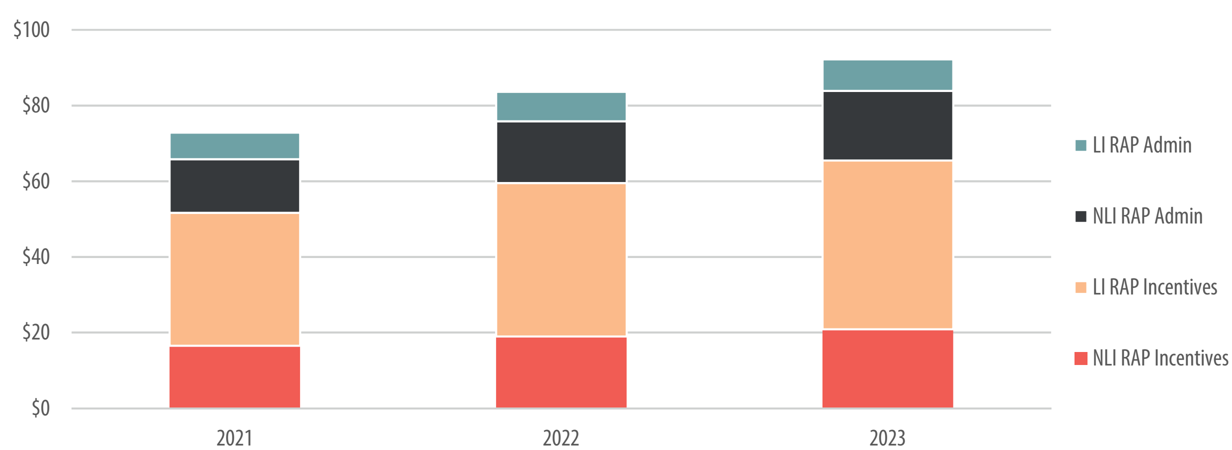
Table 5-7 provides the net present value (NPV) benefits and cost, as calculated using the UCT, across the 2021-2039 timeframe for the RAP scenario. The overall UCT ratio is 0.961. However, if low-income measures were removed, the overall UCT ratio would be nearly 1.5.

TABLE 5-7 RESIDENTIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Overall Results			
Appliances	$110.6	$107.3	1.03
Audit	$1.7	$47.8	0.03
Behavioral	$38.9	$30.4	1.28
HVAC Equipment	$427.5	$504.1	0.85
Lighting	$60.3	$75.9	0.80
Miscellaneous	$18.7	$4.8	3.89
New Construction	$75.9	$42.5	1.79
Plug Loads	$47.1	$32.4	1.46
HVAC Shell	$151.4	$146.6	1.03
Water Heating	$141.3	$122.7	1.15
Total	$1,073.4	$1,114.3	0.96
Excluding Low-Income			
Appliances	$81.9	$35.5	2.31
Audit	$1.5	$32.5	0.05
Behavioral	$38.9	$30.4	1.28
HVAC Equipment	$292.5	$153.8	1.90
Lighting	$56.1	$68.2	0.82
Miscellaneous	$18.7	$4.8	3.89
New Construction	$75.9	$42.5	1.79
Plug Loads	$45.8	$26.3	1.74
HVAC Shell	$105.5	$80.4	1.31
Water Heating	$127.2	$106.2	1.20
Total	$844.0	$580.6	1.45

Figure 5-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. These budgets are further divided into low-income (LI) and not low-income (NLI) components. The low-income incentive portion of the budget is about 48% of the RAP budget. The RAP budgets rise from $73 million to about $92 million from 2021 to 2023.

FIGURE 5-6 ANNUAL BUDGETS FOR RESIDENTIAL RAP ($ IN MILLIONS)



6 Commercial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

6.1 SCOPE OF MEASURES & END USES ANALYZED

There were 237 total electric measures included in the analysis. Table 6-1 provides the number of measures by end-use (the full list of commercial measures is provided in Appendix C). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 6-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Space Heating	31
Cooling	75
Ventilation	11
Water Heating	17
Lighting	32
Cooking	8
Refrigeration	29
Office Equipment	14
Behavioral	4
Other	16

6.2 COMMERCIAL ELECTRIC POTENTIAL

Figure 6-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 3-year technical potential is 15.6% of forecasted sales, and the economic potential is 13.9% of forecasted sales. The 3-year MAP is 10.9% and the RAP is 4.3%.

FIGURE 6-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERCIAL SALES)

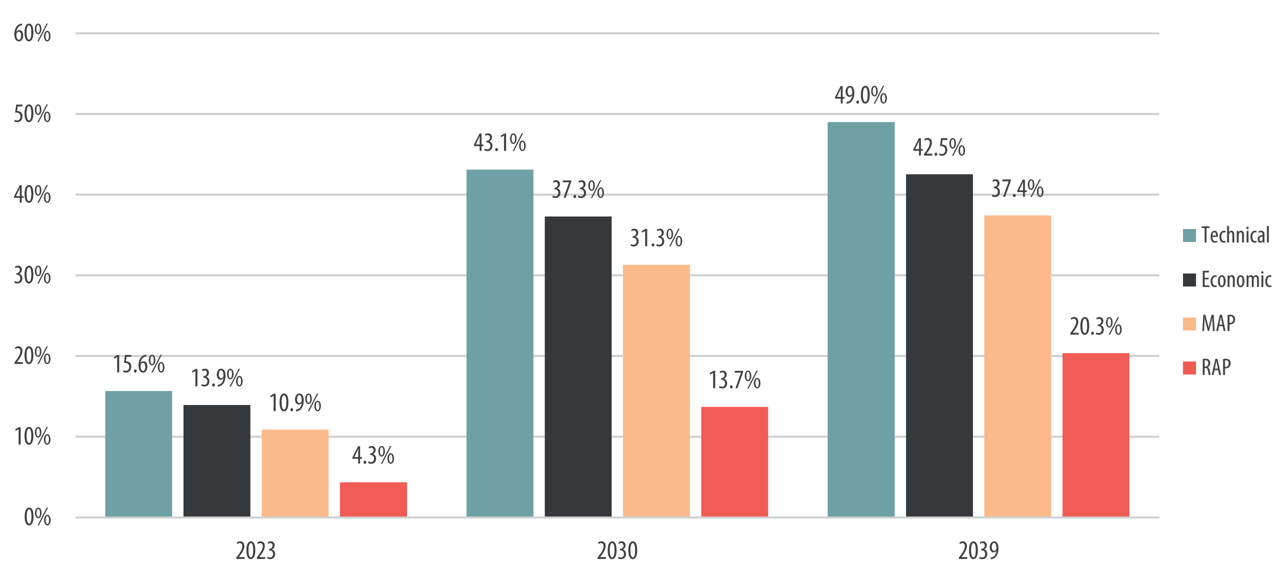


Table 6-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 3.8% after three years and rises to 17.7% by 2039.

TABLE 6-2 COMMERCIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	297,674	601,207	923,248	2,595,884	3,034,939
Economic	262,141	535,268	821,276	2,245,705	2,634,454
MAP	191,773	407,732	640,739	1,884,672	2,317,654
RAP	87,433	172,729	256,487	824,507	1,259,861
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737
Energy Savings (as % of Forecast)					
Technical	4.5%	8.9%	13.6%	37.6%	42.7%
Economic	3.9%	8.0%	12.2%	32.6%	37.2%
MAP	2.9%	6.1%	9.5%	27.3%	32.7%
RAP	1.3%	2.6%	3.8%	11.9%	17.7%

Table 6-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.5% to 2.6% per year over the next six years.

TABLE 6-3 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	297,674	336,201	364,988	325,343	444,368
Economic	262,141	293,165	314,792	283,520	387,432
MAP	191,773	226,960	253,410	249,796	343,413
RAP	87,433	87,790	88,538	128,764	163,720
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737
Energy Savings (as % of Forecast)					
Technical	4.5%	5.0%	5.4%	4.7%	6.3%
Economic	3.9%	4.4%	4.7%	4.1%	5.5%
MAP	2.9%	3.4%	3.7%	3.6%	4.8%
RAP	1.3%	1.3%	1.3%	1.9%	2.3%

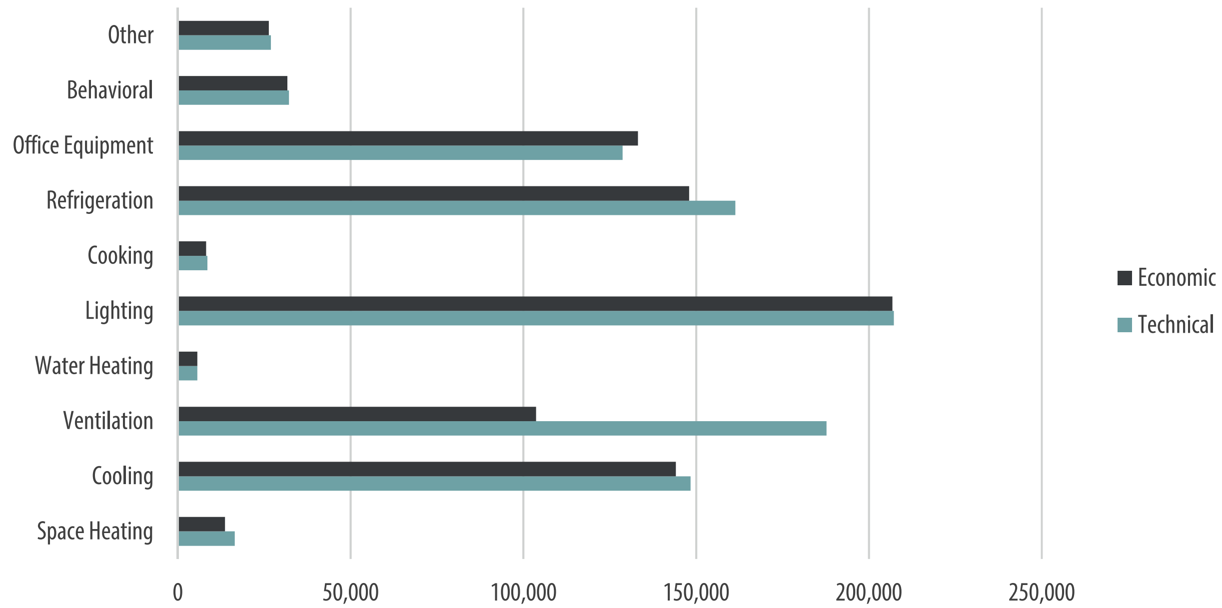
Technical & Economic Potential

Table 6-4 provides cumulative annual technical and economic potential results across the 2021-2023 timeframe, as well as for 2030 and 2039. Figure 6-2 shows a comparison of the technical and economic potential (6-year) by end use. Lighting, Ventilation, and Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE 6-4 TECHNICAL & ECONOMIC COMMERCIAL ELECTRIC POTENTIAL

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	297,674	601,207	923,248	2,595,884	3,034,939
Economic	262,141	535,268	821,276	2,245,705	2,634,454
Peak Demand (MW)					
Technical	58	123	197	683	782
Economic	36	75	119	362	415

FIGURE 6-2 3-YEAR TECHNICAL AND ECONOMIC COMMERCIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 6-3 illustrates the cumulative annual MAP results by end use across the 2021-2023 timeframe. Like technical and economic potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant MAP.

FIGURE 6-3 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

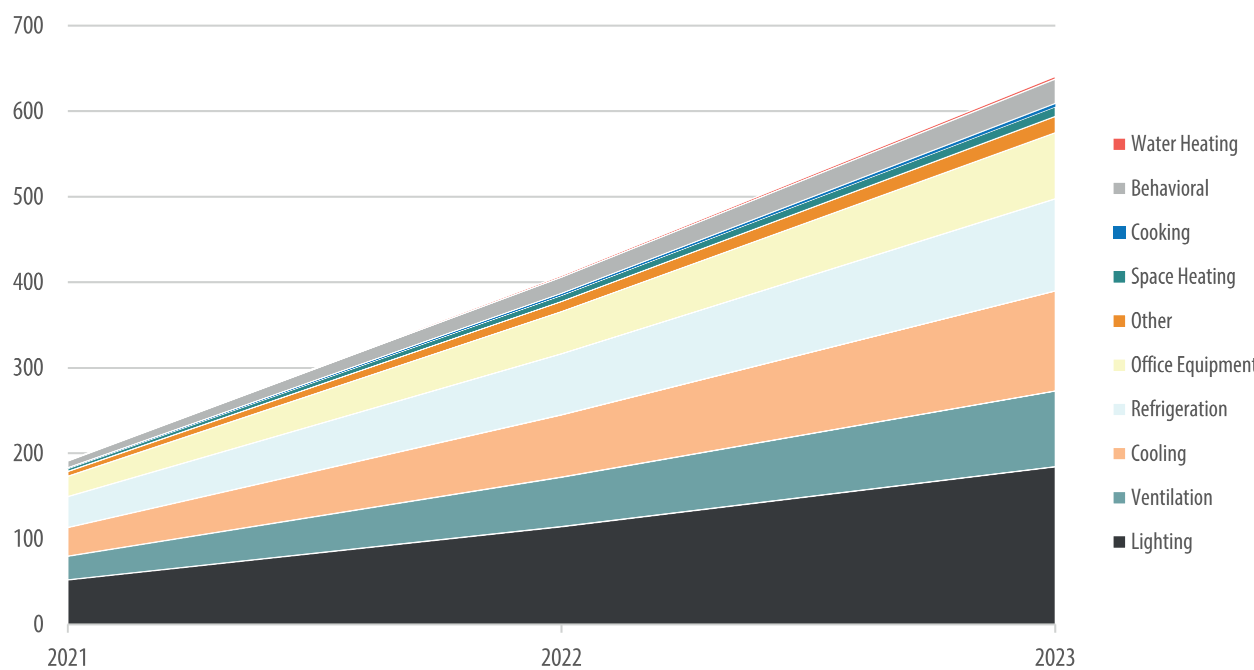


Table 6-5 provides the incremental and cumulative annual MAP across the 2021-2023 timeframe, as well as for 2030 and 2039. The incremental MAP ranges from 2.9% to 3.7% of forecasted sales across the initial three-year timeframe. Cumulative annual MAP rises to 32.7% by 2039.

TABLE 6-5 COMMERCIAL ELECTRIC MAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Space Heating	3,353	3,803	4,090	2,987	2,288
Cooling	33,453	39,299	44,232	39,320	35,727
Ventilation	27,730	30,029	30,780	5,743	36,793
Water Heating	818	1,037	1,244	1,587	1,258
Lighting	52,076	62,293	69,953	24,807	69,473
Cooking	1,043	1,298	1,550	2,387	2,415
Refrigeration	36,037	40,930	43,420	38,565	48,926
Office Equipment	23,819	25,685	27,851	38,233	39,339
Behavioral	7,843	14,811	20,103	76,212	81,477
Other	5,599	7,774	10,186	19,955	25,717
Total	191,773	226,960	253,410	249,796	343,413
% of Forecasted Sales	2.9%	3.4%	3.7%	3.6%	4.8%
Incremental Annual MW					
Total	28.8	34.5	39.8	31.2	43.0
% of Forecasted Demand	3.8%	4.5%	5.2%	3.9%	4.9%
Cumulative Annual MWh					
Space Heating	3,353	7,156	11,246	33,498	40,177
Cooling	33,453	72,752	116,985	409,286	491,096
Ventilation	27,730	57,760	88,540	205,732	254,366
Water Heating	818	1,856	3,100	11,943	15,633
Lighting	52,076	114,369	184,322	493,419	576,132
Cooking	1,043	2,342	3,892	19,035	28,770
Refrigeration	36,037	71,355	107,638	297,886	386,331
Office Equipment	23,819	49,504	77,355	233,030	310,834
Behavioral	7,843	18,915	28,559	111,574	123,588
Other	5,599	11,723	19,104	69,270	90,728
Total	191,773	407,732	640,739	1,884,672	2,317,654
% of Forecasted Sales	2.9%	6.1%	9.5%	27.3%	32.7%
Cumulative Annual MW					
Total	28.8	62.5	100.7	319.4	375.3
% of Forecasted Demand	3.8%	8.2%	13.1%	39.6%	43.2%

Realistic Achievable Potential

Figure 6-4 illustrates the cumulative annual RAP results by end use across the 2020-2023 timeframe. Like MAP, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant RAP.

FIGURE 6-4 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

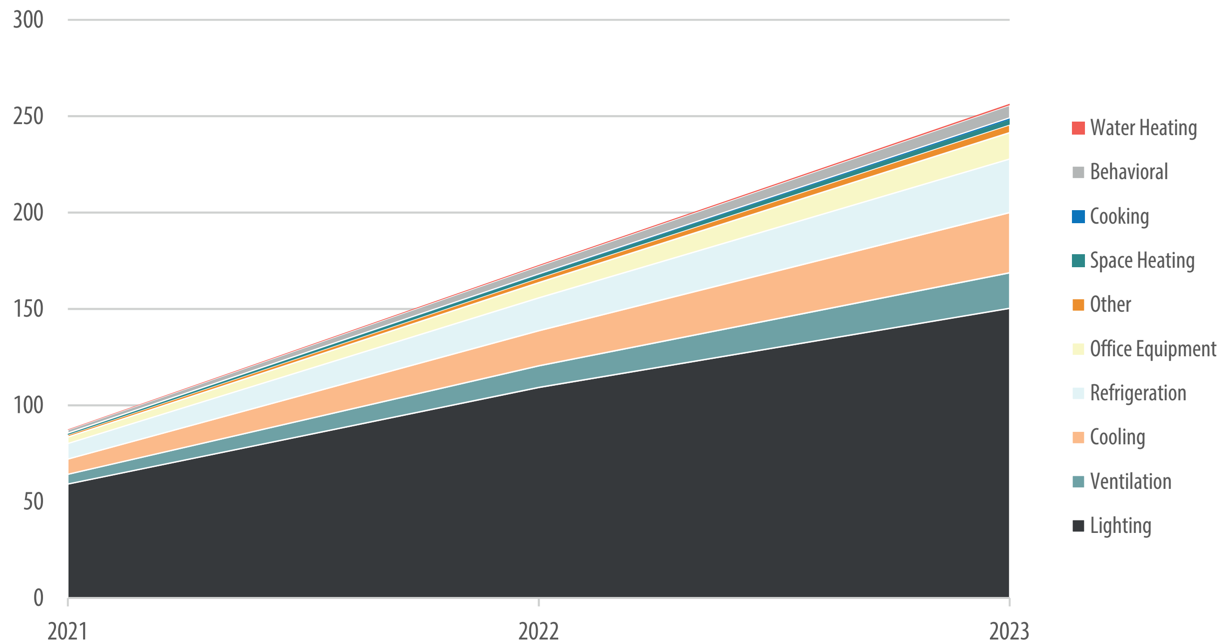


Table 6-6 provides the incremental and cumulative annual RAP across the 2021-2023 timeframe, as well as for 2030 and 2039. The incremental RAP is consistent at 1.3% of forecasted sales across the initial three-year timeframe. Cumulative annual RAP rises to 17.7% by 2039.

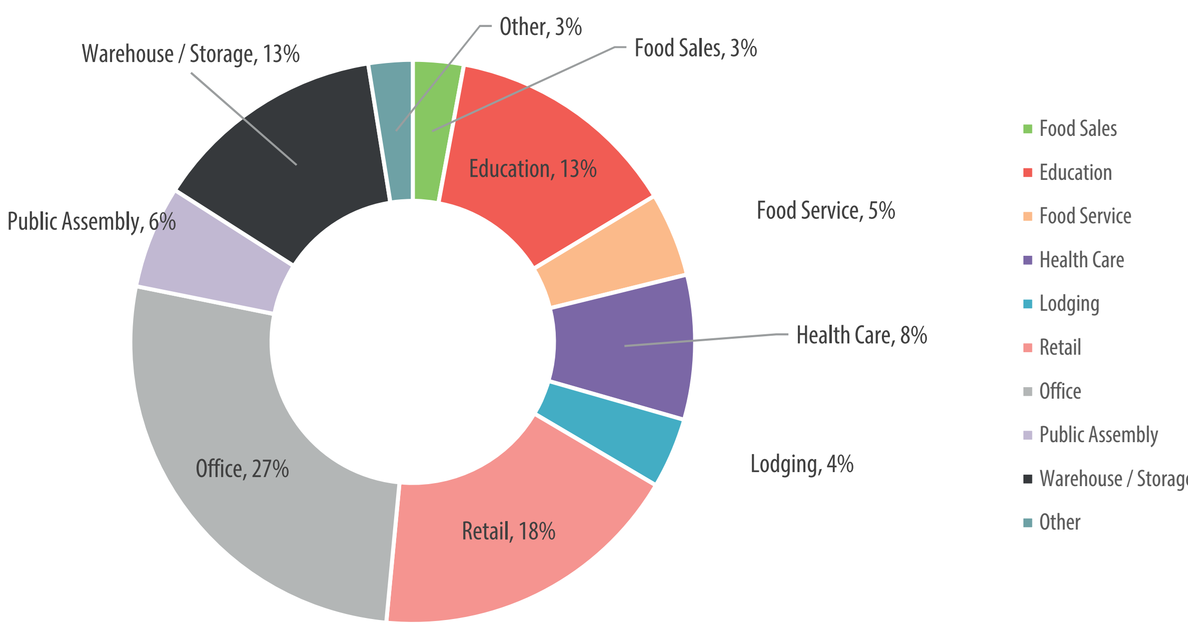
TABLE 6-6 COMMERCIAL ELECTRIC RAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Space Heating	683	868	1,062	1,816	1,212
Cooling	7,859	10,342	13,051	27,415	22,656
Ventilation	5,055	6,192	7,159	8,232	7,878
Water Heating	209	272	344	822	924
Lighting	59,173	50,101	41,063	14,771	29,873
Cooking	239	318	407	1,112	1,381
Refrigeration	8,105	10,291	12,700	24,308	28,666
Office Equipment	3,371	4,526	5,815	14,418	15,777
Behavioral	1,629	3,233	4,648	27,225	43,475
Other	1,111	1,649	2,288	8,646	11,877
Total	87,433	87,790	88,538	128,764	163,720
% of Forecasted Sales	1.3%	1.3%	1.3%	1.9%	2.3%
Incremental Annual MW					
Total	16.4	16.2	16.2	18.8	24.3
% of Forecasted Demand	2.2%	2.1%	2.1%	2.3%	2.8%
Cumulative Annual MWh					
Space Heating	683	1,550	2,612	13,635	22,370
Cooling	7,859	18,201	31,253	178,959	293,650
Ventilation	5,055	11,246	18,405	81,482	116,321
Water Heating	209	481	825	4,938	8,748

End Use	2021	2022	2023	2030	2039
Lighting	59,173	109,273	150,336	264,291	335,180
Cooking	239	557	965	6,717	14,953
Refrigeration	8,105	17,006	27,775	133,355	207,863
Office Equipment	3,371	7,897	13,712	75,871	149,742
Behavioral	1,629	4,092	6,496	39,168	64,956
Other	1,111	2,424	4,107	26,092	46,079
Total	87,433	172,729	256,487	824,507	1,259,861
% of Forecasted Sales	1.3%	2.6%	3.8%	11.9%	17.7%
Cumulative Annual MW					
Total	16.4	32.5	48.3	155.7	225.6
% of Forecasted Demand	2.2%	4.3%	6.3%	19.3%	26.0%

Figure 6-5 illustrates a market segmentation of the RAP in the commercial sector by 2023. Retail, Office, and Education are the leading building types.

FIGURE 6-5 2023 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT



RAP Benefits & Costs

Table 6-7 provides the NPV benefits and cost, as calculated using the UCT, across the 2021-2039 timeframe for the RAP scenario. Cooling and Cooking are the most cost-effective end-uses. Cooling, lighting, and refrigeration provides the most significant NPV benefits.

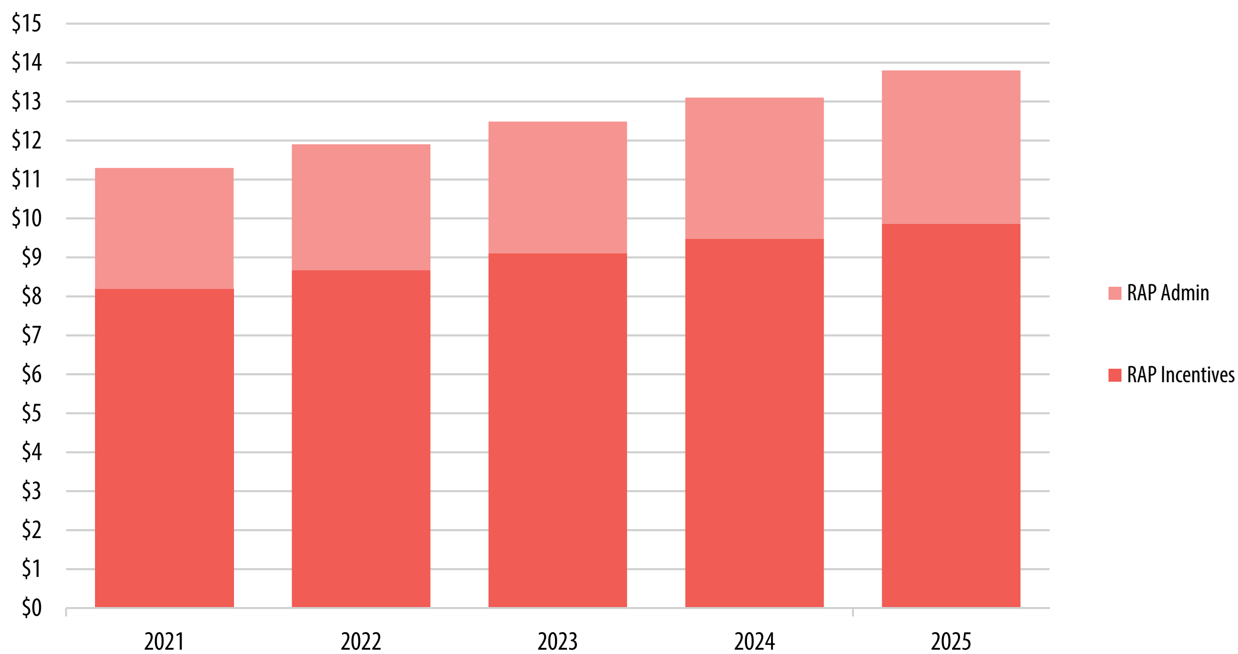
TABLE 6-7 COMMERCIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Space Heating	$7.88	$2.85	2.76
Cooling	$636.45	$44.60	14.27
Ventilation	$37.62	$21.05	1.79
Water Heating	$2.83	$0.42	6.72
Lighting	$181.94	$39.89	4.56
Cooking	$9.54	$1.19	8.04

End Use	NPV Benefits	NPV Costs	UCT Ratio
Refrigeration	$114.59	$20.53	5.58
Office Equipment	$45.41	$11.47	3.96
Behavioral	$27.33	$17.41	1.57
Other	$25.33	$6.12	4.14
Total	**$1,088.92**	**$165.53**	**6.58**

Figure 6-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The incentives rise from $8.2 million to $9.1 million, and overall budgets rise from $11.3 million to $12.8 million by 2023.

FIGURE 6-6 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS)



6.3 COMMERCIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 6-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 6.2. The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column. Table 6-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers. The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column.

The 19-year RAP is 1,259,861 MWh excluding opt-out customers. This figure rises to 1,368,560 MWh with opt-out customers included.

TABLE 6-8 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	297,674	336,201	364,988	325,343	444,368	3,034,939
Economic	262,141	293,165	314,792	283,520	387,432	2,634,454
MAP	191,773	226,960	253,410	249,796	343,413	2,317,654

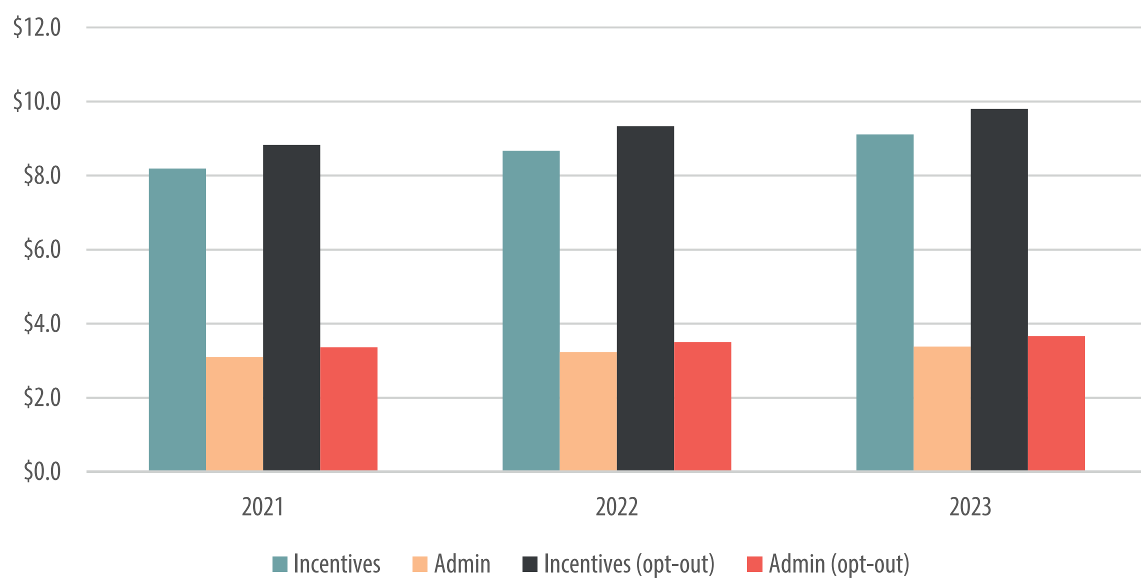
	2021	2022	2023	2030	2039	2039 (cumulative)
RAP	87,433	87,790	88,538	128,764	163,720	1,259,861
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737	7,107,737
Energy Savings (as % of Forecast)						
Technical	4.5%	5.0%	5.4%	4.7%	6.3%	42.7%
Economic	3.9%	4.4%	4.6%	4.1%	5.5%	37.1%
MAP	2.9%	3.4%	3.7%	3.6%	4.8%	32.6%
RAP	1.3%	1.3%	1.3%	1.9%	2.3%	17.7%

TABLE 6-9 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS[33]

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	319,987	361,894	393,318	355,466	483,353	3,271,659
Economic	282,388	316,313	340,107	311,127	422,935	2,845,631
MAP	217,686	257,080	286,837	309,561	396,535	2,503,275
RAP	105,544	105,937	106,745	109,342	190,102	1,368,560
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737	7,107,737
Energy Savings (as % of Forecast)						
Technical	4.8%	5.4%	5.8%	5.1%	6.8%	46.0%
Economic	4.2%	4.7%	5.0%	4.5%	6.0%	40.0%
MAP	3.3%	3.8%	4.2%	4.5%	5.6%	35.2%
RAP	1.6%	1.6%	1.6%	1.6%	2.7%	19.3%

Figure 6-7 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The overall budgets without opt-out customers rise from $11.3 million to $12.5 million by 2023. The budgets with opt-out customers included increase from $12.2 million to $13.5 million by 2023.

FIGURE 6-7 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS) – WITH AND WITHOUT OPT-OUT CUSTOMERS



[33] Due to limited number of commercial opt-out customers and minor changes in building segmentation, savings as a percentage of sales is negligible out to three decimal places.

7 Industrial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided. The results in this section exclude the savings and sales forecast associated with opt-out customers

7.1 SCOPE OF MEASURES & END USES ANALYZED

There were 130 total unique electric measures included in the analysis. Table 7-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 7-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Computers & Office Equipment	6
Water Heating	6
Ventilation	7
Space Cooling	25
Space Heating	16
Lighting	16
Other	7
Machine Drive	21
Process Heating and Cooling	10
Agriculture	16

7.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure 7-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 3-year technical potential is 6.5% of forecasted sales, and the economic potential is 6.4% of forecasted sales. The 3-year MAP is 4.9% and the RAP is 1.9%.

FIGURE 7-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

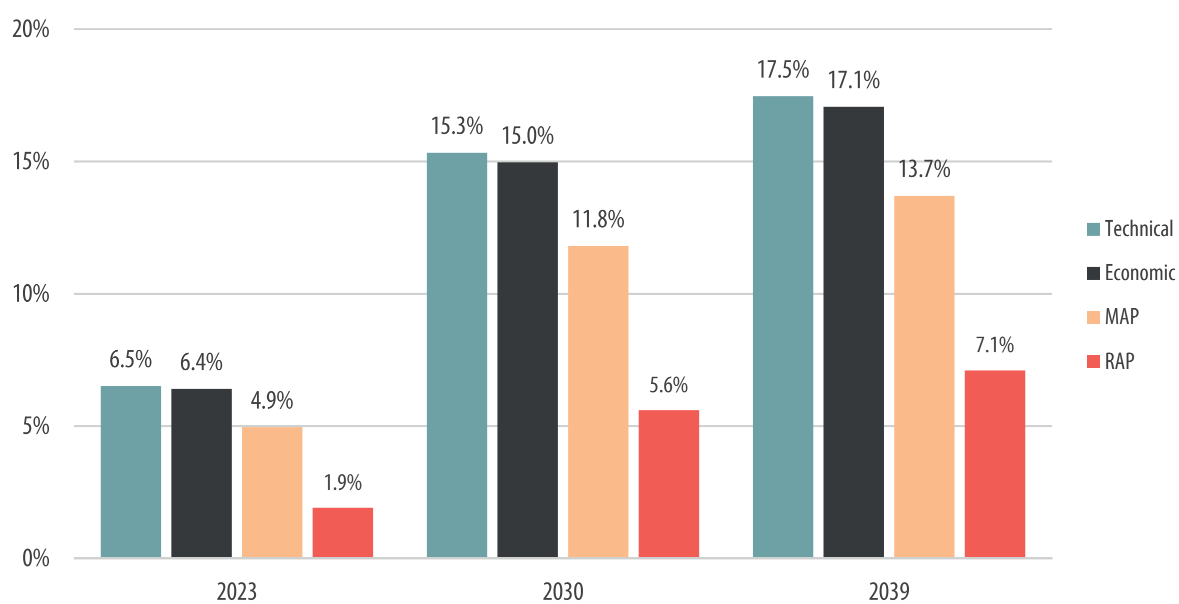


Table 7-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 1.9% after three years.

TABLE 7-2 INDUSTRIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	36,120	75,747	116,387	279,651	327,626
Economic	35,568	74,549	114,461	272,943	320,107
MAP	27,112	57,268	88,461	215,300	257,046
RAP	11,073	22,402	34,051	102,090	133,159
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218
Energy Savings (as % of Forecast)					
Technical	2.1%	4.3%	6.5%	15.3%	17.5%
Economic	2.0%	4.2%	6.4%	15.0%	17.1%
MAP	1.5%	3.2%	4.9%	11.8%	13.7%
RAP	0.6%	1.3%	1.9%	5.6%	7.1%

Table 7-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.6% to 0.7% per year over the next three years.

TABLE 7-3 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	36,120	41,420	44,609	31,108	56,280
Economic	35,568	40,774	43,880	30,622	55,999
MAP	27,112	31,400	33,941	23,031	43,434
RAP	11,073	12,149	13,001	15,566	21,577
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218
Energy Savings (as % of Forecast)					
Technical	2.1%	2.3%	2.5%	1.7%	3.0%
Economic	2.0%	2.3%	2.5%	1.7%	3.0%
MAP	1.5%	1.8%	1.9%	1.3%	2.3%
RAP	0.6%	0.7%	0.7%	0.9%	1.2%

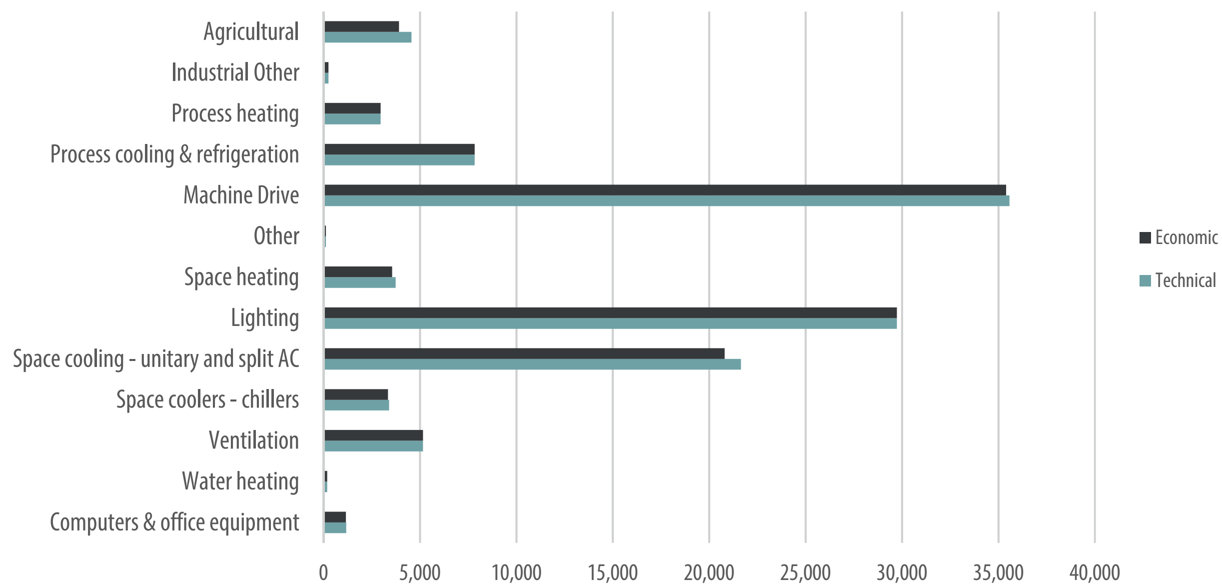
Technical & Economic Potential

Table 7-4 provides cumulative annual technical and economic potential results from 2021-2023, 2030, and 2039. Figure 7-2 shows a comparison of the technical and economic potential (6-year) by end use. Machine drive, Lighting, and Space Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE 7-4 TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	36,120	75,747	116,387	279,651	327,626
Economic	35,568	74,549	114,461	272,943	320,107
Peak Demand (MW)					
Technical	9	17	25	62	71
Economic	7	16	25	58	71

FIGURE 7-2 THREE-YEAR TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 7-3 illustrates the cumulative annual MAP results by end use across the 2021-2023 timeframe. Like technical and economic potential, Machine Drive, Lighting, and Space Cooling are the leading end uses. Ventilation and Agriculture also have significant MAP.

FIGURE 7-3 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) MAP POTENTIAL BY END-USE

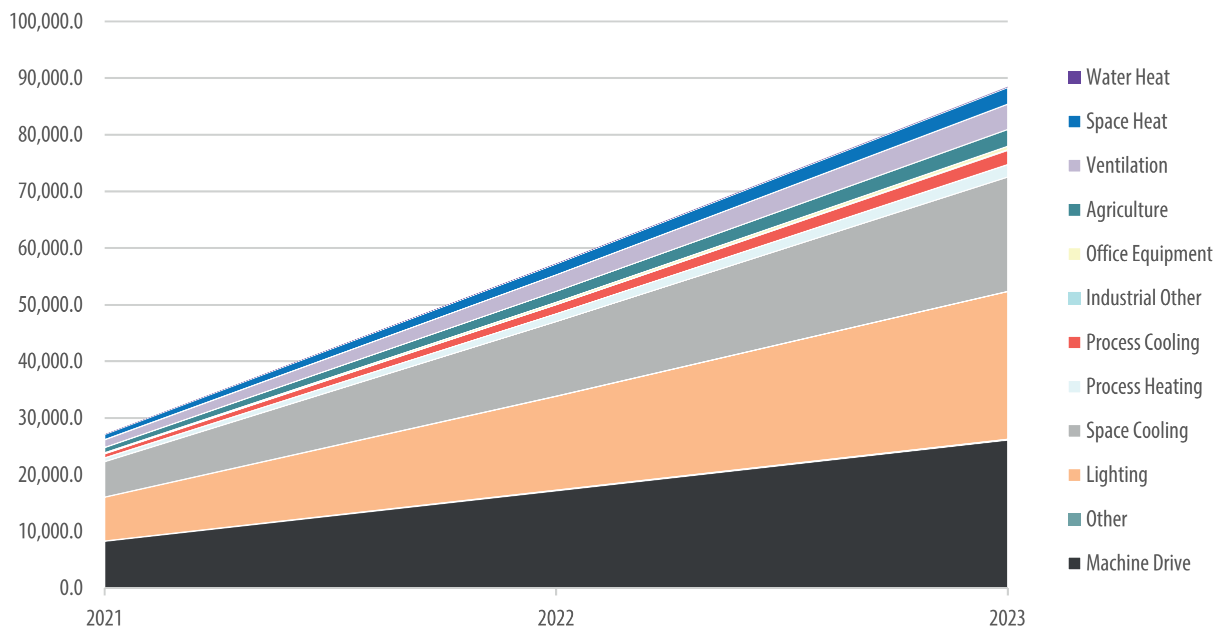


Table 7-5 provides the incremental and cumulative annual MAP across the 2021-2023 timeframe, as well as for 2030 and 2039. The incremental MAP ranges from 1.5% to 1.9% of forecasted sales across the three-year timeframe and 2.3% by 2039. Cumulative annual MAP rises to 4.95% by 2023 and 13.7% by 2039.

TABLE 7-5 INDUSTRIAL ELECTRIC MAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Computers & office equipment	166	205	239	335	351
Water heating	30	31	34	36	42
Ventilation	1,373	1,575	1,658	655	1,859
Space coolers - chillers	882	929	915	476	1,117
Space cooling - unitary and split AC	5,381	6,102	6,434	4,227	8,691
Lighting	7,747	8,993	9,775	5,452	10,733
Space heating	915	1,031	1,071	560	1,433
Other	30	37	44	40	53
Machine Drive	8,260	9,567	10,348	7,567	13,649
Process cooling & refrigeration	730	978	1,210	1,741	2,367
Process heating	639	880	1,112	1,519	2,135
Industrial Other	28	53	83	220	229
Agricultural	931	1,019	1,016	204	777
Total	27,112	31,400	33,941	23,031	43,434
% of Forecasted Sales	1.54%	1.77%	1.90%	1.26%	2.31%
Incremental Annual MW					
Total	6	7	7	5	10
% of Forecasted Demand	0.6%	0.7%	0.7%	0.5%	0.8%
Cumulative Annual MWh					

End Use	2021	2022	2023	2030	2039
Computers & office equipment	166	372	611	1,398	1,492
Water heating	30	61	95	362	464
Ventilation	1,373	2,906	4,469	9,874	11,038
Space coolers - chillers	882	1,798	2,683	5,652	7,344
Space cooling - unitary and split AC	5,381	11,362	17,525	43,824	58,430
Lighting	7,747	16,610	26,092	67,760	73,986
Space heating	915	1,925	2,948	6,684	9,165
Other	30	67	112	472	544
Machine Drive	8,260	17,185	26,133	59,275	68,772
Process cooling & refrigeration	730	1,587	2,525	7,614	11,360
Process heating	639	1,384	2,192	5,426	6,035
Industrial Other	28	64	109	487	916
Agricultural	931	1,950	2,966	6,471	7,499
Total	27,112	57,268	88,461	215,300	257,046
% of Forecasted Sales	1.54%	3.22%	4.95%	11.80%	13.70%
Cumulative Annual MW					
Total	6	12	19	46	57
% of Forecasted Demand	0.6%	1.2%	1.9%	4.3%	4.9%

Realistic Achievable Potential

Figure 7-4 illustrates the cumulative annual RAP results by end use across the 2021-2023 timeframe. Like MAP, Machine Drive, Lighting, and Space Cooling are the leading end uses. Ventilation and Agriculture also have significant RAP.

FIGURE 7-4 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) RAP POTENTIAL BY END-USE

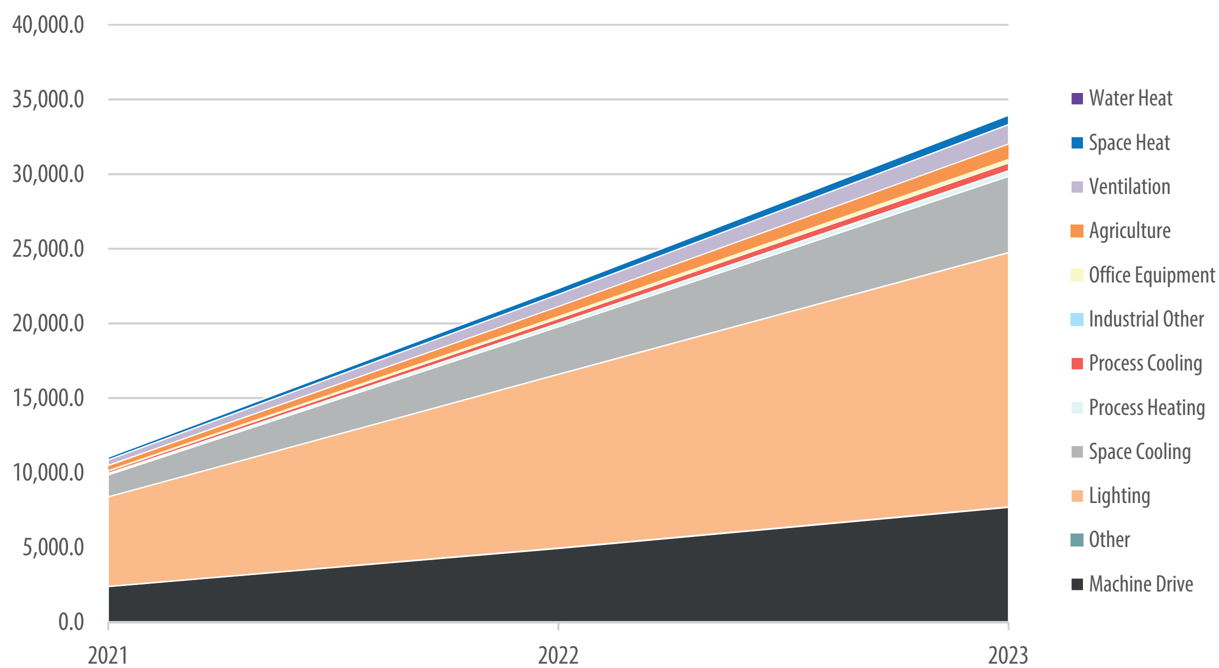


Table 7-6 provides the incremental and cumulative annual RAP across the 2021-2023 timeframe, as well as 2030 and 2039. The incremental RAP ranges from 0.6% to 0.7% of forecasted sales across the three-year timeframe and 1.2% by 2039. Cumulative annual RAP rises to 1.9% by 2023 and 7.1% by 2039.

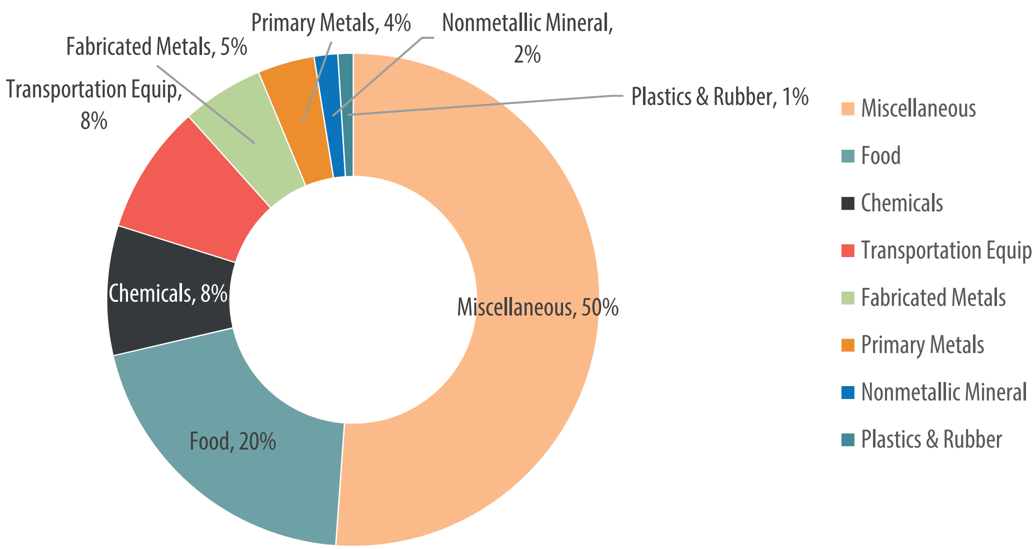
TABLE 7-6 INDUSTRIAL ELECTRIC RAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Computers & office equipment	73	89	105	191	200
Water heating	5	7	9	24	21
Ventilation	379	437	487	311	548
Space coolers - chillers	186	211	231	221	341
Space cooling - unitary and split AC	1,282	1,501	1,699	1,959	2,889
Lighting	6,001	6,306	6,497	9,228	12,481
Space heating	205	237	265	241	397
Other	7	10	13	32	24
Machine Drive	2,375	2,711	2,992	2,760	3,812
Process cooling & refrigeration	149	174	195	204	318
Process heating	108	127	142	96	169
Industrial Other	3	5	7	25	33
Agricultural	299	334	358	273	343
Total	11,073	12,149	13,001	15,566	21,577
% of Forecasted Sales	0.6%	0.7%	0.7%	0.9%	1.2%
Incremental Annual MW					
Total	2	2	2	2	3
% of Forecasted Demand	0.2%	0.2%	0.2%	0.2%	0.3%
Cumulative Annual MWh					
Computers & office equipment	73	161	266	738	845
Water heating	5	13	22	149	261
Ventilation	379	816	1,303	4,436	5,576
Space coolers - chillers	186	397	628	2,053	2,836
Space cooling - unitary and split AC	1,282	2,783	4,482	17,412	25,388
Lighting	6,001	11,642	17,033	42,602	50,791
Space heating	205	442	707	2,491	3,447
Other	7	17	30	195	326
Machine Drive	2,375	4,931	7,677	25,282	34,019
Process cooling & refrigeration	149	323	518	2,056	3,481
Process heating	108	235	377	1,334	1,718
Industrial Other	3	8	15	134	414
Agricultural	299	634	992	3,207	4,058
Total	11,073	22,402	34,051	102,090	133,159
% of Forecasted Sales	0.6%	1.3%	1.9%	5.6%	7.1%
Cumulative Annual MW					

End Use	2021	2022	2023	2030	2039
Total	2	3	4	13	19
% of Forecasted Demand	0.2%	0.3%	0.4%	1.2%	1.6%

Figure 7-5 illustrates a market segmentation of the RAP in the industrial sector by 2023. Food, chemicals, fabricated metals, nonmetallic minerals, and miscellaneous industrial are the leading market segments.

FIGURE 7-5 2025 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT[34]



RAP Benefits & Costs

Table 7-7 provides the NPV benefits and cost, as calculated using the UCT, across the 2021-2039 timeframe for the RAP scenario. Machine Drive is the most cost-effective end-use, and Facility HVAC provides the greatest NPV benefits.

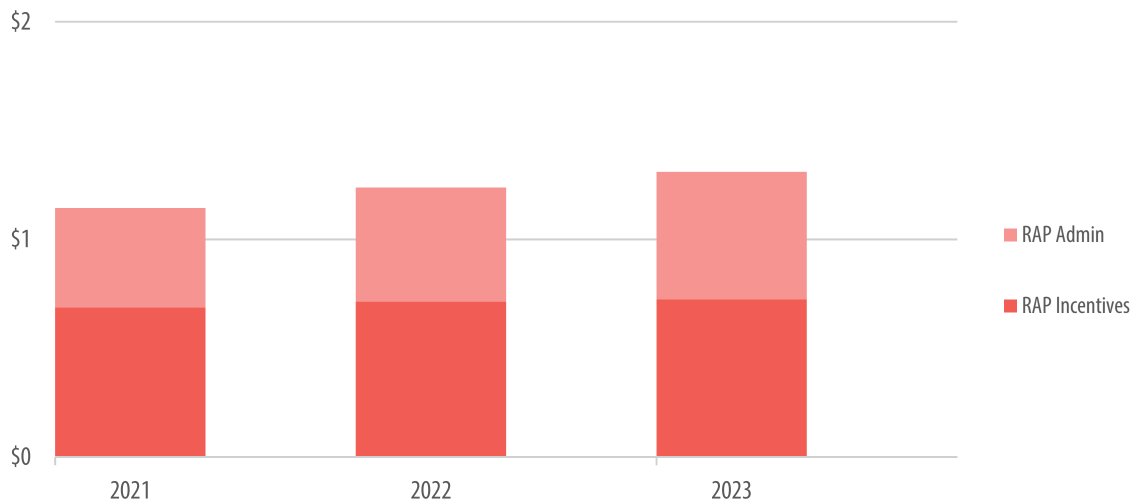
TABLE 7-7 INDUSTRIAL NPV BENEFITS AND COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Machine Drive	$24.64	$2.23	11.1
Facility HVAC	$31.46	$4.77	6.6
Facility Lighting	$29.35	$8.10	3.6
Other Facility Support	$0.85	$0.11	7.7
Process Cooling and Refrigeration	$1.97	$0.19	10.4
Process Heating	$1.05	$0.12	8.6
Other	$0.40	$0.07	5.5
Total	$89.71	$15.59	5.8

Figure 7-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The incentives rise from $0.68 million to $0.72 million, and overall budgets rise from $1.2 million to $1.3 million by 2023.

[34] "Wholesale/Retail" and "Services" industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

FIGURE 7-6 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS)



7.3 INDUSTRIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 7-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 7.2. The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column. Table 7-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers.[35] The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column.

The 19-year RAP is 7.1%, excluding opt-out customers. This figure increases to 11.8%, with opt-out customers included. The energy savings of the RAP rises from 133,159 MWh to 222,156 MWh when the opt-out customers are included in the analysis.

TABLE 7-8 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	36,120	41,420	44,609	31,108	56,280	327,626
Economic	35,568	40,774	43,880	30,622	55,999	320,107
MAP	27,112	31,400	33,941	23,031	43,434	257,046
RAP	11,073	12,149	13,001	15,566	21,577	133,159
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218	1,876,218
Energy Savings (as % of Forecast)						
Technical	2.1%	2.3%	2.5%	1.7%	3.0%	17.5%
Economic	2.0%	2.3%	2.5%	1.7%	3.0%	17.1%
MAP	1.5%	1.8%	1.9%	1.3%	2.3%	13.7%
RAP	0.6%	0.7%	0.7%	0.9%	1.2%	7.1%

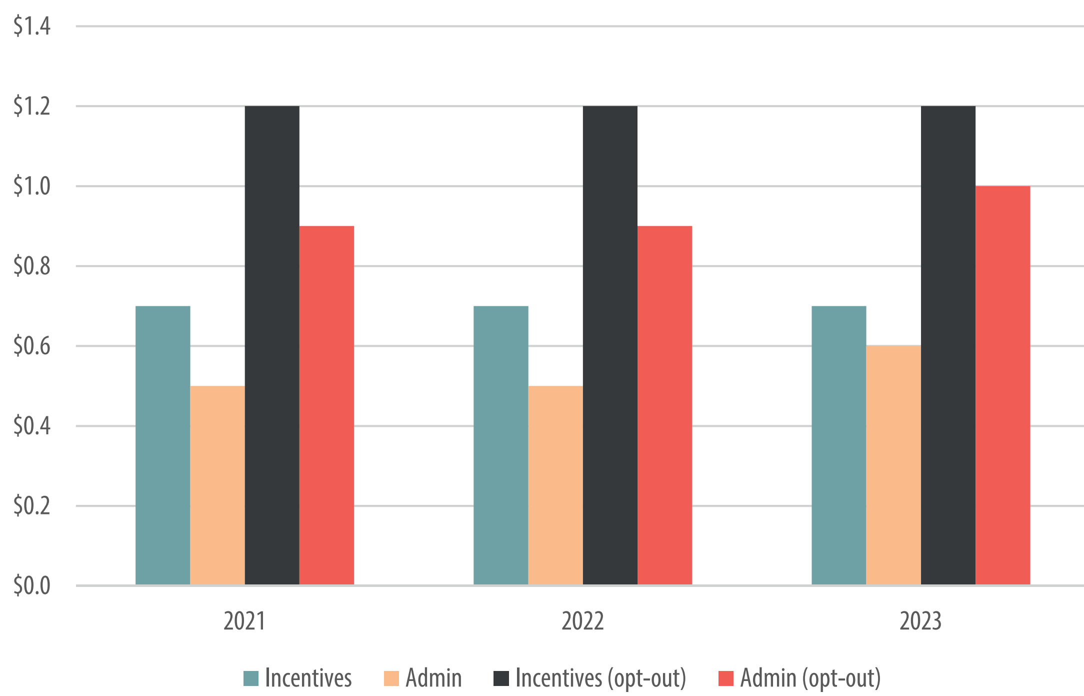
[35] Note the increase in the forecasted sales with opt-out customers included.

TABLE 7-9 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	64,747	74,252	79,969	55,786	100,910	587,157
Economic	63,759	73,093	78,664	54,916	100,404	573,695
MAP	48,586	56,273	60,829	41,292	77,855	460,561
RAP	19,181	21,114	22,647	25,391	38,043	222,156
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218	1,876,218
Energy Savings (as % of Forecast)						
Technical	3.7%	4.2%	4.5%	3.1%	5.4%	31.3%
Economic	3.6%	4.1%	4.4%	3.0%	5.4%	30.6%
MAP	2.8%	3.2%	3.4%	2.3%	4.1%	24.5%
RAP	1.1%	1.2%	1.3%	1.4%	2.0%	11.8%

Figure 7-7 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The overall budgets without opt-out customers rise from $1.2 million to $1.3 million by 2023. The budgets with opt-out customers included increase from $2.1 million to $2.2 million by 2023.

FIGURE 7-7 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS) – WITH & WITHOUT OPT-OUT CUSTOMERS



8 Demand Response Potential

This section provides the results of the MAP and RAP potential for the demand response analysis. Results are broken down by sector and program. The cost-effectiveness results and budgets for the MAP and RAP scenarios are also provided. Section 3.5 provides a description of the demand response methodology. Additional demand response results details are provided in Appendix G.

8.1 TOTAL DEMAND RESPONSE POTENTIAL

Table 8-1 and Table 8-2 show the achievable cumulative annual potential savings for the Years 1-3, 10 and 19. Achievable potential includes a participation rate to estimate the realistic number of customers that are expected to participate in each cost-effective demand response program option. These values are at the customer meter. The MAP assumes the maximum participation that would happen in the real-world, while the realistically achievable potential (RAP) discounts MAP by considering barriers to program implementation that could limit the amount of savings achieved. Asterisked programs were those that were found to be not cost-effective, providing 0 achievable potential.

TABLE 8-1 MAP SAVINGS BY PROGRAM

	Program	2021 (MW)	2022 (MW)	2023 (MW)	2030 (MW)	2039 (MW)
Residential	DLC AC - Switch	39	37	36	23	0
	DLC AC - Thermostat	15	22	29	79	151
	DLC Space Heating	4	13	27	42	45
	DLC Water Heating	9	30	64	101	108
	DLC Electric Vehicles*	0	0	0	0	0
	Total	67	102	155	245	304
Non-Residential	DLC AC - Switch*	0	0	0	0	0
	DLC AC - Thermostat	0	1	1	5	9
	DLC Space Heating	0	1	3	5	5
	DLC Water Heating	1	3	6	9	9
	Ice Storage Cooling Rate*	0	0	0	0	0
	DLC Lighting*	0	0	0	0	0
	Curtailable (Day Of)	22	54	63	68	70
	Curtailable (Day Ahead)	41	100	117	127	129
	Total (Curtailable Day Of)	24	59	73	86	92
	Total (Curtailable Day Ahead)	43	105	127	145	152
Residential & Commercial Total (Curtailable Day Of)		91	161	228	331	397
Residential & Commercial Total (Curtailable Day Ahead)		111	207	282	390	456

TABLE 8-2 RAP SAVINGS BY PROGRAM

	Program	2021 (MW)	2022 (MW)	2023 (MW)	2030 (MW)	2039 (MW)
Residential	DLC AC - Switch	39	37	36	23	0
	DLC AC - Thermostat	13	18	22	56	105
	DLC Space Heating	3	9	20	32	34
	DLC Water Heating	6	19	41	65	69
	DLC Electric Vehicles*	0	0	0	0	0
	Total	61	84	119	176	208
Non-Residential	DLC AC - Switch*	0	0	0	0	0
	DLC AC - Thermostat	0	0	1	2	4
	DLC Space Heating	0	0	1	1	1
	DLC Water Heating	0	1	3	4	4
	Ice Storage Cooling Rate*	0	0	0	0	0
	DLC Lighting*	0	0	0	0	0
	Curtailable (Day Of)	12	28	33	36	36
	Curtailable (Day Ahead)	21	52	61	66	68
	Total (Curtailable Day Of)	12	30	37	43	45
	Total (Curtailable Day Ahead)	22	54	65	73	76
Residential & Commercial Total (Curtailable Day Of)		73	114	155	218	253
Residential & Commercial Total (Curtailable Day Ahead)		83	138	184	249	284

Benefits & Costs

Table 8-3 and Table 8-4 show the MAP and RAP budget requirement (for only cost-effective programs) across the 2021-2039 timeframe that would be required to achieve the cumulative annual potential for each of the thermostat scenarios. The current and future hardware and software cost of a Demand Response Management System and the cost of non-equipment incentives are included in these budgets.

TABLE 8-3 SUMMARY OF MAP BUDGET REQUIREMENTS

	Curtailable Day Of	Curtailable Day Ahead
2021	$9,323,563	$10,637,361
2022	$17,924,342	$21,806,580
2023	$22,697,064	$28,100,280
2030	$20,810,931	$27,941,815
2039	$26,113,047	$34,781,953

TABLE 8-4 SUMMARY OF RAP BUDGET REQUIREMENTS

	Curtailable Day Of	Curtailable Day Ahead
2021	$6,148,493	$6,513,787
2022	$10,313,497	$11,400,882
2023	$14,876,821	$16,397,937
2030	$11,069,432	$13,080,488
2039	$13,753,683	$16,198,493

Table 8-5 and Table 8-6 show the MAP and RAP residential NPVs of the total benefits, costs, and savings, along with the UCT ratio for each program for the length of the study. The study period is 2021 to 2039. Two scenarios were looked at for the curtailable rate program: day of notifications and day ahead notifications. Asterisked programs were those that were found to be not cost-effective, providing 0 achievable potential.

TABLE 8-5 MAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

	Program	NPV Benefits	NPV Costs	UCT Ratio
Residential	DLC AC - Switch	$38,751,981	$11,101,437	3.49
	DLC AC - Thermostat	$118,021,492	$49,502,428	2.38
	DLC Space Heating	$59,753,588	$12,623,599	4.73
	DLC Water Heating	$143,661,898	$85,044,280	1.69
	DLC Electric Vehicles*	$4,503,262	$20,442,597	0.22
Non-Residential	DLC AC - Switch*	$65,605	$508,128	0.13
	DLC AC - Thermostat	$6,658,610	$3,890,618	1.71
	DLC Space Heating	$6,422,980	$1,980,113	3.24
	DLC Water Heating	$12,486,975	$6,641,713	1.88
	Ice Storage Cooling Rate*	$3,315,135	$23,508,572	0.14
	DLC Lighting*	$1,058,230	$4,907,195	0.22
	Curtailable (Day Of)	$136,746,749	$136,417,949	1.00
	Curtailable (Day Ahead)	$136,746,749	$136,417,949	1.00

TABLE 8-6 RAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

	Program	NPV Benefits	NPV Costs	UCT Ratio
Residential	DLC AC - Switch	$38,751,751	$11,095,762	3.49
	DLC AC - Thermostat	$84,460,054	$35,120,192	2.40
	DLC Space Heating	$44,761,294	$9,434,070	4.74
	DLC Water Heating	$91,709,001	$54,500,796	1.68
	DLC Electric Vehicles*	$2,730,501	$13,508,218	0.20
Non-Residential	DLC AC - Switch*	$65,605	$508,116	0.13
	DLC AC - Thermostat	$2,803,417	$1,999,243	1.40
	DLC Space Heating	$1,374,696	$1,136,329	1.21
	DLC Water Heating	$5,458,587	$3,404,591	1.60
	Ice Storage Cooling Rate*	$654,273	$5,632,429	0.12
	DLC Lighting*	$227,344	$1,851,493	0.12
	Curtailable (Day Of)	$38,575,756	$20,719,844	1.86
	Curtailable (Day Ahead)	$71,567,702	$38,444,116	1.86

VOLUME II

Appendices

prepared for

AUGUST 2019

APPENDIX A. DSM Market Potential Study Sources

This appendix catalogs many of the data sources used in this study, grouped by major activity. In general, GDS attempted to utilize IPL-specific data, where available. When IPL-specific data was not available or reliable, GDS leveraged secondary data from nearby or regional sources.

A.1 MARKET RESEARCH

Market research studies were used to understand home and business characteristics and equipment stock characteristics. The GDS Team conducted primary data collection activities in the residential, commercial, and industrial sectors to gather information on residential dwellings and nonresidential facilities. In addition, the primary data collection collected additional equipment and efficiency characteristics. The MPS also relied on available secondary research to supplement the primary data collection activities.

- ***IPL Residential Self-Report Survey:*** GDS collected data on 231 residential dwellings from a mail/web survey. A total of 30 questions were included in the survey, seeking to collect information about ownership of electric appliances; the type, fuel, and age of heating, ventilation, and air conditioning (HVAC) and water heating equipment in the home; the types of energy improvements that may have been made to the home, and demographic information.
- ***IPL Residential On-Site Survey:*** GDS collected data on 68 residential dwellings via an on-site survey from trained field staff. The purpose of the site-visits was to collect more detailed end-use and housing characteristics that are difficult to collect in a self-report survey. On-site data collection focused on accurate inventory counts of residential lighting and make/model information of key electric equipment and appliances.
- ***IPL Residential Willingness to Participate Survey:*** GDS collected willingness to participate data on 4 major residential end-uses given varying incentive levels. GDS collected responses from 875 residential consumers via an on-line/e-mail survey.
- ***IPL Commercial Primary Market Research:*** A detailed end use survey was then completed by technicians to collect detailed research data and WTP information from site representatives. GDS collected data in 68 commercial facilities to better understand electric equipment saturation and efficiency characteristics.
- ***IPL Industrial Primary Market Research***: A total of 40 site visits were conducted for the industrial sector, in which WTP and detailed end-use information was collected. Survey data was leveraged to determine the remaining factors for several end-uses, including motors, interior and exterior lighting and fixture measures.
- ***EIA/DOE Industrial Data:*** Including the DOE Industrial Electric Motor Systems Market Opportunities Report, the DOE Assessment of the Market for Compressed Air Efficiency Services, and EIA Industrial Demand Module of the National Energy Modeling System.
- ***US American Community Survey:*** Public Use Microdata Survey data was used to estimate the percent of low-income households (using annual household income and number of people per household) in the IPL service territory.
- ***Energy Star Shipment Data:*** Energy Star shipment data provides a detailed historical estimate of the percent of shipped equipment/appliances that meet ENERGY STAR standards. Over the long-term, this serves as a proxy for the percent of the market that could be considered energy efficient.

A.2 FORECAST CALIBRATION

The forecast calibration effort was used to create a detailed segmentation of IPL's load forecast and ensure that estimated savings would not overstate future potential. IPL supplied GDS with the most recent load forecast and data collected via primary research activities was used to further refine the existing load forecast.

- *IPL Load Forecast:* The 2016 Long-Term Electric Energy and Demand load forecast consists of the most recent ITRON load forecast completed for IPL for 2016-2036. Future years were escalated by a compound average annual growth rate.
- *IPL Commercial and Industrial Customer Database:* The 2017 historical commercial and industrial data utilized rate codes and existing NAICS code to segment historical sales by commercial building type and/or industry type.
- *InfoUSA*: GDS utilized a third-party dataset that provided additional commercial and industrial business information, including NAICS codes, to supplement the building/industry types codes supplied by IPL.
- *EIA Commercial Building Energy Consumption Survey:* GDS updated the ITRON load forecast to utilize more recent information for the East North-Central region from the EIA 2012 CBECS survey.
- *EIA Manufacturing Energy Consumption Survey:* GDS used the 2014 study to further refine the industrial load forecast by end-use.
- *BEopt:* GDS developed residential building prototypes from the market research effort to develop detailed consumption estimates by end-use and calibrated these models to IPL's residential load forecasts.

A.3 ENERGY EFFICIENCY MEASURE DATA

The energy efficiency measure analysis developed per unit savings, cost, and useful life assumptions for each energy efficiency measure in the residential, commercial, and industrial sectors. Preference was given to IPL-specific evaluated savings and/or deemed savings/algorithms in the Indiana TRM.

- *2016 & 2017 IPL EM&V Report (Cadmus):* For the development of savings estimates of measures already offered by IPL, GDS either used the estimates from the most recent evaluation reports or used the evaluation methodology to develop forward looking savings projections.
- *Indiana TRM v2.2:* In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- *IPL 2018 & 2019 DSM Portfolio Summary:* Historical incentive estimates and in some cases, incremental measure costs, were based on the IPL DSM Portfolio Summary.
- *Other TRMs:* In some cases, TRM's or deemed measure databases from other states were more applicable than the IN TRM due to more currently available estimates and the more appropriate use of updated federal standards. The Illinois TRM and the Michigan Energy Measures Database were the primary non-Indiana TRMs used.
- *Other Secondary Sources:* In some cases, following the source hierarchy listed above was not enough to develop savings estimates. In these cases, GDS leveraged other secondary research documents such as ACEEE emerging technology reports.

A.4 DEMAND RESPONSE MEASURE ANALYSIS

The DR analysis developed per unit savings, cost, and useful life assumptions for select demand response programs.

- *IPL programs / 2012 FERC DR Survey:* Demand reductions were based on load reductions found in IPL's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.
- *Indiana TRM v2.2:* In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- *Comverge:* Comverge provided an estimate of the load control switch cost and useful life.
- *Nest and Ecobee:* Nest and Ecobee product data was used to develop equipment cost assumptions.
- *Other DR Potential Studies:* In the absence of the previous data, GDS used other demand response potential studies completed for other utilities.

A.5 AVOIDED COST/ECONOMIC ANALYSIS

Avoided costs and related economic assumptions were used to assess cost-effectiveness. In addition, historical incentive levels were tied to willingness-to-participate (WTP) research to assess long-term market adoption in the achievable potential scenario.

- *Electric Avoided Costs:* Avoided cost values for electric energy, electric capacity, and avoided transmission and distribution (T&D) were provided by IPL as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.
- *Other Economic Assumptions:* Includes the discount rate, inflation rate, line loss assumptions and reserve margin requirement. All economic assumptions were provided by IPL and consistent with economic modeling assumptions used for other utility planning efforts.
- *2019 DSM Portfolio Summary:* 2021 direct measure/program non-incentive costs were calibrated to recent projected levels using the 2019 Portfolio Summary
- *Primary Market Research:* As noted above, the GDS Team completed IPL-specific research in the residential, commercial, and industrial sectors regarding customer willingness-to-purchase and install energy efficient equipment at various incentive levels. This IPL-specific customer data was used to determine long-term adoption rates by end-use for the MAP and RAP achievable potential scenarios.

APPENDIX B. Residential Market Potential Study Measure Detail

available in electronic format

APPENDIX C. Commercial Market Potential Study Measure Detail

available in electronic format

APPENDIX D. Industrial Market Potential Study Measure Detail

available in electronic format

APPENDIX E. DSM Market Potential Study Commercial Opt-Out Results

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector, with opt-out customers included. The cost-effectiveness results and budgets for the RAP scenario are also provided.

E.1 SCOPE OF MEASURES & END USES ANALYZED

There were 237 total unique electric measures included in the analysis. Table E-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE E-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Space Heating	31
Cooling	75
Ventilation	11
Water Heating	17
Lighting	32
Cooking	8
Refrigeration	29
Office Equipment	14
Behavioral	4
Other	16

E.2 COMMERCIAL ELECTRIC POTENTIAL

Figure E-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 19-year technical potential is 46.0% of forecasted sales, and the economic potential is 40.0% of forecasted sales. The 19-year MAP is 35.2% and the RAP is 17.7%.

FIGURE E-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

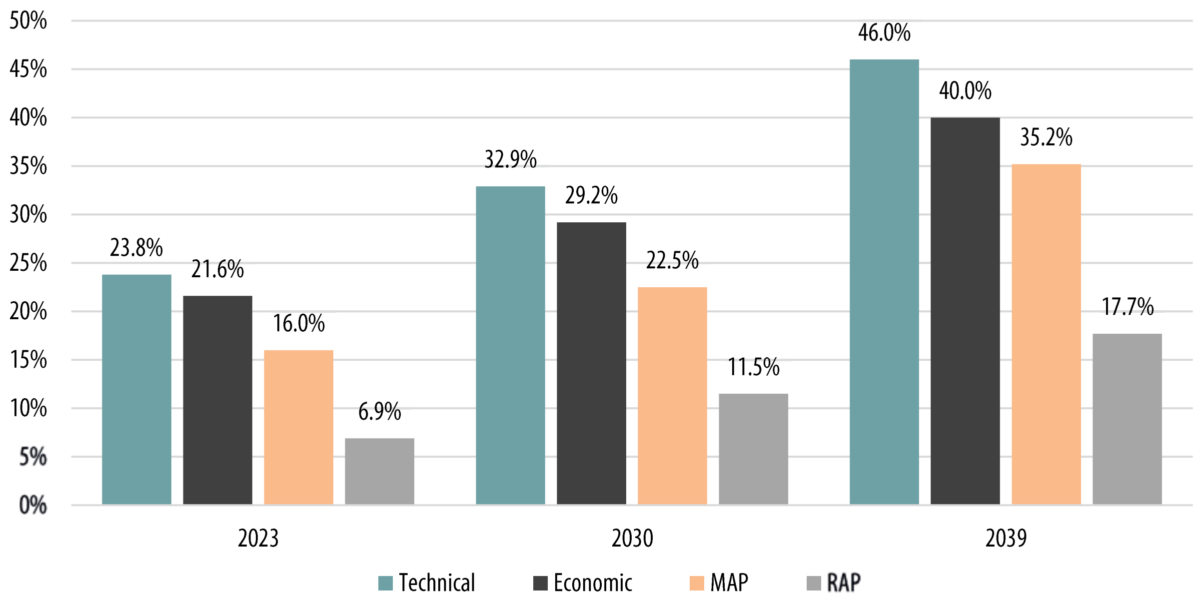


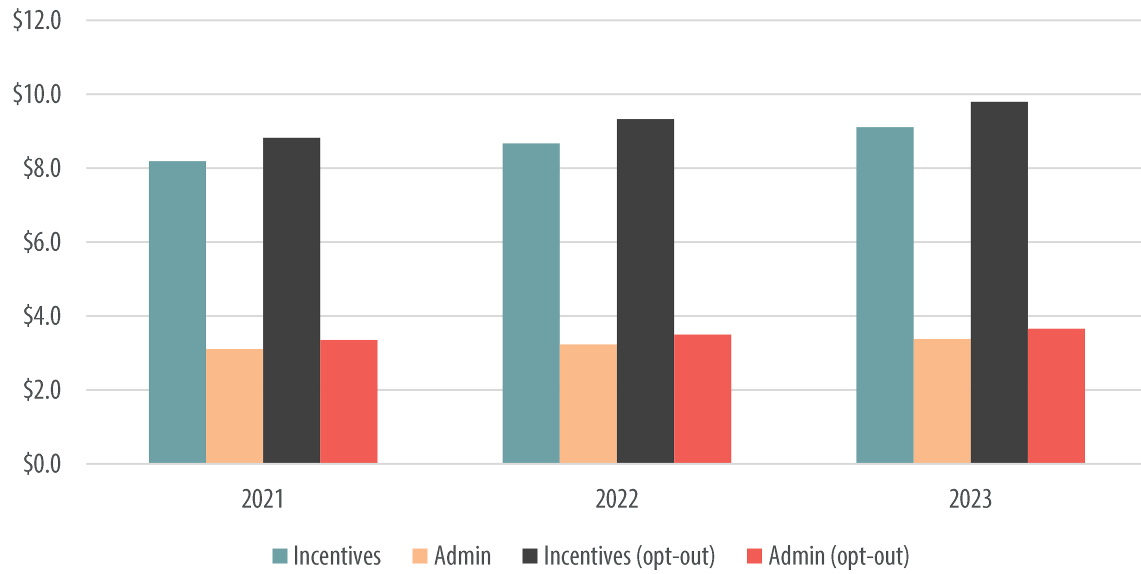
Table E-2 provides the incremental annual technical, economic, MAP and RAP energy savings, as well as 2039 cumulative total energy savings in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP is steady at 1.6% per year over the next three years, and 2.7% by 2039, with a cumulative total of 19.3% by 2039.

TABLE E-2 INCREMENTAL ANNUAL ENERGY SAVINGS & 2039 CUMULATIVE TOTAL ENERGY SAVINGS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	319,987	361,894	393,318	355,466	483,353	3,271,659
Economic	282,388	316,313	340,107	311,127	422,935	2,845,631
MAP	217,686	257,080	286,837	309,561	396,535	2,503,275
RAP	105,544	105,937	106,745	109,342	190,102	1,368,560
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737	7,107,737
Energy Savings (as % of Forecast)						
Technical	4.8%	5.4%	5.8%	5.1%	6.8%	46.0%
Economic	4.2%	4.7%	5.0%	4.5%	6.0%	40.0%
MAP	3.3%	3.8%	4.2%	4.5%	5.6%	35.2%
RAP	1.6%	1.6%	1.6%	1.6%	2.7%	19.3%

Figure F-2 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2023 timeframe. The incentives rise from $8.9 million to $9.7 million over the next three years, and overall budgets rise from $12.2 million to $13.3 million by 2023 for the Opt-outs included scenario.

FIGURE E-2 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS) – WITH & WITHOUT OPT-OUT CUSTOMERS



APPENDIX F. DSM Market Potential Study Industrial Opt-Out Results

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector, with opt-out customers included. The cost-effectiveness results and budgets for the RAP scenario are also provided.

F.1 SCOPE OF MEASURES & END USES ANALYZED

There were 130 total unique electric measures included in the analysis. Table F-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE F-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Computers & Office Equipment	6
Water Heating	6
Ventilation	7
Space Cooling	25
Space Heating	16
Lighting	16
Other	7
Machine Drive	21
Process Heating and Cooling	10
Agriculture	16

F.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure F-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 19-year technical potential is 31.3% of forecasted sales, and the economic potential is 30.6% of forecasted sales. The 19-year MAP is 24.5% and the RAP is 11.8%.

FIGURE F-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

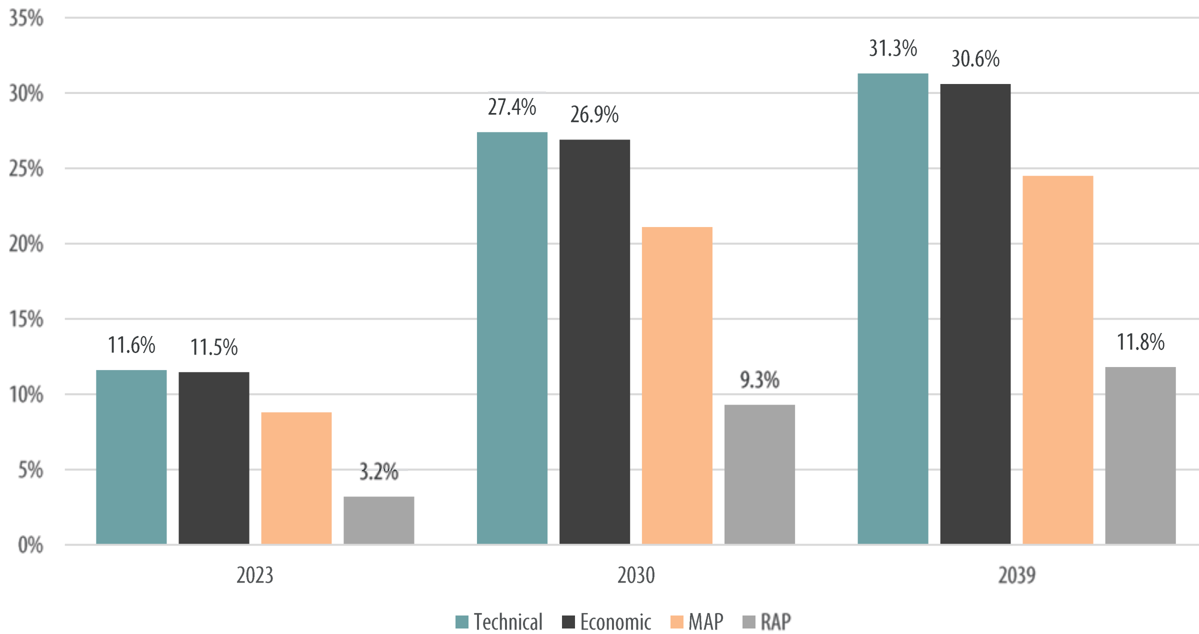


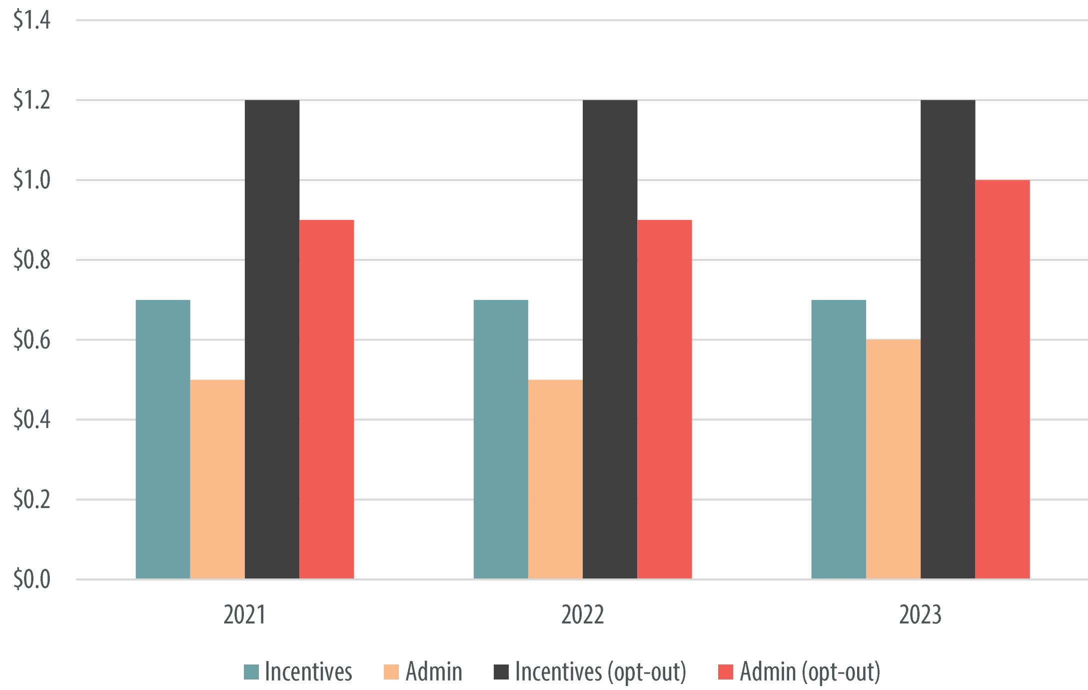
Table F-2 provides the incremental annual technical, economic, MAP and RAP energy savings, as well as 2039 cumulative total energy savings in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.1% to 1.4% per year over the next three years, and 2.0% by 2039, with a cumulative total of 11.8% by 2039.

TABLE F-2 INCREMENTAL ANNUAL ENERGY SAVINGS & 2039 CUMULATIVE TOTAL ENERGY SAVINGS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	64,747	74,252	79,969	55,786	100,910	587,157
Economic	63,759	73,093	78,664	54,916	100,404	573,695
MAP	48,586	56,273	60,829	41,292	77,855	460,561
RAP	19,181	21,114	22,647	25,391	38,043	222,156
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218	1,876,218
Energy Savings (as % of Forecast)						
Technical	3.7%	4.2%	4.5%	3.1%	5.4%	31.3%
Economic	3.6%	4.1%	4.4%	3.0%	5.4%	30.6%
MAP	2.8%	3.2%	3.4%	2.3%	4.1%	24.5%
RAP	1.1%	1.2%	1.3%	1.4%	2.0%	11.8%

Figure F-2 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2023 timeframe. The incentives are steady at $1.2 million, and overall budgets rise from $2.1 million to $2.2 million by 2023 for the Opt-outs included scenario.

FIGURE F-2 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS) – WITH & WITHOUT OPT-OUT CUSTOMERS



APPENDIX G. Demand Response Methodology

G.1 DEMAND RESPONSE PROGRAM OPTIONS

Table G-1 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study.

TABLE G-1 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

DR Program Option	Program Description	Eligible Markets
DLC AC (Switch)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). GDS looked at both the one-way communicating Cannon switches and two-way communicating L+G switches. Both switch options were assumed to be phased out as customers switch to thermostats over time.	Residential and Non-Residential Customers
DLC AC (Smart Thermostat)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load. GDS looked at the three options IPL currently has: a customer is given a free thermostat to participate along with an annual incentive, a customer is given a rebate through the marketplace or a storefront along with an annual incentive, or the customer brings an existing thermostat and is only given an annual incentive.	Residential and Non-Residential Customers
DLC Space Heating	The system operator can remotely lower the HVAC's thermostat set point during winter peak load conditions, lowering the heating load. This program is an add-on to the DLC AC Thermostat program. Only participants in the AC Thermostat program would be allowed to participate in the Space Heating program.	Residential and Non-Residential Customers
DLC Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and Non-Residential Customers
Ice Storage Cooling Rate	The use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods.	Large Non-Residential Customers
DLC Lighting	Part of the lighting load is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Non-Residential Customers
Curtailable Rate (Day Of)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers

DR Program Option	Program Description	Eligible Markets
Curtailable Rate (Day Ahead)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers

G.2 DEMAND RESPONSE POTENTIAL ASSESSMENT APPROACH

The analysis for this study was conducted using the GDS DR Model. The GDS DR Model is an Excel spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following two basic equations that can be chosen to be the model user.

ACHIEVABLE POTENTIAL. The cost-effective demand response potential that can practically be attained in a real-world program delivery scenario, if a certain level of market penetration can be attained are included in this scenario. Achievable potential considers real-world barriers to convincing customers to participate in cost-effective demand response programs. Achievable savings potential savings is a subset of economic potential.

If the model user chooses to base the estimated potential demand reduction on a per customer CP load reduction value, then:

$$\textit{Achievable DR Potential} = \textit{Potentially Eligible Customers} \times \textit{Eligible Customer Participation Rate} \times \textit{CP kW Load Reduction Per Participant}$$

The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[1] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[2] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits. Appendix A contains a table from the report summarizing the energy efficiency cost and benefits including in all five major benefit cost tests.

The GDS Demand Response Model determines the estimated savings for each demand response program by performing an extensive review of all benefits and cost associated with each program. GDS developed the model such that the value of future programs could be determined and to help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, CP kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between IPL departments interested in the deployment of demand response resources.

For this study, the Utility Cost Test (UCT) test was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as

[1] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[2] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

Achievable potential is broken into maximum and realistic achievable potential in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 19-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 19-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

This potential study evaluated DR potential for two achievable potential scenarios:

1. *Curtailable Day of Scenario*
2. *Curtailable Day Ahead Scenario*

G.3 AVOIDED COSTS & OTHER ECONOMIC ASSUMPTIONS

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by IPL. Avoided electric generation capacity refers to the demand response program benefit resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. For power suppliers, this shift in the timing of energy use can produce benefits from either the production of energy from lower cost resources or the purchase of energy at a lower rate. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

The discount rate used in this study is 6.24%. A peak demand line loss factor of 5.28% and a reserve margin of 7.9 % (for firm load reduction such as direct load control) were also applied to demand reductions at the customer meter. These values were provided by IPL.

The useful life of a smart thermostat is assumed to be 12 years[3]. Load control switches have a useful life of 12 years[4]. This life was used for all direct load control measures in this study.

The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control

[3] 2018 DSM Portfolio Summary, Measure DATA tab
[4] 2018 DSM Portfolio Summary, Measure DATA tab

up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.055[5]. The average number of non-residential thermostats per buildings was assumed to be 1.808[6].

G.4 CUSTOMER PARTICIPATION

The assumed level of customer participation for each demand response program option is a key driver of achievable demand response potential estimates. Customer participation rates reflect the total number of eligible customers that are likely to participate in a demand response program. An eligible customer is defined as a customer that is eligible to participate in a demand response program. For DLC programs, eligibility is determined by whether a customer has the end use equipment that will be controlled[7]. The eligible customers for each program is shown in Table G-2 and Table G-3.

TABLE G-2 ELIGIBLE RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION

DR Program Option	Saturation	Source / Description
DLC AC (Switch)	93.8% of residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC AC (Thermostat)	93.8% of residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC Space Heating	42.7% of residential customers	GDS IPL Saturation Study - Saturation of Space Heating
DLC Water Heaters	47.6% of residential customers	GDS IPL Saturation Study - Saturation of Electric Water Heaters
DLC Room AC	24.2% of residential customers	GDS IPL Saturation Study - Saturation of Room AC

TABLE G-3 ELIGIBLE NON-RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION

DR Program Option	Saturation	Source / Description
DLC AC (Switch)	84% of non-residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC AC (Thermostat)	81.5% of non-residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC Space Heating	38.37% of non-residential customers	CBECS Table B26 - Saturation of Space Heating in the East North Central Region
DLC Water Heaters	54.41% of non-residential customers	GDS IPL Saturation Study - Saturation of Electric Water Heaters
Ice Storage Cooling Rate	62% of non-residential customers	CBECS Table B40 - Saturation of Chillers in the East North Central Region

[5] Calculated number of central AC units per number of homes from IPL saturation study.
[6] Calculated number of central AC units per number of buildings from IPL saturation study.

DR Program Option	Saturation	Source / Description
DLC Lighting	15.1% of non-residential customers	GDS IPL Saturation Study - Saturation of T12 Lighting
Curtailable Rate (Day Of)	100% of non-residential customers	DSA/GDS Assumption
Curtailable Rate (Day Ahead)	100% of non-residential customers	DSA/GDS Assumption

G.4.1 Existing Demand Response Programs

IPL has offered their Direct Load Control program for many years. This program offers incentives to members who enroll central AC using switches (residential and non-residential) or smart thermostats (residential only). However, IPL plans to transition the DLC AC switch program to be controlled with smart thermostats instead. GDS assumed that the DLC AC switch program would be ended by phased out by the end of the 19-year study and these customers would be transitioned to using thermostats to participate in the program. A cost-effective analysis was still run for these programs, with the assumption that no new switches would be installed and participation would steadily decline until 2039.

G.4.2 Hierarchy

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. However, in this study, none of the programs interacted with each other. All residential programs considered were direct load control. Only small non-residential customers were eligible for direct load control programs, and large non-residential customers were eligible for the Ice Storage Cooling Rate and Curtailable Rate. Therefore, a hierarchy was not necessary for these programs.

G.4.3 Participation Rates

The assumed "steady state" participation rates used in this potential study and the sources upon which each assumption is based are shown in Table G-5 for residential and non-residential customers, respectively. The steady state participation rate represents the enrollment rate once the fully achievable participation has been reached. Participation rates are expressed as a percentage of eligible customers. Program participation and impacts (demand reductions) are assumed to begin in 2020. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Table G-5.

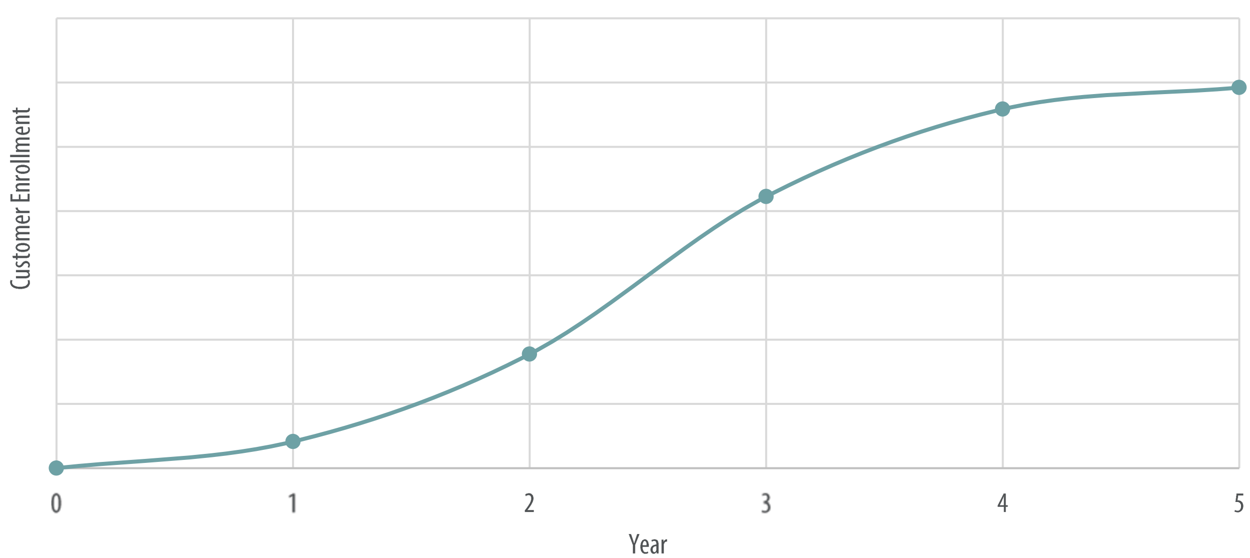
TABLE G-5 STEADY STATE PARTICIPATION RATES FOR DEMAND RESPONSE PROGRAM OPTIONS

DR Program Options	MAP Steady State Participation Rate	RAP Steady State Participation Rate	Source
RESIDENTIAL			
DLC AC (Switch)	0% *(existing program declining to 0 participants)*	0% *(existing program declining to 0 participants*)	IPL
DLC AC (Thermostat)	36%	25%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Space Heating	20%	15%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	36%	23%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Room AC	31%	20%	GDS Survey of 20 utilities (75th percentile for MAP and 50th percentile for RAP).
DLC Electric Vehicle Charging	94%	57%	MAP: Used TOU with enabling technology take rate as most electric cars are equipped with a built-in technology that allows the vehicle to charge at specific times. (Opt-Out); RAP: Plug-in Electric Vehicle and Infrastructure Analysis September 2015, Prepared for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy by Idaho National Lab. (Opt-In)
NON-RESIDENTIAL			
DLC AC (Switch)	0% *(existing program declining to 0 participants)*	0% *(existing program declining to 0 participants)*	IPL
DLC AC (Thermostat)	19%	8%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.

DR Program Options	MAP Steady State Participation Rate	RAP Steady State Participation Rate	Source
DLC Space Heating	14%	3%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	16%	7%	FERC 2012 DR Survey Data (75th percentile for MAP, 50th percentile for RAP)
Ice Storage Cooling Rate	0.81	0.16	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Lighting	14%	3%	Used Direct Load - Air Conditioning take rate from PGE Brattle Group Study. FERC 2012 DR survey data contained only one program targeting lighting with a take rate of .6%. A general search for such programs by GDS also produced no useful results.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure G-1). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

FIGURE G-1 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE



G.5 LOAD REDUCTION ASSUMPTIONS

Table G-6 presents the residential and non-residential per participant CP demand reduction impact assumptions for each demand response program option at the customer meter. Demand reductions were based on load reductions found in IPL's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.

TABLE G-6 PER PARTICIPANT CP DEMAND REDUCTION ASSUMPTIONS

DR Program Options	Per Participant CP Demand Reduction	Source
RESIDENTIAL		
DLC AC (Switch)	0.78 for one way Cannon switch, 0.58 kW for two way L+G switch	IPL
DLC AC (Thermostat)	0.7 kW	IPL
DLC Space Heating	1 kW	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	0.4 kW Summer, 0.8 kW Winter	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Room AC	0.04 kW	Cost-effectiveness of CECONY Demand Response Programs , 2013
DLC Electric Vehicle Charging	0.28 kW	Xcel Energy pilot program on EV control
NON-RESIDENTIAL		
DLC AC (Switch)	0.31 kW	IPL
DLC AC (Thermostat)	0.2759	Used ratio of switch to thermostat for residential and applied to C&I switch reduction
DLC Space Heating	1.5 kW	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	0.6 kW Summer, 1.2 kW Winter	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Ice Storage Cooling Rate	19.4 kW	MISO DR, EE, DG Potential Study: Supplemental Program Slides. Value for Local Resource Zone 5

DR Program Options	Per Participant CP Demand Reduction	Source
DLC Lighting	8.94% of coincident peak load	Business Energy Advisor/E Source, Strategies for C&I Demand Response; LIGHTING CALIFORNIA'S FUTURE: COST-EFFECTIVE DEMAND RESPONSE, Prepared For: California Energy Commission By: NEV Electronics, LLC, California Lighting Technology Center, 2011; Lighting Controls Association, Lighting Control and Demand Response, By Craig DiLouie, on May 20, 2014; Demonstration and Evaluation of lighting technologies and Applications, Lighting Research Center, Field Test Issue 6, 2011; What is the relation between energy consumption savings and peak load savings and how can this affect future energy conservation requirements? - Study conducted by the City of Toronto.

G.6 PROGRAM COSTS

One-time program development costs of $400,000[8] were included in the first year of the analysis for new programs. This cost was split between similar programs that would be comparable to start up. No program development costs are assumed for programs that already exist. It was assumed that there would be a cost of $50[9] per new participant for marketing. Marketing costs are assumed to be 33.3% higher for MAP. There was assumed to be an annual administrative cost of $30,000 per program. All program costs were escalated each year by the general rate of inflation assumed for this study. Table G-7 shows the equipment cost assumptions.

TABLE G-7 EQUIPMENT COST ASSUMPTIONS

Device	Cost	Applicable DR Programs	Source
One-way communicating load control switch	$70 equipment + $150 for installation	DLC programs controlled by switches	Comverge
Two-way communicating load control switch using Wi-Fi	$95 + $150 for installation	DLC programs controlled by switches	Comverge
Smart controllable thermostat (such as Nest or Ecobee)	$150 for thermostat + $150 installation	DLC AC Thermostat (Free thermostat option)	IPL
Smart controllable thermostat (such as Nest or Ecobee)	$50 one time incentive to join program + $50 rebate if buying through the program ($0 rebate if joining with existing thermostat)	DLC AC Thermostat (BYOT option)	IPL

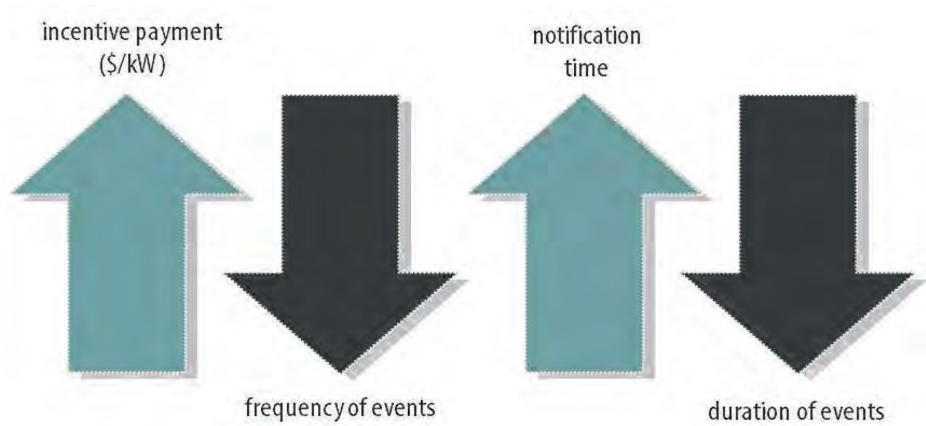
[8] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011
[9] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

G.7 LOAD CURTAILMENT PROGRAM

G.7.1 Modeling Demand Response Potential

One of the most prominent forms of demand response among non-residential customers is load curtailment agreements where the utility, or an aggregator on the utility's behalf, enters financial agreements with businesses to reduce load when dispatched. Load curtailment potential is driven by a few key factors – incentive payments, the frequency of events, the duration of events, and the level of notification participants are given about pending events. The directional effect these factors have on DR potential is shown in Figure G-2.

FIGURE G-2 DRIVERS OF DR POTENTIAL



Several different estimates of DR potential can be produced by turning levers related to these four inputs. Rather than producing several different scenario-based estimates, the research team made several simplifying assumptions regarding program design. Components of program design include how many DR events will be called, how long the DR events will last, how far in advance participants are notified of the upcoming DR event, and the incentive payment participants receive (the amount and how it is distributed – annually, monthly, per event, etc.). Table G-8 describes some of the program design inputs/assumptions the research team used in estimating DR potential. Other relevant inputs – such as the peak load forecast and avoided costs – are described in the table as well.

TABLE G-7 SUMMARY OF INPUT ASSUMPTIONS FOR LOAD CURTAILMENT MODELING

Input Variable	Sources, Notes, and Assumptions
Peak Load Forecast	The peak load forecast used in developing potential estimates was provided by IPL. The forecast, created in October of 2017, runs through 2027. For the remaining years in the study horizon, the peak forecast was escalated by a rate identical to the observed escalation rate (from 2018-2027) in IPL's peak forecast.
	The summer peak load forecast was disaggregated into peak load forecasts by sector using peak load shares provided by IPL. Load curtailment potential was examined separately for the Small C&I and Large C&I classes and customers who opt out of energy efficiency were not excluded from the eligible peak load.
Avoided Cost of Generation Capacity ($/kW-year)	Avoided costs of generation capacity were provided by IPL.

Input Variable	Sources, Notes, and Assumptions
Avoided Transmission and Distribution Capacity ($/kW-year)	We assumed a starting point of $10/kW-year for each transmission and distribution ($20/kW-year T&D total) in 2020. These values were escalated by 2% annually.
Program Design (# of events, event duration, notification level)	Previous Indiana research suggests relatively short DR events would serve the region better than relatively long events, as summer peaks are concentrated between 2:00 PM and 6:00 PM.[10] Thus, our estimates of potential assume a four-hour event duration. We're also assuming that there will be an average of seven summer events will be called (28 total event hours for the summer).
	Results were calculated for both a "day-ahead" notification design and a "day-of" notification design. "Day-ahead" notification assumes a ~24-hour notice, and "day-of" notification assumes a 3-to-6-hour notice. Potential is higher under the "day-ahead" notification design, as this provides participants greater opportunities to shift energy-intensive tasks to off-peak periods.
Participant Incentive	For C&I DR, our team modeled the incentive as a reservation payment. This is an annual payment provided to the participant. In exchange, the participant agrees to curtail load when events are dispatched. For realistic achievable potential, our approach to setting incentive levels involved optimizing net benefits. To determine the optimal incentive level, the research team performed a simulation where the critical input was the incentive level and the critical output was the net benefit of the DR program. The simulation leveraged several of the inputs discussed herein. The results indicated that the optimal incentive level in 2020 is $21/kW-year.
	For maximum achievable potential, the goal of the simulation was not to optimize net benefits. Instead, we used the simulation to determine the greatest possible incentive level that would produce a cost-effective program (e.g, largest incentive value such that the Utility Cost Test ratio does not fall below 1). The results indicated an incentive level of $39/kW-year should be used in estimating maximum achievable potential for summer 2020.
	In both cases, the incentive level is escalated annually at a rate that matches the growth rate of avoided costs. This growth rate is largely driven by the generation component (avoided cost of generation capacity was provided by IPL).
Price Elasticity of Demand Coefficients	The price elasticity of demand coefficients used in this research were derived from two years of DR performance data for C&I DR participants in Pennsylvania. Information about sector (small/large), incentive levels, and the peak load share of each participant was used in the development of the elasticity coefficients. Traditional elasticity formulas were used.

Leveraging the inputs discussed above, our team developed potential estimates via a "top-down" approach. At a high level, the approach entails disaggregating the peak load forecast into peak load forecasts by sector, and then combining these forecasts with the price elasticity of demand coefficients to estimate potential. Price elasticity of demand can be thought of as the percentage change in the

[10] Potential for Peak Demand Reduction in Indiana. Prepared for Indiana AEE by Demand Side Analytics, 2018.

quantity of electricity demanded divided by the percentage change in the price (including an incentive) of DR:

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price}$$

Rearranging the terms in the elasticity equation yields the following:

$$\%\ change\ in\ Quantity = (Elasticity) \times (\%\ change\ in\ Price)$$

Note that “% change in Quantity” can also be expressed as:

$$\%\ change\ in\ Quantity = \frac{(Summer\ peak - \ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

Combing these two “% change in Quantity” equations yields:

$$(Elasticity) \times (\%\ change\ in\ Price) = \frac{(Summer\ peak - \ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

By making assumptions about price elasticity, the percentage change in price (related to electric retail rates and the incentive level), and the summer peak load, it is possible to estimate how much DR potential exists in each market segment by solving for “DR potential”. It is important to note that the estimates of C&I DR potential discussed in this section are not incremental to existing IPL C&I DR programs. That is, we are not estimating how much DR potential exists beyond the existing IPL C&I DR resources. It is also important to note that this top-down methodology produces estimates of DR potential at the system-level (inclusive of line losses).

APPENDIX H. 2020 DSM Plan Refresh

In addition to completing the IPL Market Potential Study for the 2021-2039 planning period, the GDS team also completed an updated analysis for IPL's 2020 DSM plan (the "2020 Refresh"). 2020 is the 3rd and final year of the 3-year DSM plan approved in Cause No. 44945. In the Settlement Agreement (approved in Cause No. 44945), IPL agreed to work with the stakeholders to try to identify additional cost-effective energy savings in 2020. GDS, with review and input from IPL's stakeholders, completed an analysis to compare the 2020 "refresh" potential with the current approved plan. Among other factors considered, the analysis sought to determine if any recent changes to existing codes and standards have reduced the expected savings potential in 2020, or whether new technologies have entered the market that could cost effectively result in additional savings opportunities.[1]

The potential 2020 energy savings, as identified by GDS, for the residential and business customers are in the two sections below. These savings estimates are projections and do not take into consideration market barriers and program delivery constraints. As prescribed in the IPL Settlement Agreement, IPL and the other members of the IPL Oversight Board conducted a technical workshop on May 2nd with the implementation vendor CLEAResult; the EM&V consultant Cadmus and the MPS consultant GDS to review the 2020 MPS modeling results and determine program modifications that should be considered for the 2020 DSM Portfolio.

The modeling results, shown in Table 1 and Table 2below, served as the starting point for this collaborative exercise. Prior to the technical workshop, IPL requested that CLEAResult review the savings estimates developed by GDS to determine, based on their extensive experience in program delivery, which opportunities had promise and might be reasonable to pursue. Cadmus also reviewed the modeling results and provided their input from an EM&V perspective.

At the workshop, the IPL OSB members reviewed and discussed the findings by Cadmus and CLEAResult. Some DSM program additions suggested by GDS were considered impractical in the market at this time. Other program suggestions will be given additional consideration.

The next step in the 2020 Refresh process is for IPL to work with the implementation vendor CLEAResult to determine the cost to deliver the program modifications that were recommended in the refresh and discussed during the technical workshop. Once cost effectiveness is determined, the cost effective program modifications will then be compiled into a proposed 2020 Portfolio summary for review and approval by the IPL OSB. The proposed 2020 Portfolio summary should be complete by early Q4.

[1] GDS planning assumptions are current and are consistent with either the IN TRM or recent EM&V results. Thus, measure level savings may vary from those used to develop IPL's 2019 Portfolio summary or in plan development for IPL's filing in Cause No. 44945.

As previously indicated, these savings estimates are projections and do not take into consideration market barriers and program delivery constraints. As agreed to in the Settlement Agreement in Cause No. 44945, IPL will rely on input from CLEAResult and Cadmus to determine which revisions are practical and achievable in the market and to finalize the plan for 2020. Ultimately, any changes to the 2020 DSM Portfolio will require approval of the IPL OSB.

2020 Residential Energy Savings Potential

Residential results were developed using the GDS Market Potential Study models, and historical IPL program net-to-gross ("NTG") ratios. The NTG ratios were applied to the gross savings at the measure level. Table H-1 shows projected 2020 Gross and Net savings potential for each residential IPL program, as well as program budgets and cost per net kWh saved. Estimated residential gross energy savings in 2020 are 107,854 MWh, while total 2020 net savings are projected to be 88,710 MWh. Net peak demand savings are projected to be 15.1 MW. The total estimated 2020 residential sector program budget is nearly $22.2 million, which yields an average acquisition cost of $0.222 per kWh of projected savings. The Peer Comparison Reports program yields the greatest amount of projected net savings in 2020 at the lowest acquisition cost on a first-year basis. The Lighting & Appliances program provides the second highest projection of net savings at the second lowest acquisition cost on a first-year basis. The Whole Home program has the third greatest amount of projected net savings, but at an estimated first-year acquisition cost higher than all other programs except the Income Qualified Weatherization program. Though the budget and savings for the IQW program are higher than the 2019 planning estimates, the 2020 projections were calibrated to consider the 2019 estimates.

TABLE H-1 RESIDENTIAL 2020 ENERGY SAVINGS POTENTIAL

	Gross MWh	Net MWh	Net MW	Budget	$/Net kWh
Residential Program					
Lighting & Appliances	36,494	21,632	2.41	$4,347,002	$0.201
Not Currently Offered	2,651	2,651	0.93	$933,648	$0.352
Emerging Technology	2,111	2,111	0.46	$765,436	$0.363
Income Qualified Weatherization	2,830	2,830	0.51	$2,426,981	$0.858
Appliance Recycling	3,494	2,458	0.43	$739,223	$0.301
Whole Home	15,214	11,968	3.57	$8,409,143	$0.703
Peer Comparison Reports	35,069	35,069	5.57	$1,499,575	$0.043
School Kits	4,239	4,239	0.69	$1,006,168	$0.237
Multifamily Direct Install	4,890	4,890	0.55	$1,842,039	$0.377
Online Kits	863	863	0.00	$194,782	$0.226
Total	**107,854**	**88,710**	**15.10**	**$22,163,997**	**$0.250**

2020 Commercial & Industrial Energy Savings Potential

Commercial and Industrial results were developed using the GDS Market Potential Study models, and historical IPL program NTG ratios were applied to the gross savings at the measure level, based on whether measures were described as Prescriptive, Custom, Emerging technologies, or Small Business Direct Install.

Table H-2 shows projected 2020 Gross and Net savings potential by IPL C&I program, as well as program budgets and cost per net kWh saved. The total C&I 2020 gross savings potential is projected to be 97,915 MWh, while total 2020 net savings potential is projected to be 74,776 MWh. Net peak demand savings are projected to be nearly 13.4 MW. The total 2020 C&I budget is projected to be nearly $11.9 million, resulting in an average first-year cost per net KWh saved of $0.159 per kWh. The Prescriptive program is projected to have net 2020 savings of 51,457 MWh and a budget of just over $7.6 million, the Custom program is projected to have net savings of 17,790 MWh and a budget of just over $2.9 million, the Small Business Direct Install program ("SBDI") is projected to have net savings of 4,171 MWh and a budget of just over $1.0 million, and Emerging Technologies are projected to have 2020 net savings of 1,357 MWh and an associated budget of nearly $178,000.

TABLE H-2 – COMMERCIAL & INDUSTRIAL 2020 ENERGY SAVINGS POTENTIAL

	Gross MWh	Net MWh	Net MW	Budget	$/Net kWh
C&I Program					
Prescriptive	71,088	51,457	9.36	$7,665,863	$0.149
Custom	21,078	17,790	3.13	$2,943,701	$0.165
SBDI	4,391	4,171	0.63	$1,077,131	$0.258
Emerging	1,358	1,357	0.25	$177,609	$0.131
Total	**97,915**	**74,776**	**13.37**	**$11,864,304**	**$0.159**

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Thorpe Energy Services

prepared for

INDIANAPOLIS POWER & LIGHT COMPANY

2018 Demand Side Management Market Potential Study

August 13, 2019

FINAL REPORT

prepared by
GDS ASSOCIATES INC
DEMAND SIDE ANALYTICS
THORPE ENERGY SERVICES

Cause No. 45591

Figure 1 | Annual Energy (TWh) for Reference Case Portfolios 1a – 5a

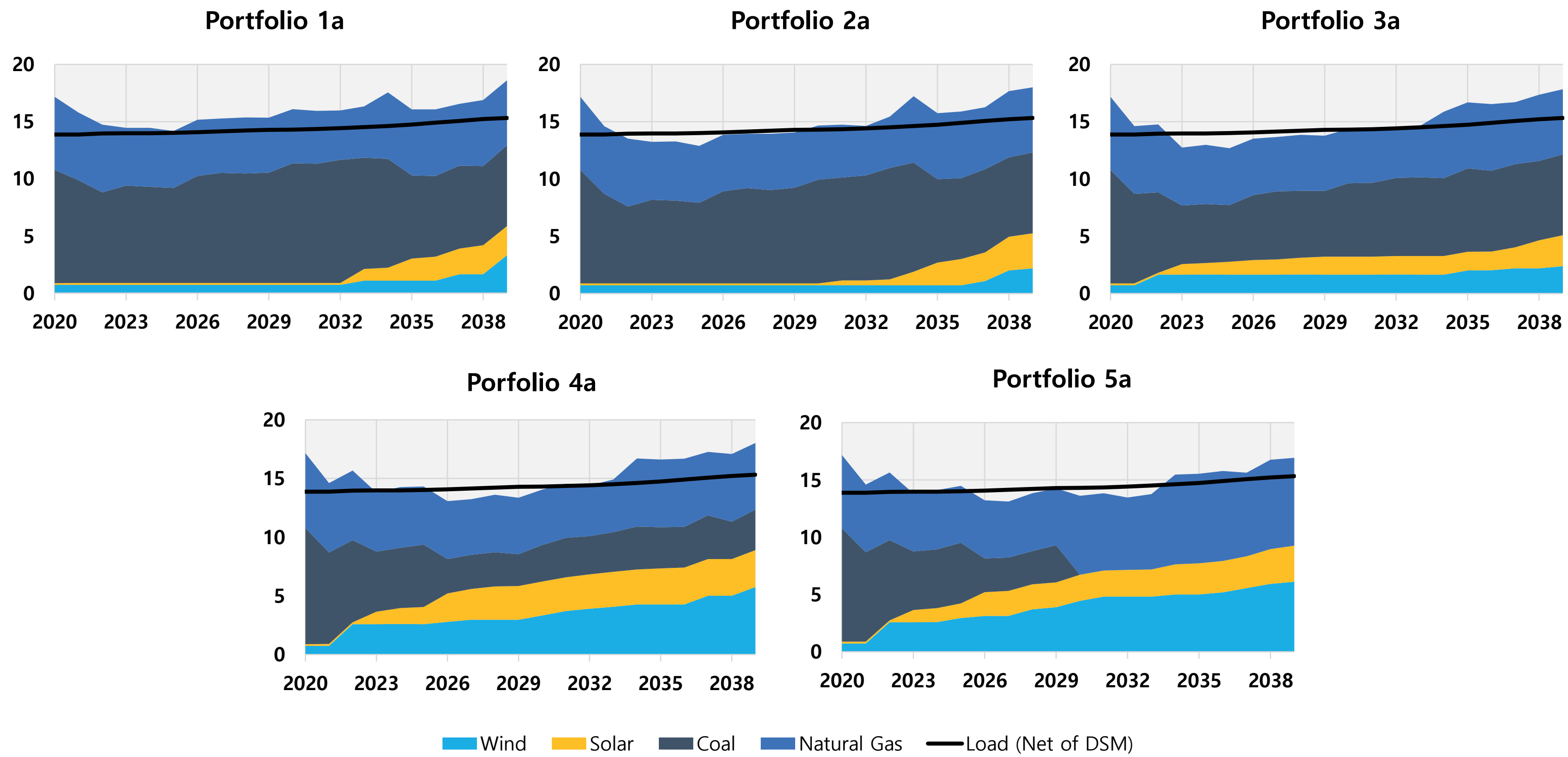


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Figure 2 | Annual Energy (TWh) for Scenario A Portfolios 1a – 5a

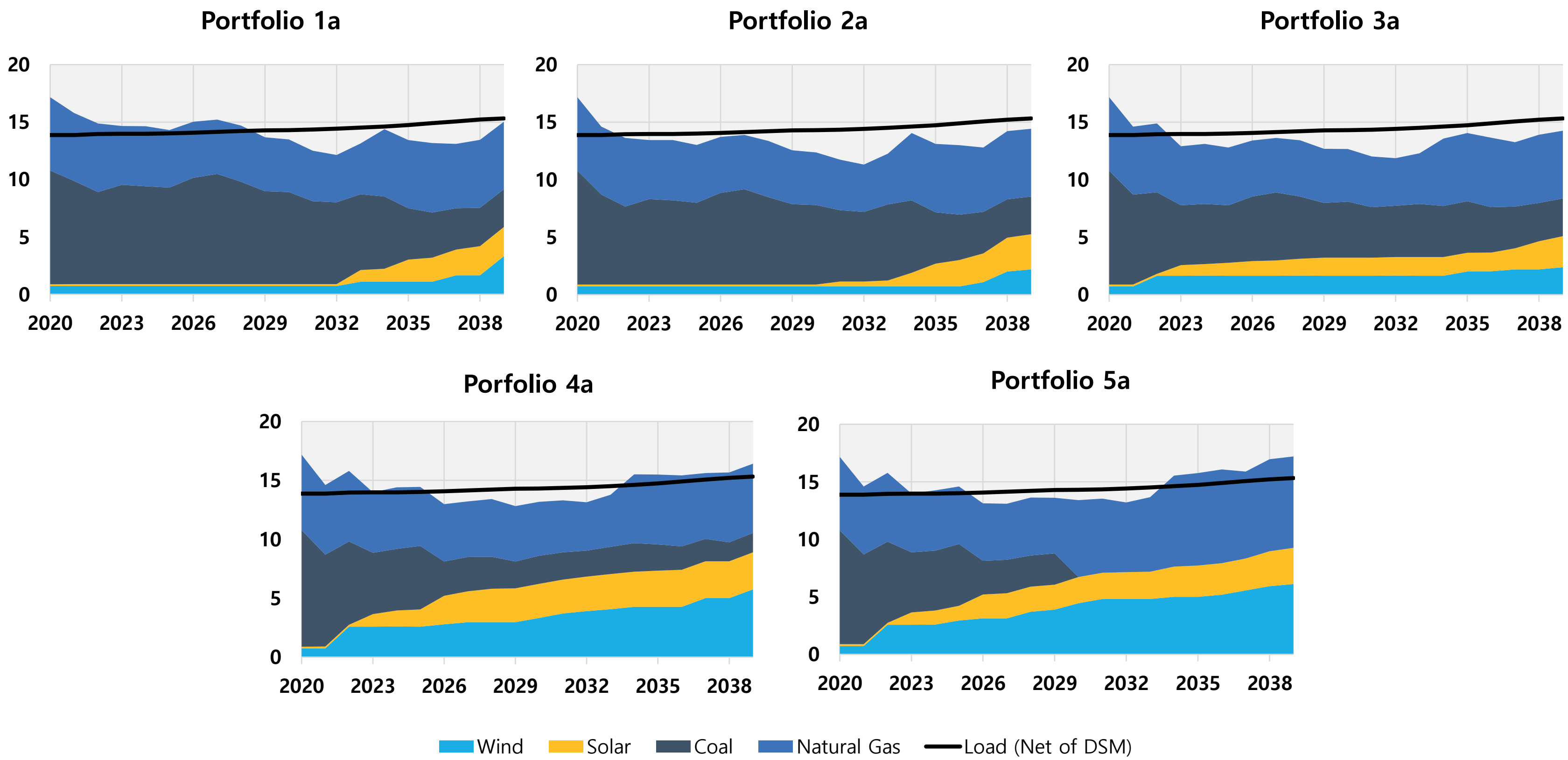


Figure 3 | Annual Energy (TWh) for Scenario B Portfolios 1a – 5a

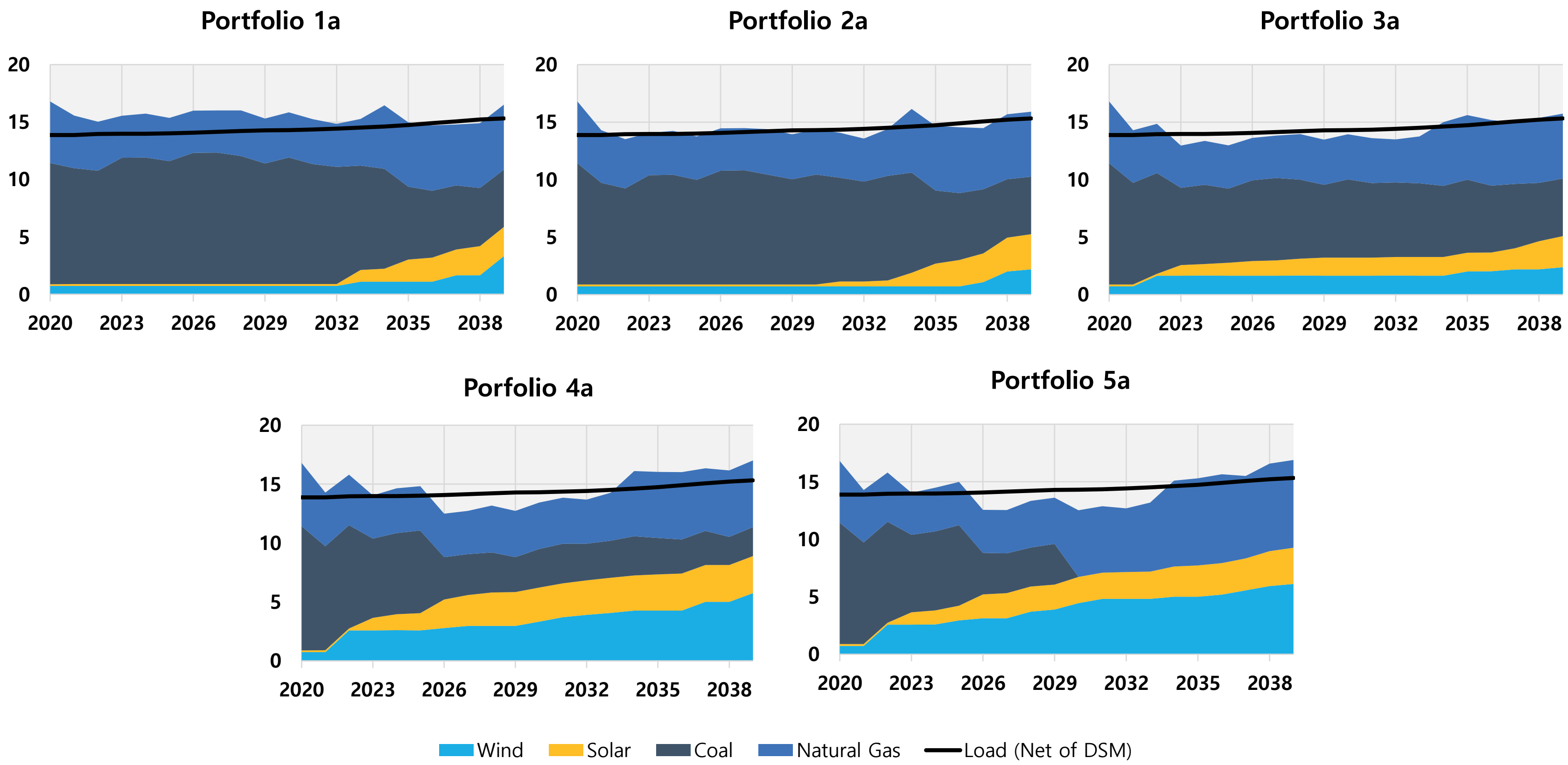


Figure 4 | Annual Energy (TWh) for Scenario C Portfolios 1a – 5a

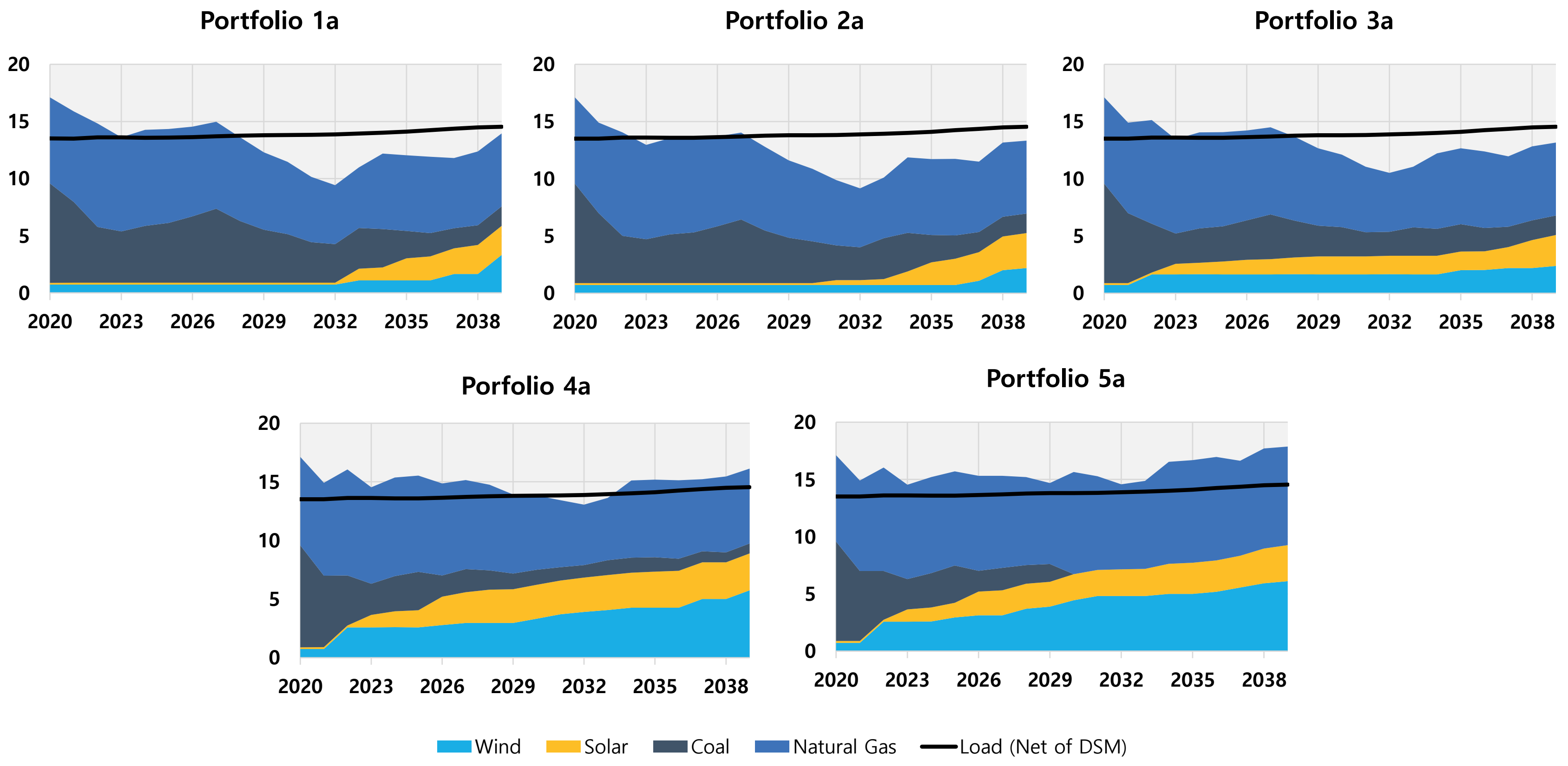


Figure 5 | Annual Energy (TWh) for Scenario D Portfolios 1a – 5a

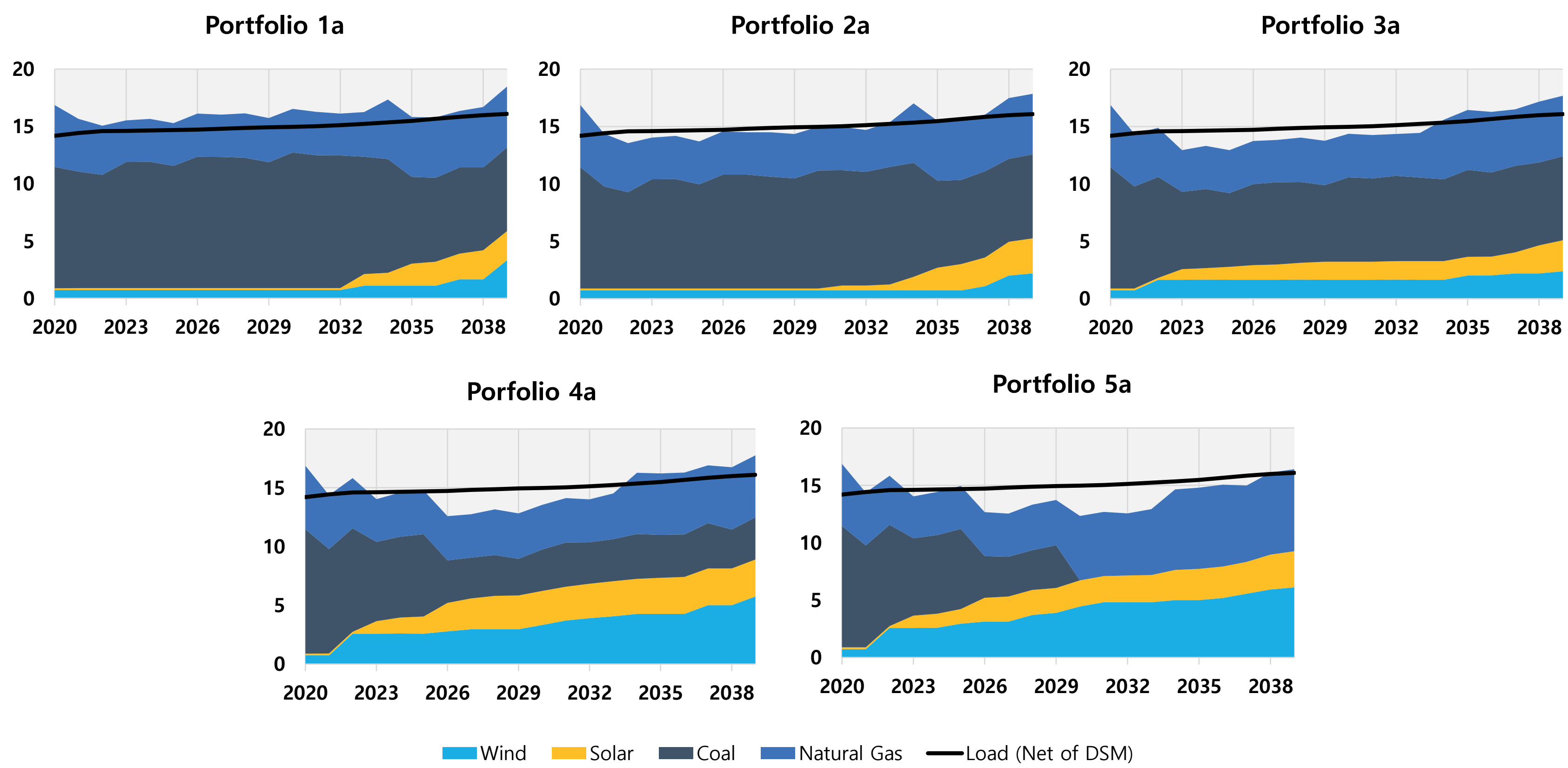


Figure 6 | Annual Energy (TWh) for Reference Case Portfolios 1b – 5b

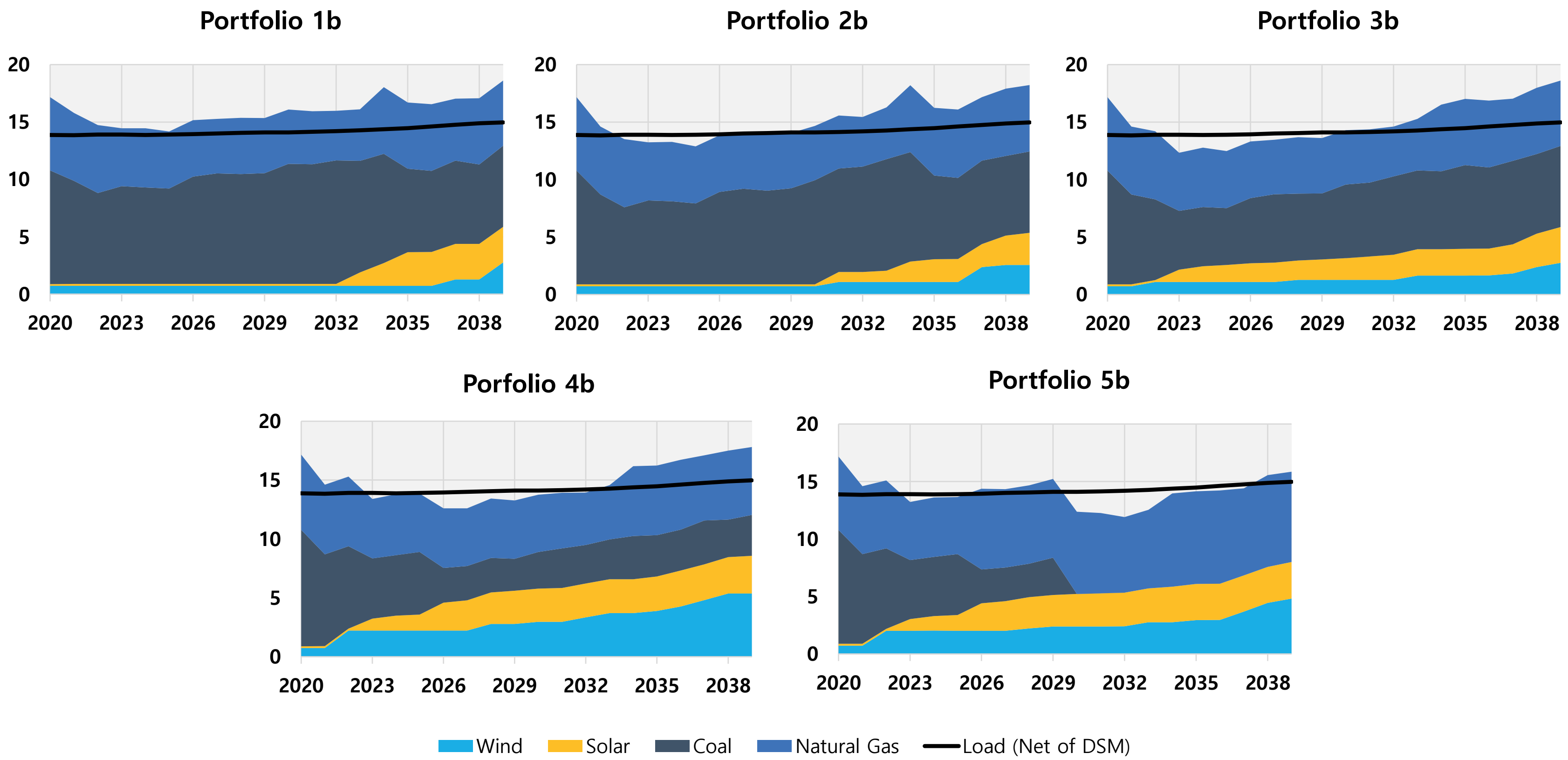


Figure 7 | Annual Energy (TWh) for Scenario A Portfolios 1b – 5b

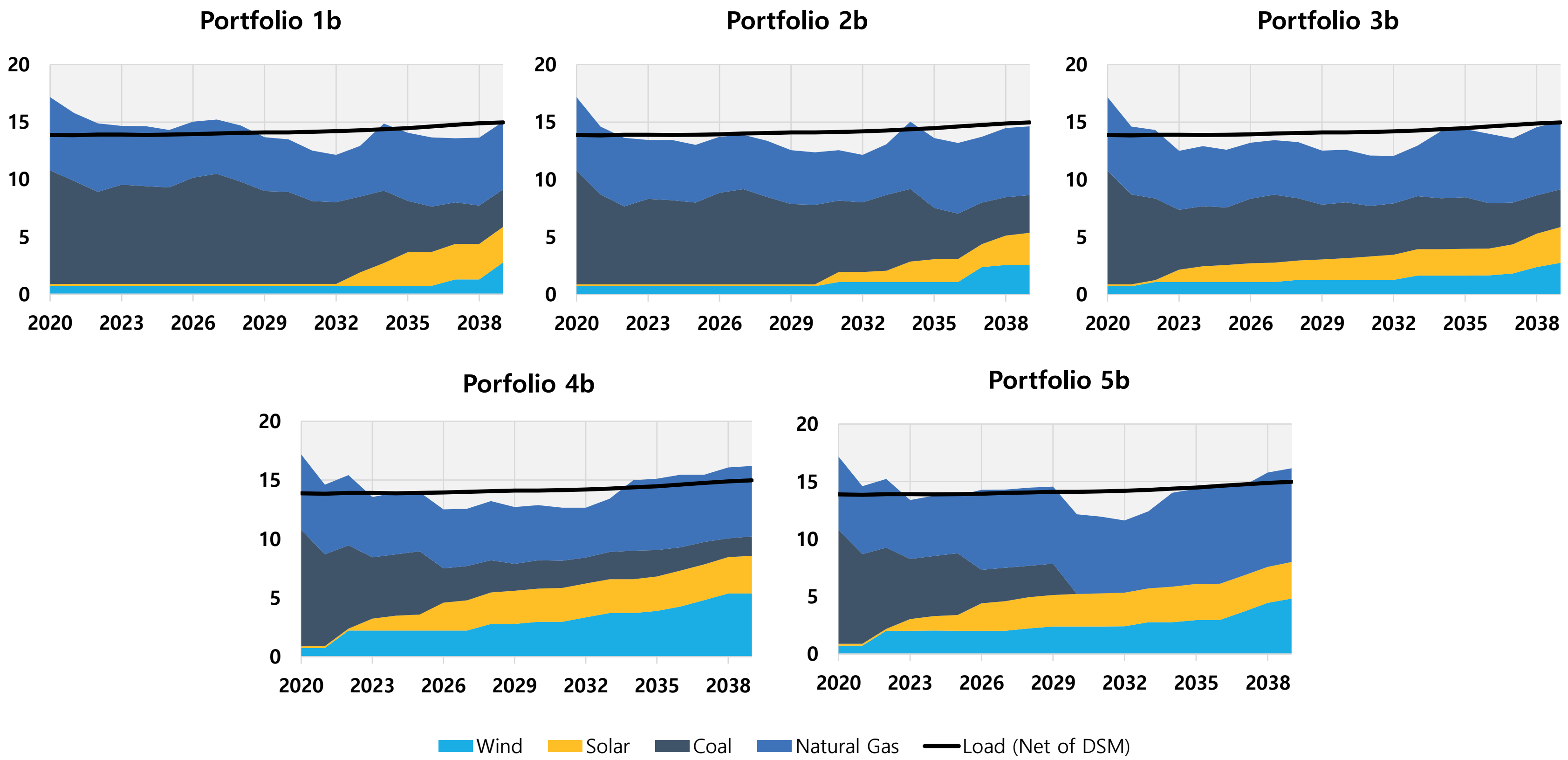


Figure 8 | Annual Energy (TWh) for Scenario B Portfolios 1b – 5b

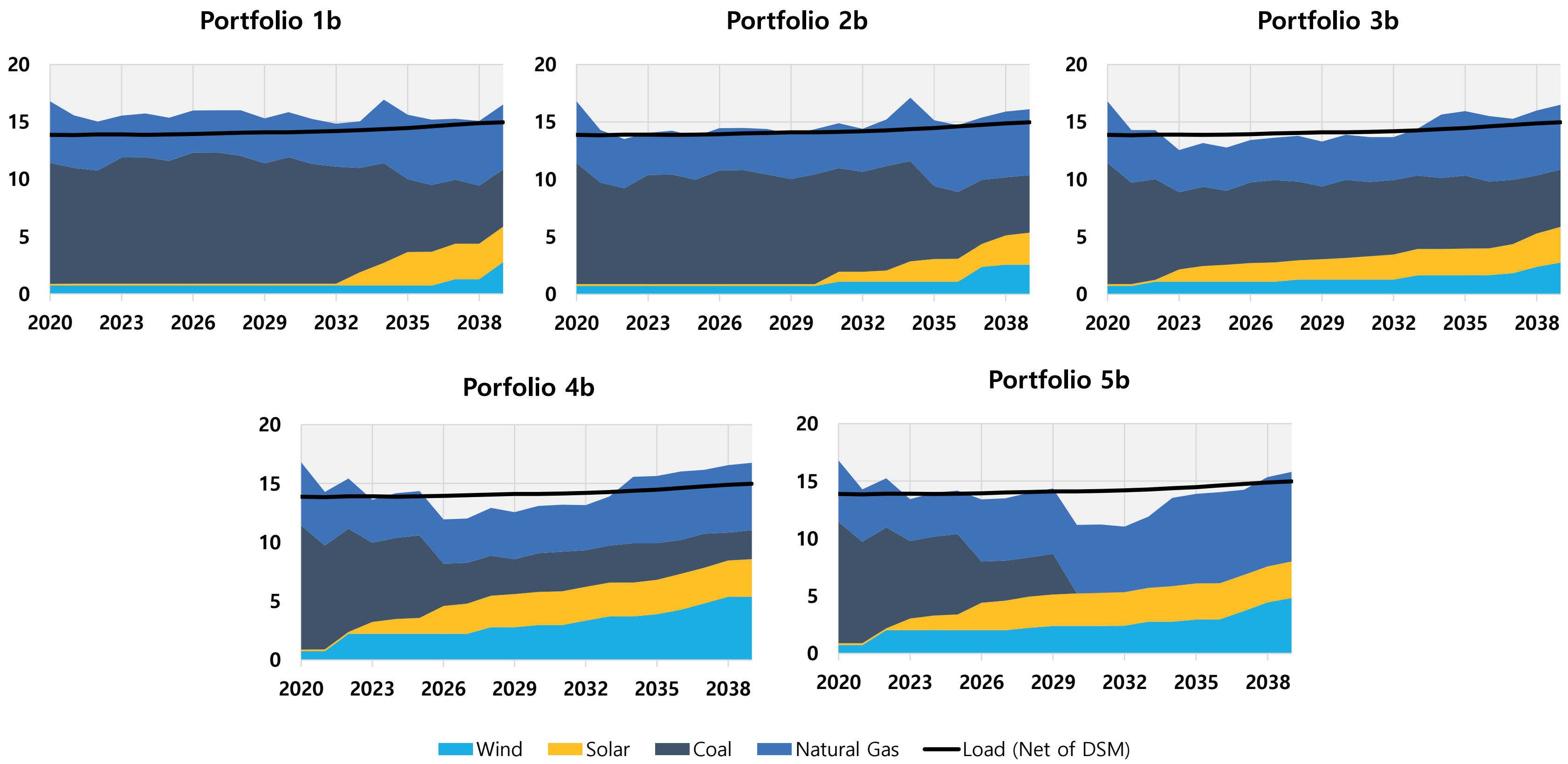


Figure 9 | Annual Energy (TWh) for Scenario C Portfolios 1b – 5b

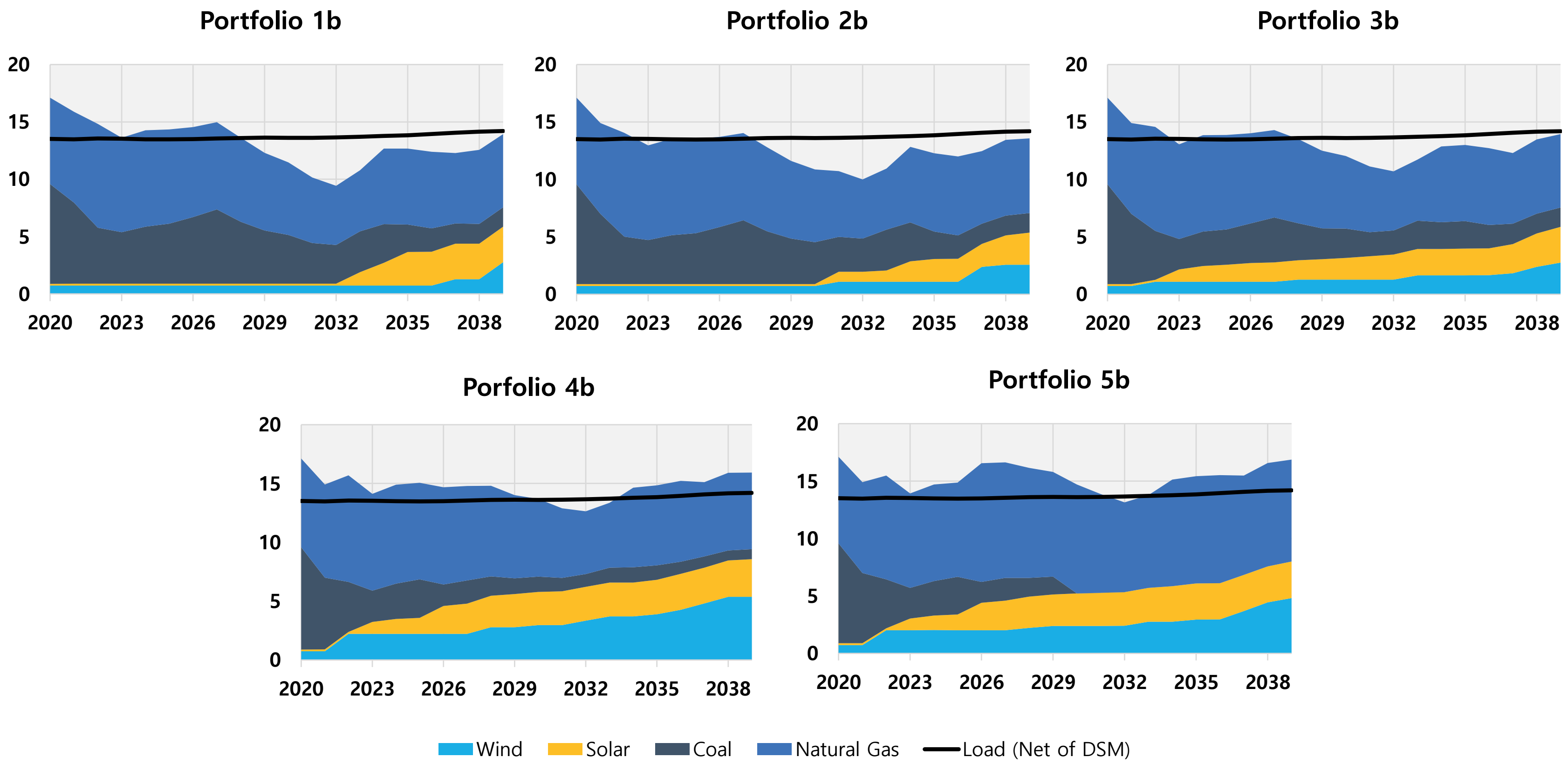


Figure 10 | Annual Energy (TWh) for Scenario D Portfolios 1b – 5b

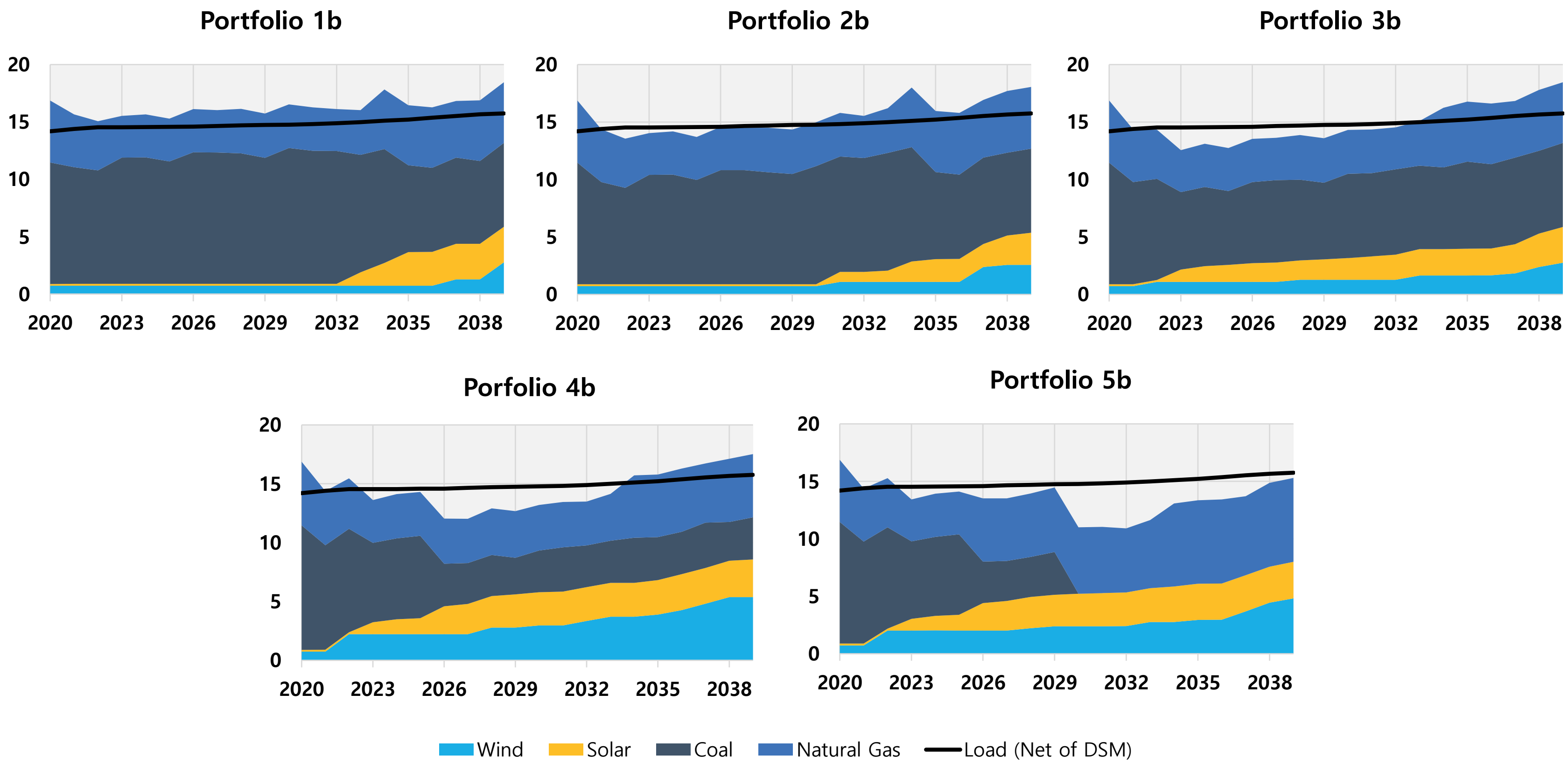


Figure 11 | Annual Energy (TWh) for Reference Case Portfolios 1c – 5c

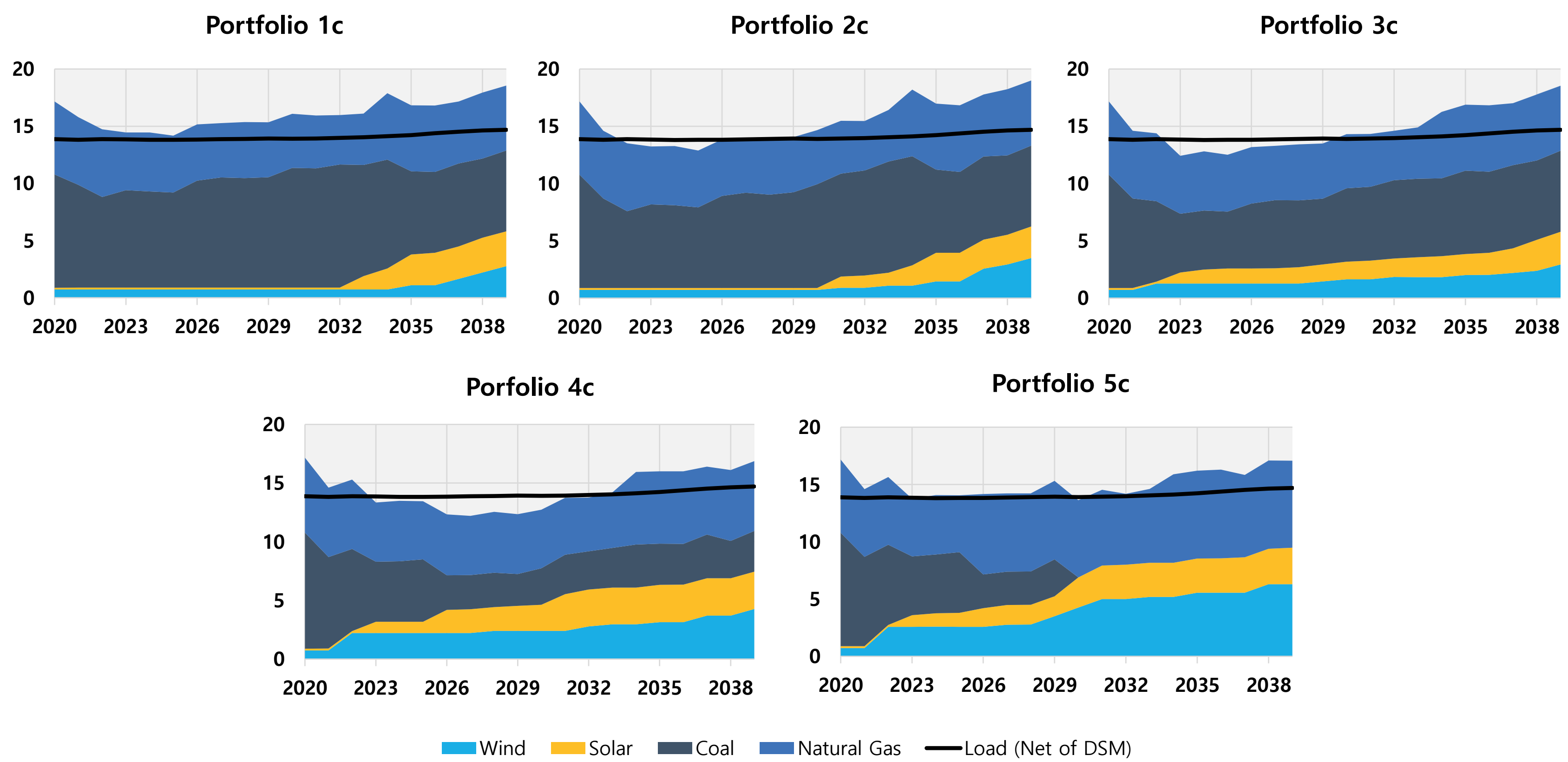


Figure 12 | Annual Energy (TWh) for Scenario A Portfolios 1c – 5c

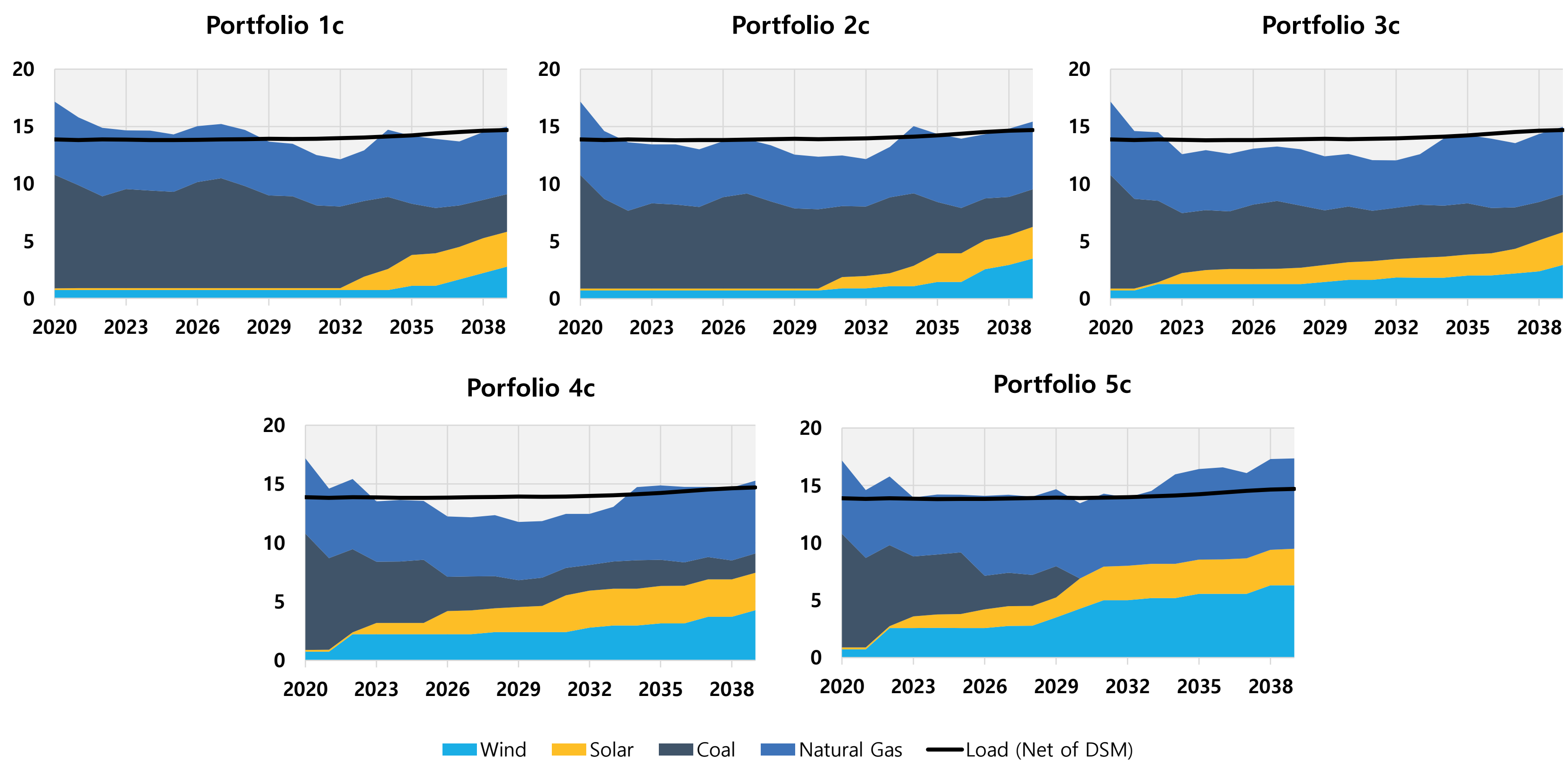


Figure 13 | Annual Energy (TWh) for Scenario B Portfolios 1c – 5c

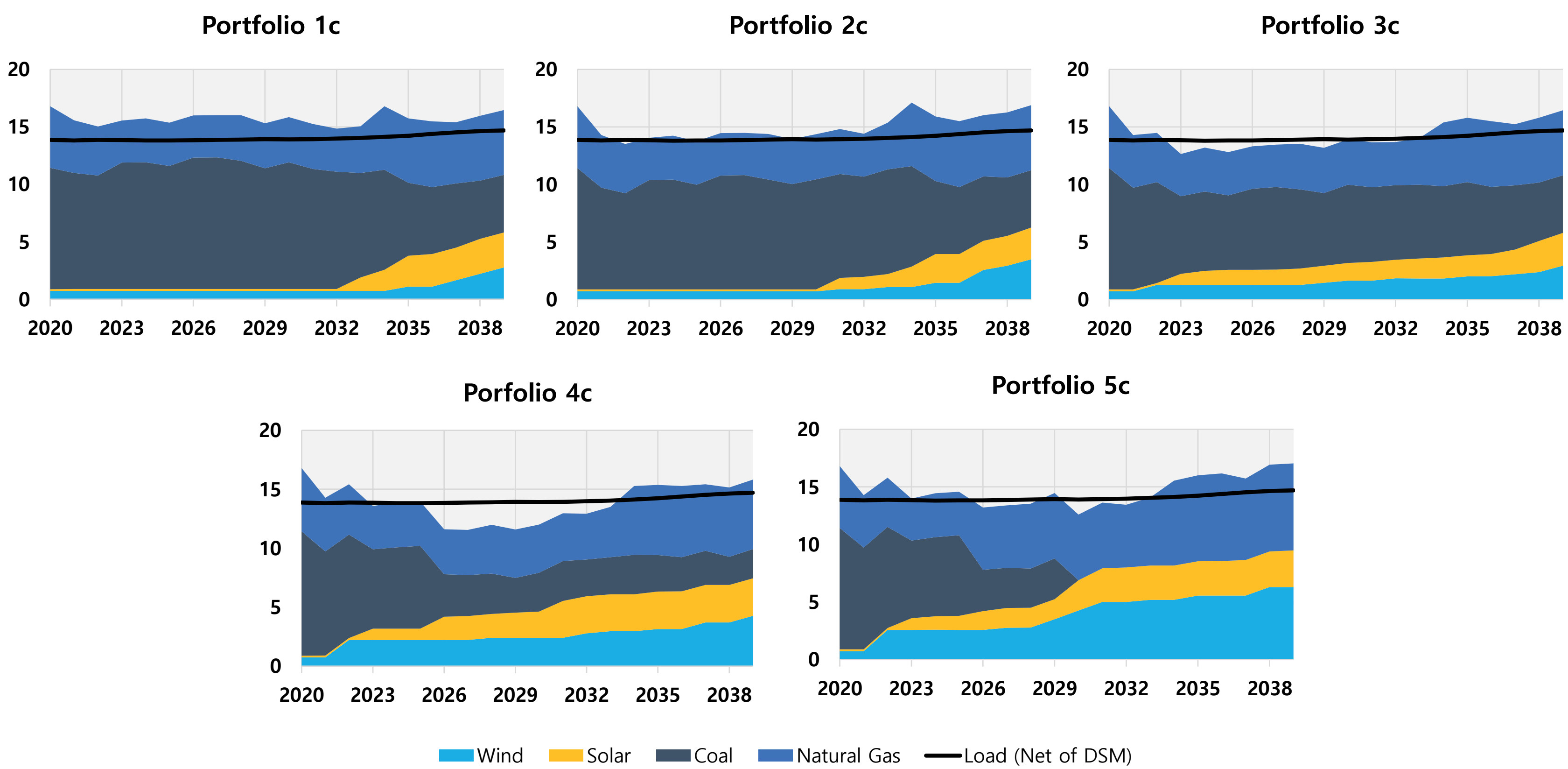


Figure 14 | Annual Energy (TWh) for Scenario C Portfolios 1c – 5c

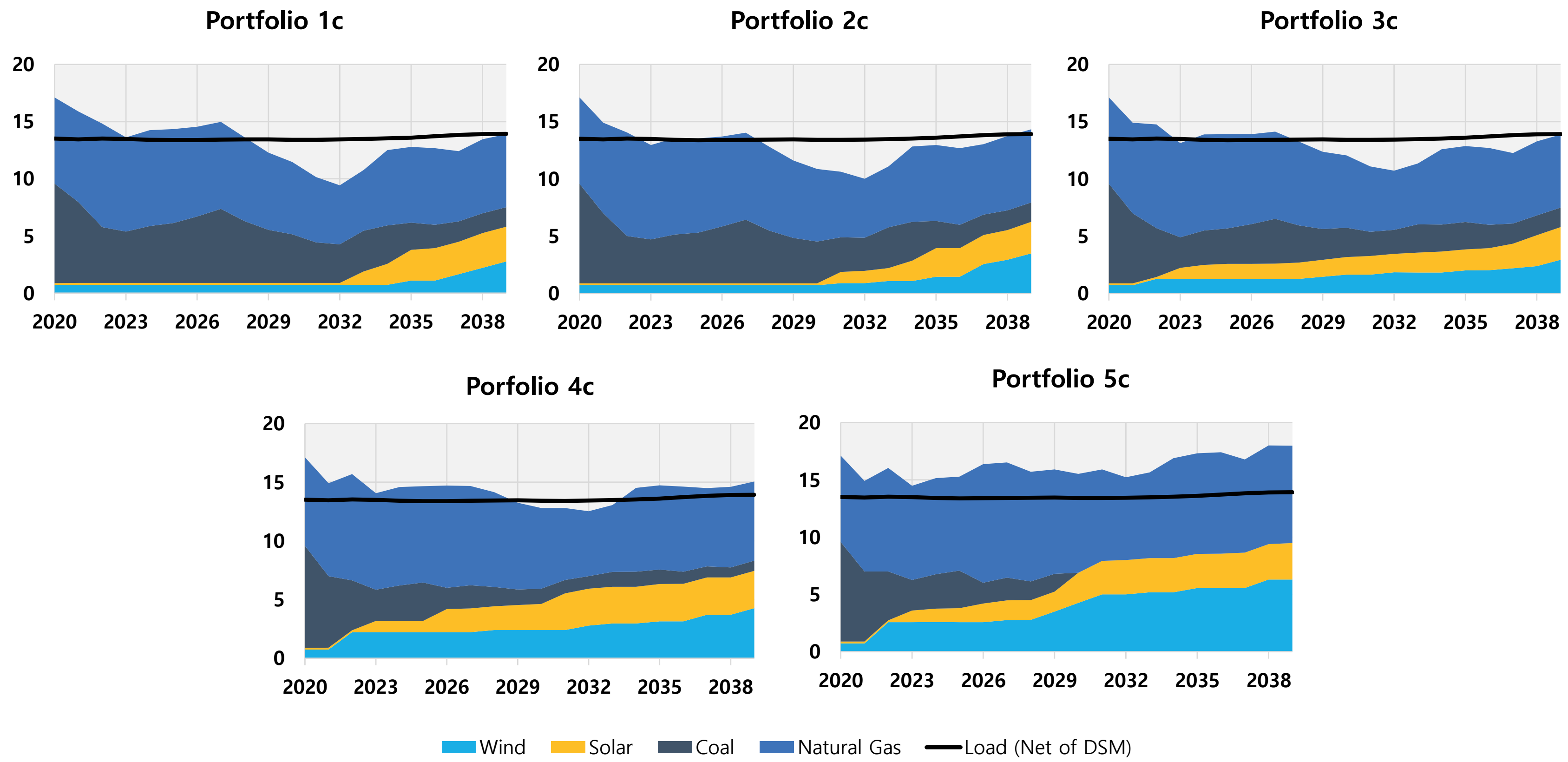
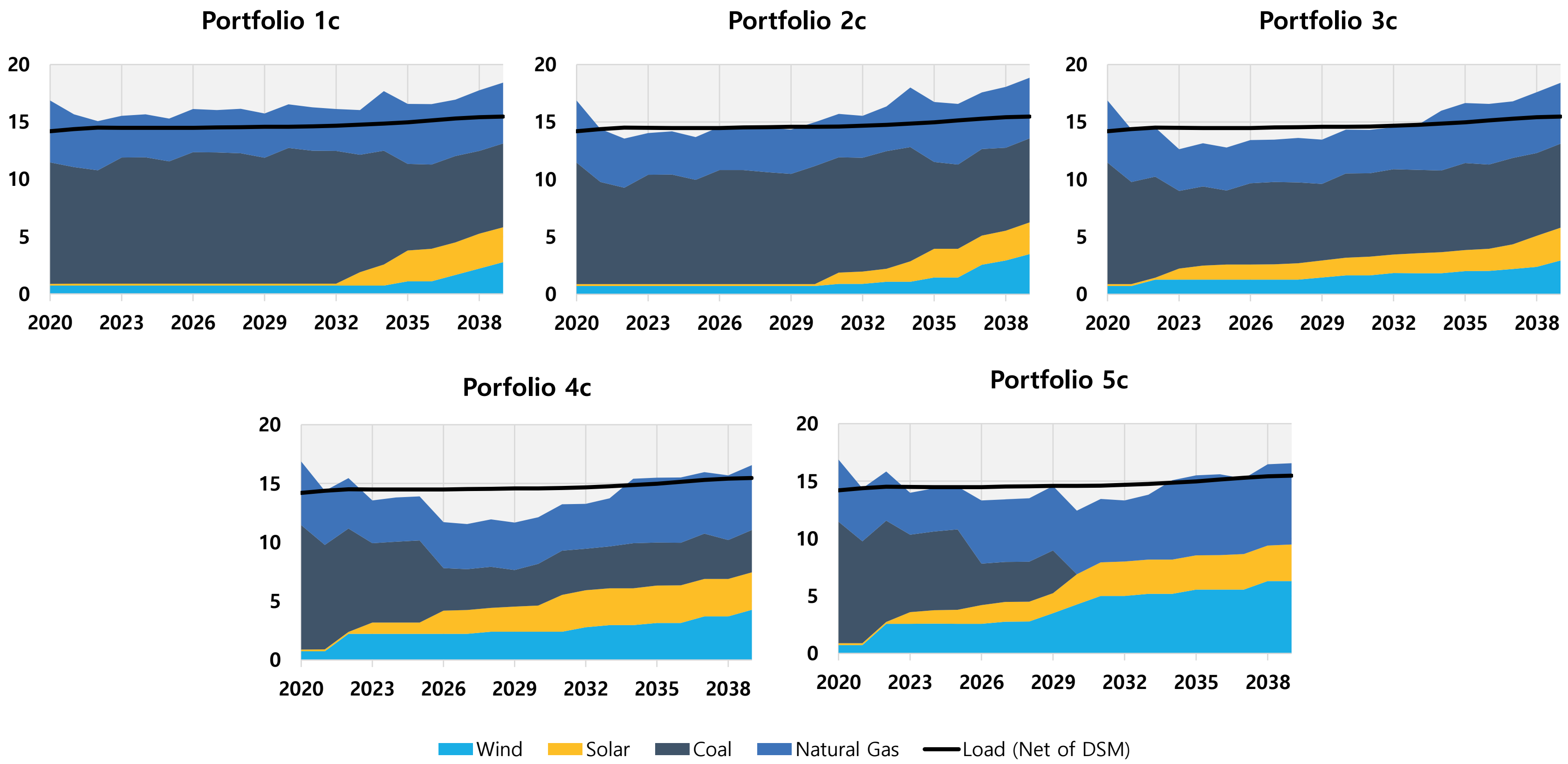


Figure 15 | Annual Energy (TWh) for Scenario D Portfolios 1c – 5c



Indianapolis Power & Light

Portfolio 1a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,373**	**3,370**	**3,366**	**3,328**	**3,327**	**3,326**	**3,326**	**3,325**	**3,324**	**3,324**	**3,134**	**3,133**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	8	8	20	20	55
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	119	129	231	243	254	282	277
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	95	190	475	494	494	532	532
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**29**	**42**	**56**	**69**	**83**	**97**	**110**	**123**	**135**	**146**	**157**	**388**	**810**	**1,206**	**1,238**	**1,263**	**1,331**	**1,364**
Total Resources	**3,381**	**3,391**	**3,400**	**3,409**	**3,383**	**3,396**	**3,409**	**3,422**	**3,435**	**3,447**	**3,459**	**3,281**	**3,290**	**3,296**	**3,323**	**3,352**	**3,383**	**3,408**	**3,475**	**3,508**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**21.8%**	**20.9%**	**20.4%**	**18.5%**	**17.9%**	**17.2%**	**16.4%**	**15.9%**	**15.6%**	**15.2%**	**8.5%**	**7.8%**	**7.3%**	**7.3%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

Indianapolis Power & Light
Portfolio 2a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**3,141**	**3,102**	**3,102**	**3,101**	**3,100**	**3,100**	**3,099**	**3,098**	**2,909**	**2,908**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	27	31
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	38	37	49	136	238	269	285	330	336
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	152	171	171	190	475	475	475	475	494
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**29**	**42**	**56**	**69**	**83**	**97**	**110**	**123**	**135**	**336**	**364**	**387**	**809**	**1,204**	**1,236**	**1,263**	**1,329**	**1,361**
Total Resources	**3,381**	**3,165**	**3,174**	**3,183**	**3,158**	**3,171**	**3,184**	**3,197**	**3,209**	**3,222**	**3,234**	**3,245**	**3,272**	**3,294**	**3,322**	**3,351**	**3,382**	**3,408**	**3,474**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**12.9%**	**12.4%**	**10.6%**	**10.1%**	**9.5%**	**8.8%**	**8.3%**	**8.0%**	**7.7%**	**7.3%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 3a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,736**	**2,735**	**2,734**	**2,734**	**2,733**	**2,543**	**2,543**	**2,542**	**2,147**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	20	20	20	20	20	20	20	20	20	20	20	20	20	27	27	31	31	35
New Utility-Scale Solar	0	0	0	168	177	186	205	205	221	227	218	210	212	203	197	191	186	205	270	295
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	38	76	76	76	95	95	95	114	323	342	361	475	494	532	532	532	532
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**49**	**268**	**328**	**351**	**383**	**416**	**445**	**464**	**487**	**699**	**730**	**750**	**1,175**	**1,204**	**1,238**	**1,263**	**1,330**	**1,362**
Total Resources	**3,381**	**3,165**	**3,194**	**3,043**	**3,065**	**3,087**	**3,118**	**3,151**	**3,179**	**3,198**	**3,220**	**3,242**	**3,273**	**3,292**	**3,322**	**3,351**	**3,383**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**13.6%**	**7.5%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light

Portfolio 4a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	523	523	523	523	523	523	523	523	523	523
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**2,247**	**2,058**	**2,057**	**2,056**	**1,661**	**1,661**	**1,660**	**1,660**	**1,659**	**1,659**
New Wind	0	0	12	20	20	27	43	47	47	47	55	62	66	70	74	74	74	90	90	105
New Utility-Scale Solar	0	0	0	202	250	255	419	436	451	437	421	405	402	392	381	383	378	366	354	348
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	323	323	323	342	361	570	589	608	722	741	779	798	874	893
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**41**	**263**	**325**	**351**	**867**	**903**	**930**	**949**	**972**	**1,184**	**1,214**	**1,237**	**1,660**	**1,690**	**1,723**	**1,749**	**1,815**	**1,846**
Total Resources	**3,381**	**3,165**	**3,186**	**3,039**	**3,062**	**3,087**	**3,117**	**3,152**	**3,179**	**3,197**	**3,219**	**3,242**	**3,271**	**3,293**	**3,322**	**3,350**	**3,383**	**3,408**	**3,474**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**13.3%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light

Portfolio 5a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	0	0	0	0	0	0	0	0	0	0
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**1,724**	**1,535**	**1,534**	**1,533**	**1,138**	**1,138**	**1,137**	**1,137**	**1,136**	**1,136**
New Wind	0	0	39	39	39	47	51	51	62	66	78	86	86	86	90	90	94	101	109	113
New Utility-Scale Solar	0	0	0	202	218	216	353	356	340	324	328	315	314	308	333	337	326	322	342	348
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	19	19	285	304	323	342	551	760	779	798	874	893	931	950	988	1,007
New Gas CC	0	0	0	0	0	0	0	0	0	0	308	308	308	308	615	615	615	615	615	615
New Gas CT	0	0	0	0	0	0	95	95	95	95	95	95	95	95	95	95	95	95	95	95
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**68**	**283**	**332**	**350**	**866**	**902**	**930**	**950**	**1,494**	**1,710**	**1,738**	**1,761**	**2,182**	**2,213**	**2,246**	**2,271**	**2,339**	**2,370**
Total Resources	**3,381**	**3,165**	**3,213**	**3,058**	**3,069**	**3,086**	**3,116**	**3,152**	**3,179**	**3,198**	**3,218**	**3,244**	**3,272**	**3,294**	**3,321**	**3,351**	**3,383**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**14.3%**	**8.0%**	**7.5%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 1b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,373**	**3,370**	**3,366**	**3,328**	**3,327**	**3,326**	**3,326**	**3,325**	**3,324**	**3,324**	**3,134**	**3,133**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	12	43
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	140	245	363	352	360	348	342
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	38	38	304	342	342	418	418
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**38**	**55**	**71**	**88**	**105**	**122**	**139**	**155**	**170**	**183**	**196**	**387**	**810**	**1,206**	**1,238**	**1,262**	**1,331**	**1,362**
Total Resources	**3,381**	**3,395**	**3,409**	**3,421**	**3,399**	**3,415**	**3,431**	**3,447**	**3,464**	**3,479**	**3,494**	**3,318**	**3,330**	**3,294**	**3,322**	**3,353**	**3,383**	**3,407**	**3,476**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**21.9%**	**21.2%**	**20.8%**	**19.0%**	**18.6%**	**18.0%**	**17.3%**	**16.9%**	**16.7%**	**16.3%**	**9.7%**	**9.1%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**

Indianapolis Power & Light
Portfolio 2b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**3,141**	**3,102**	**3,102**	**3,101**	**3,100**	**3,100**	**3,099**	**3,098**	**2,909**	**2,908**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	8	8	8	8	8	8	35	39	39
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	105	102	112	218	238	230	223	282	307
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	38	57	57	57	323	361	361	361	361
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	95	95	95	95	95
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**38**	**55**	**71**	**88**	**105**	**122**	**139**	**155**	**170**	**334**	**363**	**385**	**809**	**1,202**	**1,238**	**1,263**	**1,330**	**1,360**
Total Resources	**3,381**	**3,170**	**3,183**	**3,196**	**3,174**	**3,190**	**3,206**	**3,222**	**3,239**	**3,254**	**3,269**	**3,243**	**3,271**	**3,293**	**3,322**	**3,349**	**3,383**	**3,408**	**3,475**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**13.2%**	**12.9%**	**11.2%**	**10.8%**	**10.2%**	**9.6%**	**9.3%**	**9.1%**	**8.8%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 3b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,736**	**2,735**	**2,734**	**2,734**	**2,733**	**2,543**	**2,543**	**2,542**	**2,147**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	8	8	8	8	8	8	12	12	12	12	12	20	20	20	20	23	35	43
New Utility-Scale Solar	0	0	0	202	250	255	270	267	255	259	265	278	292	294	286	284	275	291	324	342
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	19	38	38	38	228	228	228	342	361	399	399	418	418
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**46**	**264**	**329**	**351**	**382**	**415**	**444**	**464**	**485**	**701**	**728**	**750**	**1,174**	**1,204**	**1,237**	**1,262**	**1,331**	**1,362**
Total Resources	**3,381**	**3,170**	**3,191**	**3,039**	**3,066**	**3,087**	**3,118**	**3,150**	**3,178**	**3,197**	**3,218**	**3,244**	**3,271**	**3,292**	**3,321**	**3,350**	**3,383**	**3,407**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**13.5%**	**7.3%**	**7.4%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 4b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	523	523	523	523	523	523	523	523	523	523
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**2,247**	**2,058**	**2,057**	**2,056**	**1,661**	**1,661**	**1,660**	**1,660**	**1,659**	**1,659**
New Wind	0	0	31	31	31	31	31	31	43	43	47	47	55	62	62	66	74	86	98	98
New Utility-Scale Solar	0	0	0	190	229	235	409	427	425	429	413	405	394	378	367	363	365	353	348	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	228	228	228	228	247	456	475	494	608	627	646	665	722	741
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	95	95	95	95	95	95	95	95	95	95	95	95	95	95
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**69**	**276**	**331**	**354**	**868**	**903**	**930**	**950**	**972**	**1,186**	**1,215**	**1,238**	**1,659**	**1,690**	**1,723**	**1,747**	**1,816**	**1,846**
Total Resources	**3,381**	**3,170**	**3,215**	**3,052**	**3,068**	**3,090**	**3,118**	**3,152**	**3,178**	**3,198**	**3,220**	**3,244**	**3,272**	**3,294**	**3,321**	**3,351**	**3,383**	**3,407**	**3,475**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**14.3%**	**7.8%**	**7.5%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 5b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	0	0	0	0	0	0	0	0	0	0
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**1,724**	**1,535**	**1,534**	**1,533**	**1,138**	**1,138**	**1,137**	**1,137**	**1,136**	**1,136**
New Wind	0	0	27	27	27	27	27	27	31	35	35	35	35	43	43	47	47	62	78	86
New Utility-Scale Solar	0	0	0	190	229	235	409	427	434	413	413	405	402	385	394	389	378	366	354	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	19	19	19	38	285	494	513	532	627	646	684	703	760	779
New Gas CC	0	0	0	0	0	0	308	308	308	308	308	308	308	308	615	615	615	615	615	615
New Gas CT	0	0	0	0	0	0	0	0	0	0	284	284	284	284	284	284	284	284	284	284
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**66**	**272**	**327**	**351**	**868**	**903**	**930**	**948**	**1,496**	**1,709**	**1,738**	**1,760**	**2,183**	**2,213**	**2,244**	**2,272**	**2,337**	**2,370**
Total Resources	**3,381**	**3,170**	**3,211**	**3,048**	**3,064**	**3,087**	**3,118**	**3,152**	**3,179**	**3,196**	**3,220**	**3,244**	**3,272**	**3,294**	**3,322**	**3,351**	**3,381**	**3,408**	**3,473**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**14.2%**	**7.6%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light

Portfolio 1c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,373**	**3,370**	**3,366**	**3,328**	**3,327**	**3,326**	**3,326**	**3,325**	**3,324**	**3,324**	**3,134**	**3,133**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	20	31	43
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	140	224	330	339	329	342	336
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	285	304	323	361	380
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**62**	**82**	**102**	**123**	**143**	**163**	**181**	**200**	**215**	**229**	**385**	**809**	**1,202**	**1,236**	**1,262**	**1,330**	**1,363**
Total Resources	**3,381**	**3,398**	**3,414**	**3,429**	**3,410**	**3,429**	**3,449**	**3,469**	**3,488**	**3,505**	**3,524**	**3,349**	**3,362**	**3,293**	**3,322**	**3,348**	**3,382**	**3,407**	**3,475**	**3,507**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**22.1%**	**21.4%**	**21.1%**	**19.4%**	**19.1%**	**18.6%**	**18.0%**	**17.7%**	**17.5%**	**17.3%**	**10.7%**	**10.2%**	**7.2%**	**7.2%**	**7.1%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**

Indianapolis Power & Light

Portfolio 2c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**3,141**	**3,102**	**3,102**	**3,101**	**3,100**	**3,100**	**3,099**	**3,098**	**2,909**	**2,908**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	4	4	8	8	16	16	39	47	59
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	120	131	133	218	304	294	291	288	301
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	304	342	342	399	399
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**62**	**82**	**102**	**123**	**143**	**163**	**181**	**200**	**339**	**364**	**386**	**810**	**1,202**	**1,237**	**1,263**	**1,330**	**1,362**
Total Resources	**3,381**	**3,173**	**3,188**	**3,203**	**3,185**	**3,204**	**3,224**	**3,244**	**3,263**	**3,280**	**3,298**	**3,248**	**3,272**	**3,293**	**3,323**	**3,348**	**3,383**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.4%**	**13.1%**	**11.5%**	**11.3%**	**10.8%**	**10.3%**	**10.1%**	**10.0%**	**9.8%**	**7.4%**	**7.3%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light Portfolio 3c	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,736**	**2,735**	**2,734**	**2,734**	**2,733**	**2,543**	**2,543**	**2,542**	**2,147**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	12	12	12	12	12	12	12	16	20	20	23	23	23	27	27	31	35	47
New Utility-Scale Solar	0	0	0	179	218	225	214	205	213	211	211	218	212	217	224	218	224	242	300	313
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	19	19	19	38	57	57	57	57	247	266	266	361	380	399	399	399	399
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**55**	**272**	**332**	**358**	**386**	**417**	**444**	**464**	**487**	**699**	**730**	**752**	**1,175**	**1,204**	**1,236**	**1,262**	**1,330**	**1,362**
Total Resources	**3,381**	**3,173**	**3,200**	**3,048**	**3,068**	**3,094**	**3,122**	**3,152**	**3,178**	**3,198**	**3,220**	**3,242**	**3,272**	**3,294**	**3,322**	**3,350**	**3,381**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.8%**	**7.6%**	**7.5%**	**7.5%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light

Portfolio 4c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	523	523	523	523	523	523	523	523	523	523
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**2,247**	**2,058**	**2,057**	**2,056**	**1,661**	**1,661**	**1,660**	**1,660**	**1,659**	**1,659**
New Wind	0	0	0	0	0	16	31	31	35	35	35	35	43	47	47	51	51	62	62	74
New Utility-Scale Solar	0	0	0	179	166	157	335	329	315	316	320	443	431	413	401	396	384	372	360	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	19	76	76	190	209	228	228	228	304	323	342	361	380	418	437	513	532
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	190	190	190	190	190	190	190	190	284	284	284	284	284	284
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**261**	**325**	**351**	**868**	**903**	**930**	**949**	**972**	**1,186**	**1,215**	**1,237**	**1,659**	**1,690**	**1,722**	**1,746**	**1,816**	**1,848**
Total Resources	**3,381**	**3,173**	**3,188**	**3,036**	**3,062**	**3,087**	**3,118**	**3,152**	**3,179**	**3,197**	**3,220**	**3,244**	**3,272**	**3,293**	**3,321**	**3,351**	**3,382**	**3,406**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.4%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**

Indianapolis Power & Light

Portfolio 5c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	0	0	0	0	0	0	0	0	0	0
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**1,724**	**1,535**	**1,534**	**1,533**	**1,138**	**1,138**	**1,137**	**1,137**	**1,136**	**1,136**
New Wind	0	0	0	12	16	23	35	43	43	59	74	90	90	94	94	101	101	101	117	117
New Utility-Scale Solar	0	0	0	190	208	206	270	276	264	251	382	413	409	392	381	370	358	360	348	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	19	19	133	133	152	152	532	684	703	722	836	855	893	912	969	988
New Gas CC	0	0	0	0	0	0	308	308	308	308	308	308	308	308	615	615	615	615	615	615
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**264**	**325**	**350**	**868**	**903**	**929**	**950**	**1,496**	**1,709**	**1,738**	**1,760**	**2,184**	**2,212**	**2,246**	**2,271**	**2,338**	**2,370**
Total Resources	**3,381**	**3,173**	**3,188**	**3,040**	**3,062**	**3,086**	**3,118**	**3,152**	**3,177**	**3,198**	**3,220**	**3,244**	**3,272**	**3,294**	**3,322**	**3,350**	**3,383**	**3,407**	**3,474**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.4%**	**7.4%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Cause No. 45591

Figure 1 | Market Purchases/Sales of Portfolios 2a – 5a Compared to Portfolio 1a in the Reference Case

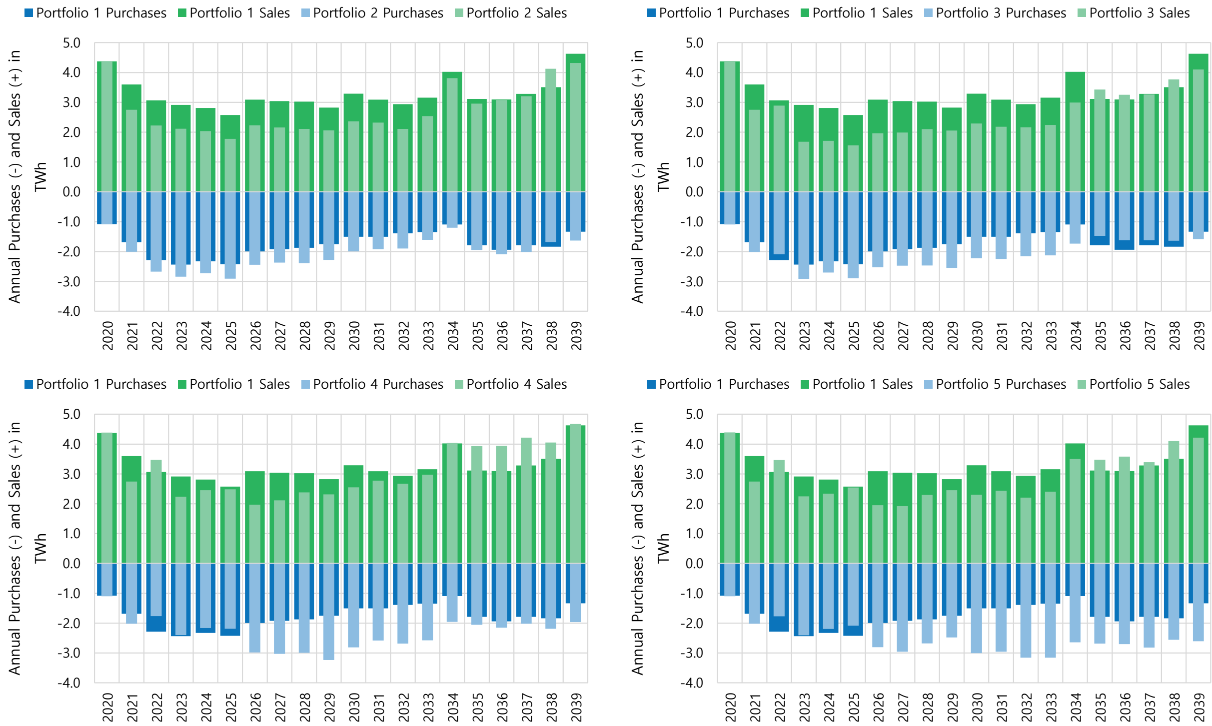


Figure 2 | Market Purchases/Sales of Portfolios 2a – 5a Compared to Portfolio 1a in Scenario A

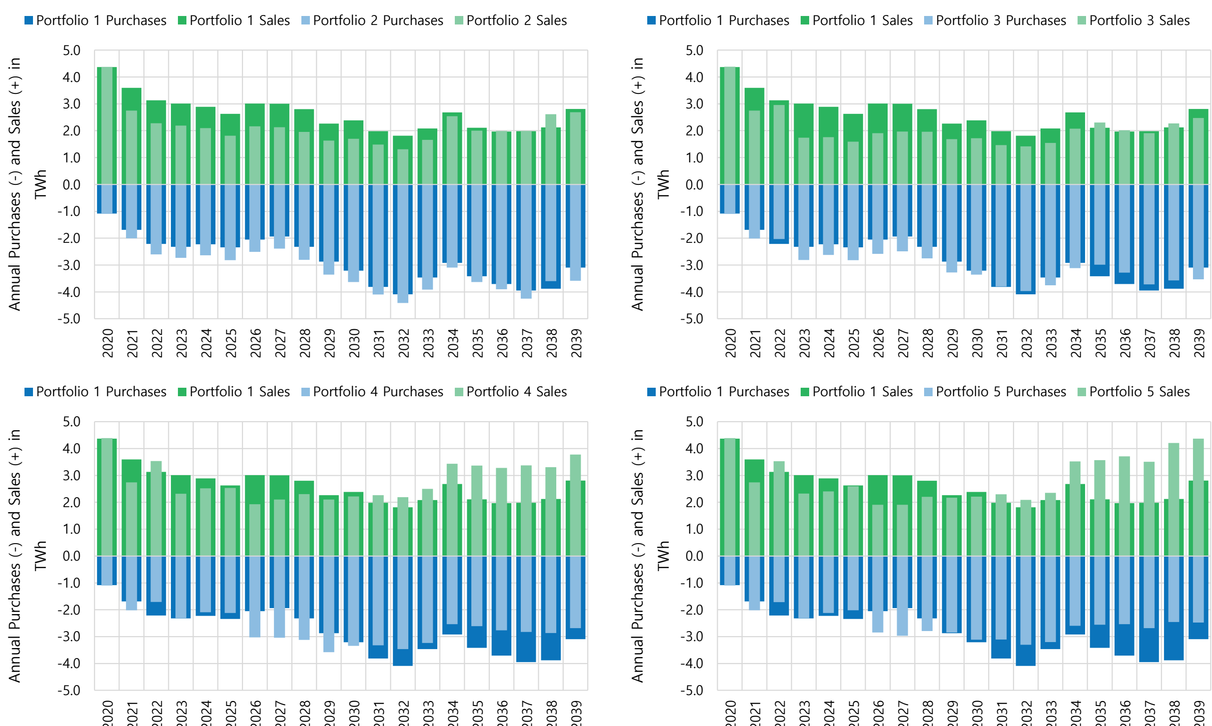


Figure 3 | Market Purchases/Sales of Portfolios 2b – 5b Compared to Portfolio 1b in the Reference Case

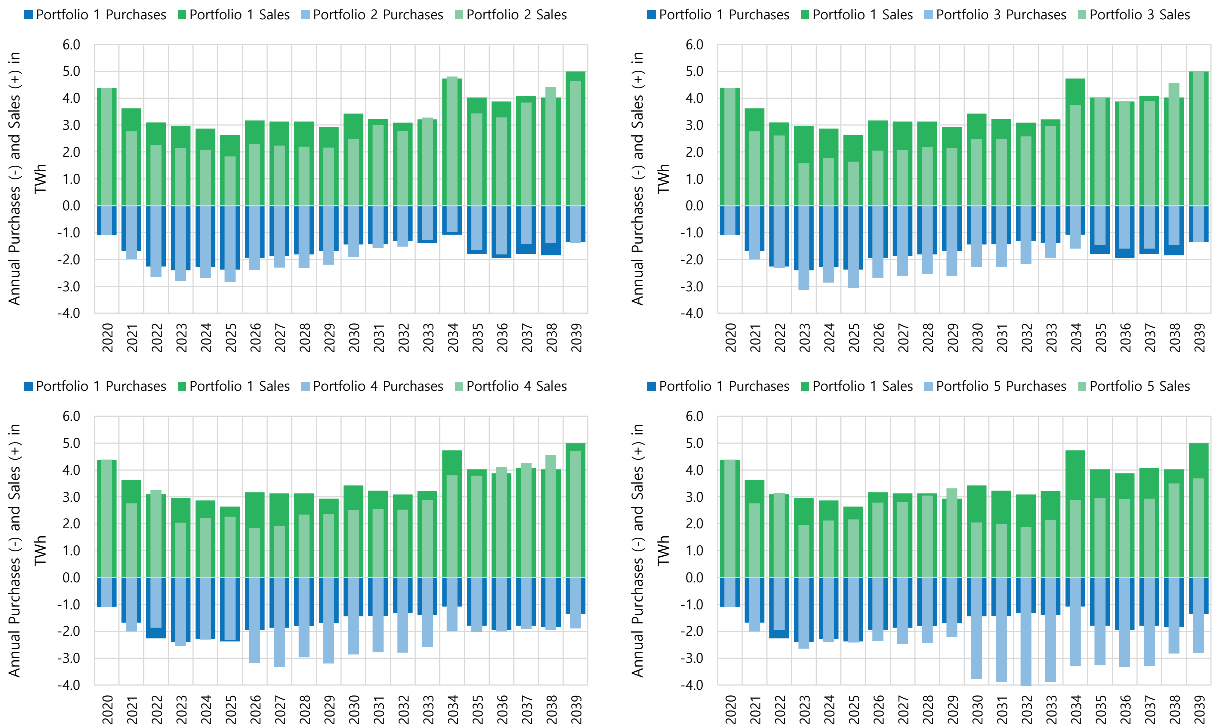


Figure 4 | Market Purchases/Sales of Portfolios 2b – 5b Compared to Portfolio 1b in Scenario A

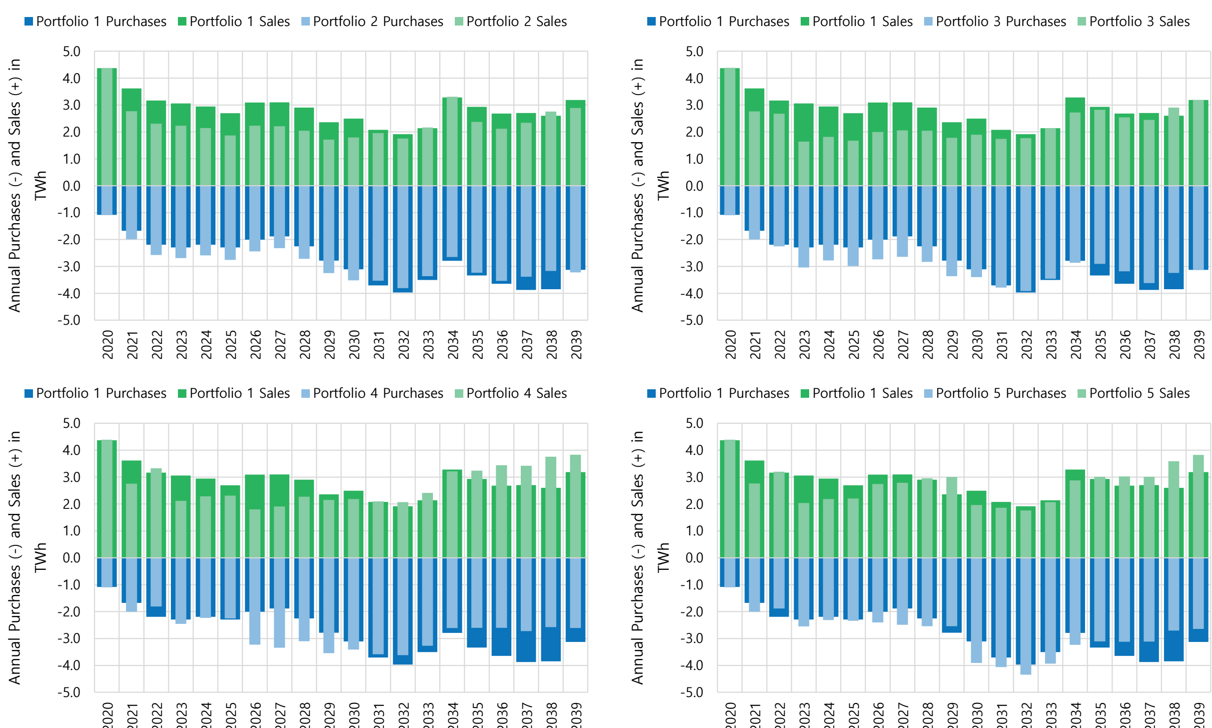


Figure 5 | Market Purchases/Sales of Portfolios 2c – 5c Compared to Portfolio 1c in the Reference Case

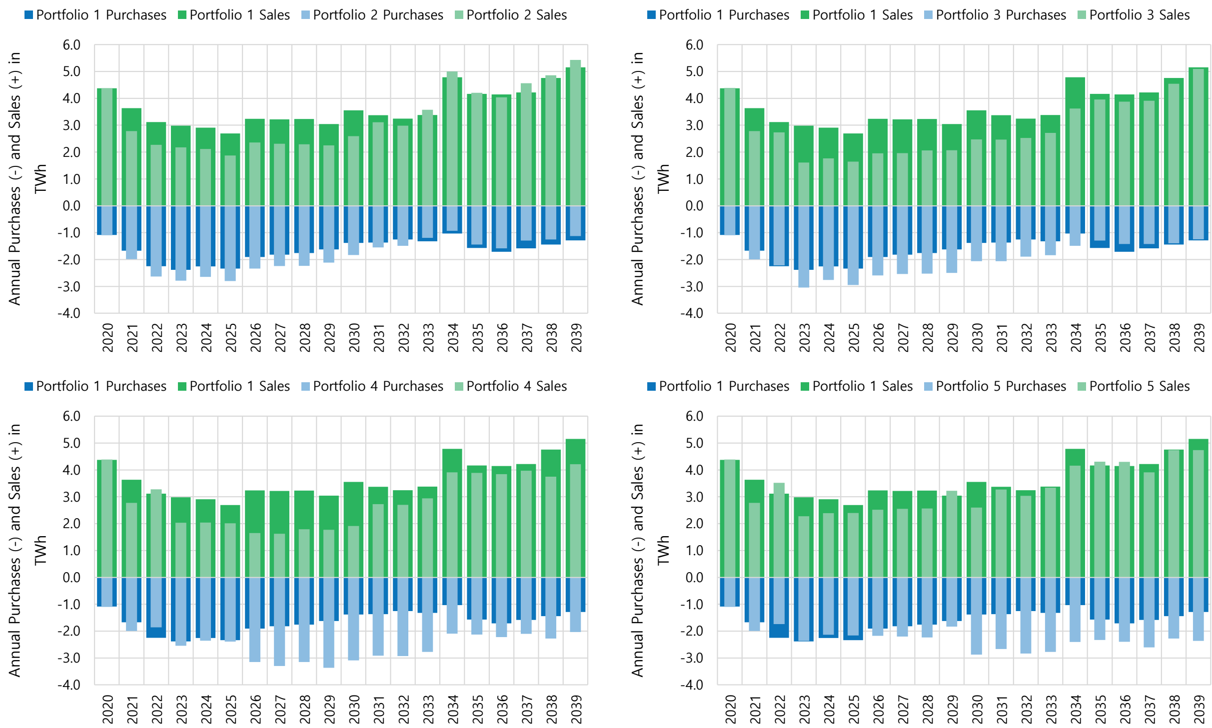
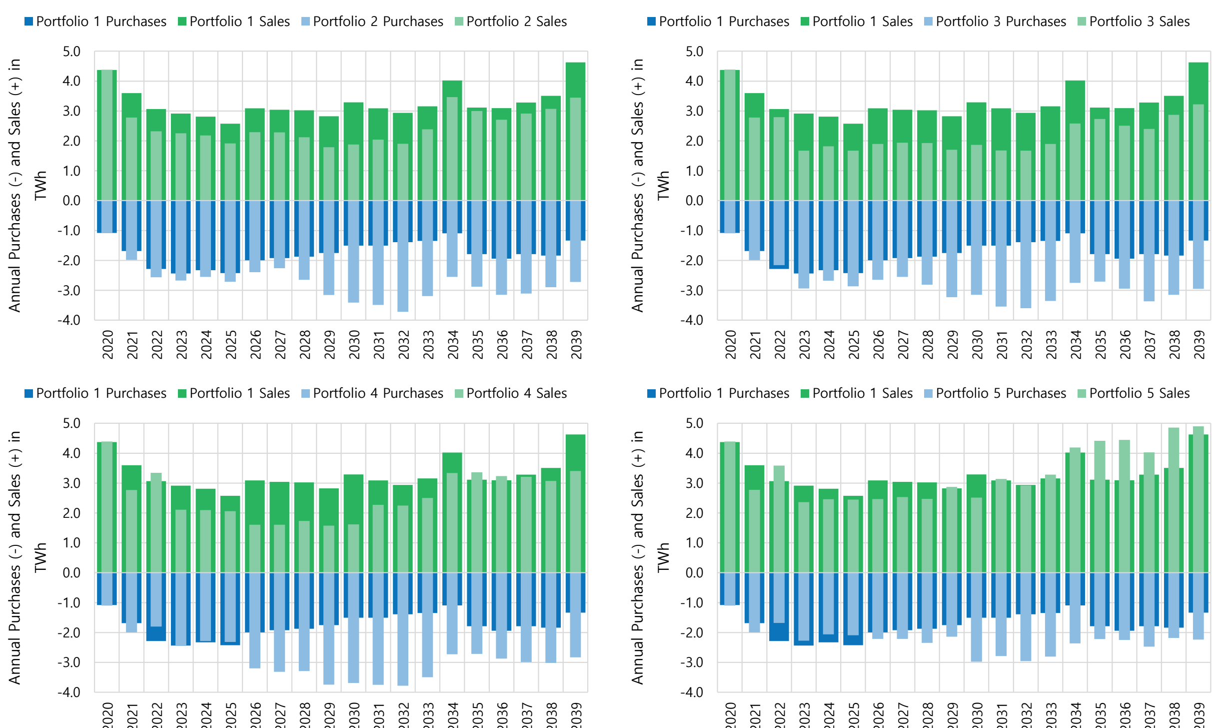


Figure 6 | Market Purchases/Sales of Portfolios 2c – 5c Compared to Portfolio 1c in Scenario A



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REGULATORY COMMISSION

Cause No. 45591

INDIANAPOLIS POWER & LIGHT COMPANY

2019 Integrated Resource Plan

Volume 1 of 3

December 16, 2019

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Acronyms List

A

AC	Alternating Current
ACEEE	American Council for an Energy Efficient Economy
ACESA	American Clean Energy and Security Act of 2009
ACI	Activated Carbon Injection
ACLM	Air Conditioning Load Management
AFUDC	Allowance for Funds used During Construction
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ARRA	American Recovery and Reinvestment Act of 2009
ARS	Automatic Resource Selection
ASM	Ancillary Services Market
ATC	Available Transfer Capability or Capacity

B

BA	Balancing Authority or Balancing Area
BACT	Best Available Control Technology
BES	Bulk Electric System
BESS	Battery Energy Storage System

C

C&I	Commercial and Industrial
CAA	Clean Air Act – EPA issued initial rules in 1970
CAAA	Clean Air Act Amendments – 1990
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCT	Clean Coal Technology
CDD	Cooling Degree Days
CFL	Compact Fluorescent Lighting
CHP	Combined Heat & Power
CIP	Critical Infrastructure Protection
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CPW	Cumulative Present Worth
CVR	Conservation Voltage Reduction
CSPAR	Cross State Air Pollution Rule – EPA issued rules July 2011
CT	Combustion Turbine

D

DA	Distribution Automation, or Day Ahead Scheduling
DG	Distributed Generation
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand-Side Management

E

ECS	Energy Control System
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFORd	Equivalent Forced Outage Rate demand
EIA	Energy Information Administration of the U.S. Department of Energy
ELCC	Electric Load Carrying Capability
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicles

F

FAC	Fuel Adjustment Clause
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

G

GDP	Gross Domestic Product
GHG	Green House Gas

H

HAP	Hazardous Air Pollutant
HDD	Heating Degree Days
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning

I

ICAP	Installed Capacity
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gas Combined Cycle
IMM	Independent Market Monitor
IRP	Integrated Resource Planning
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission

K

kWh	Kilowatt hour

J

JCSP	Joint Coordinated System Planning

L

LAER	Lowest Achievable Emission Rate
LCOE	Levelized Cost of Energy
LMR	Load Modifying Resource
LMP	Locational Marginal Pricing
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load Serving Entity

M

MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MFDI	Multi Family Direct Install
MISO	Midcontinent Independent System Operator
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	Midcontinent ISO Transmission Expansion Planning
MVA	Mega Volt Ampere, Mega Volt Amplifier, or Multivariate Analysis
MVP	Multi-Value Projects (transmission for both reliability and economic benefits)
MW	Megawatt

N

NAAQS	National Ambient Air Quality Standard – EPA issued rules January 2013
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation (formerly Council)
NG	Natural Gas
NID	Net Internal Demand
NIST	National Institute of Standards and Technology
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance
OSM	Office of Surface Mining

P

PC	Pulverized Coal
PCT	Participant Cost Test (see EM&V)
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM LLC (Regional Transmission Organization)
$PM_{2.5}$	Particulate Matter that is 2.5 micrometers in diameter or smaller
PPA	Purchase Power Agreement

PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PV	Photovoltaic
PVRR	Present Value Revenue Requirement

R

RCRA	Resource Conservation and Recovery Act (coal ash disposal regulations)
REC	Renewable Energy Credit
REP	Renewable Energy Production
RES	Renewable Energy Standards
RF, RFC	ReliabilityFirst, Reliability First Corporation
RFP	Request for Proposals
RIIA	Renewable Impact Integration Assessment
RIM	Rate Payer Impact Measure (see EM&V)
RTO	Regional Transmission Organization (Independent System Operator)

S

SAE	Statistically Adjusted End Use
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction (pollution control)
SIP	State Implementation Plan (environmental)
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide

SREC	Solar Renewable Energy Credit

T

TBEL	Technology Based Effluent Limits
TOU	Time of Use
TRC	Total Resource Cost Test
TW	Terawatt

U

UCAP	Unforced Capacity
UCT	Utility Cost Test

V

VAR	Volt Ampere Reactive, Variance, or Value at Risk

W

WQBEL	Water Quality Based Effluent Limits

X

XEFORd	Equivalent demand Forced Outage Rate excluding causes Outside of Management Control

Executive Summary

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The 2019 Integrated Resource Plan ("IRP") was developed in an environment with expectations for unprecedented technological change and power market evolution over the planning horizon. Changing customer preferences and expectations, declining costs of renewables and storage, a changing regional resource mix, and the growing importance of carbon reduction have all played into IPL's planning strategy and process for this IRP.

IPL's 2019 IRP process and preferred resource portfolio meet four core company objectives and areas of focus:

Customer Centricity

Focuses on customer needs and wants

IPL' s Preferred Resource Portfolio delivers safe, reliable, and economic electricity to customers at just and reasonable rates. IPL conferred with customers and various stakeholders throughout its evaluation and in advancing its recommendation to the Indiana Utility Regulatory Commission. The Preferred Resource Portfolio best serves IPL customers today and into the future, contemplates customers' evolving energy needs, and relies on data-driven models.

Economics

Considers optimal current and expected market economics

IPL's Preferred Resource Portfolio is based on known and forecasted market economics, potential risks modeled across a wide range of futures, and stakeholder input. Replacement resource additions will be selected based upon an all-source competitive process with detailed regulatory filings before the Commission.

Flexibility & Balance

Measured approach maintaining optionality

Preserving flexibility and optionality benefits customers. IPL is pursuing a gradual approach, and only planning to retire units where the option value is not economically prudent. A phased retirement approach with smaller capacity impacts over time mitigates large rate impacts and exposure to the market. Further, a more diverse, scalable and balanced fleet helps protect against fuel price swings and capacity factor variances of different generation sources. Simply put, diverse fleets optimize the customer position in varying economic and political scenarios.

Greener Energy Future

Moves the company to more renewables

IPL continues to invest in its existing thermal generation to the extent it makes economic sense for customers while at the same time preparing for the evolving role of renewable generation. The cost of renewables will generally continue to decline, and customers are increasingly demanding cleaner sources of energy. IPL's Preferred Resource Portfolio is the reasonable least cost option, which also provides a cleaner and more diverse generation mix for customers.

The 2019 IPL Preferred Resource Portfolio contains the following elements:

- **Retirement of 630 MW of coal by 2023**: Based on extensive modeling, IPL has determined that the cost of operating Petersburg ("Pete") 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 cheaper and cleaner resources while maintaining a reliable system.

- **Competitive bid(s) request for approximately 200 MW of replacement capacity**: IPL intends to issue an all-source Request for Proposal ("RFP") in order 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, storage, and energy efficiency 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 approximately 130,000 MWh per year of demand side management (DSM) and energy efficiency programs:** IPL plans to continue to be a state leader in DSM implementation and will target approximately 130,000 MWh per year 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 systemic changes in wholesale power markets are impacting the viability of coal in MISO, Pete 3 and 4 provide firm, dispatchable capacity and maintaining those units preserves optionality in the face of uncertainty over the next five years. The IRP process is every three years, and IPL has established a robust and transparent process for evaluating the future cost effectiveness of the remaining coal units through time. IPL will closely monitor market forces, federal and state regulation, and other industry trends that could impact the future economics of our remaining coal units.

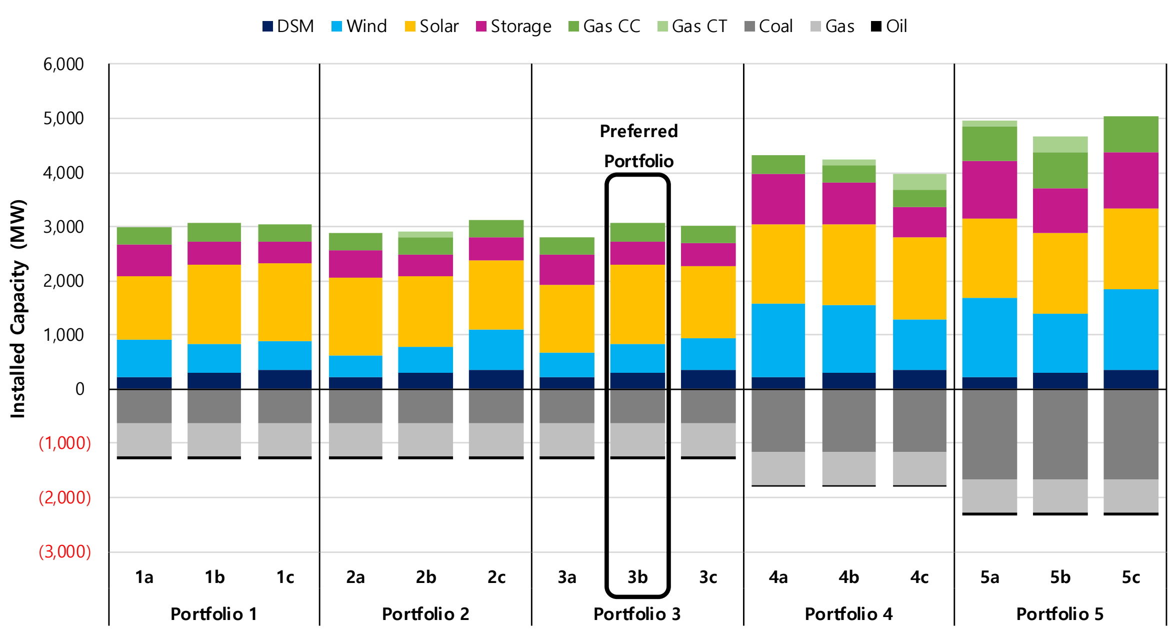
2019 IRP Modeling

IPL evaluated a set of fifteen (15) candidate resource portfolios created from a modeling process that incorporated an evaluation of coal retirement dates, DSM market potential, 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.

IPL held five public stakeholder meetings and other technical meetings, continuing to build upon the stakeholder process in the 2016 IRP. IPL provided detailed modeling assumptions early in the process, allowing for meaningful feedback and discussion about inputs and methodology. The company utilized public data when possible to provide transparency, and confidential data was provided to interested stakeholders, consistent with Non-Disclosure Agreements.

IPL's Preferred Resource Portfolio, highlighted in Figure A, adds over 1,000 MW of wind, solar, storage, and DSM by 2030 and over 3,000 MW by 2039. The retirement of Petersburg Units 1 and 2 by 2023 allows IPL to take advantage of expiring tax credits for wind and solar, which benefits customers in both the short term and long term.

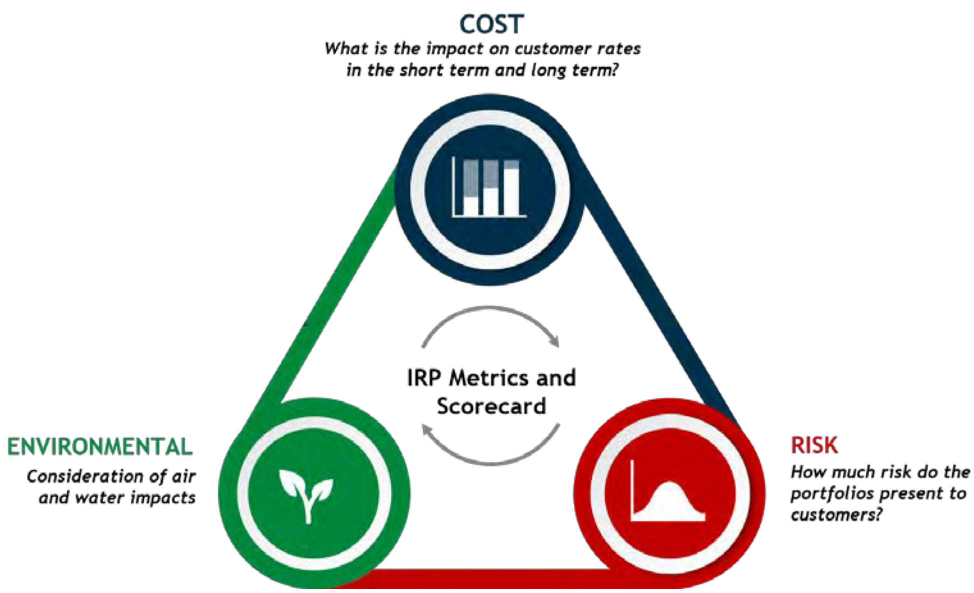
Figure A | Candidate Portfolios: Cumulative Capacity Changes through 2039



IRP Modeling Results Summary

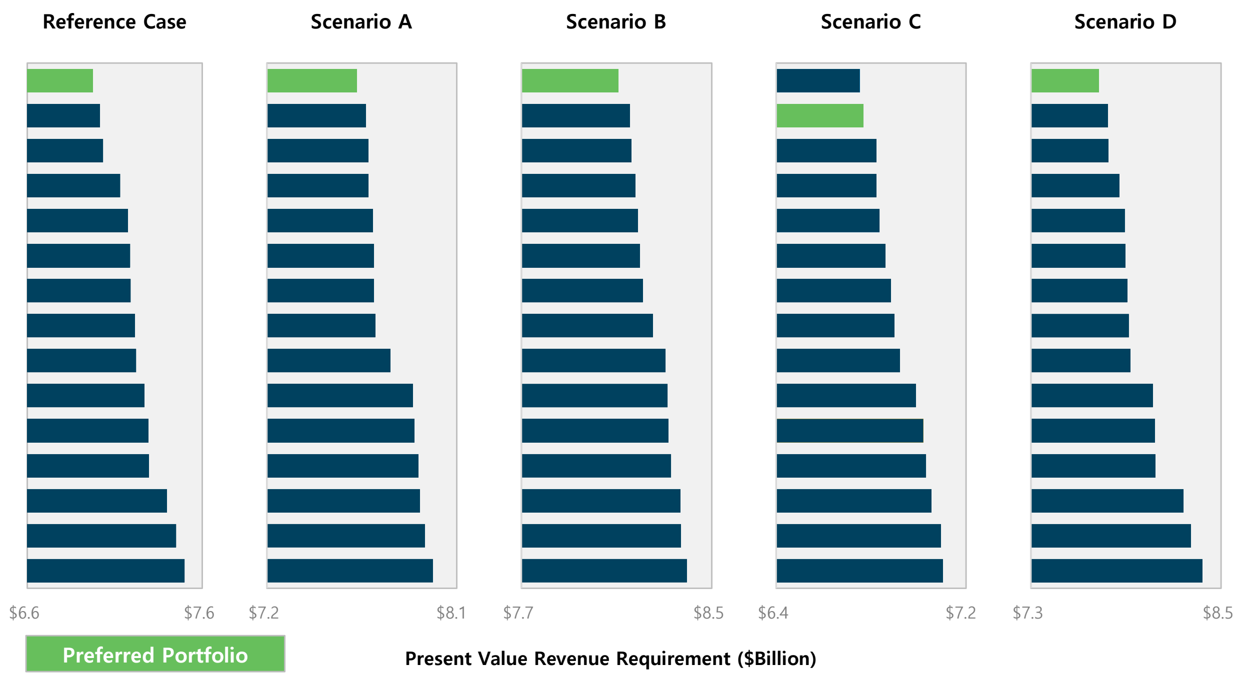
The decision criteria for selecting the Preferred Resource Portfolio (Figure B) was based on a comprehensive set of stakeholder informed modeling and analysis and comparison of each portfolio on attributes for cost, risk, and environmental impact. Additionally, IPL considered other qualitative factors in to the decision, including employee and community impact, the ability of the plan to react to changing market conditions, and the risks that each portfolio could introduce to IPL customers.

Figure B | 2019 IRP Portfolio Metrics Foundation



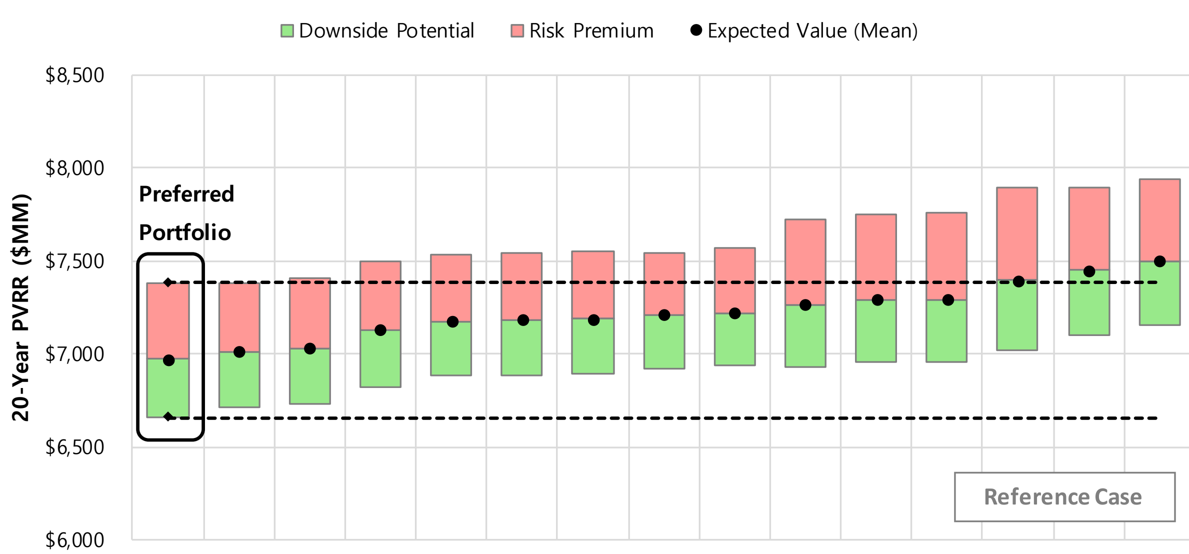
As shown in Figure C, the Preferred Resource Portfolio was the lowest cost portfolio across multiple scenarios and provides a balance of long-term portfolio savings and mitigation of short term rate impacts. Economic retirements of Pete 1 and 2 will create cost savings that can be used to offset the cost of replacement capacity. In modeling sensitivities on the cost of replacement capacity, IPL found that the Preferred Resource Portfolio is the lowest cost plan even if the cost of replacement resources is higher than what we currently forecast. Overall, the Preferred Resource Portfolio, which retires two coal units by 2023 and fills the capacity shortfall with a mix of DSM, wind, solar, and storage, is the lowest cost plan for IPL customers.

Figure C | Preferred Resource Portfolio: Lowest Cost Across Wide Range of Scenarios



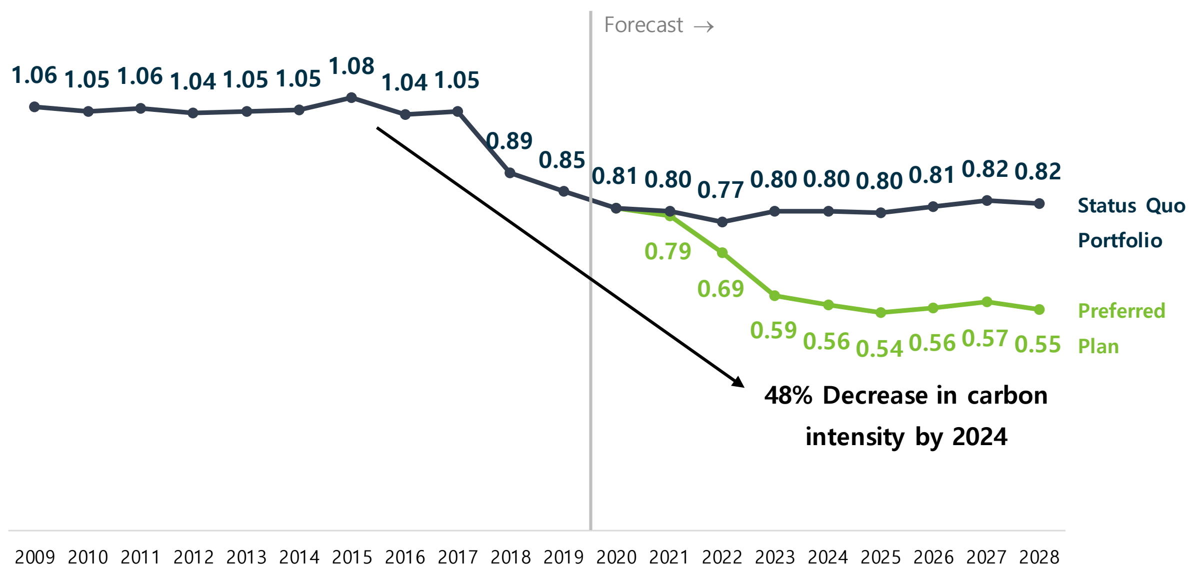
Through IPL's robust modeling effort that incorporated risk and uncertainty with stochastic modeling of weather, load, renewable profiles, and commodity prices, we were able to effectively build risk analysis into the entire modeling framework and decision analysis in this IRP. The variations in modeling assumptions applied probabilistically across multiple scenarios created a wide range of uncertainty considered. Figure D shows that the Preferred Resource Portfolio provides the optimal tradeoff of risk and cost for IPL customers.

Figure D | Preferred Resource Portfolio Lowest Cost on Risk-Adjusted Basis



In addition to benefits of being the lowest cost and least risk plan, the Preferred Resource Portfolio also allows IPL to significantly improve our carbon footprint and continue our decade-long efforts for portfolio diversification and decarbonization. As shown in Figure E, over the course of a 10-year period (2014-2023), IPL will be able to reduce our carbon intensity by almost 50% while at the same time providing our customers with future cost-effective carbon mitigation strategies.

Figure E | IPL Carbon Intensity, 2009 – 2028 (tons/MWh)



Section 1: Introduction

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 Reliability Corporation ("NERC"), which has been designated as the Electric Reliability Organization under the Energy Policy Act of 2005 ("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.

Every three years, IPL submits an Integrated Resource Plan ("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.

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

1.1 IRP Objective

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The objective of IPL's IRP is to identify a preferred resource portfolio to provide safe, reliable, sustainable, and reasonable least cost energy service to IPL customers. The study period for this IRP is 2020-2039, giving due consideration to potential risks and stakeholder input.

IPL engaged in a bottom-up review of every modeling assumption and modeling approach from the 2016 IRP in preparation for this IRP. Through five public stakeholder meetings and three technical workshops, IPL developed the assumptions and modeling framework in an open, transparent, and fact-based manner that considered a wide range of factors facing IPL's generation fleet over the next 20 years. A robust analytical process coupled with qualitative risk analysis contributed to the selection of the preferred resource portfolio.

1.2 Guiding Principles

IPL's guiding principles describe more fully its decision analysis process:

1. IPL will comply with IURC Orders, Indiana Administrative Code ("IAC") requirements, North American Electric Reliability Council ("NERC") reliability standards and FERC approved MISO tariffs.
2. Cost estimates for supply-side resources were based on a thorough analysis of cost estimates from multiple sources and benchmarked to recent public all-source RFP information. Demand-side management cost estimates were based on a detailed MPS report built up from the measure level.
3. Demand Side Management ("DSM") modeling included traditional capacity expansion modeling as well as an incremental decrement analysis.
4. IPL plans to continue to offer cost-effective DSM programs that are inclusive for customers in all rate classes while appropriate for our market and customer base, modify customer behavior, and provide continuity from year to year.

IPL assumed the following parameters remain constant in the IRP study period of 2020-2039. Should these change in the future, the analyses subsequent to the 2019 IRP may vary.

- Regulatory framework remains – This IRP assumes current regulatory frameworks for IPL based on the IURC and FERC scopes of jurisdiction.
- MISO capacity construct – While IPL is aware of MISO's plans to propose tariff changes to its capacity construct with FERC via the recent Resource Availability and Need (RAN) process, the specific details are not yet known and the filing not yet complete. Therefore, the resource capacity requirements for this study period are based upon the current construct.
- MISO interaction – IPL will continue to engage in the MISO stakeholder process to influence tariff and business practice changes to benefit customers.
- Distributed Generation – Distributed Generation ("DG") is synchronized with the distribution grid as a best safety practice and designed to align with system requirements to support no production curtailment such as might occur with wind resources connected to a transmission system.

IPL recognizes the following items may initiate future changes in its resource portfolio.

- Technology improvements – All resource technologies will likely improve in performance. The model assumes known factors today and projected cost forecasts based on industry knowledge.
- Future elections – Policy changes may follow national, state and local election results in the next few years.
- Stakeholder sustainability interests – As discussed in multiple stakeholder forums within the IRP public advisory process, regulatory proceedings, customer meetings, and investor interactions in the normal course of business, IPL recognizes the potential for continued pressure to change its resource mix in response to advocates' interests in cleaner sources of energy.
- Environmental regulations – the largest driver of portfolio value in modeled scenarios involved the impact of a carbon tax in scenarios. While no federal carbon tax exists, public pressure, proposed legislation, and corporate support for carbon pricing has led us to include a carbon tax as a proxy for future carbon legislation. The carbon tax level and formation of prices could vary significantly. Any future IRPs will incorporate changes in the state and federal environmental landscape.

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

1.3 2019 IRP Improvements

IPL has incorporated changes in its 2019 IRP based on stakeholder feedback from its 2016 IRP. Changes are summarized in Figure 1.1.

Figure 1.1 | Targeted IRP Improvements

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

The IRP results include potential candidate future resource portfolios considering uncertainties and risk factors identified to date. Subsequent resource changes which may result after the submission of IRPs will be based upon further analysis and specific competitive processes with detailed regulatory filings before the IURC.

1.4 Stakeholder Engagement

170 IAC 4-7-4(30)

The 2019 meeting series included discussions of the IRP process, modeling assumptions, data inputs, modeling DSM, scenario development, sensitivity analysis, modeling results, and metric analysis to compare portfolios. IPL incorporated stakeholder suggestions throughout the process, such as completing a DSM decrement analysis. Furthermore, IPL provided data releases of detailed modeling assumptions early in the IRP process. The first release was on April 19, 2019 (Data Release #1). Followed by Data Release #2 (May 14, 2019), Data Release #3 (June 21, 2019), Data Release #4 (October 28, 2019), Data Release #5 (November 6, 2019), and Data Release #6 (November 14, 2019).

IPL engaged in discussions with individual stakeholders and its Advisory Board. Prior to Public Advisory Meetings, IPL met with technical stakeholders who executed a Nondisclosure Agreement ("NDA") with IPL regarding IRP information. In these technical workshops, IPL provided data files and discussed modeling status and results. IPL approached stakeholders early and often for ample discussion and time for feedback.

Discussions proved to be quite productive and facilitated dialogue among stakeholders prior to the IRP filing. Public Advisory Meeting materials are provided as Attachment 1.2.

1.5 Contemporary Issues

170 IAC 4-7-4(17)

IPL participates in the Commission's IRP Contemporary Issues Technical Conference held each year. In 2019, the Conference was held on April 15, 2019. IPL Director of Resource Planning, Patrick Maguire, was a panelist on the topic of "Utilization and Maintenance of Massive Data Bases" and IPL Director of T&D Operations, Mike Holtsclaw, was a panelist on the topic of "Integration of DERs into Distribution System Planning and IRPs". The Conference also covered topics such as load shapes, the changing availability and flexibility requirements of MISO, long-term utility planning assumptions and procurement decisions, preliminary lessons learned from NIPSCO's all-source RFP, risk analysis and life cycle analysis of greenhouse gas emissions.

Section 2: Resource Adequacy and Transmission Planning

170 IAC 4-7-6(a)(5) 170 IAC 4-7-6(b)(4)(D)170 IAC 4-7-6(b)(4)(E)

2.1 Resource Adequacy

To be resource adequate, a utility must possess enough resources to satisfy forecasted future loads. The IRP process focuses on developing potential resource portfolios needed to meet two different types of customer needs: energy use and peak demand. Annual energy use is measured in MWh to reflect the accumulation of electricity used over time. Annual peak demand is the measure of the highest hour of usage for the year and is measured in MW. The Resource Adequacy analysis serves as the foundation of the IRP process to create resource portfolios to meet the annual forecasted peak demand throughout the 20-year study period. Energy contributions of each resource are dependent upon the economic dispatch model results in individual scenarios. Each scenario includes a set of input assumptions which are based upon varying potential futures and related risks such as commodity prices and increased or decreased load growth. The scenarios are described in Section 7 of this IRP.

2.1.1 Reserve Margin Criteria

When planning to meet future peak needs, utilities input the expected (forecasted) peak demand, plus an appropriate Planning Reserve Margin ("PRM"). PRMs are necessary to account for two primary uncertainties: forecast uncertainty and resource availability uncertainty.

MISO calculates an Installed Capacity ("ICAP") PRM and an Unforced Capacity ("UCAP") PRM. The ICAP PRM is higher than the UCAP PRM because it does not account for generator outage events that translate into a unit's Equivalent Forced Outage Rate Demand ("xEFORd"). For the 2019-2020 MISO Planning Year, the ICAP PRM is 16.8% and the UCAP PRM is 7.9%. IPL's capacity expansion model accounts for individual units' xEFORd, and therefore uses the UCAP PRM, or 7.9%. This more accurately reflects how IPL's assets participate in MISO's Planning Resource Auction.

MISO defines a Planning Year in seasonal terms of June 1 through May 31. The 7.9% PRM is based on Loss of Load Expectation ("LOLE") Studies performed annually by MISO and applied across the footprint.[1] LOLE Studies are used to determine an appropriate PRM given many factors including the forecast uncertainty and resource availability uncertainty across the MISO footprint. Consideration is given to historic forecast error, historic unit unavailability at time of peak, the type and size of

[1] MISO's most recent LOLE study may be found at this link: https://cdn.misoenergy.org/20180911%20LOLEWG%20Item%2002%202019-20%20PY%20LRR%20%20PRM273420.pdf

generating units and other resources, and the transmission system configuration. MISO uses load forecast information from Load Serving Entities ("LSEs") coupled with the previous calendar year actual system peak to determine coincidence factors for subsequent year planning purposes in the LOLE process. The coincident peak factor measures how closely IPL's specific peak load aligns with the MISO footprint peak load. For 2020, the IPL coincidence peak factor is 97.33% and is used throughout the IRP study period. IPL multiplies the peak load by 0.9733 to account for IPL's peak load being shifted slightly from MISO's peak load.

The MISO LOLE Studies produce a PRM that when applied to all the peak load forecasts in the MISO footprint results in an expectation of one loss of load event once every 10 years. That is, if all utilities in the MISO footprint carried an average of 7.9% reserves, the expectation would be that once every 10 years there would be a loss of load event somewhere in the footprint resulting from peak load exceeding resources available at peak. The LOLE study accounts for generation and transmission reliability impacts. Actual reserve margins will vary annually in part due to the "lumpy" nature of adding resources, load variances and other factors.

2.1.2 Resource Capacity Credit

Resource capacity that is planned to meet the Planning Reserve Margin Requirement ("PRMR") is calculated differently for varying technologies. The PRM is used to cover uncertainty related to both unavailability of traditional resources and forecast error. Resource capacity credits are based upon MISO business practices in terms of ICAP and UCAP.[2] For thermal units, ICAP is based upon annual maximum unit capability test results, also called the Generation Verification Test Capacity ("GVTC"). UCAP is calculated from the ICAP value, the results of annual GVTC and a 3-year rolling average of the xEFORd.

Wind capacity credit is calculated from its Effective Load Carrying Capability ("ELCC") which accounts for the probabilistic shortfalls of wind generation coinciding with peak load in the MISO footprint. Due to the mismatch of low wind production during high load periods, wind is given a much lower capacity credit than thermal generation. MISO's latest study for Indiana (Zone 6) indicates an ELCC of 7.8%.[3] All resources must have firm transmission to receive capacity credit. IPL has firm transmission for Hoosier Wind Park but not for Lakefield Wind Farm, so it only receives capacity credit for Hoosier Wind Park.

[2] For more detail see MISO Business Practices Manual (BPM-11) at this link:
https://www.misoenergy.org/legal/business-practice-manuals/

[3] https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf.

Similarly, production from solar units at time of peak load have proven to be less than traditional thermal unit production. MISO currently gives solar a capacity credit of 50%, which is approximately the capacity credit applied to the 96 MW of solar generation under contract in IPL's service territory. The contracted solar is connected to the IPL distribution system and reduces its load requirements and associated PRMR rather than being offered as a resource in the MISO market. Increased penetration of solar in the MISO footprint will change the net load profile and dictate a lower capacity credit over time. IPL has accounted for this and it is covered in more detail in Section 5.

Demand response resource capacity credit is based upon the capability of the resource to contribute to peak demand reductions for a minimum of four hours based on engineering estimates or field testing. IPL is modeling 55 MW of UCAP capacity from demand response resources. These resources provide capacity credit through the Air Conditioning Load Management ("ACLM") program, Conservation Voltage Reduction ("CVR") program, and Rider 17 of IPL's tariff. These programs contribute 38.6 MW, 15.3 MW, and 1.1 MW respectively and are considered Load Modifying Resources ("LMRs") in MISO.

IPL does not include capacity credit for its existing Battery Energy Storage System ("BESS"). While it has the capability to provide capacity credit, IPL operates the BESS to provide Primary Frequency Response and other reliability services.

2.1.3 The MISO Capacity Construct

While IPL's IRP process is used to develop long term plans for providing the energy and capacity needs of IPL's customers, IPL also participates in MISO's resource adequacy (or capacity) construct as outlined in Module E-1 of MISO's FERC approved tariff.[4] IPL, not MISO, is responsible for resource adequacy and developing long term resource plans per 170 IAC 4-7.

Since MISO's capacity adequacy construct is focused on the short term (one planning year), its focus is on existing resources and does not plan for resources in the future.

Each November each LSE provides MISO with a peak demand forecast for the following Planning Year. MISO adds a reserve margin, based on its most recent LOLE Study, and adds MW to cover expected transmission losses to produce each LSE's PRMR.

MISO conducts an auction each April, and if an LSE has resources in the MISO accounting system equal to its PRMR, then that LSE will not be billed capacity costs in the auction. If an LSE has less capacity than its PRMR in the MISO capacity accounting system at the time of the auction it will be assessed

[4] MISO FERC Approved Tariff can be found at https://www.misoenergy.org/legal/tariff/.

capacity costs by MISO for its shortage in the auction. If an LSE or other type of Market Participant has more capacity than PRMR, it may receive revenues from the excess capacity in the auction.

In addition to owning a resource with capacity credit, an LSE can also purchase or sell capacity through the bilateral market in order to meet its PRMR. By allowing resource owners and LSEs to buy and sell capacity credits from each other, and at the same time requiring that each LSE meet its PRMR with an appropriate number of capacity credits prior to the summer, the MISO capacity construct allows utilities to optimize their investments and not exactly meet their PRMR with their own resources. Figure 2.1 describes the PRMR calculation. Figure 2.1 illustrates the PRMR for IPL for a single year.

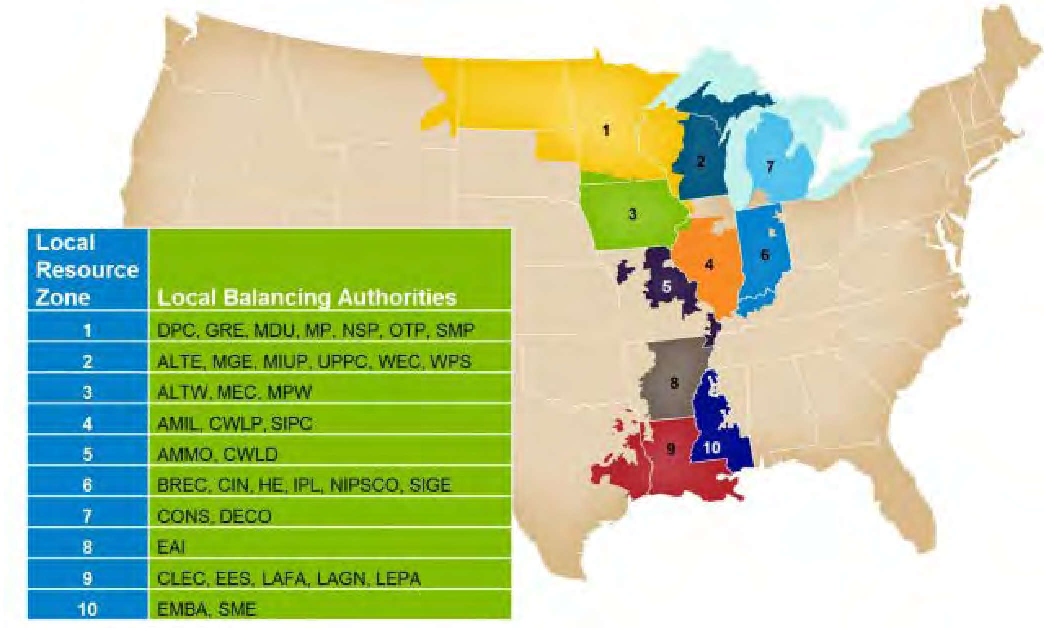
Figure 2.1 | Illustrative Example – Annual Reserve Margin Requirement Calculation

(A)	Non-Coincident IPL Peak Load Forecast	3,003 MW	
(B)	IPL Coincident Peak Factor	97.33%	
(C)	IPL Coincident Peak Load Forecast	2,923 MW	(C) = (A)*(B)
(D)	Losses	2.1%	
(E)	IPL Peak Load Forecast	2,985 MW	(E) = (C)*(1+D)
(F)	MISO Planning Reserve Margin	7.9%	
(G)	Final IPL Planning Reserve Margin Requirement	3,220 MW	(G) = (E)*(1+F)

By holding each LSE accountable for meeting its PRMR, MISO can be assured that the resources will meet or exceed the forecasted MISO demand and reserve margin as determined in MISO's annual LOLE study.

MISO established zones for it auction framework as shown in Figure 2.2. IPL is in Zone 6.

Figure 2.2 | MISO Zones [5]



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

If all LSEs satisfied their PRMR with resources from the Zone in which their load resides the Zones would not be needed. But since the auction sometimes uses resources from one zone to meet the needs in another zone the auction must establish and honor transport limits between zones. Honoring transport limits can result in clearing prices being different for different zones. MISO's capacity construct has resulted in varying prices by zone over the past several years.

MISO is always considering what must be done to maintain service and reliability throughout the footprint. Most recently the RAN initiative is evaluating proactive practices to keep pace in a changing energy landscape, namely an aging generation fleet and increased renewable generation penetration. Through this RAN effort, MISO will study the potential implementation of a seasonal capacity construct as opposed to the current annual planning year. This is in the early stages and not much is known yet about what a potential seasonal construct would look like, let alone whether it would be implemented. For this reason, IPL has modeled the Planning Resource Auction ("PRA") as it currently exists but will continue to follow the issue through the MISO stakeholder process.

[5] https://cdn.misoenergy.org/2019%20LOLE%20Study%20Report285051.pdf.

2.2 Fuel Procurement

170 IAC 4-7-4(20)

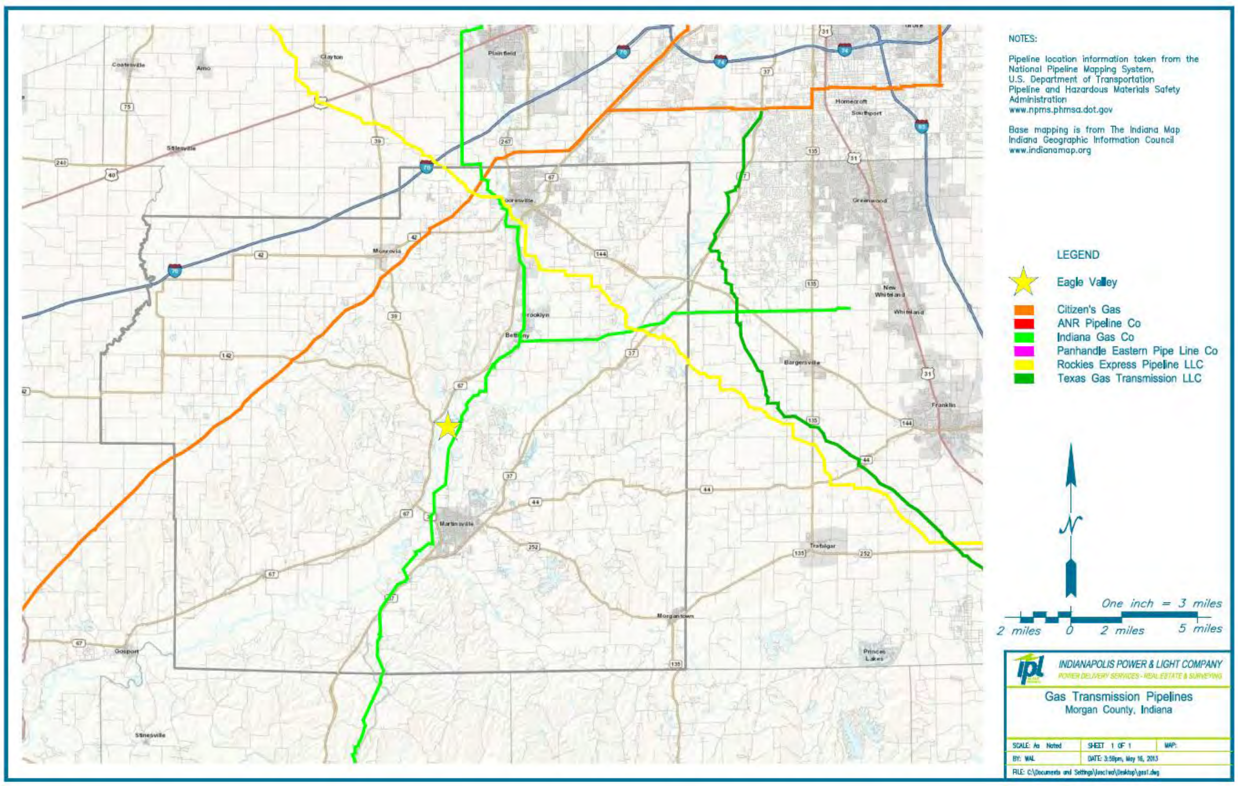
IPL procures and manages a reliable supply of fuel for its generating units at the lowest cost reasonably possible, consistent with maintaining low busbar cost and compliance with all environmental requirements and/or guidelines. Busbar costs reflect those costs needed to produce a kilowatt of energy at the production facility. They do not include transmission or substation expenses.

IPL seeks competitive prices for coal using competitive bidding for both long-term contracts and spot purchases. Long term contracts provide price and supply certainty for IPL customers. Spot purchases are made for three reasons: (1) to meet needs of short term position due to stronger than forecast burns; (2) to test quality of coal and reliability of the producer; (3) to take advantage of occasional low market price coal. IPL considers all material factors, including, but not limited to; (a) availability of supply from qualified suppliers, (b) current inventory levels, (c) diversity of suppliers and transportation options, (d) forecast of fuel usage, (e) market conditions and other factors affecting price and availability, and (f) existing and anticipated environmental standards. To help manage market variability from year-to-year, IPL uses a combination of multi-year contracts with staggered expiration dates to limit the extent of IPL's coal position open to the market in any given year. Many of these multi-year contracts contain some level of volumetric variability as an additional tool to address market variability. IPL prepares long-term projections of fuel purchased, annual inventory levels, quality, and delivered cost for each plant.

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

Natural gas ("NG") is currently purchased on a daily basis as required based on availability and pricing from several suppliers for its NG-fired peaking units at Harding Street and Georgetown. The Eagle Valley CCGT dispatches as a baseload unit so IPL uses a combination of baseload hedges that may include fixed price, index, and daily purchases to supply natural gas to the station. IPL maintains firm pipeline transportation contracts which provide access to Texas Gas Transmission ("TGT") supply zones to supply the Eagle Valley CCGT and Harding Street. The TGT contracts allow IPL scheduling flexibility to draw or hold limited quantity of natural gas which is used for unexpected unit starts & stops to mitigate fuel availability risks. The lateral gas line that serves the Eagle Valley CCGT also has a connection to the Rockies Express pipeline ("REX"). Having a connection with two major supply pipelines allows IPL the ability to balance these two sources for pricing advantages as well as supply certainty. Figure 2.3 is a map of gas transmission around the IPL Eagle Valley CCGT. Since the Georgetown and Harding Street units are used for peaking needs only, firm transportation contracts are not cost-effective. IPL contracts with Citizens Gas for firm redelivery and balancing services to the generating units located at the Harding Street and Georgetown plants, and with Vectren for firm redelivery to the Eagle Valley CCGT.

Figure 2.3 | Gas Transmission Map



2.3 Transmission Planning

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

2.3.1 Transmission System Overview

IPL provides electric power to the City of Indianapolis and portions of the surrounding counties as a member of MISO. The IPL transmission system consists of approximately 458 circuit miles of lines at 345,000 volts ("345 kV), 408 circuit miles of line at 138,000 volts ("138 kV"), and associated substations.

The IPL transmission system includes 345 kV and 138 kV voltage levels. The 345 kV system consists of a 345 kV loop around the City of Indianapolis and 345 kV transmission lines connecting the IPL service territory to the Petersburg power plant in southwest Indiana. At Petersburg, IPL has 345 kV interconnections with Indiana Michigan Power Company ("AEP"), which ties to the PJM footprint and Duke Energy Indiana ("DEI"), and 138 kV interconnections with DEI, Hoosier Energy Rural Electric Cooperative, Inc. ("HE"), and Vectren Corporation ("Vectren") within the MISO footprint. In the Indianapolis area, IPL has 345 kV interconnections with AEP and DEI and 138 kV interconnections with DEI and HE. Autotransformers connect the 345 kV network to the underlying IPL 138 kV network transmission system which principally serves IPL load.

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

2.3.2 Transmission Planning Process

170 IAC 4-7-4(27)

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

As a member of MISO, IPL actively participates in the MISO Transmission Expansion Plan ("MTEP") process with MISO functioning as the NERC registered Planning Coordinator ("PC"). MISO annually performs MTEP studies to facilitate a reliable and economic transmission planning process. The IPL assessment and MTEP study process includes identification of transmission issues, optional proposals and selects efficient solutions. MISO through either the MTEP or other study processes may additionally propose transmission system projects or other upgrades that are not reliability based but are economically based to relieve congestion. For potential economic projects, MISO assesses costs and benefits to ensure that costs allocated are commensurate with benefits received. Factors in the cost/benefits analysis include: the value of congestion, fuel savings, reductions in operating reserve needs, system planning reserve margins, and transmission line losses of a proposed transmission project or portfolio. Through the MTEP, MISO ensures that transmission is developed system-wide through one uniform planning process that coordinates system needs in order to minimize costs. Generator interconnection requests (additions or material modifications) to the IPL system would be coordinated and studied through the MISO Generation Interconnection Process. Generator retirements would be studied through the MISO Attachment Y process. IPL actively participates in these MISO processes to ensure that the transmission system meets the performance requirements.

The MTEP analysis may be found on the MISO website at URL:

https://www.misoenergy.org/planning/planning/mtep-2018-/

ReliabilityFirst also performs seasonal, near-term, and long-term assessments of transmission system performance conditions based on information from each transmission planner including both MISO and IPL. The transmission system seasonal assessment summarizes the projected performance of the bulk transmission system within ReliabilityFirst's footprint for the upcoming summer peak season and is based upon the studies conducted by ReliabilityFirst staff, MISO, PJM, and the Eastern Interconnection Reliability Assessment Group ("ERAG"). As an entity within the reliability region of ReliabilityFirst, IPL actively participates and reviews the studies and study processes of the assessments.

These assessments may be found on the RF website at URL:
https://rfirst.org/ProgramAreas/RAPA/

IPL seeks to upgrade on a regular basis its ability to model the transmission system and to more accurately forecast its performance. This includes review of available computer software, data collection techniques, equipment capabilities and parameters, and developments in industry and academia. It also includes information sharing with neighboring transmission owners and regional transmission organizations.

Based on its own individual efforts, as well as in concert with others, IPL constantly works to ensure that its transmission system will continue to reliably, safely, efficiently, and economically meet the needs of its customers.

IPL's FERC Form 715 was submitted by MISO to FERC. The FERC 715 was based on MTEP 18 studies which contain the most recent power flow study available to IPL including interconnections. In MTEP 18, MISO conducted studies using models for 2020 Spring Light Load, 2020 Summer Peak, 2023 Spring Light Load, 2023 Summer Shoulder, 2023 Summer Peak, and 2028 Summer Peak. MTEP 19 studies are being finalized.

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

2.3.3 Transmission Planning Criteria

170 IAC 4-7-4(27)

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

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

A summary of IPL transmission planning criteria follows. IPL transmission planning criteria are periodically reviewed and revised.

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

("IEEE") standards, National Electrical Safety Code, IPL electric service and meter guidelines, and all other applicable local, state, and federal laws and codes. Guidelines of the National Electric Code may also be incorporated.

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

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

IPL transmission facilities are also planned and coordinated with the following reliability criteria.

The reliability standards of NERC including the Transmission System Planning Performance Requirements ("TPL") standards, Modeling Data Analysis ("MOD") standards, and Facility Ratings ("FAC") standards. The NERC reliability standards may be found on the NERC website at http://www.nerc.com .

The regional reliability standards of the reliability entity ReliabilityFirst. The RF reliability standards may be found on the RF website at http://www.rfirst.org. IPL is in the RF region.

The IPL Transmission Planning Criteria can be found on the MISO website at https://www.misoenergy.org/planning/transmission-planning/#nt=%2Freport-study-analysistype%3ATO%20Planning%20Criteria&t=10&p=0&s=&sd=asc

IPL complies with NERC TPL-001-4 Planning Events (Contingencies). The transmission system is assessed to meet the performance requirements for System performance of the Bulk Electric System under each Category:

- (Category P0) Under normal (no contingency) conditions.
- (Category P1) For the loss of the one of the following elements: Generator, transmission circuit, transformer, shunt, or single pole of a DC line.
- (Category P2) System performance of the Bulk Electric System for the loss of the one of the following elements: Opening of a line section w/o a fault, bus section fault, or internal breaker fault.
- (Category P3) For loss of multiple elements: Generator and a generator, transmission circuit, transformer, shunt, or single pole of a DC line.

- (Category P4) Following the loss of multiple Bulk Electric System elements caused by a stuck breaker attempting to clear a fault on a generator, transmission circuit, transformer, shunt or bus section.
- (Category P5) Following the loss of multiple Bulk Electric System elements due to a delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following generator, transmission circuit, transformer, shunt or bus section.
- (Category P6) For loss of multiple elements: Transmission circuit, transformer, shunt, or single pole of a DC line.
- (Category P7) For loss of multiple elements for circuits on common structure or loss of a bipolar DC line.

2.3.4 Transmission System Performance Assessment

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

Summary of Performance

- IPL transmission performance analysis using dynamic simulations for stability as evaluated under the NERC Transmission System Planning Performance Requirements (“TPL”) reliability standards shows no evidence of system or generator instability.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows a few localized thermal violations appearing on IPL lines and transformers resulting primarily from multiple element outages of internal IPL transmission facilities.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows transmission voltages in the expected range on IPL facilities.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows expected loss of demand that is planned, controlled, small, and localized.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of curtailed firm transfers.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of area-wide cascading or voltage collapse.

- Applicable operating and mitigation procedures, in conjunction with planned major transmission facility additions and modifications, result in transmission system performance which meets the requirements of the NERC TPL reliability standards.

At the present time there is no measure of system wide reliability that covers the reliability of the entire system that includes transmission, distribution, and generation.

2.3.5 Coordinating Transmission and Resource Planning

During the evaluation of future resource portfolios, it is important that transmission system limitations are evaluated to ensure reliability. One process used to evaluate the transmission system is a power transfer study to determine the import capability into the IPL load pocket. The IPL load pocket is the Indianapolis area load that is supplied by the highly networked IPL 138 kV transmission system that is supplied by external and internal generation. External generation is primarily supplied by seven 345 kV transmission lines connected to a 345 kV loop around load pocket. The 345 kV transmission loop design is analogous to Interstate 465 around Indianapolis. The 345 kV loop connects to the 138 kV system through 345-138 kV autotransformers. The 345-138 kV autotransformers can be analogously thought of as off-ramps on the interstate. Internal generation is interconnected directly to the 138 kV transmission system and is currently located at the three IPL generation plants: Harding Street, Eagle Valley, and Georgetown.

If future resource plans remove generation that is interconnected directly to the 138 kV transmission system, assuming all other parameters remain consistent, more power must be supplied by external generation and transferred to serve the IPL load pocket. A transfer study determines transmission system limitations for the applicable reliability criteria. If the transfer capability is insufficient for a future resource plan, additional transmission upgrades would be needed to meet the reliability criteria. Additionally, the current internal generation provides other ancillary services like reactive power and voltage control, short circuit strength, frequency response and Blackstart capability. Specific analyses will determine the need for any additional upgrades or modification to the transmission system which may be needed to provide these services.

The import capability into the IPL 138 kV system for different NERC contingency categories include a single element failure or breaker failure ranges from 2,233 to 2,934MW. The limit based on a double element failure ranges from 1,415-2,005 MW. Figure 2.4 depicts detailed information about these contingencies.

Figure 2.4 | Import Capability Summary

NERC Category	Limiting Element	Import Capability (MW)	Contingency Description
Single Element (P1)			
2022	Guion North XFMR	2233	Guion South 345-138 kV XFMR
2025	Stout Auto XFMR	2934	Rockville to Thompson 345 kV line
Breaker Failure			
2022	Guion North XFMR	2233	345 kV Breaker #20 at Guion
2025	Future Guion XFMR	2556	Guion N & S 345-138 kV XFMR
Double Element (P6)			
2022	Guion North XFMR	1415	Guion South 345-138 kV XFMR &Whitestown to Hortonville 345 kV line
2025	Hanna East XFMR	2005	Hanna to Stout & Hanna to Sunnyside 345 kV lines
* Import capability can vary based on many factors			

Section 3: Distribution Planning

3.1 IPL's Distribution System Overview

The distribution system consists of 4,961 circuit miles of underground primary and secondary cables and 6,110 circuit miles of overhead primary and secondary wire. Underground street lighting facilities include 773 circuit miles of underground cable. Also included in the system are 138 substations. Depending on the voltage levels at the substation, some substations may be considered both a bulk power substation and a distribution substation. There are 73 bulk power substations and 117 distribution substations; 52 substations are considered both bulk power and distribution substations. IPL uses a Secondary Network System to serve the City of Indianapolis Central Business District, sometimes also referred to as the "Mile Square." A unique feature of the Secondary Network System is that the loss of a single component, such as a primary feeder or a network transformer, typically will not result in any customer losing power.

IPL is incrementally investing in smart grid assets. Standard equipment specifications include smart grid enabled communication devices, such as relays, reclosers, load tap changers ("LTCs"), and capacitor controls. In 2016, IPL deployed a Distributed Temperature Sensing ("DTS") pilot project to monitor temperature in the duct lines and manholes of the downtown network system. The system uses fiber optic cable to monitor temperatures in one-meter increments. As of 2016, IPL has installed approximately 36,000ft of fiber optic cable for the DTS project. In addition to the DTS project, in 2018, IPL deployed a Distributed Acoustic Sensing pilot project ("DAS"). The DAS system essentially turns the fiber optic cable into a linear acoustical sensor. The system allows us to determine the location of primary cable faults and potential damage to our infrastructure from other entities. As part of the proposed IPL TDISC Plan, see Section 3.3, starting in 2020, IPL would install over 100,000ft of fiber optic cable to complete both the DAS and DTS systems.

3.2 Distribution System Planning

170 IAC 4-7-4(18)

IPL's Electric Distribution System Plans are based on various criteria and parameters that are used to determine expansion and replacement requirements. The criteria and parameters include: consideration of load growth, equipment load relief, timely equipment replacement to optimize performance, effects of major system events, reliability improvements, National Electric Safety Code ("NESC") requirements, and industry guides and design standards.

Distribution construction projects are based on the results of IPL's small area load studies. Grid area data, such as historical data, land use statistics, and demographic customer data, provide the basis for long-range demand projections. These projections are modified for the short-term based on known customer additions, DG projects, and recent historical substation load growth since the grid area data cannot predict short-term deviations from long-term statistical trends. Distribution substations additions or improvements are planned when projected area loads cannot be served from existing substations or if existing substation facilities reach their design limits. In parallel, circuit construction is planned to utilize newly installed substation capacity, to provide relief to circuits projected to exceed design capacity, or to improve reliability or operational performance.

Industrial substation expansion provides capacity for known industrial load additions and relieves existing or anticipated overloaded facilities. Several customers, either by internal policy or government regulations, may be required to maintain 100% emergency capacity, and the Company's additional investment is recovered through excess facility agreements. IPL's policy is to provide such service to certain public service customers, such as hospitals and communications facilities, provided the customer meets specific engineering design criteria.

3.3 IPL's Pending Transmission Distribution Storage System Improvement Charge ("TDSIC") Plan

On July 24, 2019, IPL filed its TDSIC Plan with the IURC. IPL's TDSIC Plan proposes seven years of defined investment, totaling $1.2 billion, to replace, rebuild, upgrade, redesign and modernize a wide range of IPL's aging T&D system assets in two thematic areas: *Age and Condition*, and *Deliverability*.

The *Age and Condition* (83.3% of the estimated Plan cost) category addresses the many risks posed by aging assets. The category includes the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and rebuilding portions of the central business district. The *Deliverability* (16.7% of the estimated Plan cost) category deploys new technologies for advanced distribution management, adds new substation equipment to meet growth-driven capacity requirements, and creates system and operating efficiencies through automation, control functions, and other advanced infrastructure.

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

For more information on IPL's pending TDSIC Plan, see IURC Cause No. 45264. As part of IPL's proposed TDSIC Plan, certain projects will have impacts on the IPL Distribution System. These projects include 4 kV Conversion project, Advanced Metering Infrastructure project and Distribution Automation project. These projects, if approved by the Commission, contribute to a hardened and resilient grid which can better withstand the impact of weather and is easier to restore when outages inevitably occur.

3.3.1 4 kV Conversion

Included in the IPL TDSIC Plan, a 4.16 kV to 13.2 kV conversion plan is included and consists of the replacement of critical transformers and the conversion of radial circuits where 13.2 kV sources are available to avoid overloads on critical substations. This plan is formulated to avoid the failure of adjacent substations that may lead to a cascading outage event. Any equipment with remaining life that is removed due to conversion is used to provide adequate capacity to the remaining 4.16 kV loads, to provide spare units to cover unforeseen transformer or switchgear failures, or to permit the retirement of equipment which has outlived its useful life and cannot provide reliable service.

3.3.2 Advanced Metering Infrastructure ("AMI")

170 IAC 4-7-4(16)

If approved by the IURC under the IPL TDSIC Plan, IPL will replace approximately 350,000 residential and small commercial single and three phase electric meters over a five-year period beginning in 2020. The planned deployment rate is approximately 5,833 per month. IPL has been using an Automatic Meter Reading ("AMR") system for its energy-only metered customers since 2001 to automatically read meters. Since the AMR system operates well in acquiring daily readings for energy only meters, beginning in 2010, as part of the Smart Energy Project, IPL initiated AMI to capture demand meter interval data which was still being manually read. There have continued to be additional single-phase meter replacements since that time. IPL has 182,162 AMI meters as of October 2019 with remote connect/disconnect capability located in areas of high customer turnover. Over 99% of IPL's meters are automated, which enables customers using the IPL web-portal known as PowerView® to see their energy usage information (with a one-day delay).

AMI benefits include 15-minute interval usage data, avoided truck rolls for service reconnection, better outage prediction through a "last gasp" from meters, remote verification of outage status, remote voltage sensing which supports distribution operations, and residual customer satisfaction from these enhanced services

3.3.3 Distribution Automation

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

As part of the pending TDSIC Plan, the Distribution Automation Project adds distribution infrastructure and replaces older control systems with modern control systems that will increase automation, improve distribution infrastructure safety, operation and reliability, facilitate outage management and service restoration; enable voltage control and associated energy conservation; and improve interconnection with distributed resources. If approved, IPL will install 1,200 new distribution line reclosers and a new central control system to further increase system automation; to improve distribution system operation and reliability; to enable voltage management and associated energy conservation; and to facilitate interconnection with distributed energy resources and new loads.

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

3.4 Future Distribution System Needs

3.4.1 Distribution Generation

170 IAC 4-7-4(18)

IPL's Smart Grid network enables dispatch personnel to interface with large DG assets in real-time to monitor production and control the interconnecting equipment to protect line personnel when necessary. IPL has successfully connected 96 MW of solar DG since 2011 through its Rate Renewable Energy Production ("REP") program with operating agreements to enable monitoring and control of facilities with nameplate capacities of 500 kW and above. This includes nineteen (19) utility scale sites ranging in size from 500 kW to 10 MW in nameplate alternating current capacity. Attachment 3.2 includes a list and map of the Rate REP facilities. IPL's experience with solar facilities indicates no significant impact to its distribution or transmission system. This is due to many factors including the decision to limit the total capacity per site to 10 MW, connect the facilities at 13.2 kV, and establish the engineering criteria for a maximum of 10 MW connected per substation transformer.

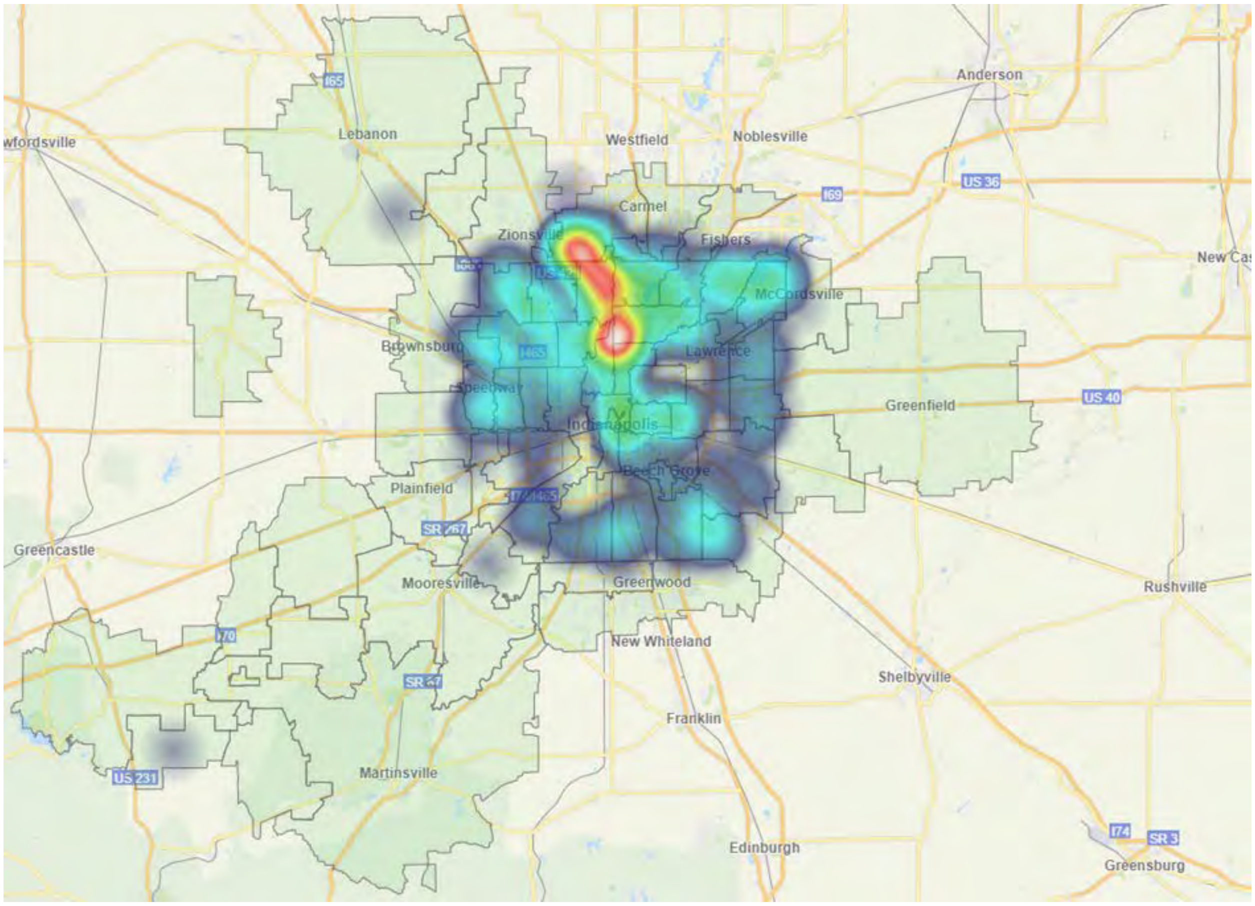
Distribution circuit impacts have been monitored and mitigated through IPL's DG interconnection working group comprised of personnel from engineering, planning, construction, and operations groups. Specifically, remote control capabilities are enabled through reclosers connected to IPL's DA network. Protection settings for the inverter control systems, reclosers, and IPL feeder relays are reviewed by IPL engineers and adapted as needed to avoid "nuisance" tripping that isolates the DG from the IPL grid. IPL monitors the output of the sites over 500 kW in real-time through its dSCADA system. IPL will continue to evaluate the business practices as more DG comes on-line. Section 5 contains more information about existing and "new" solar resources. Smart Grid infrastructure allows IPL to interface with DG resources and gather and monitor output in real time.

As further described in Section 5, IPL has 234 net metered customers as of the end of September 2019. They are smaller facilities than Rate REP and do not provide real time data to IPL dispatchers.

3.4.2 Electric Vehicles

Since the 2016 IRP, IPL has worked to develop a process which utilizes internal and external data to map and locate Electric Vehicle (EV) charging throughout our service territory. See Figure 3.1 below, which shows penetration of EV ownership by zip code. A higher penetration of EV ownership as shown represents a proxy for associated on-premise charging in absolute terms. In other words, the heat map does not reflect the level of demand or energy associated with electric vehicle charging but defines geographic areas where EV adoption is highest. This mapping, which will be updated periodically, is being incorporated into IPL's distribution software for ongoing distribution planning and analysis purposes.

Figure 3.1 | Heat Map of EV Adoption by Zip Codes



As of the summer of 2019, there are approximately 600 plug-in EVs in IPL's service territory, which represents ~0.1% of total passenger vehicles in Marion County (Indianapolis)[6].

As EV penetration grows over time, IPL will continue to leverage internal and external data sources to assess and manage impacts on the distribution system. IPL is working towards mapping individual IPL customers to their transformers in IPL's CYME distribution model. IPL is also mapping BMV lists for hybrid and EV customers to their respective transformers. Awareness of EV charging locations allows engineers to verify existing facility capacity and upgrade requirements. To date these have been limited to customers' service and panel upgrades, but any future transformer replacements will be managed closely by IPL. Understanding grid impacts will help guide development of future customer program

[6] The number of electric vehicles is from internal/external data sources from summer 2019. The total number of registered passenger vehicles is based on registration data from https://www.stats.indiana.edu/topic/vehicles.asp

offerings like time varying rates, managed EV charging, and/or other targeted demand response solutions.

IPL has supported EVs since our electric vehicle ("EV") pilot program as part of the Smart Energy Project initiated in 2012. That initial effort included the deployment of one hundred sixty-two (162) chargers and special EV rates for home, business and public use. EV meters allow IPL to monitor impacts to the distribution grid. These impacts are minimal today but will increase through time as EV penetration grows. Transformer loading analyses are being completed for each site request for an EV meter. The work thus far has not required any transformer replacements.

EV penetration in the Indianapolis area has been slower than anticipated. Section 4 contains more information about impacts of EVs on energy consumption which is incorporated in the EV forecast completed for IPL by the consultant MCR in this IRP.

3.4.3 Future Smart Grid Expectations

IPL recognizes that as more distributed energy resources ("DERs") are added to our system, their role will increase in future transmission, distribution and resource planning efforts. These planning efforts inform each other to ensure alignment in the consideration of DERs across the system. These resources can provide capacity and energy benefits. IPL continues to incorporate additional business and operational practices to maximize benefit.

Section 4: Load Research, Load Forecast, and Forecasting Methodology

170 IAC 4-7-4(11)

IPL forecasts load to be flat with average annual growth of 0.4% over the IRP planning horizon before consideration of any DSM impacts.[7] EIA projected efficiency trends with strong lighting and ventilation intensities in the commercial sector are the key contributor to the stagnant load trend.

4.1 Load Research

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

IPL conducts load research based on historic customer load shape data by segment. This information is used in Cost of Service studies and rate design efforts. The granular data aligns with load forecasting data, but it is not a direct input to the forecast at this time. See Attachment 4.1 for the Hourly Load Shapes by Rate and Customer Class from the July 2016 to June 2017 Test Year in IPL's Rate Case (Cause No. 45029). IPL anticipates using AMI more fully for load research and load forecasting as an improvement in the next IRP.

Load shape data is maintained by IPL at the rate class/customer class level. The sample for the Small Commercial Class (Rate SS) is stratified using North American Industry Classification System ("NAICS") codes into manufacturing low and high use and non-manufacturing low and high use strata. All load research is developed by IPL.

4.1.1 Energy Only (Non-Demand) Metered Customers

IPL currently maintains a load research sample of 542 load profile meters. The distribution of these meters by rate and class are shown in the following table, Figure 4.1.

Figure 4.1 | Load Research Meters by Rate Class – Energy Only

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

[7] IPL-sponsored DSM has been removed from the load forecast.

4.1.2 Large Commercial and Industrial Customers

In addition to the Residential and Small Commercial & Industrial meters outlined above, all Large Commercial & Industrial have 15-minute profile metering. The 15-minute information provides load research and billing increment data for our demand metered customers.

Figure 4.2 shows the load research sample design which is designed based upon a 90% confidence interval plus or minus 10% error. The stratification criteria are shown for the following rates:

RS – Residential General Service

RC – Residential General Service with electric water heating

RH – Residential General Service with electric heat

SS – Small Commercial & Industrial Secondary Service (Small)

SH – Small Commercial & Industrial Secondary Service (Electric Space Conditioning)

Figure 4.2 | Load Research Design

Rate	Number of Strata	Criteria
RS	4	high/low winter and high/low summer
RC	4	high/low winter and high/low summer
RH	5	small/large heat pump houses, small/large resistance houses and apartments
SS	4	survey small/large by manufacturing; non-manufacturing; billing manufacturing/non-manufacturing
SH	4	annual kWh

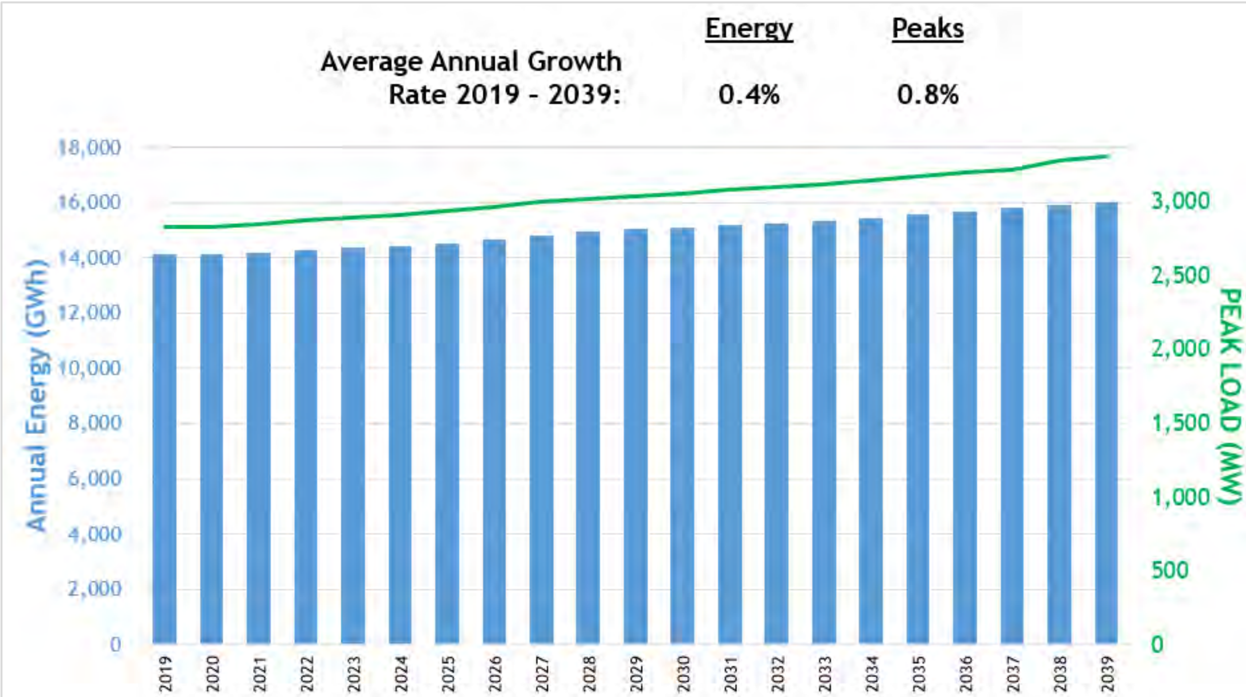
Furthermore, Hourly 8760 data is retained in Excel spreadsheets.

Historical billing data by account for the demand billed customers is maintained on an on-going basis.

4.2 IPL Forecast Overview

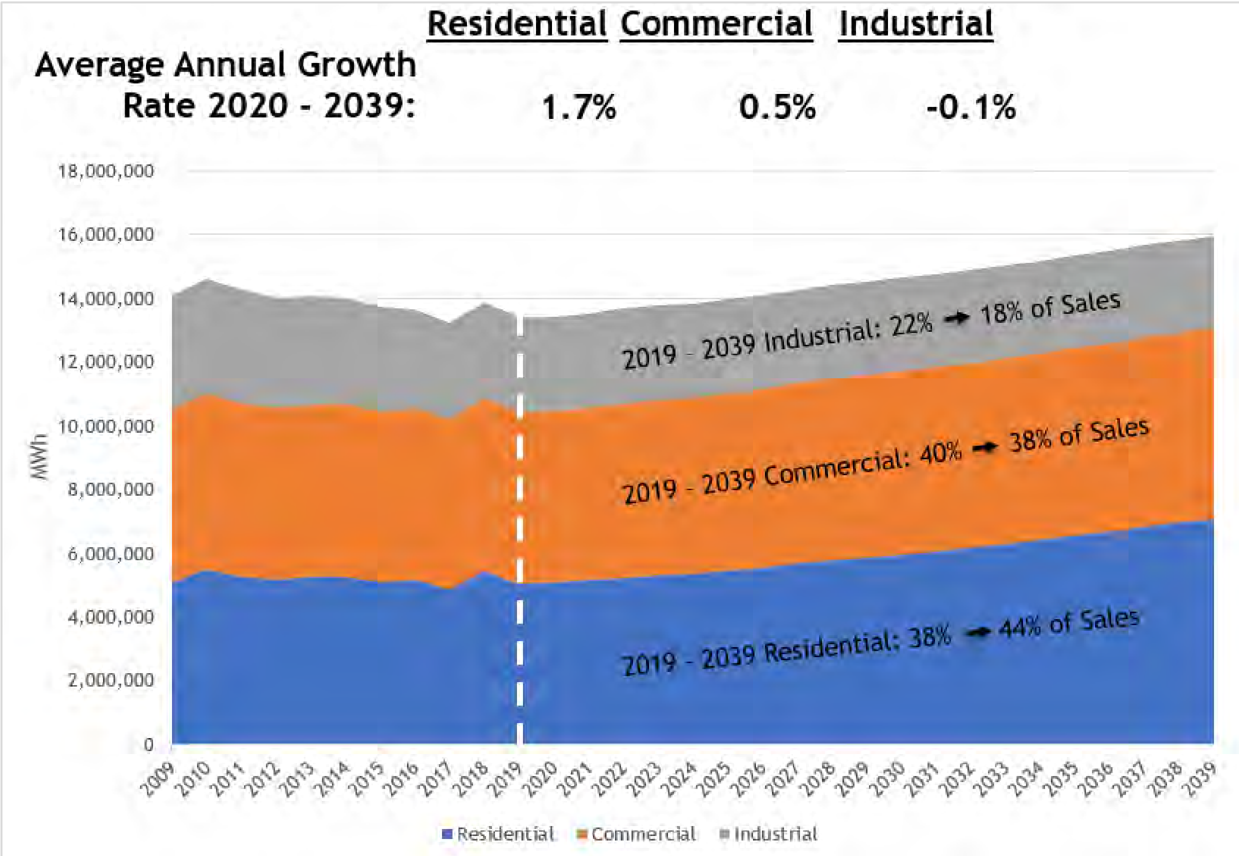
IPL developed a forecast with the average annual growth rate over the study period 2020 – 2039. Figure 4.3 shows the energy and peak forecast.

Figure 4.3 | Energy and Peak Forecast



IPL anticipates stable customer growth in the Residential sector primarily in multifamily units, such as apartments, condos and townhouses. This growth is expected to increase average annual load at a rate of 1.7% over the planning period. Customer growth is expected to be modest in the Commercial sector keeping load relatively flat with an average annual growth of 0.5%. Industrial sector load is anticipated to decline at an average annual rate of -0.1% over the planning period due to a declining manufacturing employment outlook and efficiency trends. Figure 4.4 illustrates the customer sector trends.

Figure 4.4 | IPL Sales by Sector (no losses included)



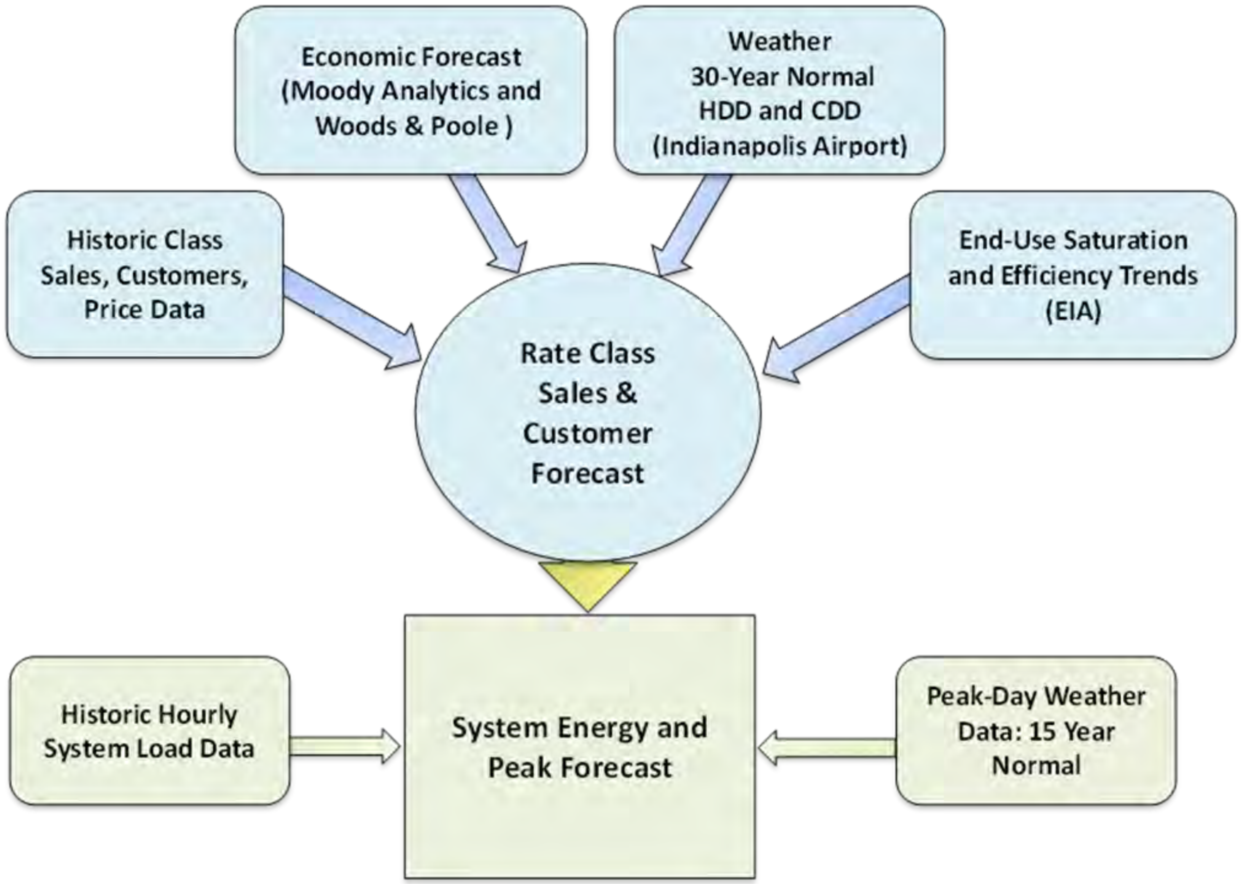
4.3 Forecast Methodology

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

The load forecast in this IRP was developed by IPL using Itron's Statistically Adjusted End-use ("SAE") load forecasting methodology. Historically, GDP and other economic indicators exhibited strong correlation with electricity sales. As such, load forecasts were heavily reliant on GDP and economic forecasts. However, since 2008 this linkage is less pronounced. Sales have flattened due to efficiency improvements from codes and standards and utility-sponsored DSM while GDP has continued to grow. Itron's SAE methodology addresses this issue by incorporating end use saturations and efficiency trends using EIA data.

Figure 4.5 provides an overview of the workflow of Itron's SAE model that builds up to a System Energy and Peak forecast. The dependent variables are being predicted using estimates of cooling requirements (XCool), heating requirements (XHeat) and other uses (XOther). These three variables are constructed using the weather, economic, utility price, and end use inputs. Thus, all structural and equipment changes, predicted economic impacts, price elasticities and weather assumptions are captured in the resulting forecast.

Figure 4.5 | Forecasting SAE Model Overview of Inputs



IPL forecasts monthly sales and customers for each rate code using the method described above. The rate code level forecasts are aggregated into a system-level forecast where line losses are added based on historic loss factors. This system-level forecast along with the system hourly load history, peak-day weather and end use intensity data drive the peak forecast.

Figure 4.5 illustrates the independent variable inputs that flow into the model. The independent variables with data source descriptions are as follows:

- *End-use appliance saturation and efficiency trends data* - Energy intensities are derived from Energy Information Administration's ("EIA") 2018 Annual Energy Outlook ("AEO") for the East North Central Census Division. The EIA End Use Data is available in Confidential Attachment

4.2a – 4.2g. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types. The EIA doesn't provide saturation and efficiency trends for the industrial sector.

As part of the DSM Market Potential Study that began in 2018, IPL conducted an in-depth end-use analysis of each customer sector in order to gain an accurate representation of the saturations and efficiencies of equipment in the service territory. Results from the analysis informed the EIA intensity base year assumptions used in the Itron models. Future intensities still rely on the EIA forecasts of equipment saturation and efficiencies. For more information regarding end use modeling techniques, see Attachment 4.3.

- *Economic data* – Economic inputs are Moody's Analytics projections from Q4 2018, see Confidential Attachment 4.4a. The high and low forecasts use a combination of different Moody's Q4 2018 economic scenarios and forecast model standard deviations, see Confidential Attachments 4.4b and 4.4c. The high and low load forecasting approach will be described later in this section.

- *Historical class sales and customers* – IPL tracks historical sales and customer data for each discrete rate code which serves is an input into the load forecasting models.

- *IPL price forecast* – Historical prices are derived from billed sales and revenue data. Prices are calculated as a 12-month moving average of the average rate (revenues divided by sales including trackers); prices are expressed in nominal dollars.

- *Weather data* – Historical and normal monthly heating degree days ("HDD") and cooling degree days ("CDD") are derived from National Oceanic and Atmospheric Administration daily temperature data for the Indianapolis Airport. For residential classes, a temperature base of 60 degrees is used in calculating HDD and a temperature base of 65 degrees are used in calculating CDD. For commercial classes, a temperature base of 55 degrees is used in calculating HDD and a temperature base of 60 degrees are used in calculating CDD. Generally, industrial classes are not considered weather sensitive and only receive a small if any weather adjustment. The base temperature selection is determined by evaluating the sales/weather relationship and determining the temperature at which heating and cooling loads begin.

For future normal weather assumptions, IPL uses a 20-year weather trend approach to capture the effects of climate change on normal temperatures. Figure 4.6 and Figure 4.7 illustrate this approach. Using this approach, IPL calculated the year-over-year trend in the 20-year rolling average HDDs and CDDs over the past 20 years. HDDs have declined on average by -0.3%; whereas CDDs have increased by 0.6%. These trend percentages are assumed to continue over the period of the analysis. The base year (2019) normal HDDs and CDDs are 20-year averages of 2009 – 2018 HDDs and CDDs.

Figure 4.6 | HDD Weather Trend Approach

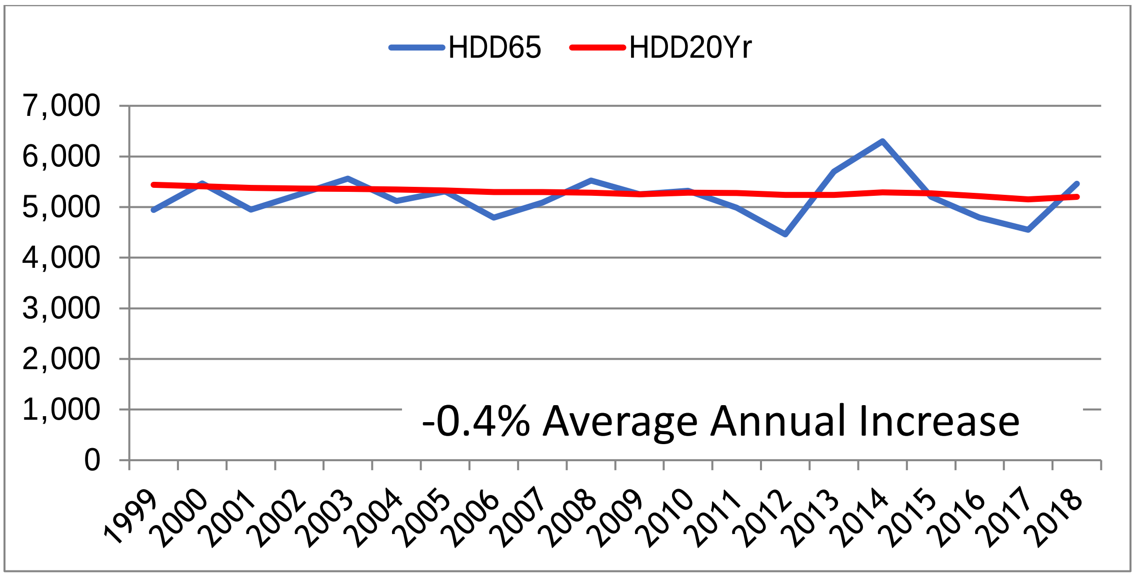
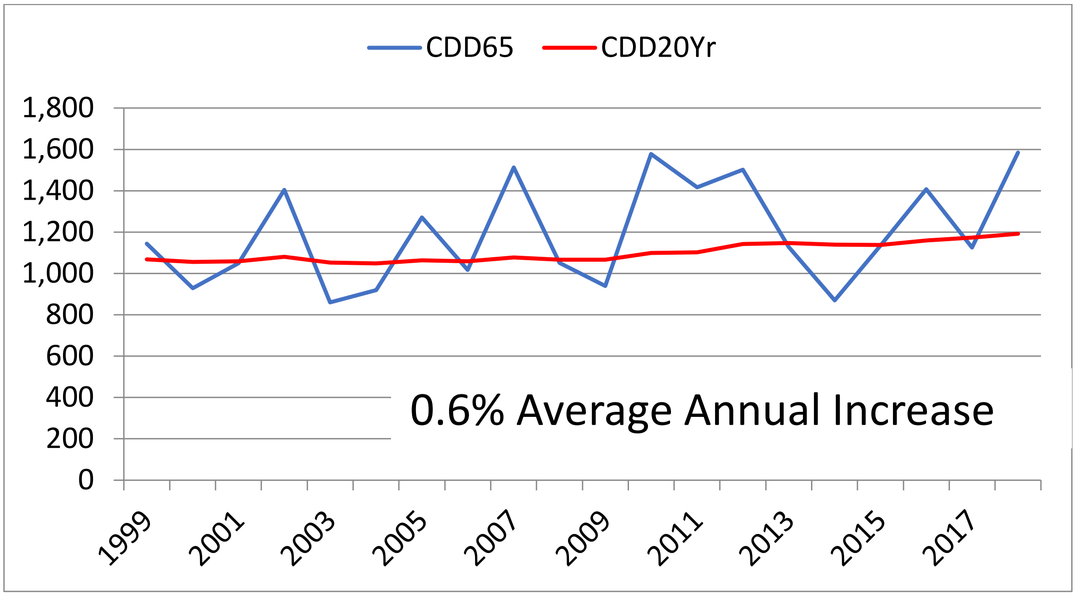


Figure 4.7 | CDD Weather Trend Approach

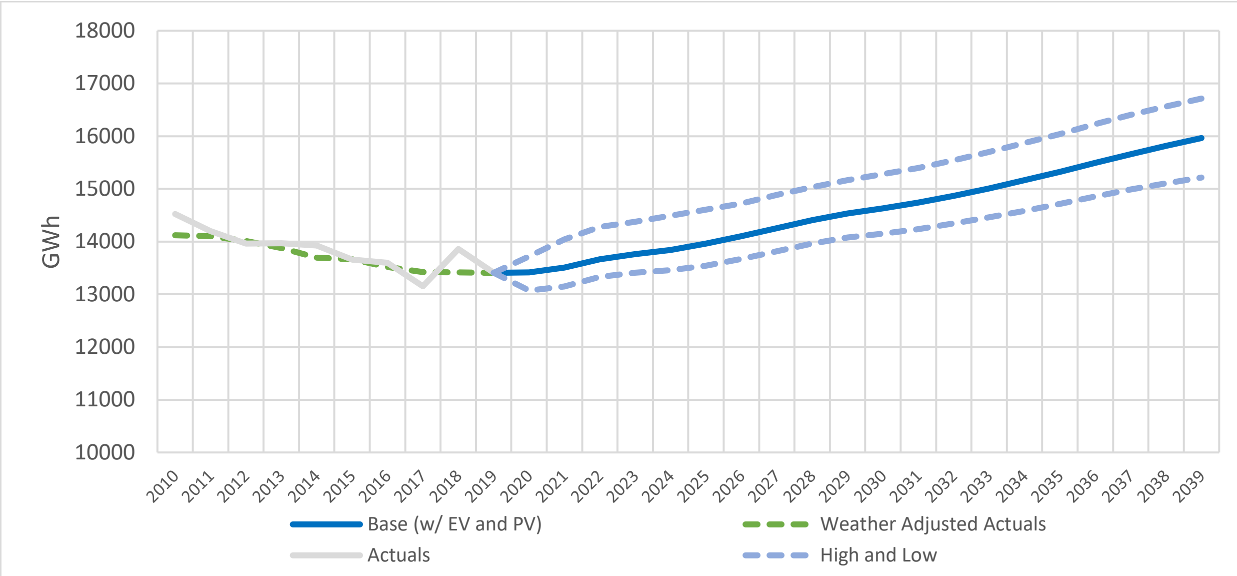


- *IPL-sponsored DSM* was included as an endogenous variable in the sales models. As an input, the models assessed correlation between historic sales and historic DSM estimating a DSM coefficient. For example, if the model estimates a coefficient of 0.5, then the model is saying that 50% of the historic DSM is captured in the historic sales. IPL then adjusts out any planned DSM based on this approach.

  As noted, future IPL DSM was not included in the base, high or low energy and peak forecasts that were used as inputs into the IRP. New DSM bundles were included as part of the process for developing candidate resource portfolios. See Section 8 for more detail on DSM selection for the IRP.

In addition to the base forecast, IPL developed high and low load forecasts for use in certain IRP scenarios. The forecasts were developed using the growth rates from Moody's "Lower Trend" (low forecast) and "Exceptionally Strong Growth" (high forecast) scenarios with one standard deviation from the base forecast mean (as calculated using the Itron models) as the target in 2039. See Confidential Attachments 4.4a-c for Moody's data. The Base, High and Low Load Forecasts assume normal weather. The IPL Base, High and Low Forecasts (Figure 4.8) does not include future DSM. Attachment 4.5 is the 10 Year Forecast and Attachment 4.6 is the 20 Year High, Base and Low Forecast.

Figure 4.8 | IPL Base, High & Low Load Forecast (2020-2039)



4.3.1 Residential Sector

The Residential Sector is comprised of three primary customer types; those with gas heat, electric heat and gas heat with electric water heat. On a percent of customer basis, the residential customer types are disaggregated as follows: 57% gas heat, 7% electric heat and 36% gas heat with electric water heat. While on a percent of sales basis, the residential customer types are disaggregated as follows: 46% gas heat, 8% electric heat and 46% gas heat with electric water heat. The Residential Sector makes up 38% of IPL's total sales.

The key residential forecast economic drivers are Marion County housing starts, Marion County household income and Marion County household size. Over the next 20 years, the number of housing starts are projected to grow at an average annual rate of 2% while household income is projected to grow at an average annual rate of 0.8%. Both will increase customer volume and total usage. Household size is anticipated to decline at a rate of -0.4% which is consistent with the trend in household growth primarily coming in the form of multifamily apartments described in detail below.

Figure 4.9 displays the projected trends in customer count and Figure 4.10 presents average electricity use across the Residential Sector. New customers are projected to increase at an average annual rate of 0.8% while average use is expected to increase at an average annual rate of 0.4%.

Figure 4.9 | Residential Customers

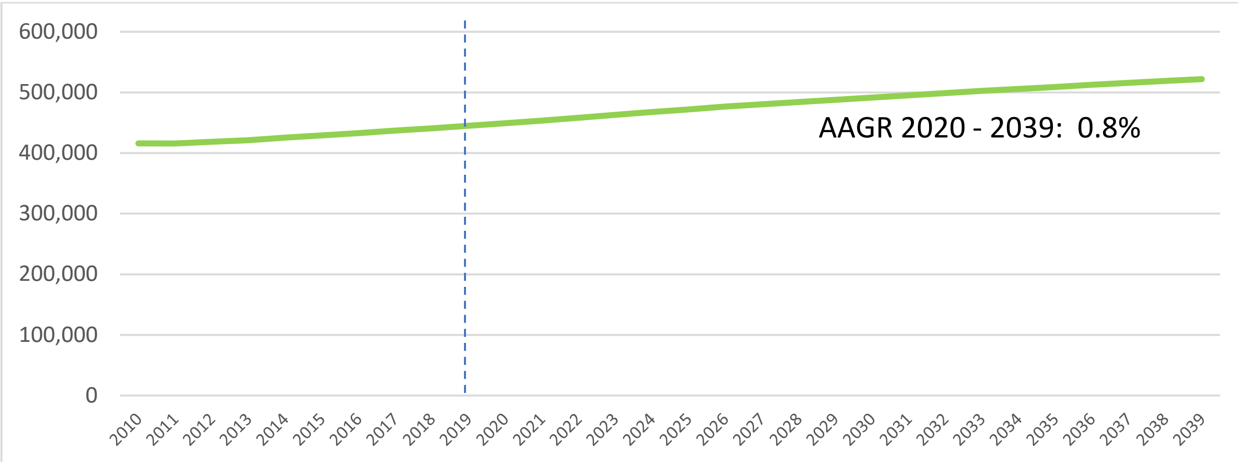
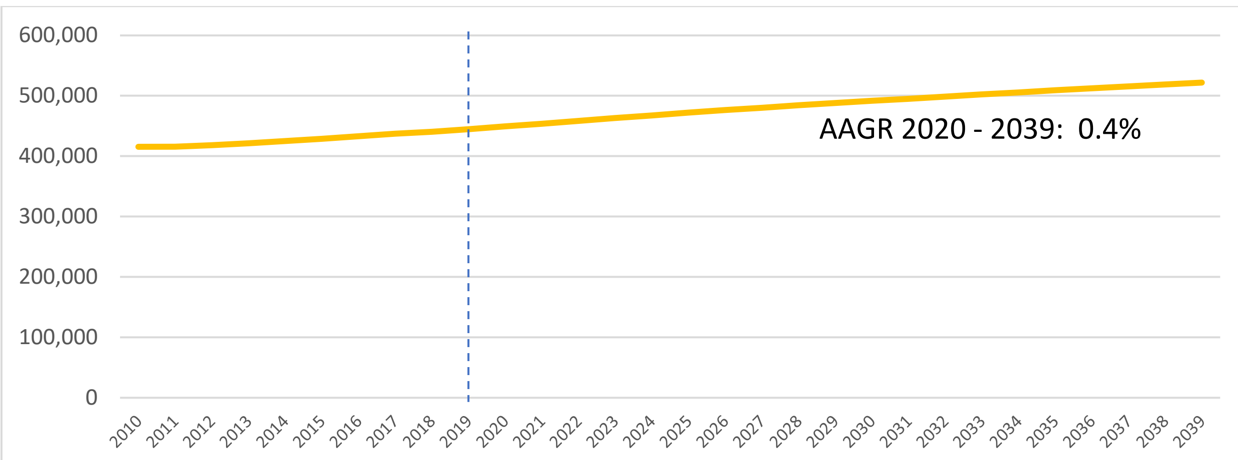
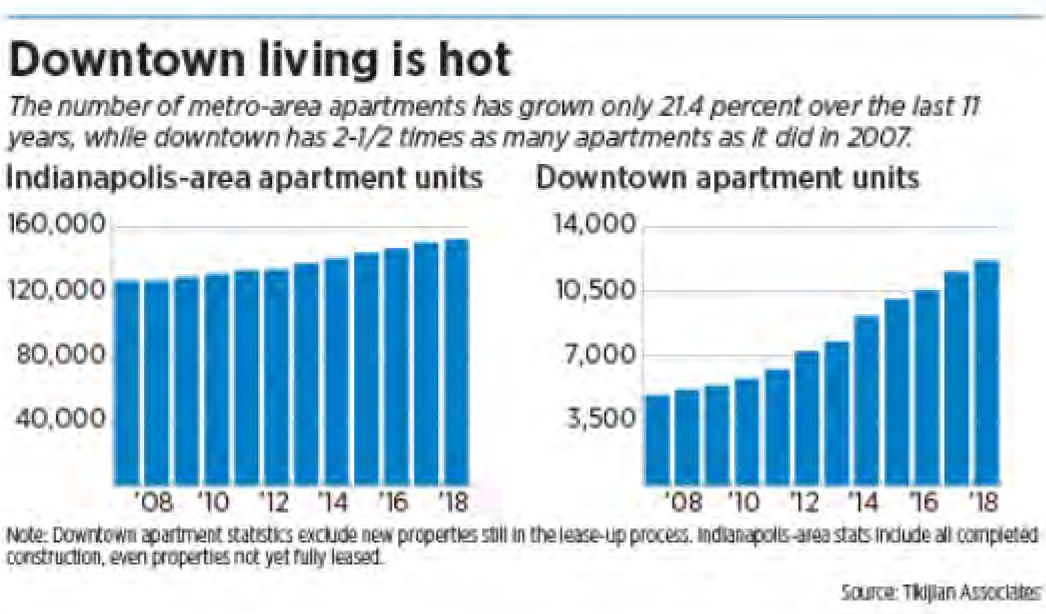


Figure 4.10 | Residential Average Use



Customer growth is expected to come primarily through additional multifamily apartments; a trend that was demonstrated by the Indianapolis Business Journal (IBJ) in Figure 4.11. Between 2007 and 2018, the volume of apartments in downtown Indianapolis has grown by 250%. Apartments are on average smaller in conditioned square footage than a single-family home and therefore require less electricity. This growth is evident from new projects like the conversion of the Coca-Cola Bottling site into the mixed use Bottleworks development.

Figure 4.11 | Indianapolis Apartment Growth[8]

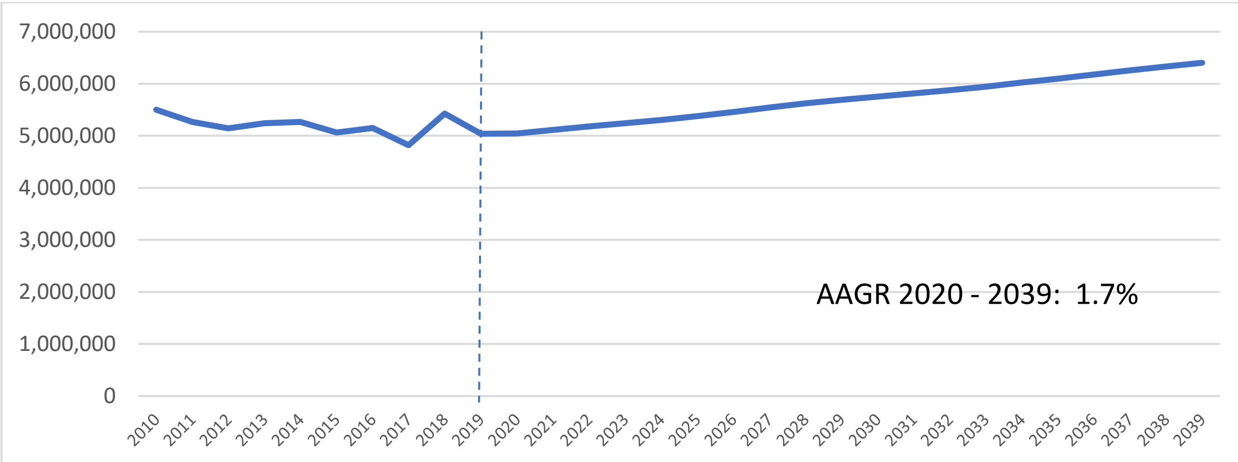


The shift in the Residential sector to a higher percentage of multifamily homes in combination with organic efficiency contributes to the forecasted flat-to-declining sales per customer.

Overall, customer volumetric growth is anticipated to outpace the decline in average electricity use, leading to a sales forecast that is projected to grow at an average annual rate of 1.7%, as shown in Figure 4.12.

[8] Source: Indianapolis Business Journal

Figure 4.12 | Residential Sales



4.3.2 Commercial Sector

The Commercial sector includes customers with demand of less than 500 kW including small commercial gas and electric heat rates of 75 kW or less. Also included in this sector are larger secondary service demand metered customers between 50 – 500 kW; examples include grocery and box stores. The Commercial sector comprises 40% of total IPL sales. IPL anticipates continued growth in this sector from large commercial projects with tech companies like Infosys, 16 Tech and the city's new Criminal Justice Center.

The key economic drivers to the Commercial forecast are Marion County nonmanufacturing employment and Marion County nonmanufacturing GDP. As mentioned previously, the forecast uses an economic variable that is heavily weighted towards nonmanufacturing employment which is a better predictor of sales – 80% nonmanufacturing employment / 20% nonmanufacturing GDP. Over the 20-year IRP period, nonmanufacturing employment is expected to grow at an average annual rate of 0.8% and nonmanufacturing GDP at a rate of 1.9%. The combined variable used in the forecast had an average annual growth rate of 1.04%. Commercial sales growth is kept modest in the long term due to more aggressive lighting and ventilation efficiencies that the EIA is now including in their outlook.

Figure 4.13 and Figure 4.14 display the projected customer count and average electricity use for the Commercial sector. The number of new customers is projected to grow at an average annual rate of 0.42%; while the average use per customer is exhibits only modest growth at an average annual rate of 0.13%.

Figure 4.13 | Commercial Customers

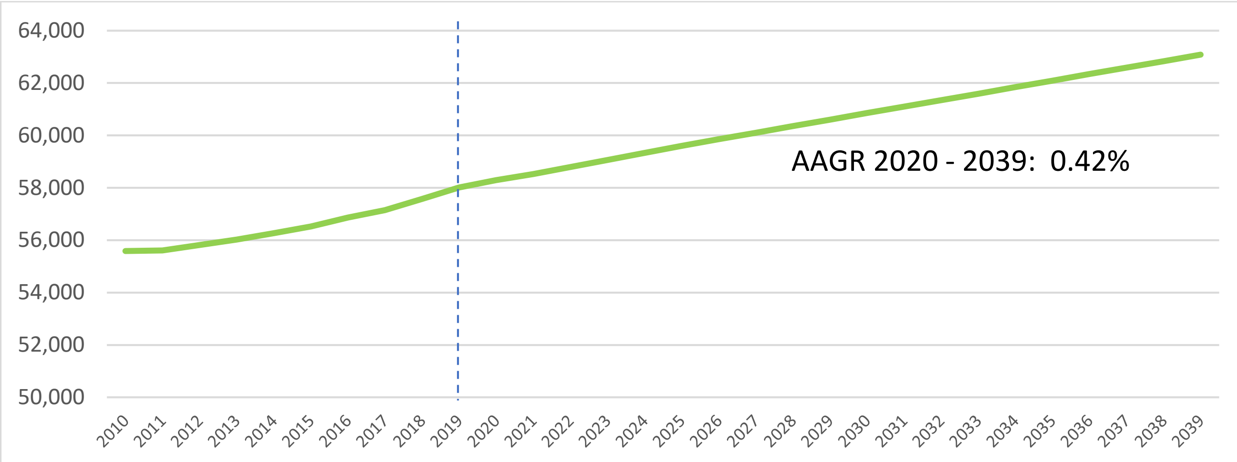
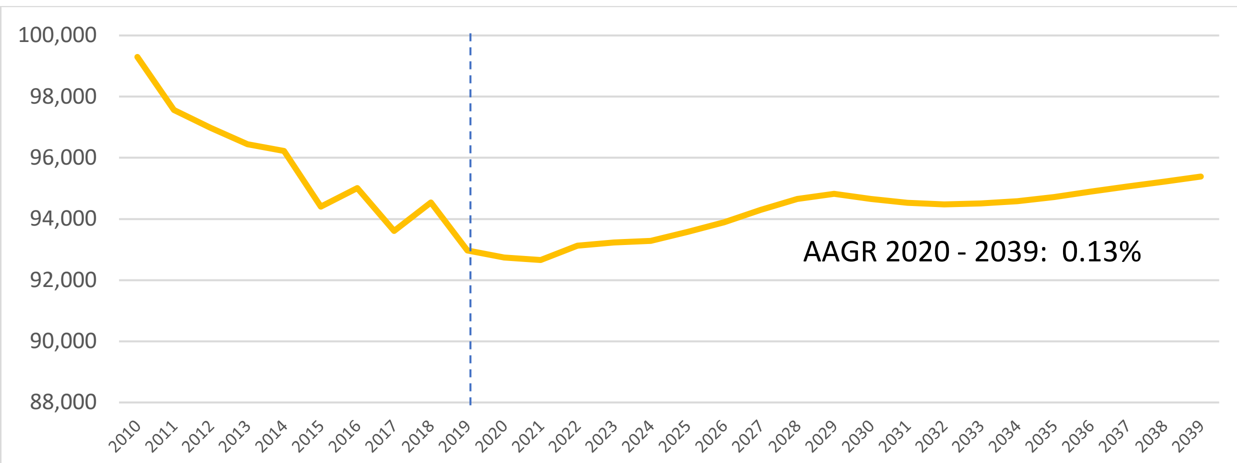
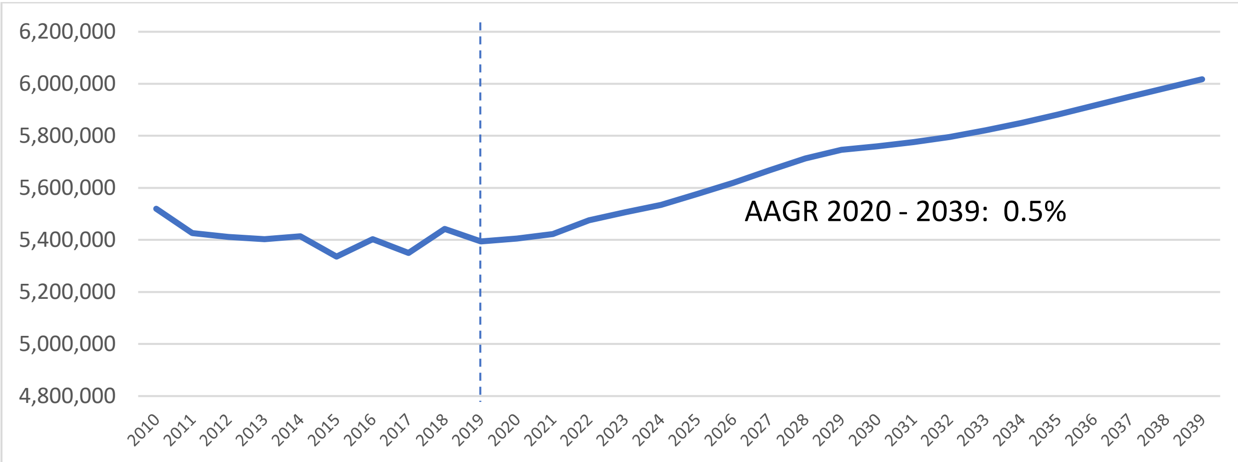


Figure 4.14 | Commercial Average Use



Commercial sales are projected to grow at an average annual rate of 0.5% as demonstrated in Figure 4.15.

Figure 4.15 | Commercial Sales



4.3.3 Industrial Sector

The Industrial Sector is comprised of demand metered customers larger than 500 kW. These customers all receive three phase primary service with IPL-owned transformers and other substation equipment located on the customer premises. IPL serves roughly 200 of these customers with total energy usage at around 22% of total IPL sales.

The primary economic drivers for IPL's Industrial forecast are Marion County manufacturing GDP (Figure 4.16) and Marion County manufacturing employment (Figure 4.17). Over the IRP period, manufacturing GDP is anticipated to increase at an average annual growth rate of 1.57% while employment is anticipated to decline at a rate of -0.53% annually. As noted earlier in this section, the economic input used in the forecast is weighted more heavily to employment resulting in a variable with an average annual growth rate of 0.93%. Figure 4.18 exhibits the trend in the economic variables.

Figure 4.16 | Indianapolis Manufacturing GDP

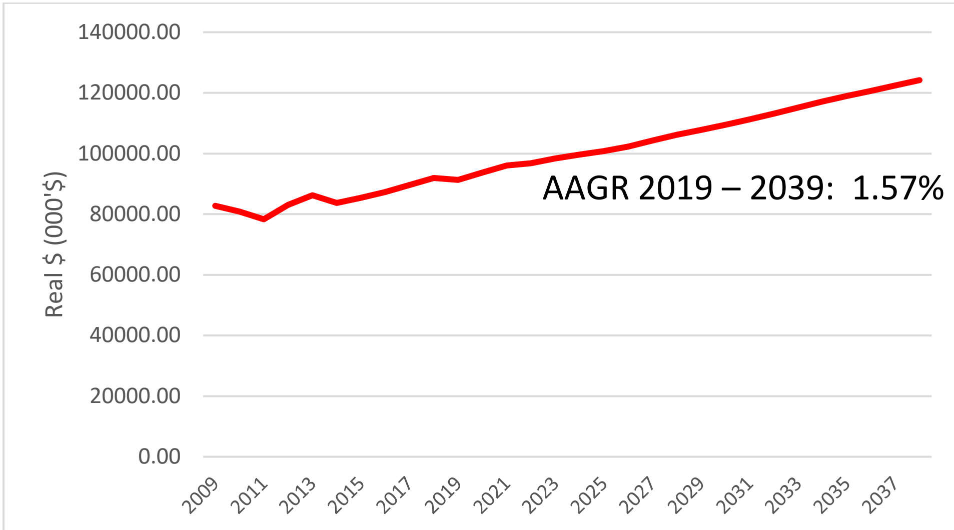


Figure 4.17 | Indianapolis Manufacturing Employment

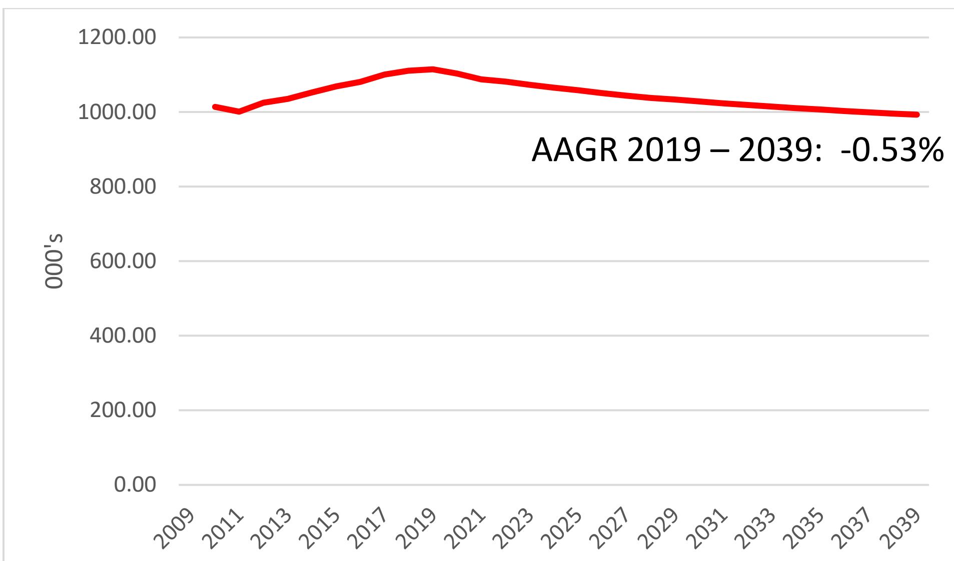
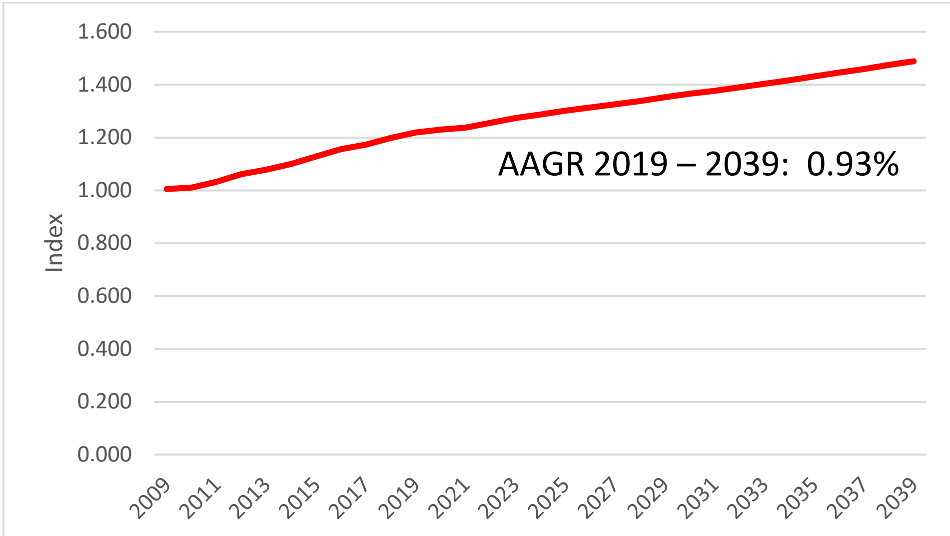


Figure 4.18 | Weighted Economic Variable



Confidential Attachment 4.7a-c provides the energy forecast drivers and Attachment 4.8 provide the peak forecast drivers and input data.

IPL exogenously adjusted the load forecast for anticipated customer loads larger than 5MW. It is assumed customers this large are not being picked up in the growth exhibited in the Moody's economic input data and therefore the load forecasting regression model. These customer additions are tracked by IPL's Strategic Accounts group, who regularly assist large industrial customers with billing items. The following customer additions in Figure 4.19 are included in the Industrial forecast:

Figure 4.19 | Expected (MW) Additions by IPL Industrial Customer

Company	2020	2021	2022	2023
Customer #1	2.5	2.5	2.5	2.5
Customer #2	5	5	5	0
Customer #3	0	5	5	0
Customer #4	6.25	6.25	0	0
Total	13.75	18.75	12.5	2.5

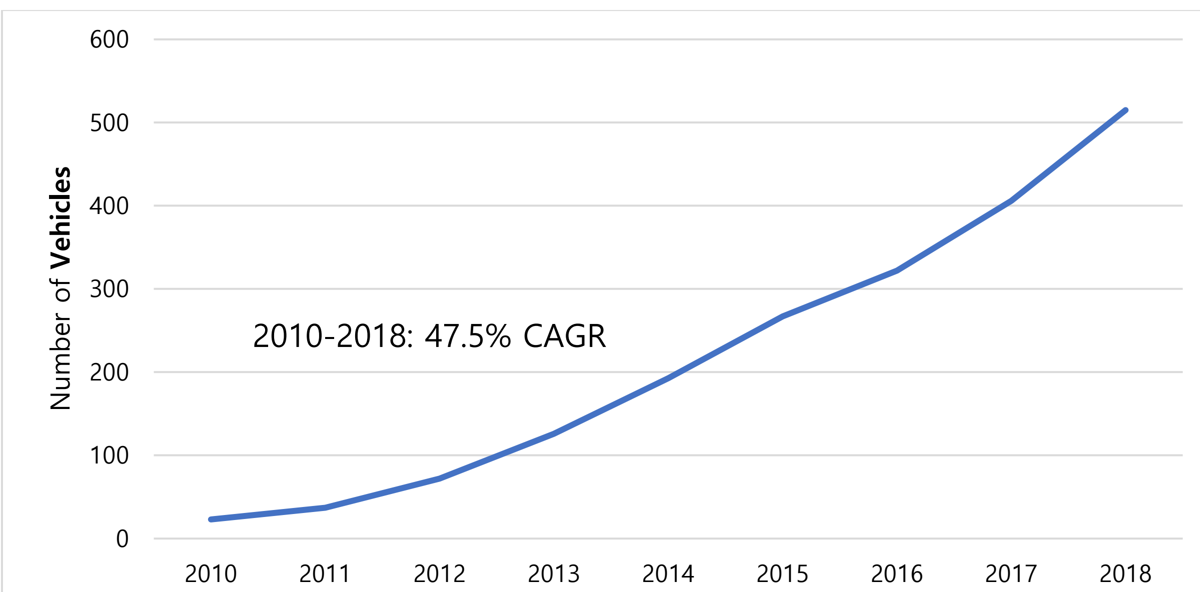
4.4 Electric Vehicles and Distributed Solar

Beneficial electrification of transportation is consistently identified as a significant means by which to reduce environmental impacts and improve transportation efficiency. The market for Electric Vehicles ("EV") is expected to grow rapidly, driven by declining battery costs and improved performance. Given their energy conversion efficiency, EVs are expected to eventually be significantly less costly and less polluting to operate. This increased EV adoption has the potential to result in significant measurable future grid impacts. Eventually, controlled EV charging may also serve as a resource in grid management. IPL expects that this trend of increased EV adoption will also be realized in our service territory over the next several years.

As Figure 4.20 below illustrates, the number of EVs in our service territory continues to grow at a rapid rate, but in total remains relatively small with approximately 500 EVs registered in the City of Indianapolis as of late 2018.

With approximately 515,300 vehicles registered in the greater Indianapolis area, the penetration rate remains below 0.01%. Given the relatively low EV penetration to date, IPL has experienced no material impacts on the distribution system impacts, but as discussed below we are continuing to monitor and assess necessary infrastructure upgrades as EV adoption market share increases.

Figure 4.20 | Historical Light Duty EV Fleet Growth



To better understand EV impacts and provide innovative solutions for customers, IPL has undertaken significant efforts in this area. IPL first implemented an Electric Vehicle ("EV") program in 2011. This program resulted in integrated charging infrastructure in homes, business and public parking facilities. The initial investments were accomplished in part, with partial Smart Grid Investment Grant ("SGIG") funding support from the U.S. Department of Energy ("DOE") and the State of Indiana Office of Energy Development. The funding resulted in the deployment of 162 charging stations installed in local homes and businesses.

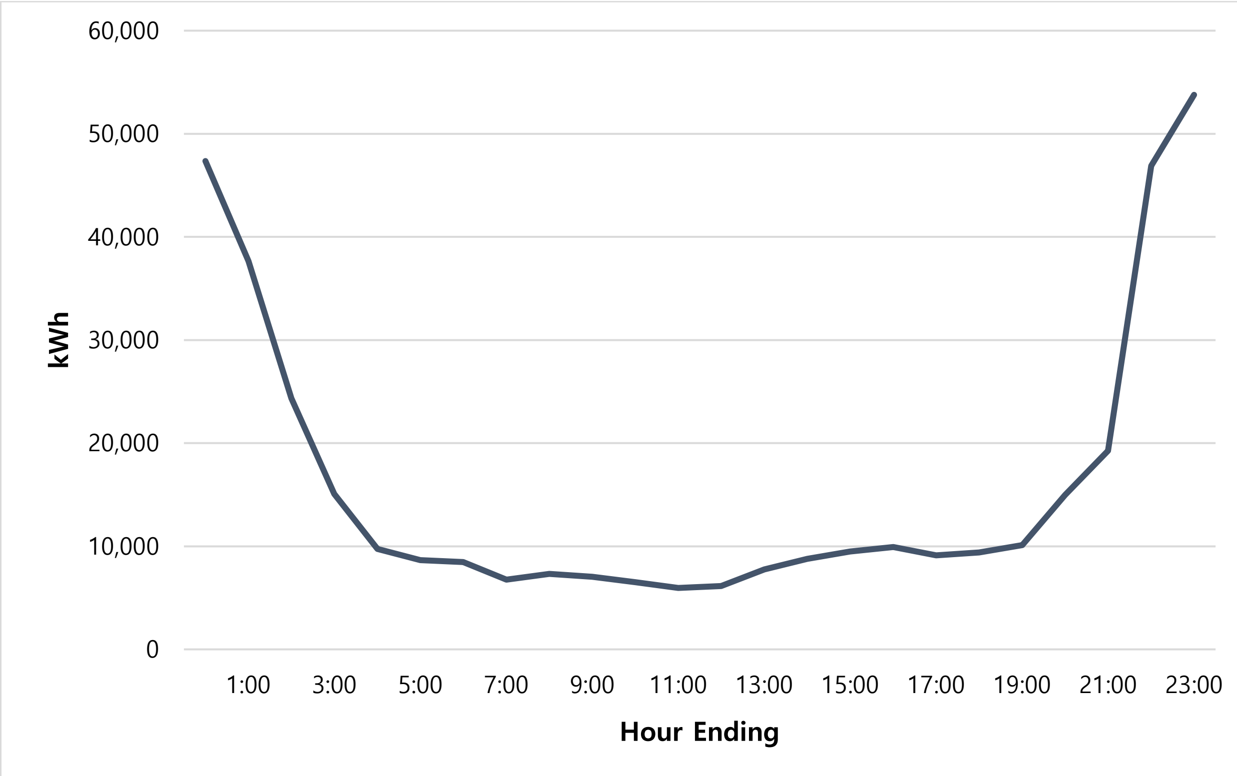
IPL has both a Time of Use ("TOU") EVX rate for customer premises and a public EVP rate for public charging stations. At present, approximately 130 customers participate in Rate EVX. The Rate EVX Rate schedule is shown in Figure 4.21.

Figure 4.21 | IPL EVX Rate Schedule

		Non-Holiday Weekends	Holidays & Weekends	Cents/kWh
Summer (Jun-Sep)	Peak	2pm - 7pm		12.150
	Mid-Peak	10am - 2pm; 7pm - 10pm	10am-10pm	5.507
	Off-Peak	12am - 10am; 10pm - 12am	12am - 10am; 10pm - 12am	2.331
Winter (Jan-May; Oct-Dec)	Peak	8am - 8pm	8am - 8pm	6.910
	Off-Peak	12am - 8am; 8pm - 12am	12am - 8am; 8pm - 12am	2.764

A representation of the Rate EVX charging patterns is shown in the graph below. As the graph illustrates, the vast majority of vehicle charging under IPL's Rate EVX occurred off peak. IPL found that approximately 92% of the charging occurred during off peak periods and only about 8% of the charging occurred during the Summer Peak and Mid-Peak periods. While participation and usage of the Rate EVX usage remain modest, IPL believes that the results demonstrate customers' willingness to charge off-peak in recognition of the TOU rate structure.

Figure 4.22 | EV Charging Curve – IPL Electric Vehicle Rates



The public EV rate (Rate EVP) is based upon a flat fee of $2.50 regardless of the duration of the charging session. Twenty-two (22) public chargers were initially deployed at eight (8) locations as a result of the pilot program. The public systems may be used by any customer or visitor to Indianapolis enabled by a key fob and credit card-based system. Since the pilot program concluded IPL has scaled back number of public chargers. There are currently three public chargers deployed at two stations. This reduction was made in part because of the large number of other public charging stations that have been deployed by other local entities, such as parking garages. While public charging remains less robust than might be expected, it does serve to mitigate range anxiety for EV drivers.

The City of Indianapolis asked IPL in 2013 to support its plan to implement an all-electric car sharing program with the City's partner, Bolloré Group/BlueIndy for up to 500 EVs at 200 electric vehicle charging station locations. As of November 30, 2018, 92 locations have been installed. Also, as of this date, there were 455 vehicle chargers and 196 vehicles deployed. See Attachment 4.9 for the report that summarizes BlueIndy activities. This is the final report that was filed pursuant to the Order in Cause No. 44478.

4.4.1 Electric Vehicle Forecast

For purposes of the IRP, IPL engaged the consulting firm of MCR Performance Solutions ("MCR") to assist us in developing a forecast of the market potential for EVs (as well as Solar PV) in the IPL service territory. MCR made a considerable effort to understand EV market share and penetration rates in the IPL service territory.

The EV forecasting process began with MCR assembling pertinent material from its existing library of work related to EV from several jurisdictions; conducting preliminary research to begin understanding the Indianapolis Power & Light Company ("IPL"), Indianapolis Indiana and national policy context; and current EV market penetration. This included developing an understanding of what utility rate and state policy structures exist, the current and known future status of federal tax incentives, what the general size of the existing EV fleet, and how IPL treated EVs in previous IRPs. Outcomes of this first work step included:

- Assembly of the IHS/Polk registered automobile census for the IPL service territory
- Compilation of an overview of the IPL service territory and customer base (i.e., customer population by rate and segment)
- Summary of pertinent rate structures
- Summary of federal tax incentive structures
- Development of carinsurance.com and kbb.com data on driving behavior, EV pricing and availability of EVs in Indiana and the IPL service territory
- Development of fueleconomy.gov EV efficiency in kWh per 100 miles driven
- Alignment that the general direction for the forecasting methodology would be a spreadsheet-based approach or an existing online tool or tools
- Alignment that the forecasting methodology would first define prototypical system characteristics such as size, cost, etc. and then apply a forecast of the number of units of EV to the prototypical systems to generate the MW and MWh forecasts

4.4.2 Literature Review and Prototypical EV

To develop recommended approaches to prepare the EV forecast for IPL, MCR conducted a literature review on EV adoption rates and forecasting techniques. Recognizing the IndyGo public transportation system is progressive with respect to electrification of its bus fleet, MCR also assembled secondary and primary (i.e., interview-based) data on the IndyGo bus electrification plans. Lastly, MCR undertook a web-based review of the status of electrified medium- and heavy-duty trucks.

MCR's literature review examined over 60 resources on EVs, from a combination of online research, and mining of IPL and MCR resource libraries. The methodology for conducting the literature review was to first assemble a complete bibliography of references and then conduct an initial, brief review of each to determine whether their vintage, geographic scope and applicability to our primary goal of finding spreadsheet-based methodologies or online tools and readily available data rendered them appropriate for deeper review by MCR's subject matter experts. For the resources escalated for subject matter expert review, MCR's subject matter experts first confirmed or rejected the appropriateness of the references and then examined more deeply those that were confirmed for such review. The output of the literature review included summaries of 16 EV resources that MCR identified as having the most relevance for developing forecasts for IPL.

With respect to IndyGo MCR developed detailed assumptions on the specific buses and associated charging patterns as well as the timing of IndyGo replacement of existing diesel buses with electric. The IndyGo transition to an electric bus fleet began in earnest with the opening of the all electric Red Line route in Q3 of 2019 and will continue will additional all electric bus routes over the next few years.

With respect to medium- and heavy-duty trucks, MCR concluded that these technologies and the deployment of them are at too early a stage to attempt to include them in a forecast, but we did identify for IPL local manufacturers of interest (i.e., Navistar/Volkswagen) as well as potential early adopters of the technology as it emerges (i.e., the FedEx hub at Indianapolis International Airport).

Development of prototypical EV systems and detail on the IndyGo bus transition was based on the following primary resources:

- EV: fueleconomy.gov, carinsurance.com, kbb.com, IHS/Polk data, IPL actual EV charging data
- IndyGo: 2017 IndyGo Capital Plan, BYD[9] manufacturer data and IndyGo staff interviews

Assumptions for the prototypical EV and the busses to be deployed on the IndyGo bus system are summarized below in Figure 4.23 and Figure 4.24.

[9] BYD is a battery electric bus manufactured by the Chinese automaker BYD Auto. BYD was chosen by INDYGO! to supply the busses for the be the bus supplier for Rapid Transit system that is being built out in Indianapolis.

Figure 4.23 | EV Summary and Prototypical EV

Attribute	Value	Source
Count	515	IPL-provided IHS/Polk
kWh/100 miles	31	www.fueleconomy.gov
Annual miles	11,655	www.carinsurance.com
Annual kWh	3,613	= 31 * (11,655/100)
Price	$40,267	www.kbb.com

Figure 4.24 | IndyGo Summary and Plan

Attribute	60' BYD BRT	40' Fleet
Current quantity	2	21
2032 quantity	56	144
Range	275	250
Miles/year	45,600	45,600
Charger	40 kW x 2	40 kW x 2
Battery kWh	652	489
Charge time hours	6	4.5
Cost	$1,200,000	$675,000

4.4.3 Forecasting Methodology

Upon completion of the literature review, assembly of EV and IndyGo summaries, and development of the prototypical systems, MCR conducted a workshop with the IPL project team to review the results and discuss application of them to come to alignment on the specific approach MCR would take to developing the forecasts. Recall that two fundamental methodological decisions were made at the outset:

1. Forecasts would be developed for the number of units of EV, then the prototypical system attributes and IPL charging meter data-based EV consumption profiles would be applied.
2. The approach to developing the unit forecasts would be either spreadsheet-based or rely upon existing online calculators or tools.

The general approach agreed upon was to utilize existing, recent national forecasts and adjust or scale them to the IPL service territory.

EV Forecasting Methodology

The forecast of units of EV was developed by using a "percent of fleet" approach for light duty vehicles and then adding the known (expected) IndyGo bus data. The Edison Electric Institute (EEI) EV forecast was identified as the primary source because it is a highly-regarded and frequently cited meta forecast based on five other EV forecasts. However, the time horizon of the forecast extends only through 2030, so the relationship between the forecasted EV fleet size and that forecasted by Bloomberg New Energy Finance ("BNEF") through 2040 was utilized to extend the base EEI forecast to 2040.

United States Census Bureau projections, Marion County population projections from Indiana University, and the IHS/Polk vehicle registration data were all used to adjust and scale the modified EEI forecast to yield an IPL-specific unit forecast of numbers of light duty EV10. The modified EEI forecast provided annual national data on EV as a percent of total light duty vehicle fleet, which was scaled to IPL's territory based on the Marion County population data and growth rates. Because light duty EV purchase decision-making is known to be heavily influenced by median household income, a final adjustment

[10] Because the number of EV registered in the IPL service territory as of 2018 is unusually low relative to the adjusted and scaled EEI forecast, and recognizing that cost equivalence of EV and internal combustion vehicle prices can be expected in approximately 2026, the forecast is started with the adjusted and scaled EEI forecast number of vehicles rather than the actual 2018 IPL-area IHS/Polk number in order to prevent the numbers of EV to be expected in later years from being unrealistically low.

was made to reflect the Marion County median household income as a percentage of the national median household income. IndyGo bus quantities were reached by 2032 based on annual numbers of additions discussed with IndyGo staff during interviews.

IPL Rate EVX costing periods, IPL metered EV charging data, and the prototypical EV attributes in Figure 4.23 enabled conversion of numbers of units of light duty EV to on-peak and off-peak MWh and MW. Likewise, given the IndyGo bus attributes in Figure 1.20 and an assumption of overnight (i.e., 10:00 pm to 4:00 am) charging, and IPL's Rider 8 – Off-Peak Service costing periods, the MWh and MW forecasts for the buses were developed.

MCR created an average 8,760-hour EV charging profile using IPL EVX customer's AMI meter data from 2018. IPL utilized this load shapes to spread the monthly on and off peak EV forecasts out to every hour for the IRP model.

PV Forecasting Methodology

The PV forecasting process closely mirrored the approach MCR took in developing the EV forecast described above. Again, MCR assembled pertinent material from its existing library of work related to PV; and by conducting preliminary research to begin understanding the Indianapolis Power & Light (IPL), Indianapolis Indiana and national policy context. The current market penetration for PV was also considered. MCR developing an understanding of IPL's current rate structure and state policy, as well as federal tax policy. Outcomes of this first work step in addition to the outcomes discussed above included:

- Assembly of the IPL net metered, renewable energy production (Rate REP), and cogeneration and small power production (Rate CGS) inventories of installed solar
- Summary of Rate CGS and Rider 9 (Net Metering) rate structures
- Receipt of the National Renewable Energy Laboratory (NREL) Advance Technology Baseline (ATB) report on solar system pricing
- Alignment that the general direction for the forecasting methodology would be a spreadsheet-based approach or an existing online tool or tools
- Alignment that the forecasting methodology would first define prototypical system characteristics such as size, cost, etc. and then apply a forecast of the number of units of PV to the prototypical systems to generate the MW and MWh forecasts

The PV unit forecast was developed using the December 2018 Solar Energy Industries Association (SEIA) and Wood Mackenzie Power and Renewables Solar Market Update Report, often referred to as the Greentech Media or GTM report, as the primary source. The specific methodology was a straightforward matter of developing the 2019-2023 GTM report compound annual growth rates for residential and commercial & industrial solar installations and applying that to the number of residential and commercial & industrial net metered installations in the IPL service territory as of year-end 2018.

IPL Rate CGS costing periods and PVWatts 8,760 annual hour production data for the 8-kW prototypical residential system and 125-kW prototypical commercial & industrial system as described in Figure 4.25 were used to develop the on-peak MWh, off-peak MWh and peak MW forecasts.

IPL created an average 8,760-hour PV profile using IPL's Rate REP solar customer data. IPL used this profile to spread MCR's monthly PV forecast out to every hour for the IRP model.

Assumptions for the prototypical PV system are Figure 4.25.

Figure 4.25 | PV Summary and Prototypical PV Systems

Attribute	Residential	C&I
IPL NEM count (Adjusted EIA counts from IPL 2018 NEM file)	177	21
Size (kW - DC)	8	125
Panel type	Anti-reflective crystalline silicon	Anti-reflective crystalline silicon
Array type	Fixed	Fixed
Capacity factor	15.8%	15.8%
Production basis	PVWatts – 46241	PVWatts – 46241
System cost/watt	$2.70	$1.83
System cost	$21,600	$228,750
Annual O&M	$192	$2,250

4.4.4 EV and Distributed Solar Forecasting Results

The final IPL 2020-2040 forecasts of numbers of units and capacity by technology type are summarized in Figure 4.26, and the energy (MWh) by technology type are summarized in Figure 4.27. By the end of the study period, there are expected to be nearly 200,00 EVs in the IPL service territory, resulting in

32 MW of demand on the IPL system. Solar PV is expected to provide approximately 21 MW of supply by the end of the study period.

Figure 4.26 | IPL Forecast of EV & PV Counts and Demand

	EV Count	EV Summer kW	EV Non-Summer kW	PV Count	PV MW
2020	5,621	901	1,226	240	4.34
2021	7,843	1,255	1,709	264	4.65
2022	9,968	1,596	2,174	291	4.98
2023	11,939	1,913	2,605	321	5.34
2024	15,469	2,481	3,379	354	5.72
2025	19,543	3,138	4,273	390	6.13
2026	24,364	3,915	5,331	430	6.56
2027	30,566	4,915	6,693	474	7.04
2028	37,743	6,073	8,269	524	7.67
2029	46,268	7,448	10,142	579	8.34
2030	56,148	9,043	12,313	640	9.07
2031	68,348	11,012	14,995	707	9.84
2032	82,173	13,246	18,036	761	10.66
2033	97,192	15,673	21,340	863	11.55
2034	112,667	18,173	24,745	953	12.51
2035	128,128	20,671	28,147	1,053	13.54
2036	143,283	23,120	31,481	1,163	14.65
2037	157,912	25,484	34,700	1,285	15.86
2038	171,925	27,748	37,783	1,421	17.30
2039	185,298	29,909	40,726	1,571	18.85
2040	197,177	31,829	43,339	1,737	20.53

Note: The EV forecast kW are for Rate EVX.

Figure 4.27 | 2020 – 2040 IPL Forecast of EV and PV MWh

	EV Summer Peak MWh	EV Summer Mid-Peak MWh	EV Summer Off-Peak MWh	EV Non-Summer Peak MWh	EV Non-Summer Off-Peak MWh	EV Annual MWh	PV Peak MWh	PV Off-Peak MWh	PV Annual MWh
2020	500	1,076	6,273	3,610	13,506	24,965	4,388	1,619	6,007
2021	697	1,500	9,129	5,031	19,595	35,952	4,701	1,734	6,435
2022	887	1,908	11,277	6,399	24,255	44,726	5,035	1,858	6,893
2023	1,063	2,287	13,296	7,668	28,631	52,944	5,399	1,992	7,391
2024	1,378	2,966	16,620	9,947	35,883	66,795	5,783	2,134	7,917
2025	1,743	3,751	20,399	12,578	44,140	82,611	6,197	2,286	8,483
2026	2,175	4,680	24,803	15,693	53,776	101,126	6,632	2,447	9,079
2027	2,730	5,875	30,362	19,702	65,961	124,630	7,114	2,626	9,740
2028	3,374	7,259	36,738	24,343	79,945	151,657	7,754	2,861	10,615
2029	4,138	8,903	44,241	29,856	96,417	183,555	8,432	3,111	11,543
2030	5,023	10,809	52,878	36,248	115,389	220,348	9,170	3,383	12,553
2031	6,117	13,163	63,456	44,142	138,644	265,523	9,948	3,670	13,618
2032	7,358	15,833	75,151	53,094	164,413	315,848	10,777	3,976	14,753
2033	8,706	18,734	87,718	62,822	192,132	370,112	11,677	4,308	15,985
2034	10,095	21,723	100,667	72,845	220,694	426,023	12,648	4,666	17,314
2035	11,483	24,709	113,604	82,859	249,229	481,884	13,689	5,050	18,739
2036	12,843	27,636	126,285	92,675	277,200	536,639	14,811	5,464	20,275
2037	14,156	30,462	138,525	102,150	304,200	589,493	16,034	5,916	21,950
2038	15,414	33,168	150,251	111,227	330,063	640,122	17,490	6,453	23,943
2039	16,615	35,751	161,440	119,888	354,744	688,439	19,057	7,031	26,088
2040	17,681	38,045	171,380	127,583	376,669	731,358	20,756	7,658	28,414

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

Most IPL's other distributed energy resources are related to the IPL feed in tariff (Rate REP). Rate REP was initially offered in 2011 and is fully subscribed and not available to new participants.

4.5 Load Model Performance and Analysis

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

During forecast development a number of models are analyzed at the rate level. The adjusted R-squared statistic, Mean Absolute Percent Error ("MAPE"), the Durbin-Watson statistic, and reasonableness of each model to IPL are statistically evaluated. The target adjusted R-squared values better than 90%; this is accomplished in nearly all cases. Further, MAPE needs to be less than 2%, and the Durbin-Watson statistic is targeted around 2.0. IPL considers independent variables with T-statistics of at least 2.0 acceptable. This judgment is somewhat subjective and dependent upon the implied importance of the variable. Please see Attachment 4.10 for summary of these model statistics.

Evaluation of the variance of energy sales and peak demand is completed each month and consider the impact of weather adjustments. IPL's forecasting staff uses this information to evaluate model performance. If the monthly variance moves reasonably with current "knowns" like economic factors and/or weather, a conditional approval supports the forecast. However, should variance move contrary to "knowns," an investigation of possible bias and other elements is undertaken. A similar determination, but with greater detail, is made at year-end. Actual and weather-adjusted results are compared to the forecasted values generated each of the previous five years. This is done with respect to energy sales at the class level, namely Residential, Small C&I, and Large C&I. Summer peak and winter peak, both actual and weather-adjusted, are reviewed in similar fashion.

The Mean Percent Error ("MPE") is used to evaluate overall forecast performance after the fact. Two interesting comparisons that gauge IPL's forecasting ability are those that compare weather-adjusted annual GWh sales and weather-adjusted summer peak to their respective forecasts. IPL's one-year-out energy forecast, as measured by MPE, is on average, within 1.5% of weather-adjusted sales. The summer MPE peak forecast averages 3.9%. IPL targets a one-year forecast error of less than 2%. Occasionally, rapidly changing external conditions, such as the extreme winter/polar vortex of 2013-2014, can cause fluctuations that exceed this bandwidth. However, reviewing forecast updates on a quarterly basis allows IPL to make both tactical adjustments in the short-term and initiate additional scenario analyses in the long-term. Figure 4.28 and Figure 4.29 highlight IPL's overall retail energy sales and summer peak demands forecast performance, respectively, for the last 10 years. The remainder of the forecast error analyses at the class level may be found in Attachment 4.9.

Figure 4.28 | Forecast Error Analysis: Weather-Adjusted Energy Sales vs. Forecasts

ANNUAL "INDIANAPOLIS ONLY" GWH SALES
Adjusted & Forecasted

		Forecast Made:				
For	Adjusted Sales *	One Year Ago	Two Years Ago	Three Years Ago	Four Years Ago	Five Years Ago
2009	14,296.266	15,208.790	15,472.539	15,612.025	15,932.337	15,838.873
		6.4%	8.2%	9.2%	11.4%	10.8%
2010	14,120.637	14,287.148	15,356.932	15,702.517	15,817.438	16,173.497
		1.2%	8.8%	11.2%	12.0%	14.5%
2011	14,010.057	14,172.293	14,420.894	15,520.059	15,914.802	16,020.434
		1.2%	2.9%	10.8%	13.6%	14.3%
2012	14,011.544	14,268.134	14,391.694	14,717.444	15,705.912	16,149.633
		1.8%	2.7%	5.0%	12.1%	15.3%
2013	13,878.196	14,118.020	14,263.240	14,491.940	14,783.227	15,691.466
		1.7%	2.8%	4.4%	6.5%	13.1%
2014	13,696.867	13,999.408	14,241.352	14,411.550	14,627.775	14,917.986
		2.2%	4.0%	5.2%	6.8%	8.9%
2015	13,728.657	14,085.083	14,141.772	14,409.551	14,526.255	14,700.724
		2.6%	3.0%	5.0%	5.8%	7.1%
2016	13,447.981	13,999.475	14,140.651	14,204.751	14,567.446	14,612.900
		4.1%	5.2%	5.6%	8.3%	8.7%
2017	13,434.558	13,838.176	14,015.988	14,089.805	14,175.427	14,514.876
		3.0%	4.3%	4.877%	5.5%	8.0%
2018	13,433.004	13,412.786	13,763.267	14,003.301	14,001.728	14,114.648
		-0.2%	2.5%	4.2%	4.2%	5.1%

Mean % Error	2.4%	4.4%	6.6%	8.6%	10.6%
Mean Absolute % Error	2.4%	4.4%	6.6%	8.6%	10.6%

Figure 4.29 | Forecast Error Analysis: Weather-Adjusted Summer Peak Demands vs. Forecasts

SUMMER PEAK DEMANDS
Actual & Forecasted

		Forecast Made:									
For	Actual Peak Demand	One Year Ago	Two Years Ago	Three Years Ago	Four Years Ago	Five Years Ago	Six Years Ago	Seven Years Ago	Eight Years Ago	Nine Years Ago	Ten Years Ago
2009	2924	3218 10.0%	3236 10.7%	3293 12.6%	3236 10.7%	3313 13.3%	3257 11.4%	3321 13.6%	3536 20.9%	3457 18.2%	3419 16.9%
2010	2901	3117 7.4%	3253 12.1%	3274 12.8%	3343 15.2%	3281 13.1%	3354 15.6%	3300 13.8%	3364 16.0%	3590 23.8%	3514 21.1%
2011	2894	2943 1.7%	3173 9.6%	3287 13.6%	3312 14.4%	3391 17.2%	3327 15.0%	3395 17.3%	3344 15.5%	3408 17.8%	3645 26.0%
2012	2899	2938 1.4%	3001 3.5%	3253 12.2%	3320 14.5%	3350 15.6%	3445 18.8%	3372 16.3%	3429 18.3%	3388 16.9%	3453 19.1%
2013	2839	2928 3.1%	2975 4.8%	3047 7.3%	3311 16.6%	3352 18.1%	3388 19.3%	3489 22.9%	3418 20.4%	3484 22.7%	3432 20.9%
2014	2880	2937 2.0%	2981 3.5%	3004 4.3%	3064 6.4%	3355 16.5%	3385 17.5%	3426 19.0%	3536 22.8%	3463 20.2%	3533 22.7%
2015	2849	2945 3.4%	2984 4.7%	3031 6.4%	3003 5.4%	3073 7.8%	3400 19.3%	3418 20.0%	3464 21.6%	3584 25.8%	3509 23.2%
2016	2835	2841 0.2%	2975 4.9%	3026 6.8%	3,047 7.5%	2989 5.4%	3082 8.7%	3445 21.5%	3451 21.7%	3502 23.5%	3630 28.0%
2017	2815	2866 1.8%	2865 1.8%	2983 6.0%	3051 8.4%	3,055 8.5%	2978 5.8%	3087 9.7%	3494 24.1%	3485 23.8%	3541 25.8%
2018	2812	2861 1.7%	2864 1.8%	2882 2.5%	2982 6.1%	3072 9.3%	3,079 9.5%	2962 5.3%	3092 10.0%	3540 25.9%	3519 25.2%

Mean % Error	3.3%	5.8%	8.4%	10.5%	12.5%	14.1%	15.9%	19.1%	21.9%	22.9%
Mean Absolute % Error	3.3%	5.8%	8.4%	10.5%	12.5%	14.1%	15.9%	19.1%	21.9%	22.9%

Section 5: Resource Options

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5.1 Existing IPL Resources

5.1.1 Existing Supply-Side Resources

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IPL's resource portfolio has changed dramatically over the last several years. Coal made up 79% of the IPL fleet in 2007, but by 2018 only represented 44% of the nameplate capacity. Through the resource planning process, IPL has sought to find the reasonable least-cost solution to meet the needs of its customers. Prudent portfolio management suggests that diversity of resource options helps to mitigate cost volatility. Figure 5.1 provides an overview of recent major changes to IPL's portfolio.

Figure 5.1 | Recent Significant Changes to IPL's Portfolio

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

Figure 5.2 shows the Installed Capacity ("ICAP") value and Unforced Capacity ("UCAP") value of IPL's resources. ICAP values are based on annual unit testing.

Figure 5.2 | IPL Resources Installed and Unforced Capacity Credit

	ICAP MW	UCAP MW
Coal	1,690	1,600
Gas	1,746	1,634
Oil/Diesel	38	37
Wind/Solar	396	54
Other	55	55
Total	3,926	3,380

Each resource has an estimated useful life with a corresponding age-based retirement year. This 2019 IRP analyzes the calendar years 2020 through 2039. Figure 5.3 illustrates the age-based retirement years falling within this IRP study period in terms of UCAP. It also shows IPL's capacity position transitioning from having excess capacity to having a capacity deficiency relative to its peak load and reserve margin. The first year this shift can be seen is 2031 after two of the Harding Street units retire.

Figure 5.3 | IPL UCAP Net Position using Age-Based Retirement Years

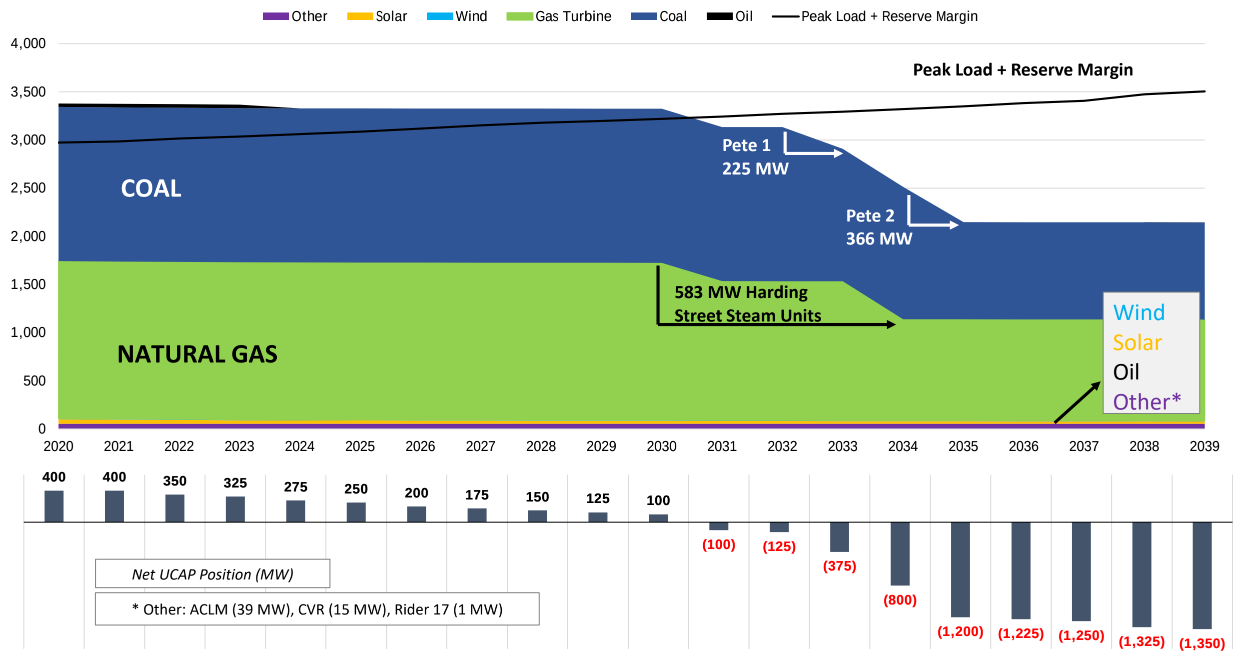


Figure 5.4 and Figure 5.5 illuminate more detail into IPL's existing thermal generating resources.

Figure 5.4 | IPL's Existing Coal Assets

Unit	Name	Type	ICAP MW	UCAP MW	In-Service Year	Estimated Last Year In-Service
Petersburg						
PETE ST1	Pete 1	Coal	235	225	1967	2032
PETE ST2	Pete 2	Coal	401	366	1969	2034
PETE ST3	Pete 3	Coal	518	486	1977	2042
PETE ST4	Pete 4	Coal	536	523	1986	2042
Total Coal:			1,690	1,600		

Figure 5.5 | IPL's Existing Gas and Oil Assets

Unit	Name	Type	ICAP MW	UCAP MW	In-Service Year	Estimated Last Year In-Service
Eagle Valley						
EV CCGT	Eagle Valley	CCGT	671	617	2018	2055
Harding Street						
HS 5G	Harding Street 5	Gas ST	100	95	1958	2030
HS 6G	Harding Street 6	Gas ST	99	94	1961	2030
HS 7G	Harding Street 7	Gas ST	415	394	1973	2033
HS GT4	Harding Street GT4	Gas CT	74	70	1994	2044
HS GT5	Harding Street GT5	Gas CT	74	70	1995	2045
HS GT6	Harding Street GT6	Gas CT	154	143	2002	2052
HS GT1 & GT2	Harding Street GT1&2	Oil	38	37	1973	2023
Georgetown						
GTOWN GT1	Georgetown 1	Gas CT	79	75	2000	2050
GTOWN GT4	Georgetown 4	Gas CT	79	76	2001	2052
Total Natural Gas:			1,746	1,634		
Total Oil:			38	37		

Figure 5.6 shows both the nameplate capacity and UCAP value for IPL's wind and solar PPAs. IPL's Solar REP is on the distribution system and therefore reduces load rather than participates as a generating resource. IPL does not receive direct UCAP capacity credit for its Solar REP and does not offer solar PPA generation directly into the MISO market, but its capacity still contributes towards reducing IPL's peak demand. It's also important to realize that IPL's Solar REP UCAP decreases with time due to the saturation of solar in the MISO footprint. Incremental solar shifts the load profile, thus reducing solar's effectiveness at coinciding with peak demand. This is covered in more detail in Section 5.3.2. IPL receives capacity credit for Hoosier Wind Park commiserate with MISO's Zone 6 ELCC. IPL does not have firm transmission rights for its Lakefield Wind Park and so receives no capacity credit for this resource.

Figure 5.6 | IPL's Existing Renewable PPAs

Unit	Type	ICAP MW	UCAP MW	PPA Start	PPA Expiration
Wind and Solar					
Hoosier Wind Park (IN)	PPA	100	6.6	Nov-09	Nov-29
Lakefield Wind (MN)	PPA	200	0	Oct-11	Oct-31
Solar (Rate REP) *	PPA	96	47.5	varies	2021-2030
Total Renewables:		396	54		

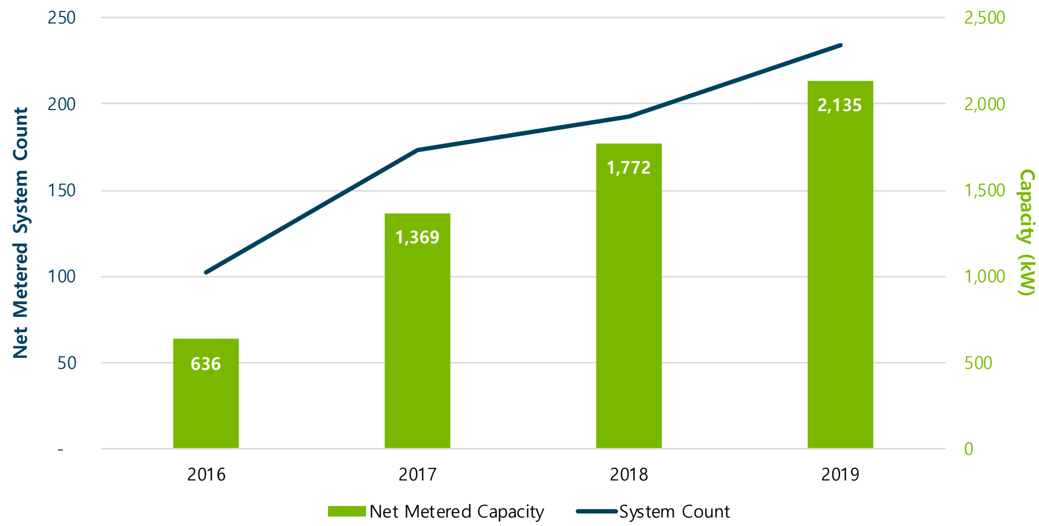
*IPL is using 47.5 MW for 2020, but this value decreases over time.

IPL's current PPA contracts expire within the IRP study period. It is assumed that these contracts will be renegotiated, and the resources will continue to perform in alignment with their historical generation.

Figure 5.7 summarizes the growth of net metered customers in the IPL Service territory, as of September 2019. IPL has experienced modest growth in PV net metered customers. Except for a federally funded 1 MW project, most net metered projects are relatively small solar installations.[11] Net metered capacity reduces IPL load requirements in terms of energy and does not materially affect capacity.

[11] All the Indiana IOUs file an annual net metering report with the IURC. The 2018 report published March 2019, is available at https://www.in.gov/iurc/files/2018%20Net%20Metering%20Required%20Reporting%20Summary.pdf.

Figure 5.7 | Summary of IPL Net Metering Participation



5.1.2 Existing Demand Side Resources

IPL's current portfolio of DSM resources (2018 – 2020) was approved on February 7, 2018 in Cause No. 44945. This comprehensive set of programs provides energy efficiency opportunities for all IPL customers.

Current Energy Efficiency Programs

The current energy efficiency programs and the actual 2018 evaluated energy savings of approximately 162,000 Net MWh are identified in Figure 5.8. Through the first eight months of 2019, the IPL energy efficiency and demand response programs have contributed an estimated 111,669 MWh of energy savings benefits and approximately 56.9 MWs of demand savings benefits[12]

The total 2019 net energy efficiency savings are forecast to be approximately 145,000 MWh.

[12] YTD gross savings from the August 2019 Scorecard as provided to the IPL Oversight Board ("IPL OSB"). Results are subject to Evaluation, Measurement & Verification ("EM&V") which will be completed after the program year.

Figure 5.8 | 2018 DSM Program Energy Savings

DSM Program	Evaluated 2018 Program Achievement (Ex Post Net kWh)*
Residential Programs	
Demand Response	68,609
Appliance Recycling	1,865,513
Community Based Lighting	8,014,916
Income Qualified Weatherization	2,256,228
Lighting & Appliances	20,125,603
Multifamily Direct Install	2,423,349
Peer Comparison	27,332,805
School Kits	4,003,124
Whole Home	4,027,393
Total Residential	**70,118,086**
Business Programs	-
Demand Response	-
Custom	14,639,238
Prescriptive	73,836,844
Small Business Direct Install	3,091,457
Total Business	**91,567,539**
Total All Programs	**161,685,625**

*Ex Post Net reflects the net impact of DSM programs following third party evaluation. More information can be found in the IPL 2018 Demand Side Management Portfolio Evaluation Report dated June 27, 2019 as filed with the Commission in Cause No. 44945.

IPL's ACLM ("CoolCents®") and Income Qualified Weatherization Programs are IPL's longest continually offered DSM programs. The Residential ACLM program has been offered since 2003 and represents the largest DSM program in terms of customer participation and peak demand reduction. As of the end of 2018, IPL has approximately 49,500 residential customers with load control switches or smart thermostats. In 2018 there were also approximately 430 load control switches installed at business customer's facilities. In total these devices contributed approximately 31.6 MW of demand reductions.[13]

[13] 2018 Demand Side Management Evaluation Report, Indianapolis Power & Light Company, June 27, 2019, Tables 13, 14 and 15, p. 10.

Of current offerings, the most significant DSM programs in terms of energy efficiency savings in 2019 are expected to be the Business Prescriptive Program (approximately 57,000 gross MWh savings through October 31, 2019) and the Residential Peer Comparison Report (with approximately 27,000 gross MWh savings through October 31, 2019).

Current Demand Response Programs

In addition to the energy efficiency DSM programs and the ACLM demand response program described above, IPL also has several Load Curtailment/Interruptible programs that are tariff offerings targeted to business customers. Since 2014 these programs have seen a significant decrease in participation and the amount of capacity that is being provided. The programs had mostly been targeted to customers that have emergency back-up generation. Customers were called upon from time to time to operate the emergency generation equipment on IPL's behalf to reduce load. However, the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines ("RICE/NESHAP") rules caused most customer owned emergency generation to no longer be available to participate in utility sponsored programs due to air emission constraints. As a result of these EPA restrictions, the current level of participation in IPL's Load Curtailment / Interruptible programs is just under 1 MW as shown below.

IPL also has the capability to operate the Conservation Voltage Reduction systems as needed. This system can provide an additional 15.3 MW of load relief.

In summary, Figure 5.9 shows the demand response resources for which IPL received capacity credit from MISO totaling 55.0 MW in 2018. There is no end of useful life shown since IPL plans to support this program through customer enrollment and replacement technologies as needed throughout the study period.

Figure 5.9 | Existing DR program Contributions

Demand Response Type	ICAP Value (MW)
Air Conditioning Load Management	38.6
Rider 17: Curtailment Energy	1.1
Conservation Voltage Reduction	15.3
Total	55.0

5.2 Supply-Side Resource Options

170 IAC 4-7-4(6) 170 IAC 4-7-4(7) 170 IAC 4-7-4(31) 170 IAC 4-7-6(b)(3)(A)

Key Highlights for Supply-Side Resources
• IPL conducted thorough research to develop the cost and operational parameters of new supply-side resources. • New natural gas resources modeled included combined cycle, simple cycle gas turbines, and quick start technologies like aeroderivative turbines and reciprocating engines • Near-term costs for wind, solar, and storage were benchmarked to publicly available market bids • Future costs for wind, solar, and storage are expected to decrease in real terms through time, and future costs used information from NREL, IHS Markit, BNEF, and Wood Mackenzie to provide an average consensus for price trajectories through time

Below is a list of the supply-side resource options considered followed by a more detailed description of each technology:

Natural Gas

- Simple Cycle Combustion Turbine (“CT”)
- Combined Cycle Gas Turbine (“CCGT”)
- Aeroderivative Turbines (“Aero CT”)
- Reciprocating Engines

Renewables and Storage

- Indiana Wind
- Utility-Scale single-axis tracking solar
- 4-Hour Battery Storage

Figure 5.10 | Modeled Resources in the 2019 IRP

NATURAL GAS
- Combined Cycle
- Simply Cycle Combustion Turbine
- Aeroderivative Turbine
- Reciprocating Engines

WIND
- Indiana Wind

SOLAR
- Utility-Scale Single-Axis Tracking

STORAGE
- Standalone Front-of-meter
- Energy Arbitrage and Capacity Battery Storage

DSM/EE
- Measures bundled into decrements by cost

Capital costs were developed using a combination of publicly available data sources and proprietary, third-party vendor forecasts. Base capital costs were for most technologies using an average of the following data sources: NREL 2018 Annual Technology Baseline ("ATB"), IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. These averages were benchmarked against other publicly available data sources including the Lazard Levelized Cost of Energy report Version 12.0 and NIPSCO's published summary of bid responses from their 2018 RFP. Confidential Attachment 5.5 contains confidential underlying assumptions for the build up of capital costs in the 2019 IRP.

IPL also conducted a sensitivity analysis that varied capital costs for wind, solar, and storage, which can be found in Section 7.

Figure 5.11 | Public Data Sources for Resource Capital Costs

National Renewable Energy Laboratory (NREL)

- 2018 Annual Technology Baseline (ATB)
- https://atb.nrel.gov/electricity/2018/

Lazard

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

NIPSCO RFP Average Bid Prices

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

Figure 5.12 | Proprietary Third-Party Data Sources for Capital Costs

IHS Markit

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

Bloomberg New Energy Finance (BNEF)

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

Wood Mackenzie

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

5.2.1 Natural Gas

Simple-Cycle Combustion Turbine

For purposes of the IRP analysis, IPL assumed the incremental addition of a 100 MW CT in its expansion planning. Conventional frame CTs are a mature technology, widely used for peaking applications. The units are characterized by low capital costs, low non-fuel variable Operation and Maintenance Costs ("O&M"), modular designs and short construction lead times.

Combined Cycle Gas Turbine

The typical combined cycle installation consists of gas turbines discharging waste heat into a heat recovery steam generator ("HRSG"). The HRSG supplies steam that is expanded through a steam turbine cycle driving an electric generator. Combined cycle units have the distinct advantage of being the most efficient fossil-fueled process available.

Aeroderivative Turbine

Aeroderivative combustion turbines ("Aero CT") offer a fast-ramping, flexible peaking resource. Aero CTs have higher capital costs, but offer smaller, more modular design with faster dispatching parameters compared to a simple cycle CT.

Reciprocating Engines

Reciprocating engines are a mature technology that offer fast-ramping, firm dispatchable capacity with minimal water use and design flexibility due to their modular nature. Often used in CHP applications, engines can be sized as small as 10 kW and as large as 18 kW[14]. IPL modeled a "bank" of six (6) 18 MW engines with a total capacity of 108 MW. Reciprocating deployment is often seen in areas with high penetration of wind and solar, such as California, Texas, and states in the Southwest Power Pool (SPP)[15]. Fast-ramping, flexible resources like reciprocating engines could play a role in a high renewable grid.

Figure 5.13 contains cost and operations characteristic for new natural gas resources.

[14] https://www.energy.gov/sites/prod/files/2016/09/f33/CHP-Recip%20Engines.pdf

[15] https://www.eia.gov/todayinenergy/detail.php?id=37972

Figure 5.13 | Natural Gas New Resource Assumptions

Unit	1x1 CCGT	Frame CT	Aero CT	Recip. Engine
Description	Combined Cycle	Combustion Turbine	Aeroderivative Turbine	6x0 18 MW Reciprocating Engines
COST				
Overnight Construction Cost [2023 COD] (2018$/kW)	$960	$749	$1,406	$1,305
Variable O&M (2018$/MWh)	$0.96	$0.48	$4.57	$6.03
Fixed O&M (2018$/kW-year)	$17.00	$15.60	$12.75	$5.84
CAPACITY AND OPERATION				
MISO ICAP (MW)	325.0	100.0	126.0	108.0
xEFORd %	5.370%	5.180%	5.180%	5.180%
MISO UCAP (MW)	307.5	94.8	119.5	102.4
Econ Max (MW)	325	100	42	18
Econ Min (MW)	145	62.5	21	8
Modeled Forced Outage %	5.8	10	2.03	3.3
Heat Rate at Max Load (Btu/kWh)	6,744	10,012	9,500	8,502
EMISSION RATES				
SO2	0.0006	0.001	0	0.001940921
NOx	0.0072	0.028	0.01	0.02512
CO2	119	119	119	119

5.3 Renewables and Storage

170 IAC 4-7-4(6) 170 IAC 4-7-4(31) 170 IAC 4-7-6(b)(3)(A)

IPL considered a wide range of renewable and storage applications for this IRP cycle. The three mature, commercially available technologies modeled were utility scale wind, solar, and front of the meter storage.

5.3.1 Wind

New Wind Resource Summary

- Modeled Generic Project Size: 50 MW
- Assumed location: Northwestern Indiana
- Annual Capacity Factor: 42%
- Capacity Credit: 7.8%
- Cost:
  - LCOE ~$31/MWh nominal with 80% PTC for 2021 COD
  - LCOE ~$50/MWh nominal with 0% PTC for 2025 COD

Production Profiles

The generic wind resource available for selection in the capacity expansion tool was an Indiana based wind farm located in northwestern Indiana. As discussed in a previous section, IPL has an existing PPA for Hoosier Wind Park in Benton County, IN. IPL has access to historical hourly data going back to 2009 for this wind farm. However, this wind farm is 10 years old, has a hub height of only 80 meters, and uses older turbines and technology. New wind farms are expected to have higher capacity factors. Therefore, IPL utilized other data sources for building the profile for the generic wind project.

IPL used the NREL Wind Toolkit and Wind Prospector[16] to build a generic wind profile for this IRP. We chose a midpoint capacity factor of 42% for Benton County to build the energy profile for a generic 50 MW project. NREL provides 5-minute simulated production data in MW based on the power curve of the wind site. IPL integrated the data to hourly data and scaled up the hourly generation for a 50 MW project. The result was four years of hourly simulated historical data for that wind farm location. Figure 5.14 contains an example of a month of scaled hourly data from NREL for May 2009. Figure 5.15 shows the process flow for data being incorporated in the PowerSimm model.

PowerSimm uses the scaled historical data in conjunction with a forecasted monthly energy production target to simulate a wind profile through time. Through PowerSimm's weather simulation, the shape will be different in each iteration and will scale to the mean output entered monthly.

A sensitivity analysis on the capacity factor was conducted and results can be found in Section 7.4.3.

[16] NREL Wind Prospector. Retrieved from: https://maps.nrel.gov/wind-prospector/?aL=p7FOkl%255Bv%255D%3Dt&bL=clight&cE=0&lR=0&mC=40.21244%2C-91.625976&zL=4

Figure 5.14 | Example NREL Wind Toolkit Scaled Hourly Data, May 2009

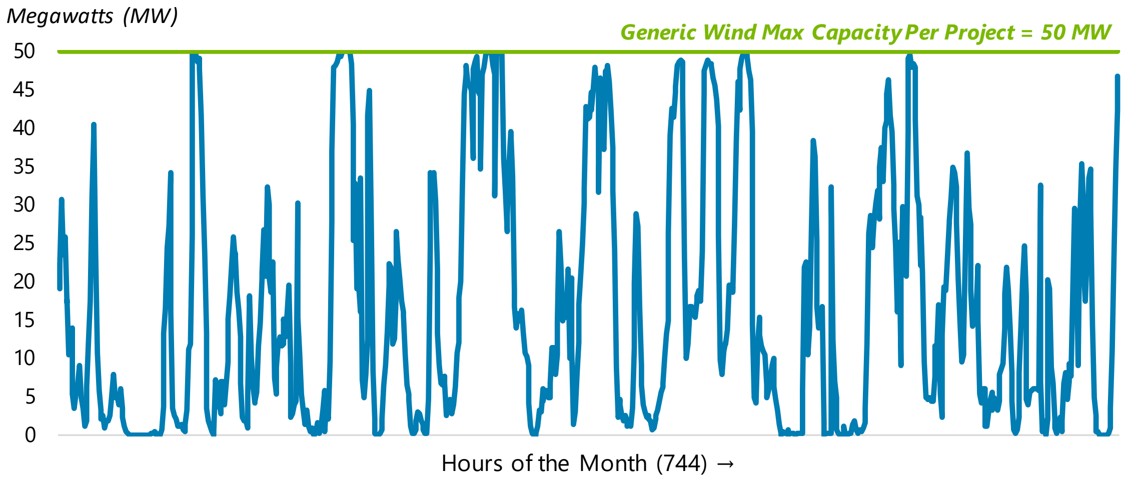


Figure 5.15 | Process Data Flow for Developing Generic Wind Profiles

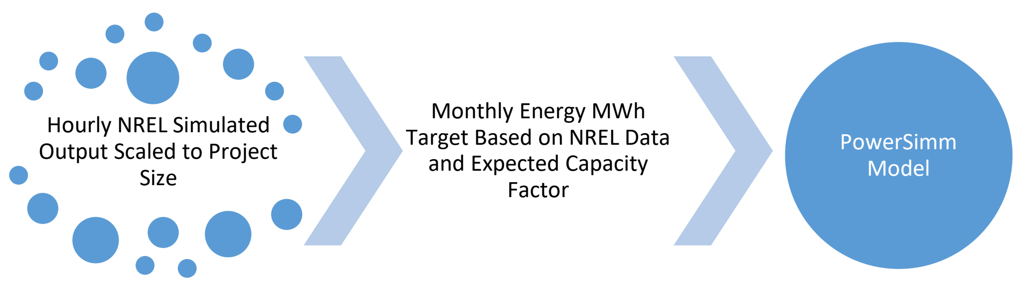
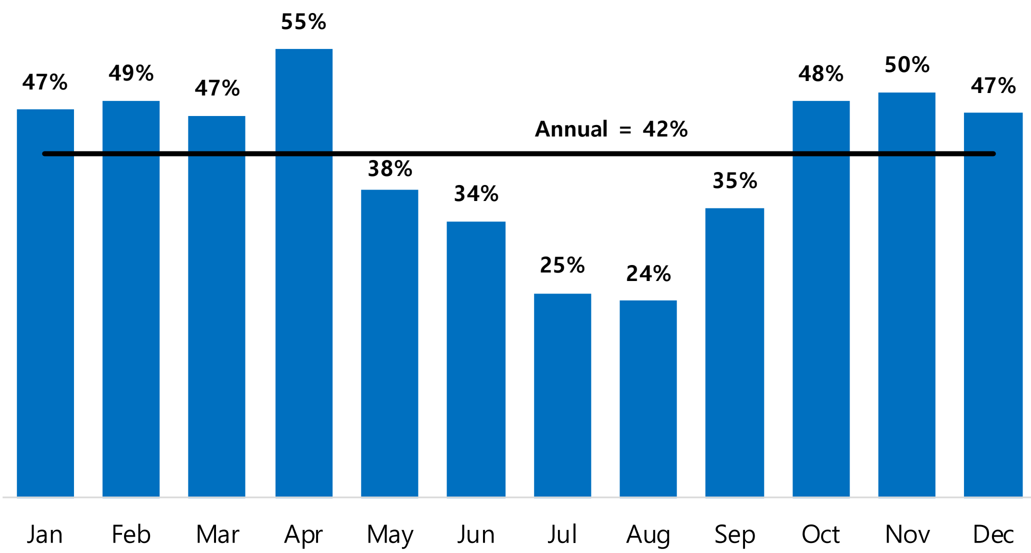


Figure 5.16 | Generic New Wind Monthly Capacity Factors



Capacity Credit

The capacity credit was modeled at 7.8% ELCC for Zone 6 throughout the planning study based on the PY 2019/2020 Wind Capacity Credit report published by MISO in December 2018[17]. MISO conducts a two-phase Effective Load Carrying Capability ("ELCC") study annually to assess the capacity credit of wind. The first phase includes a probabilistic assessment of system-wide wind in MISO, and the second phase is a deterministic allocation of the system-wide capacity to individual projects based on historical performance and location.

New wind projects with no commercial operation meter data receive the system-wide MISO ELCC (15.6% for PY 19/20) and will receive the unit specific allocated UCAP in all subsequent years. There is uncertainty regarding what capacity credit a new Indiana wind project would receive after the first year. Newer turbines with higher hub heights could be allocated a higher capacity credit relative to older vintage wind projects. To be conservative, IPL is modeling new wind with a 7.8% capacity credit. This is higher than the three-year average at Hoosier Wind Park and is the best available information at the time of this IRP modeling exercise. Any risk or opportunity created by a potential mismatch in planning capacity credit and realized capacity credit can be mitigated on a yearly basis through active position management and through the capacity tracker.

[17] https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf

Capital and O&M Costs

Base capital costs for new wind projects were based on a blend of capital cost projections from NREL, IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. The Production Tax Credit (PTC) is a major driver of value for wind projects, and Figure 5.17 contains assumptions for how the PTC was modeled in the 2019 IRP. IPL assumed that new wind met the 5% safe harbor rules to be eligible for 100% in 2020, stepping down to 0% by 2024. In the PowerSimm capacity expansion module, capital costs entered were adjusted down for the value of the PTC rather than entered as a credit to variable O&M. As Figure 5.18 shows, each 20% reduction in the PTC increases the LCOE by about $3.50/MWh in real terms, and the PTC can reduce overall costs by as much as 60%.

All new projects in the IRP are modeled as 100% IPL-owned assets, and the revenue requirement calculation reflects traditional rate recovery assuming a rate case every year. Tax equity financing would could be required for any new IPL-owned wind project with PTC eligibility, and the actual ownership level, tax implications, and final net costs would be fully modeled at the time of a regulatory filing for an actual project. Additional capital cost sensitivities were conducted to capture some of the uncertainty around capital costs. That analysis is described in Section 7.4.1.

Figure 5.17 | Production Tax Credit Assumptions for New Wind in 2019 IRP

	2020	2021	2022	2023	2024
Wind PTC Assumption	**100%**	**80%**	**60%**	**40%**	**0%**
Overnight Capital Cost (2018$/kW)	$1,423	$1,406	$1,393	$1,382	$1,372
PTC-Adjusted Capital Cost (2018$/kW)	$633	$779	$925	$1,071	$1,372
LCOE - No PTC (2018$/MWh)	$44.57	$43.99	$43.55	$43.17	$42.82
LCOE with PTC (2018$/MWh)	$25.34	$28.75	$32.18	$35.63	$42.82

Figure 5.18 | New Wind Capital Cost (2018$/kW)

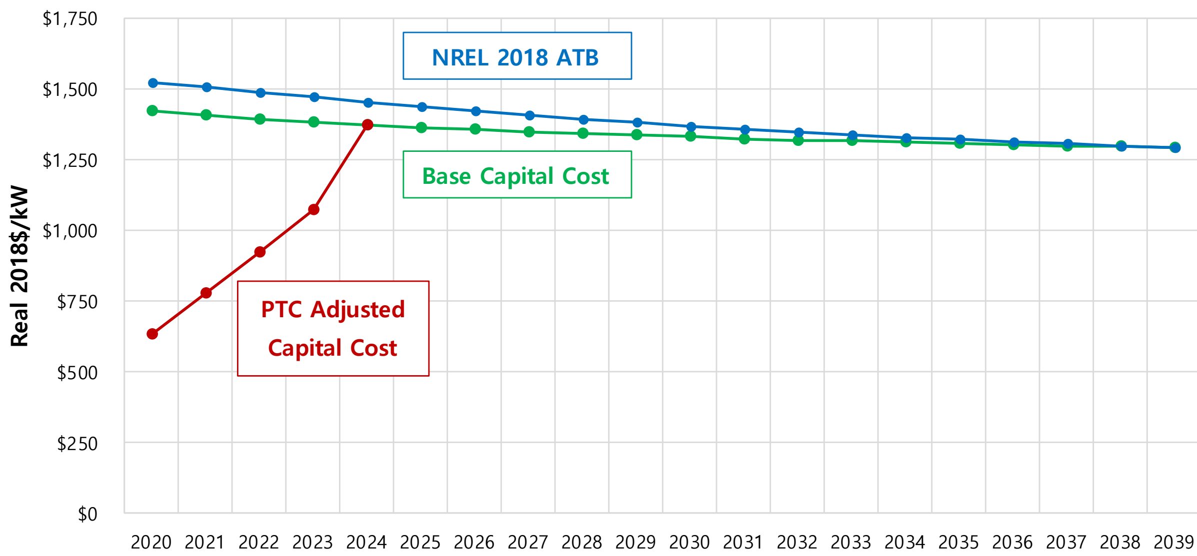
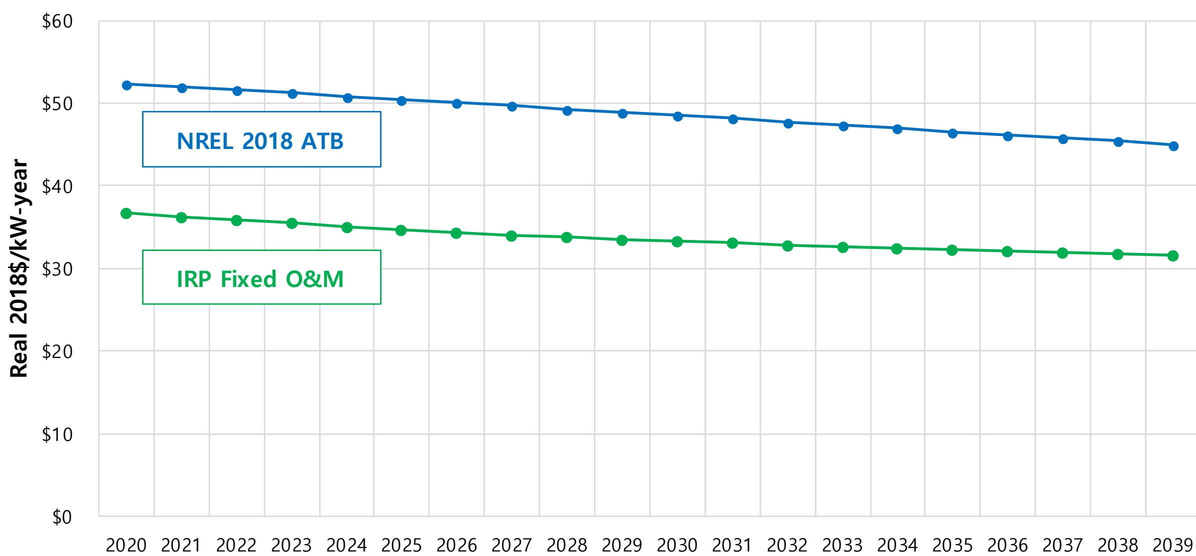


Figure 5.19 | New Wind Fixed O&M ($/kW-year)



5.3.2 Solar

New Solar Resource Summary

• Modeled Generic Project Size: 25 MW
• Assumed location: Central Indiana
• Annual Capacity Factor: 23%
• Capacity Credit: Declining ELCC from 63% in 2020 to 23% in 2039
• Cost:
  • LCOE ~$35/MWh nominal with 100% ITC for 2023 COD
  • LCOE ~$45/MWh nominal with 10% ITC for 2025 COD

Capacity Factor and Profile

IPL utilized hourly historical production from IPL-contracted REP solar projects to build production profiles for generic new solar projects. All generic new solar was assumed to be utility-scale, single-axis tracking solar located in central Indiana.

Figure 5.20 contains the process data flow for developing generic solar profiles. The process is very similar to creating wind profiles, with three years of historical data and monthly energy targets scaled to the generic project size entered in PowerSimm. Solar profiles are simulated based on this historical data and scaled to the monthly energy that is directly related to the capacity factor assumption.

Figure 5.20 | Process Data Flow for Developing Generic Solar Profiles

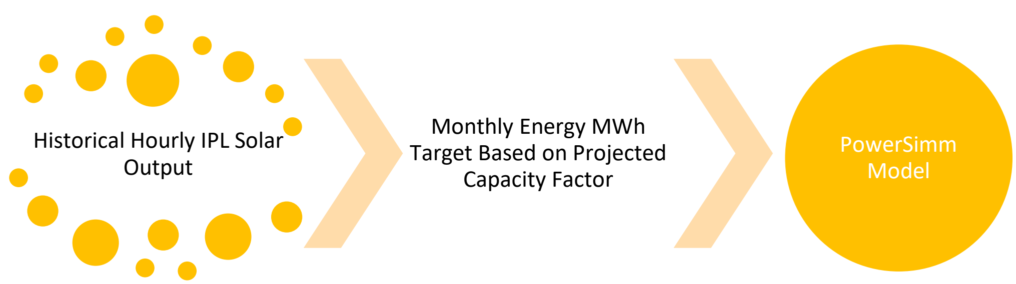
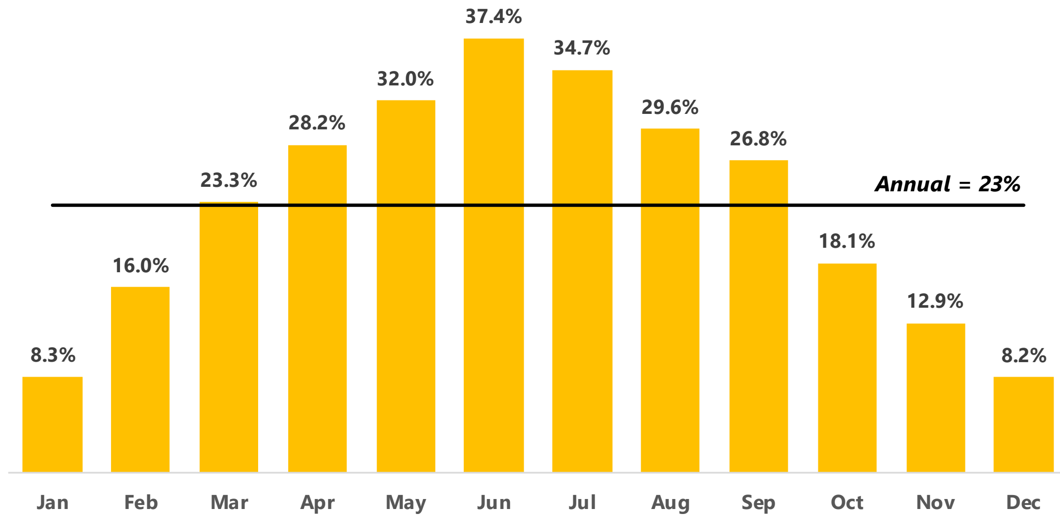


Figure 5.21 shows the monthly capacity factor assumption used for new solar projects. The annual capacity factor assumed was 23%, with monthly capacity factors ranging from 8% in winter to above 35% in the summer.

Figure 5.21 | IRP Generic Single-Axis Tracking Solar, Monthly Capacity Factor



Capacity Credit

Solar production occurs during the day, which provides capacity contribution during some of the highest load hours in the summer. MISO's Resource Adequacy Business Practice Manual[18] (BPM-011) contains the following language for determining solar capacity credit:

> Solar photovoltaic (PV) resources will have their annual UCAP value determined based on the 3 year historical average output of the resource for hours ending 15, 16, and 17 EST for the most recent Summer months (June, July, and August)… Resources with less than 30 days of metered values would receive the class average of 50% for its Initial Planning Year.

By default, new solar resources in MISO receive a 50% capacity credit for the first year, and capacity credit in subsequent years will be based on average hourly production for each hour between 2pm and 5pm (Hours ending 13-17) EST. Figure 5.22 contains a three-year historical average output of IPL tracking solar by hour. The capacity factor for HE 15-17 for the period of 2016-2018 was approximately 63%. This was used as the capacity credit for the first year of the IRP study (2020).

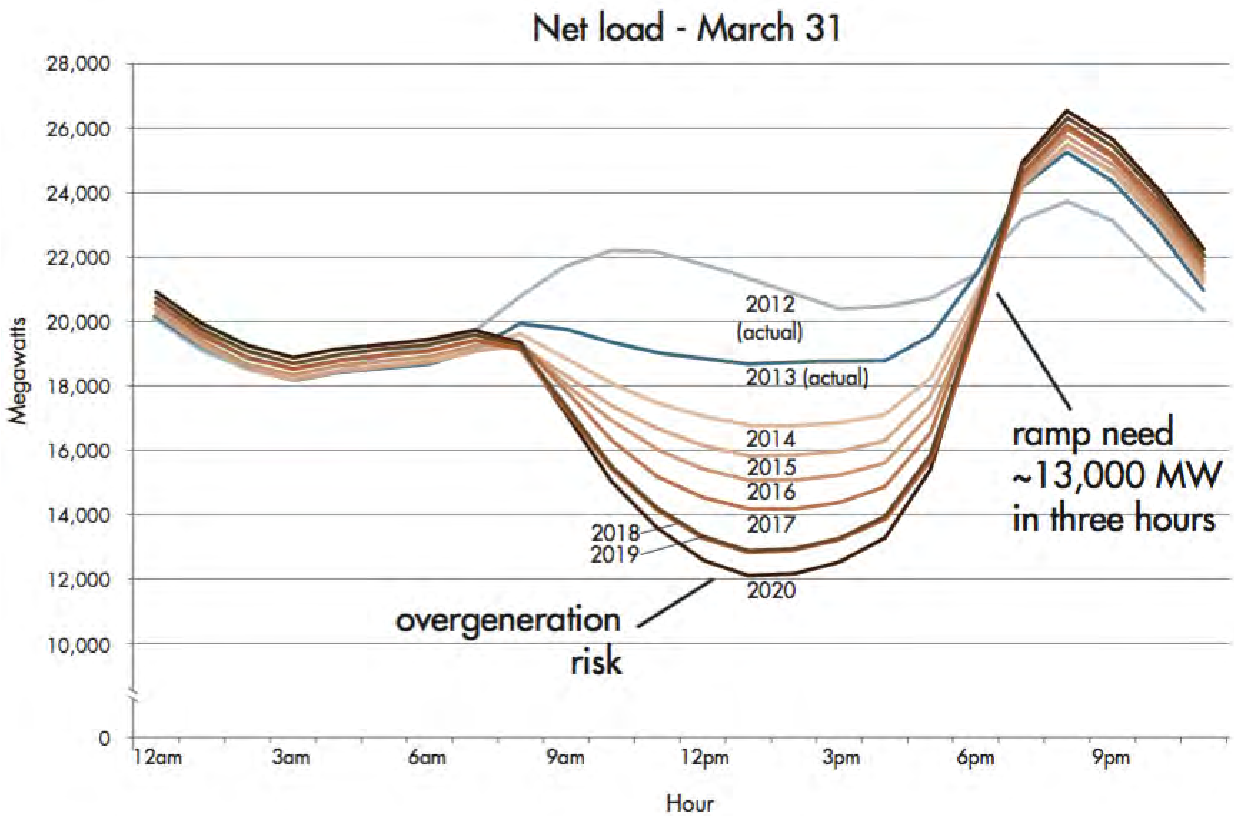
[18] https://www.misoenergy.org/planning/resource-adequacy

Figure 5.22 | IPL Single-Axis Tracking Average Capacity Factor, 2016 – 2018

HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	2%	1%	0%	0%	0%	0%	0%
7	0%	0%	1%	4%	9%	21%	17%	5%	1%	0%	0%	0%
8	0%	0%	7%	27%	31%	53%	46%	28%	17%	6%	1%	0%
9	3%	11%	33%	51%	51%	70%	63%	50%	47%	30%	13%	3%
10	16%	31%	52%	59%	62%	76%	71%	62%	62%	45%	32%	15%
11	25%	41%	56%	62%	66%	76%	70%	66%	65%	50%	38%	25%
12	25%	47%	60%	66%	68%	75%	72%	67%	66%	50%	40%	27%
13	26%	49%	59%	67%	68%	73%	69%	68%	65%	49%	38%	28%
14	26%	47%	59%	66%	69%	71%	69%	66%	64%	47%	39%	28%
15	26%	45%	56%	63%	66%	**69%**	**65%**	**66%**	63%	45%	38%	26%
16	23%	41%	52%	57%	62%	**68%**	**64%**	**60%**	59%	42%	33%	22%
17	13%	30%	46%	52%	61%	**67%**	**62%**	**54%**	52%	29%	12%	7%
18	2%	10%	27%	37%	53%	60%	55%	44%	29%	7%	0%	0%
19	0%	0%	6%	12%	32%	37%	34%	18%	5%	0%	0%	0%
20	0%	0%	0%	1%	9%	8%	8%	2%	0%	0%	0%	0%
21	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

For future years, the capacity credit was decreased in accordance with information provided by MISO as part of the Renewable Integration Impact Assessment ("RIIA") study. It is helpful to think of solar's capacity contribution in terms of net load. Net load is defined as the load not being served by renewables, which is simply calculated as the actual load minus renewable production for each hour of the day. As more solar is added to the system, the peak net load hour shifts to later in the day when solar production starts to drop off. This is often referred to as the "duck curve" problem observed by regions like California that have more solar on the system (the duck being the outlined shape in the new net load curve). Figure 5.23 shows the original net load chart from the California ISO (CAISO).

Figure 5.23 | Original California ISO (CAISO) Duck Curve Chart[19]



Through MISO's RIIA study[20], MISO provided an estimated ELCC curve at different installed amounts of solar by examining the capacity credit at increasing capacity levels. Figure 5.24 contains the curve for wind and solar as well as the equations used by MISO to calculate how much solar and wind need to be installed to meet the RIIA inflection points for renewable penetration.

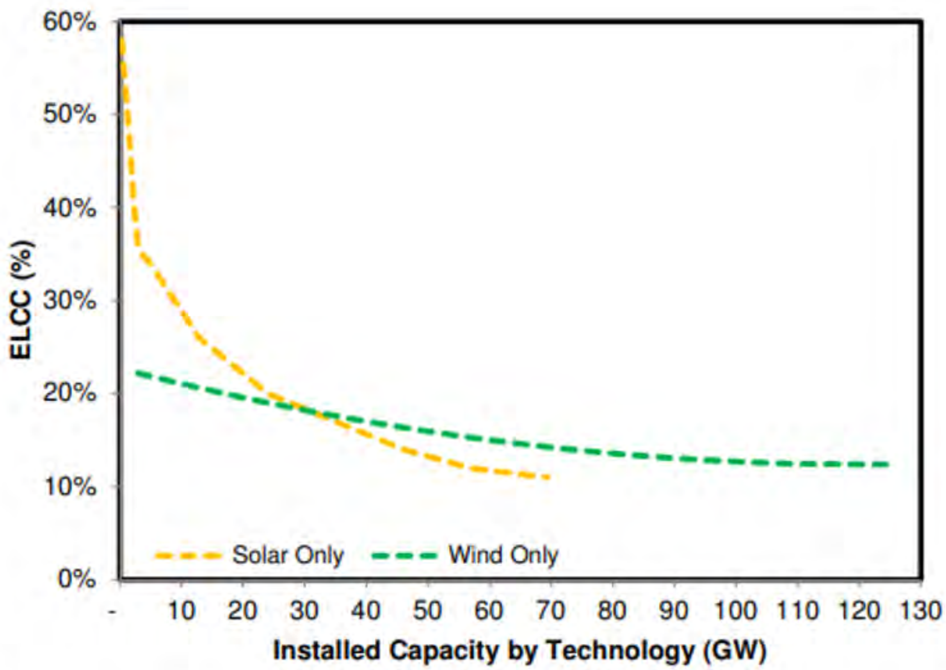
To calculate the ELCC by year for the IRP, IPL used annual forecasted installed solar in MISO from Wood Mackenzie's H1 2018 Long Term Outlook. Figure 5.25 contains the annual capacity credit used in modeling for the IRP. Different capacity credit was given to fixed tilt and tracking solar, which is consistent with a more detailed ELCC study[21] from MISO and validated by IPL experience with data from existing solar.

[19] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[20] MISO RIIA Assumptions Document, Version 6. https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v6301579.pdf

[21] B. Heath and A. L. Figueroa-Acevedo, "Potential Contribution of Wind and Solar Generation in MISO System," in IEEE International Conference on Probabilistic Methods Applied to Power Systems, Boise, ID, 2018.

Figure 5.24 | MISO RIIA Assumptions: Solar ELCC %



These graphs were approximated by the *siting- and fuel-mix specific* functions in Equation 1, where UCAP is unforced capacity and ICAP is installed capacity.

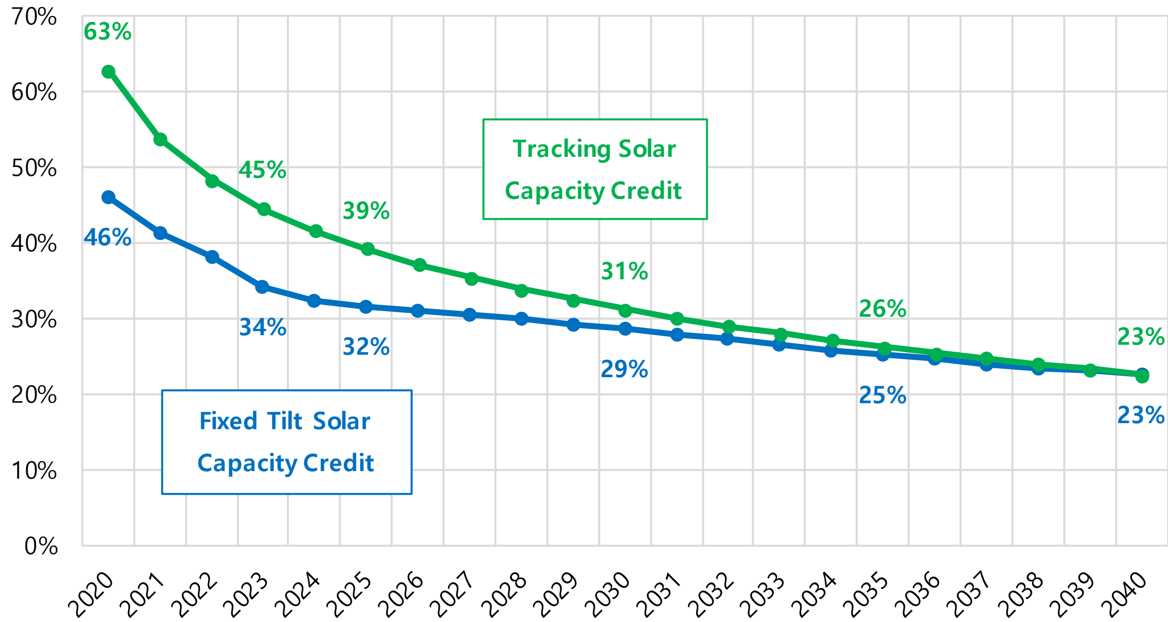
Equation 1 Approximate ELCC functions for wind and solar

$$\text{Wind } UCAP = (-0.3\ln(ICAP) + 0.26) * ICAP$$

$$\text{Solar } UCAP = (-0.07\ln(ICAP) + 0.42) * ICAP$$

Source: MISO

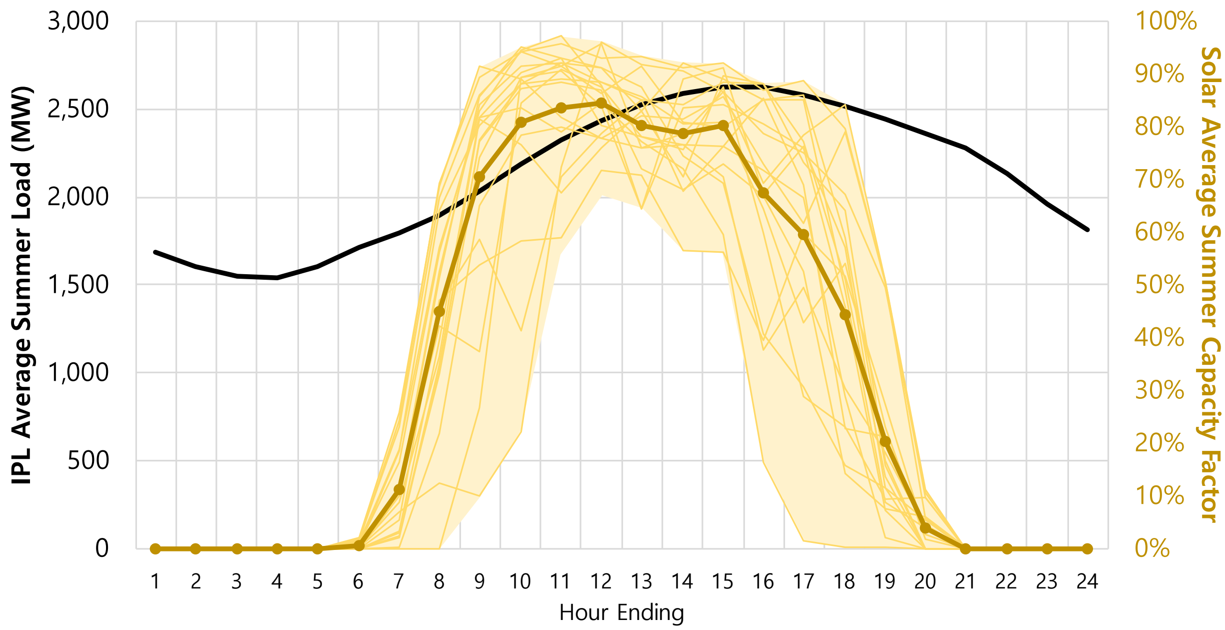
Figure 5.25 | Modeled Annual Solar Capacity Credit for 2019 IRP



To validate these solar capacity credit assumptions, IPL evaluated the coincidence of solar production with load for the top 20 peak summer and winter load days over the past three years for our own system.

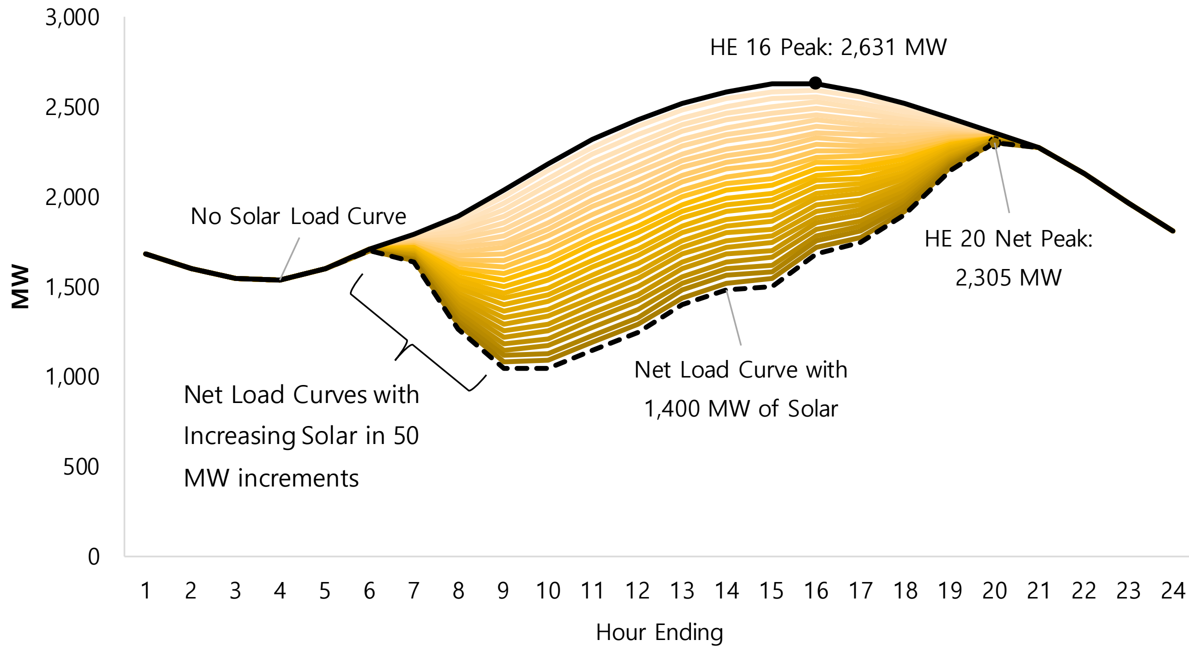
Figure 5.26 shows the average IPL load profile by hour of day for the top 20 summer days from 2016 to 2018 as well as the hourly capacity factor of IPL tracking solar for the same days. The chart shows that on average solar production is limited between 7am and 9pm EST, and there is ample production across the highest load hours (2pm to 5pm). IPL's average peak hour is HE 16 for this data sample, and IPL tracking solar averaged production of 67% of nameplate capacity during that hour for the same data sample.

Figure 5.26 | IPL Load and Solar Profile: Top 20 Peak Summer Days, 2016 - 2018



To estimate the impact of increasing solar on IPL's net load curve, we scaled up the typical summer profile in increments of 50 MW up to 1,400 MW of solar. Figure 5.27 shows how the net peak load for IPL shifts from HE 16 (3-4pm) to HE 20 (7-8pm) as the amount of solar increases on the system.

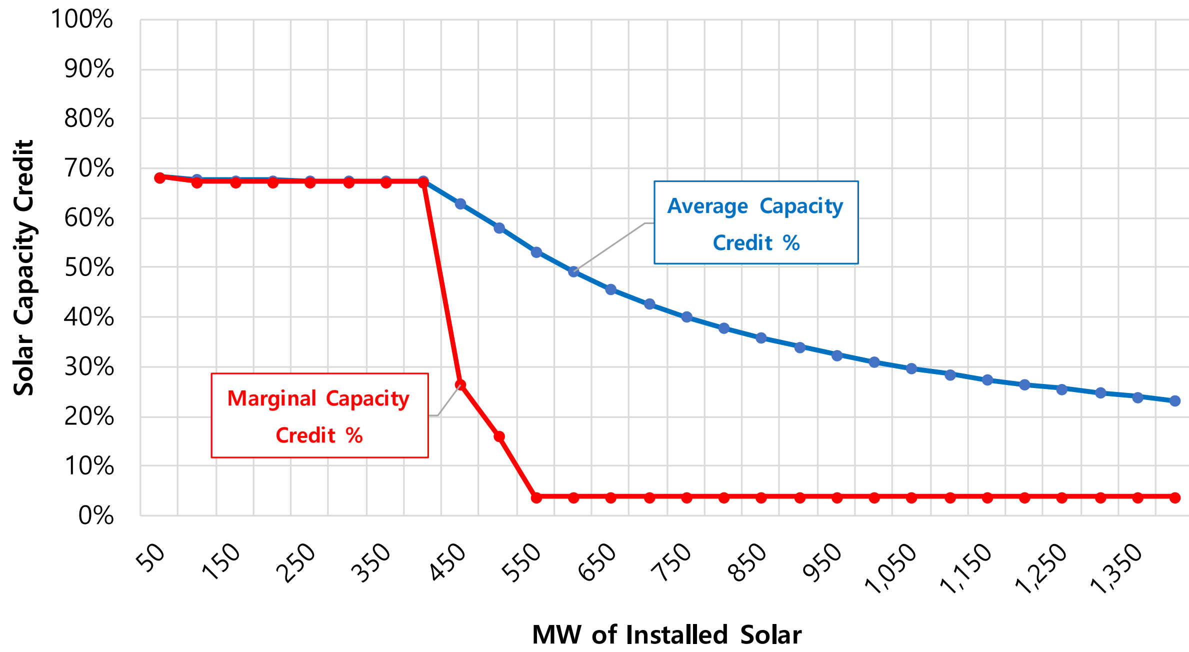
Figure 5.27 | IPL Net Load Curve with Increasing Solar Levels



From this data, we can calculate the average and marginal capacity credit for each level of solar installed on the system. The average capacity credit is the cumulative peak load reduction divided by the cumulative level of installed solar assumed. The marginal capacity credit is a calculation of the incremental peak load reduction for each incremental addition of solar. The steep reduction in marginal capacity credit past 400 MW is a result of the peak net load hour shifting later into the evening (HE 20) where solar production is minimal. The data shows that for each 50 MW increase in solar on IPL's system only contributes 2 MW of capacity past 500 MW of installed solar. Figure 5.28 shows the average and marginal capacity credit for each increment of solar installed from 50 MW to 1400 MW.

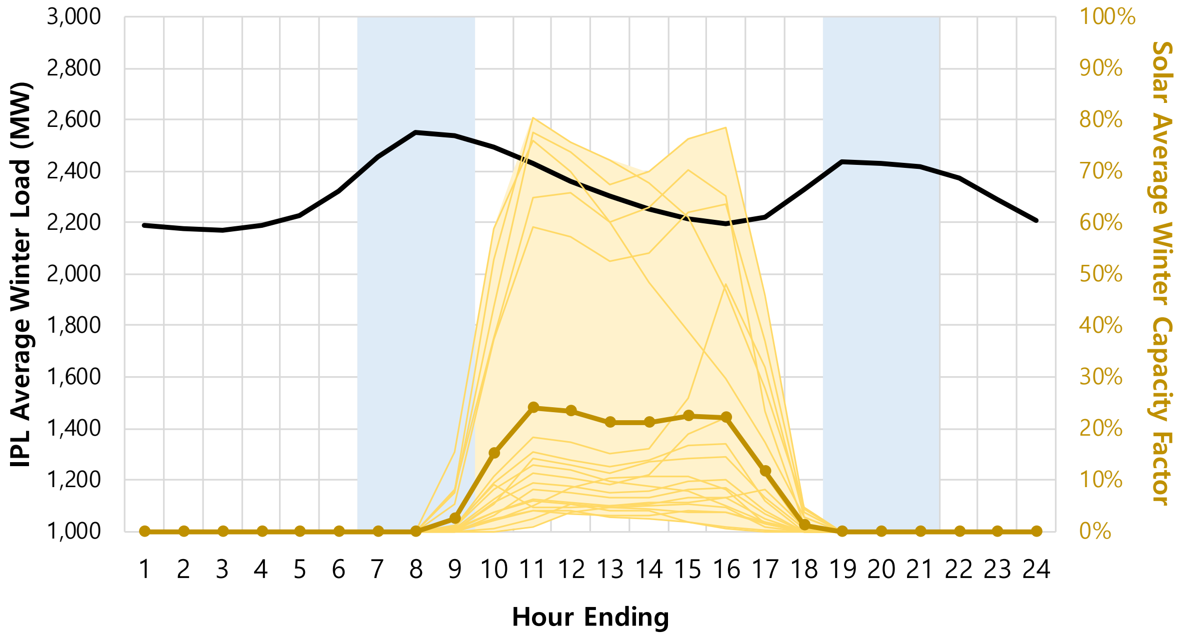
This analysis should not be viewed as a final say on the potential solar capacity on IPL's system or in our portfolio. It was conducted to provide a secondary analysis of future solar capacity accreditation using our own load and solar data and provides a useful framework to build upon as more solar is installed in Indiana and in the MISO region.

Figure 5.28 | Estimated Solar Capacity Credit on IPL System with Increasing Solar Levels



We also evaluated the top 20 peak winter days from the past three years (2016 – 2018). Figure 5.29 shows the average load by hour for those peak winter days as well as the tracking solar production for the same days. Solar production averages about a quarter of the production compared to summer. Additionally, solar production has no coincidence with the morning and evening peaks, providing no capacity contribution in winter as a standalone resource.

Figure 5.29 | IPL Load and Solar Profile: Top 20 Peak Winter Days, 2016 - 2018



Overall, the IPL load and solar data validates the assumptions used for this IRP for the annual solar capacity credit. **There is a lot of uncertainty going forward regarding this issue, and IPL will closely study this through time.** The pace of solar build in MISO, changing load patterns, and new MISO market rules could change solar's capacity accreditation in the future. Additionally, there are some actions IPL directly take to improve the capacity contribution of solar. Some examples include battery storage applications, new rate design to incentivize load to shift to midday, demand response programs, electric vehicle charging programs, and selection of geographically diverse solar locations.

Capital and O&M Costs

Base capital costs for new wind projects were based on a blend of capital cost projections from NREL, IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. Figure 5.30 contains assumptions for how the Investment Tax Credit (ITC) was modeled in the 2019 IRP. IPL assumed that new solar met the 5% safe harbor rules to be eligible for 100% through 2023, stepping down to 10% by 2024 and remaining at that level through the end of the study. Similar to PTC treatment for wind, the capital cost for solar was adjusted down for the ITC in PowerSimm for capacity expansion. As Figure 5.30 shows, the 30% ITC lowers the LCOE by $13-15/MWh and is a significant driver of value for solar.

All new projects in the IRP are modeled as 100% IPL-owned assets, the revenue requirement calculation reflects traditional rate recovery assuming a rate case every year. Tax equity financing could be required for any new IPL-owned solar project with ITC eligibility, and the actual ownership level, tax implications, and final net costs would be fully modeled at the time of a regulatory filing for an actual project. Additional capital cost sensitivities were conducted to capture some of the uncertainty around capital costs. That analysis is described in Section 7.4.1.

Figure 5.30 | Solar Investment Tax Credit (ITC) Assumptions

	2020	2021	2022	2023	2024
Solar ITC Assumption	**30%**	**30%**	**30%**	**30%**	**10%**
Overnight Capital Cost (2018$/kW)	$1,099	$1,034	$989	$929	$911
ITC-Adjusted Capital Cost (2018$/kW)	$724	$682	$652	$612	$808
LCOE - No ITC (2018$/MWh)	$53.36	$50.12	$47.87	$44.96	$43.91
LCOE with ITC (2018$/MWh)	$36.92	$34.74	$33.22	$31.26	$39.45

Figure 5.31 | New Solar Capital Costs (2018$/$kW_{AC}$)

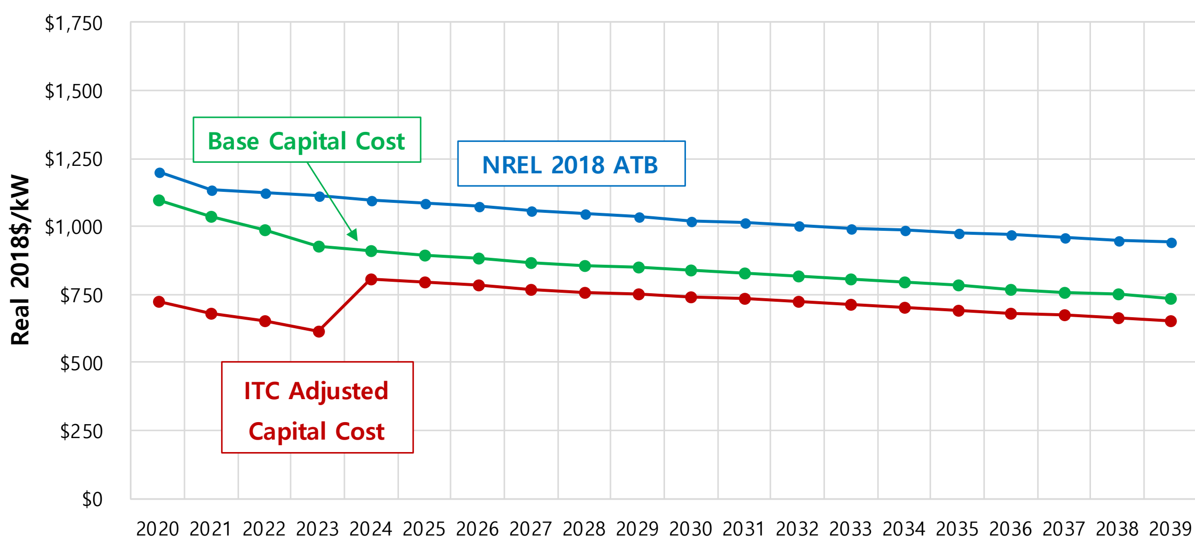
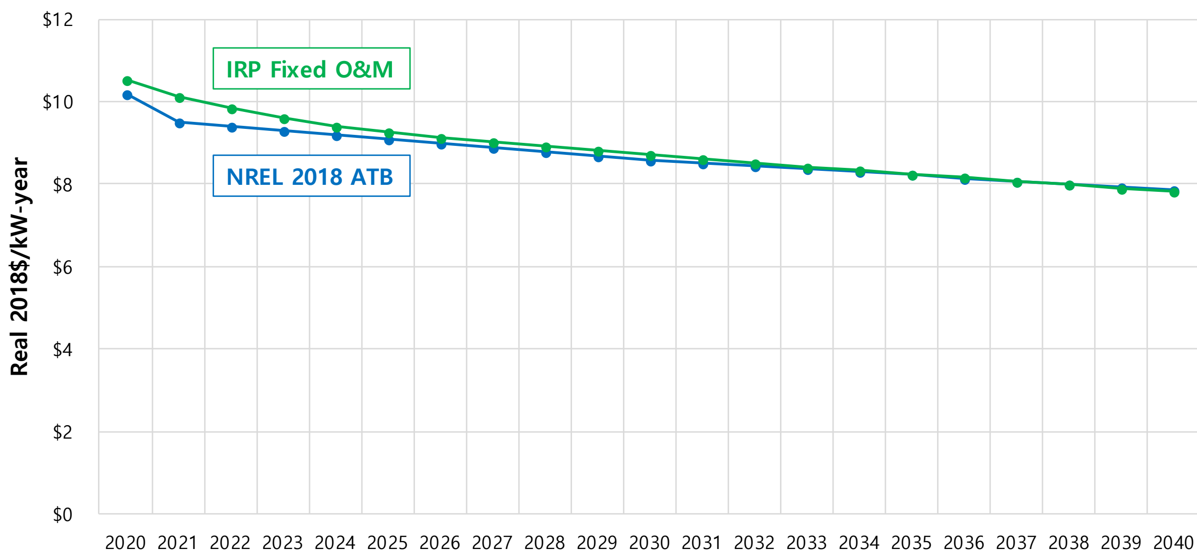


Figure 5.32 | New Solar Fixed O&M (2018$/kW$_{AC}$-year)



5.3.3 Storage

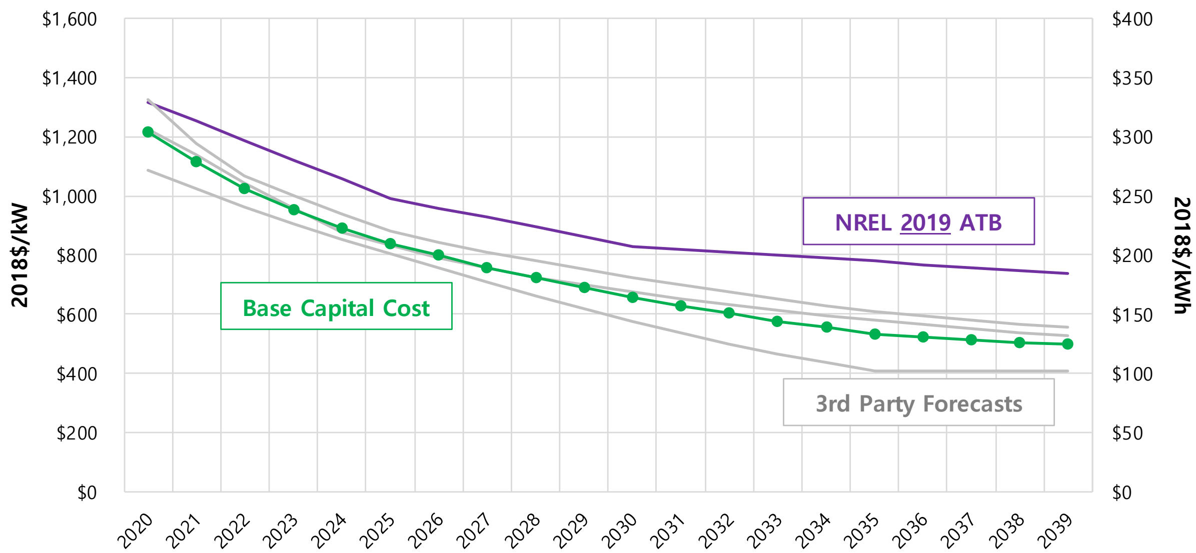
IPL included an energy arbitrage and capacity 4-hour battery storage resource in the 2019 IRP. Storage was optimized using the BatterySimm module in PowerSimm. The storage resource modeled was a **20 MW, 80 MWh** lithium ion battery storage project capable of charging and discharging subject to a set of unit constraints. Figure 5.33 contains a summary of cost and operating characteristics of new storage in the 2019 IRP.

Figure 5.33 | IRP Assumptions for New Battery Storage Projects

Unit	STORAGE
Description	4-hour lithium ion battery storage project
COST	
Overnight Construction Cost [2023 COD] (2018$/kW)	$954
Variable O&M (2018$/MWh)	$4.53
Fixed O&M (2018$/kW-year)	$19.02
CAPACITY	
MISO ICAP (MW)	20.0
xEFORd %	5.0%
MISO UCAP (MW)	19.00
Energy per Project (MWh)	80.00
OPERATIONAL	
Round Trip Efficiency %	88%
Min Storage Limit (MWh)	4.0
Max Storage Limit (MWh)	76.0
Charge/Discharge Limit (MW/hour)	20.0

Figure 5.34 shows the trend in capital cost for storage used in the model compared to NREL and other confidential third-party vendors. At the time capital costs were developed for this IRP, the NREL 2018 ATB was available, and that release only contained data for 8-hour storage, so it was not used. In the NREL 2019 ATB, NREL did update storage cost estimates for 4-hour storage projects. This is shown in Figure 5.34 in purple. As the figure shows, storage costs are expected to decline through time as a faster pace than any other supply-side resource included in this IRP.

Figure 5.34 | 4-Hour Storage Capital Cost (2018$/kW)



5.4 Summary of Supply-Side Resources

Figure 5.35 contains a list of modeled supply-side resources in the 2019 IRP as well as a description of types of resources that were screened out for this IRP.

Figure 5.35 | Supply-Side Resource Summary Table

Resource Type	Description	Included in 2019 IRP	Notes
Natural Gas	1x1 Combined Cycle	Yes	Section 5.2.1
Natural Gas	Simple Cycle Combustion Turbine	Yes	Section 5.2.1
Natural Gas	Aeroderivative Turbine	Yes	Section 5.2.1
Natural Gas	Reciprocating Engines	Yes	Section 5.2.1

Natural Gas	Coal to Gas conversion for Pete 1 and 2	No	Conversion of Pete 1 and 2 was not considered for this IRP. The age of the units and the location were the two primary limiting factors. Pete 1 and 2 are 52 and 49 years old, respectively, and are nearing age-based retirement dates. Planning, engineering, procurement, and actual conversion work would take several years while the units incur millions of dollars in maintenance and overhaul costs. Additionally, one of the most important factors that led IPL to convert the Harding Street steam units to gas was their location on the IPL 138 kV distribution system. The Harding Street units play a critical role in maintaining reliability on the IPL distribution system. Due to the location of Petersburg, conversion of Pete 1 and 2 would not provide the same reliability benefits. Lastly, conversion of Pete 1 and 2 to natural gas would cause IPL to have nearly half of our capacity tied to natural gas steam units with pending retirement dates in the next decade.
Coal	New Coal	No	Screened out for permitting constraints, cost
Nuclear	New nuclear	No	Screened out for cost and size
Renewable	Utility-scale land-based wind	Yes	Section 5.3.1
Renewable	Utility-scale, single-axis tracking solar	Yes	Section 5.3.2
Renewable	Utility-scale fixed tilt solar	No	Utility-scale tracking solar provides more energy, greater capacity credit, and with minimal to no cost premium compared to fixed tilt projects, residential solar, and commercial solar. Since the model is optimizing on a "profit maximization" basis per project, it will always choose single-axis tracking solar. IPL will evaluate all solar technologies as part of an ongoing process for commercial, transmission, distribution, and portfolio fit aspects.
Renewable	Residential and/or commercial solar	No	
Storage	4-Hour Battery Storage	Yes	Section 5.3.3

5.5 Demand Side Resource Options

170 IAC 4-7-4(6) 170 IAC 4-7-4(31) 170 IAC 4-7-6(a)(6) 170 IAC 4-7-6(b)(2)(A)

IPL's demand side management ("DSM") programs are comprised of both energy efficiency and demand response analogous to energy and peak requirements. Energy Efficiency is reduced energy use for a comparable or imposed level of energy service (as measured in kWh), and Demand Response is a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions (as measured in kW).

5.5.1 IPL's DSM Guiding Principles

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

IPL has continuously offered DSM programs to benefit customers and optimize demand side resources for over twenty-five years. Despite the changes in policy that eliminated the state energy efficiency standard and the Energizing Indiana statewide program, IPL has remained dedicated to offering DSM programs. The current level is approximately equal to prior EE levels. IPL developed this list of guiding principles that characterize DSM offerings.

IPL's guiding principles shape future DSM program offerings:

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

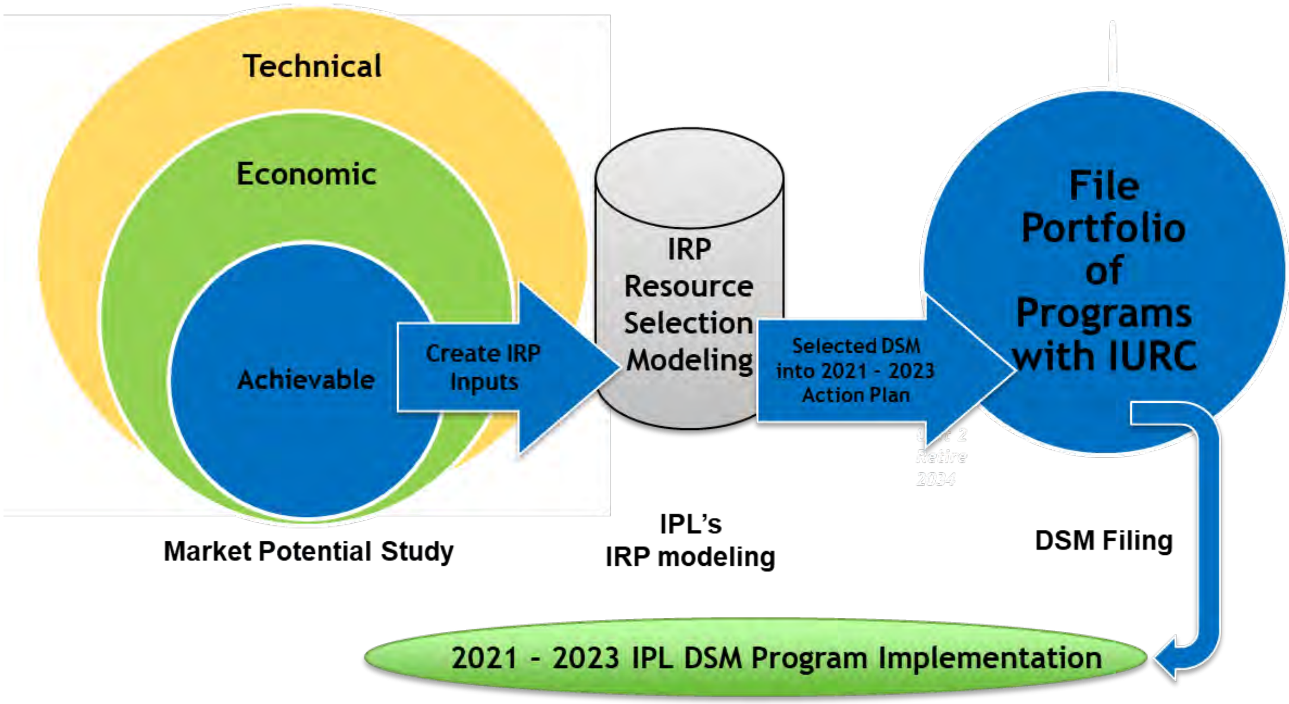
The Company expects to continue to propose and deliver additional cost-effective programs consistent with the IURC IRP and CPCN rules for demand side management options. The specific programs to be delivered will be identified and proposed in subsequent IPL DSM plans to be filed with the IURC.

5.5.2 DSM Planning Overview

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

Figure 5.36 below illustrates the stages of IPL's DSM planning process. The objective of this process is to identify IPL's opportunities to provide DSM for the 20-year IRP planning period in a manner that aligns with direction provided by the IURC and that is consistent with IRP rules. DSM opportunities identified in the IRP process will be used as the starting point for development of a cost-effective 2021 – 2023 DSM Action Plan for consideration and approval by the IURC. This Action Plan will be consistent with Ind. Code Section 8-1-8.5-10 ("Section 10") which defines energy efficiency goals as all energy efficiency produced by cost effectives plans that are 1) reasonably achievable; 2) consistent with the utility's IRP; 3) designed to achieve an optimal balance of energy resources in the utility's service territory.

Figure 5.36 | Overview of DSM Process



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

Per IURC IRP rule 170 IAC 4-7-8(c)(4), demand-side resources should be modeled on a consistent and comparable basis with supply-side resources. To accomplish this, IPL took the Realistic Achievable Potential ("RAP") results from the MPS and created IRP model inputs (stage 2 in Figure 5.36) with a load shape and levelized costs similar to a supply-side resource. The RAP results were then divided into eight "bundles", that each provided a 0.25% reduction in IPL load. The bundles were rank ordered starting with the most cost-effective measure. This bundling approach is discussed in more detail in Section 5.4.3.

The results from the IRP modeling will be used to inform the DSM Action Plan for the 2021-2023 period. DSM measures from the bundles will be developed into deliverable programs and a plan that will be filed with the IURC for its consideration and approval. The DSM modeling process and DSM Action Plan is discussed in more detail in Section 5.4.4 and 9.1.1, respectively, of this section.

IPL DSM Program Year 2020

Currently, IPL is delivering energy efficiency programs pursuant to the IURC Order received in Cause No. 44945. This Order that approved IPL's DSM Plan, which includes DSM and Energy Efficiency ("EE") programs for the 2018-2020 period. In program year 2020, IPL is planning to achieve approximately 140,000 MWh in energy efficiency savings or 1% of electric sales. Since IPL already has authority to deliver programs in 2020 at a level consistent with the 2016 IRP, the 2020 energy efficiency savings are already reflected as a reduction to the 2020 load forecast in this IRP.

DSM Stakeholder Engagement

IPL has maintained a strong collaborative relationship with its stakeholders throughout the DSM planning and IRP process making all DSM planning documents available to stakeholders with confidentiality agreements. Additionally, IPL has welcomed stakeholder input into the process and made an effort to incorporate stakeholder ideas into its methods, e.g. decrement bundling methodology described later in this report. Throughout the MPS process, IPL hosted technical meetings with stakeholders to share findings and to receive feedback during the DSM planning process. A list of stakeholder technical meeting dates and topics are as follows:

- 2019 Market Potential Study (MPS) & End Use Analysis Meeting – November 27, 2018
- MPS Models Review Meeting – April 1, 2019
- Between January and May 2019, IPL hosted bi-weekly meetings with GDS Associates and the IPL DSM OSB members.
- IRP Technical Workshop (prior to Public Meeting #2) – March 21, 2019
- IRP Technical Workshop (prior to Public Meeting #3) – May 9, 2019
- IRP Technical Workshop (prior to Public Meeting #4) – September 26, 2019

Opt-Out Customers

Senate Enrolled Act 340 provides the option for C&I customers that have a load greater than 1 MW to opt-out of participation in IPL's DSM programs. The MPS analysis that GDS completed considered the reduction in eligible load that was available to participate in IPL sponsored DSM programs. At the time the analysis was completed, 117 of IPL's largest customers representing approximately 23% of IPL's total sales had opted out of participation in IPL's DSM programs. These customers and their associated load have been excluded from the MPS analysis.

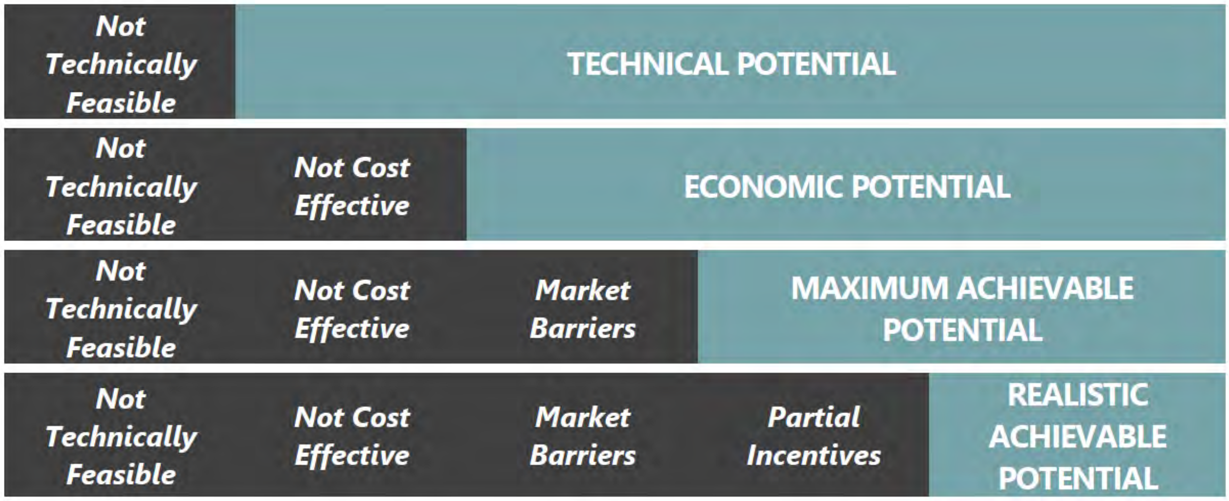
5.5.3 Market Potential Study ("MPS") and End Use Analysis

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

The primary objective of the MPS was to establish Technical, Economic, Maximum Achievable, and Realistic Achievable Potentials for DSM in IPL's service territory. IPL contracted GDS to conduct this analysis which began in the Fall of 2018. To summarize the process, GDS developed the potential savings estimates by 1) creating IPL's Market Characterization or establishing a forecast of the saturation and efficiency levels of existing equipment used by IPL's customers; 2) creating the Measure Characterization or developing a comprehensive list of cost-effective energy efficiency measures; 3) developing Potentials or estimating adoption of the list energy efficiency measures using the saturation and efficiency forecast as a basis for efficiency uptake. Through this approach, the Technical, Economic, Maximum Achievable, and Realistic Achievable Potential estimates were developed which are defined as follows and graphically illustrated in Figure 5.37:

- Technical Potential – potential for DSM adoption that assumes no barriers to customer adoption, e.g. financial limitations, customer awareness, and willingness to participate.
- Economic Potential – potential for DSM that only includes measures that are deemed to be cost-effective based on a measure-level screening using the Utility Cost Test (UCT).
- Maximum Achievable Potential – potential for DSM that assumes paying an incentive equal to 100% of the measure incremental cost and limited barriers to participation.
- Realistic Achievable Potential – potential for DSM that assumes the incentives paid for DSM and barriers to participation are aligned with historic levels with no constraints placed on spending.

Figure 5.37 | Market Potential



GDS initially undertook an End Use Analysis beginning in the Fall of 2018. The purpose of the End Use Analysis was to determine the saturation and efficiency levels of equipment located on the premises of IPL's residential, commercial and industrial properties. These equipment saturations and efficiencies established the baseline year for the load forecast and helped establish the Market Characterization for DSM opportunities. GDS conducted 231 residential, 68 commercial, and 40 industrial customer surveys that gathered customer information on the volume and type of equipment located at their location. Additionally, GDS followed up with 40 residential, 68 commercial, and 40 industrial site visits to confirm the information provided by the customers in the survey. Historically, end use information was taken from the Energy Information Association's saturation and efficiency outlook for the region. IPL decided to include the End Use Analysis as part of this MPS in order to improve the accuracy of the represented baseline. For more information on the End Use Analysis, including residential, commercial, and industrial saturation and efficiency levels see pages 3 – 10 in GDS' Market Potential Report attached as Attachment 5.1 to this IRP. The electronic appendices of the IPL/GDS MPS are included as Attachments 5.2a - c. The annual and lifetime energy and demand savings associated with the decrement bundles is included in Attachment 5.3.

In order understand of the current market segments in IPL's service territory or create a Market Characterization for efficiency, GDS defined the appropriate market sectors, market segments and equipment vintages, saturations, and end uses. Informed by the End Use Analysis described earlier, the Market Characterization set a baseline or current state of appliance saturations and efficiency adoption. GDS used propriety modeling tools like BeOpt™ for the Residential Sector to disaggregate customer usage and NAICS code data to segment the Commercial and Industrial businesses for efficiency adoption.

Next, GDS developed a comprehensive list of energy efficiency technologies suitable for IPL's market. IPL worked closely with stakeholders in reviewing and developing the list to ensure all technologies were assessed. In addition to stakeholder suggestions, the list was informed by a range of sources including the Indiana and other state Technical Reference Manual ("TRM"), IPL's current program offerings and other commercially viable emerging technologies. GDS also defined the measure savings, cost and useful life assumptions in this step using sources like the Indiana and Illinois TRM, Michigan Energy Measures Database ("MEMD"), and National Renewable Energy Labs ("NREL") Energy Measures Database.

GDS carefully considered the assumptions used for LED lighting when formulating the Measure Characterization. With rollbacks of codes and standards, LED savings assumptions have proven to be a moving target. From GDS' MPS report (Attachment 5.1) – "Recognizing that there remains significant uncertainty regarding the future potential of residential screw-in lighting, GDS reviewed the latest lighting-specific program designs and consulted with industry peers to develop critical assumptions regarding the future assumed baselines for LED screw base omnidirectional, specialty/decorative, and reflector/directional lamps over the study timeframe.

EISA Impacts. LED screw base omnidirectional and decorative lamps are impacted by the EISA 2007 regulation backstop provision, which requires all non-exempt lamps to be 45 lumens/watt, beginning in 2020. Based on this current legislation, the federal baseline in 2020 will be roughly equivalent to a CFL bulb. However, in January 2017, the Department of Energy expanded the scope of the standard to include directional and specialty bulb but stated that they may delay enforcement based on ongoing dialog with industry stakeholders. Although there is uncertainty surrounding EISA and the backstop provision, the Market Potential Study assumes the backstop provision for standard (A-lamp) screw-in bulbs will take effect beginning in 2022. The analysis assumes the expanded definition of general service lamps to include specialty and reflector sockets will impact those sockets beginning in 2023. Last, the analysis assumes a limited opportunity for direct install of LED bulbs replacing halogen bulbs through 2024 in both low-income and non-low-income households." Figure 5.38 provides the assumed lighting baseline technology by year used in the MPS.

Figure 5.38 | Lighting Baseline Technology by Year

Delivery Approach/Bulb Type	2021	2022	2023	2024
Buydown				
Standard LED	Halogen	CFL	CFL	CFL
Specialty LED	Incandescent	Incandescent	CFL	CFL
Reflector LED	Incandescent	Incandescent	CFL	CFL
Direct Install				
Standard LED	Halogen	Halogen	Halogen	CFL
Specialty LED	Incandescent	Incandescent	Incandescent	CFL
Reflector LED	Incandescent	Incandescent	Incandescent	CFL

GDS used an Excel-based model to determine the Technical, Economic, Maximum Achievable, and Realistic Achievable Potential estimates from the Market Characterization and Measure Characterization assumptions. The Technical and Economic Potential are considered the upper bound for DSM, where even the best designed and most expensive portfolios would fall short of achieving the targets. The Maximum Achievable and Realistic Achievable Potentials are developed in order to define attainable targets. Figure 5.39 provides the cumulative savings results from the Residential Potential Analysis. Lighting makes up a small portion of the overall potential whereas it encompasses over 50% of the savings in IPL's 2018 portfolio of programs.

Figure 5.39 | Residential Energy Efficiency Potential Results 2021 – 2029 (Gross MWh)

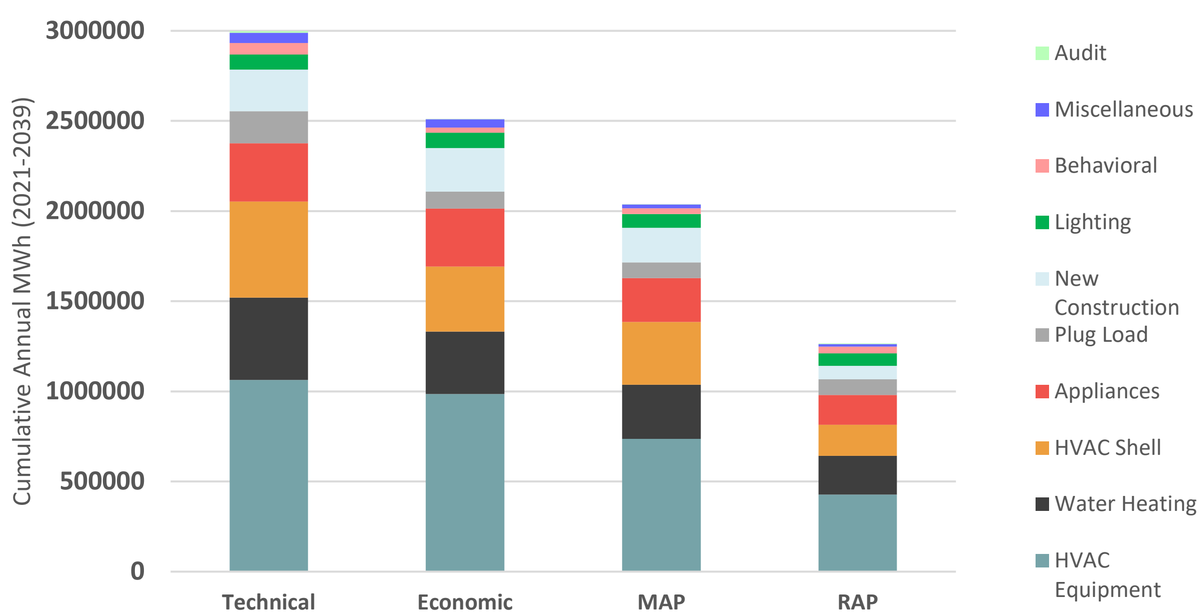
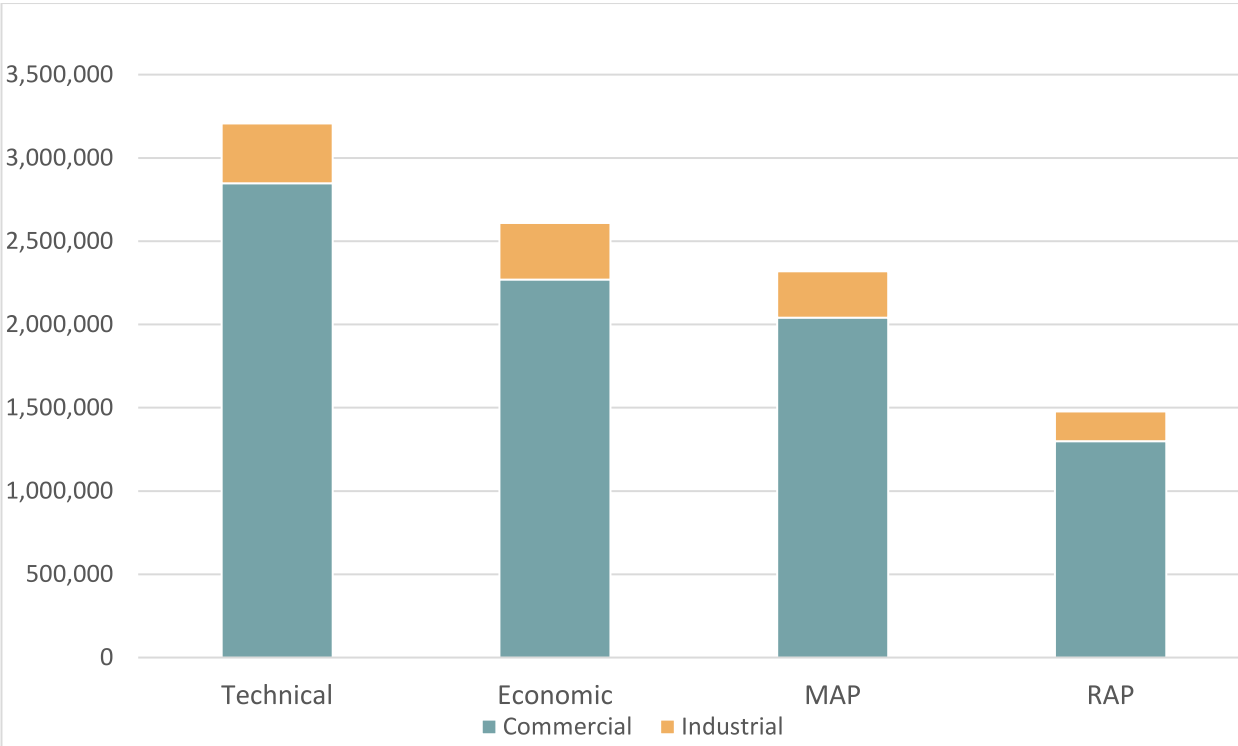


Figure 5.40 provides the cumulative savings results from the C&I Potential Analysis. Because 40% of Industrial savings have opted out of participation, the bulk of the potential savings comes from the commercial sector.

Figure 5.40 | C&I Energy Efficiency Potential Results 2021 – 2029 (Gross MWh)



DSM Bundling for Resource Selection Model

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

In early 2019, with the MPS nearly wrapped, the bundling process initiated with a meeting between IPL and its stakeholders with confidentiality agreements. The Citizen's Action Coalition (CAC) and their consultant presented their preferred method for integrating DSM into the IRP model called the Decrement Pricing Methodology. IPL liked the basic idea of the methodology which (at a very high level) consisted of loading DSM savings equal to 2% of IPL load divided up into 0.25% of load decrements and letting the model determine an avoided cost (equal to the change in PVRR with and without the DSM loaded in). The CAC suggested that the resulting avoided cost along with the 2% savings target be put in a Request for Proposals from energy efficiency implementation vendors; where vendors must bid to hit the 2% savings target for a price less than or equal to the total avoided cost. IPL like the approach but had some concerns: 1) if avoided costs are made available to bidders, then bidders would likely provide bids equal to the avoided cost in the RFP meaning the energy efficiency portfolio would breakeven and not maximize cost effectiveness to customers; DSM benefits = DSM costs 2) if through the RFP process bidders indicate the 2% savings level cannot be achieved, then the IRP and the plans for future generation that had been optimized at the 2% savings level would be need to be reevaluated at a lower savings level.

IPL decided to employ the core concepts of the Decrement Pricing Methodology where the DSM bundles are defined as 0.25% reductions in load; however, instead of including the full avoided costs in an RFP as the DSM cost ceiling, IPL let the model determine a cost-effective level of DSM based on predefined DSM cost inputs. These predefined costs were based on IPL's current costs to deliver DSM assigned to the individual measures.

Figure 5.41 provides a graphical representation of the bundling approach. The blue line represents a DSM supply curve which is built up from the individual measures in the RAP. IPL and GDS divided the supply curve up into eight sections or "bundles" starting from the most cost-effective measures to the least cost-effective measures. Each bundle had a levelized cost defined by the measures making up the bundle and an 8760 hourly load shape. Load shapes were assigned to each measure from GDS' load shape database. Each bundles load shape was then aggregated from the individual measure load shapes. There are eight total bundles with each bundle representing 0.25% of load totaling 2% of total load reduction. Each additional 0.25% bundle decrement becomes more expensive because a higher DSM target is more expensive to achieve. Each bundle spans the IRP 2021 – 2039 planning period (2020 already determined in DSM Cause No. 44945) and includes both residential and C&I potentials.

Figure 5.41 | MPS – Realistic Achievable Potential Supply Curve

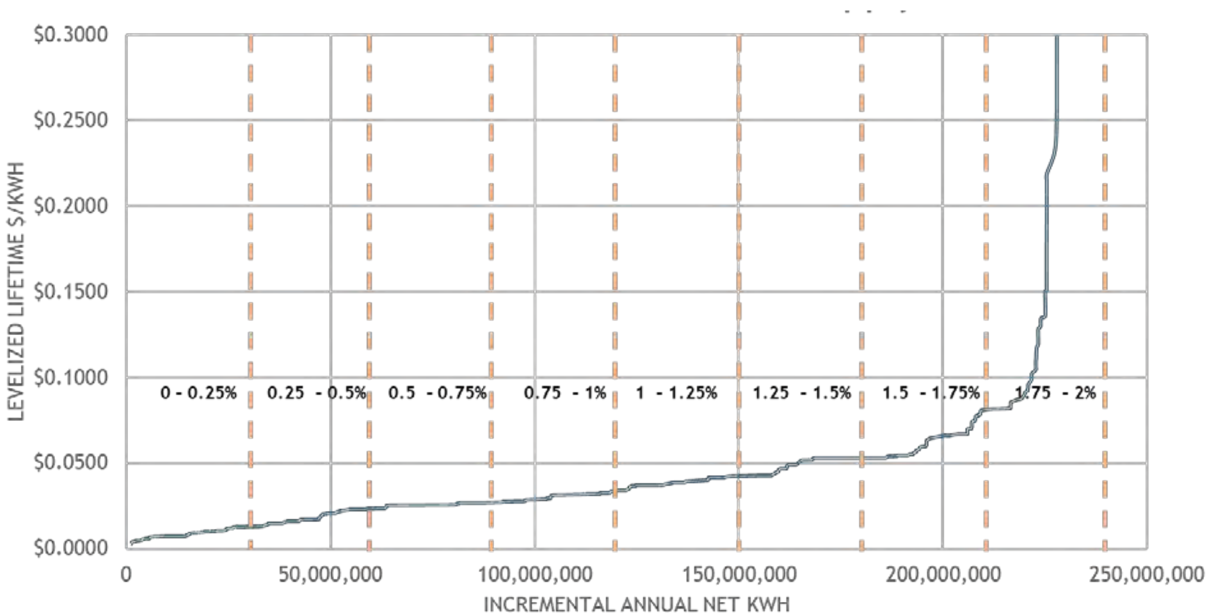


Figure 5.42 illustrates the impacts from the decrement bundles to forecasted load. If IPL were to implement net DSM at an annual level of 2% of incremental sales or all eight bundles over the planning period, the cumulative impacts from DSM would reduce load by 16% in 2039. This level would be equal to the Realistic Achievable Potential as defined by the MPS.

Figure 5.42 | Cumulative Impacts to Forecasted Load from the DSM Decrement Bundles

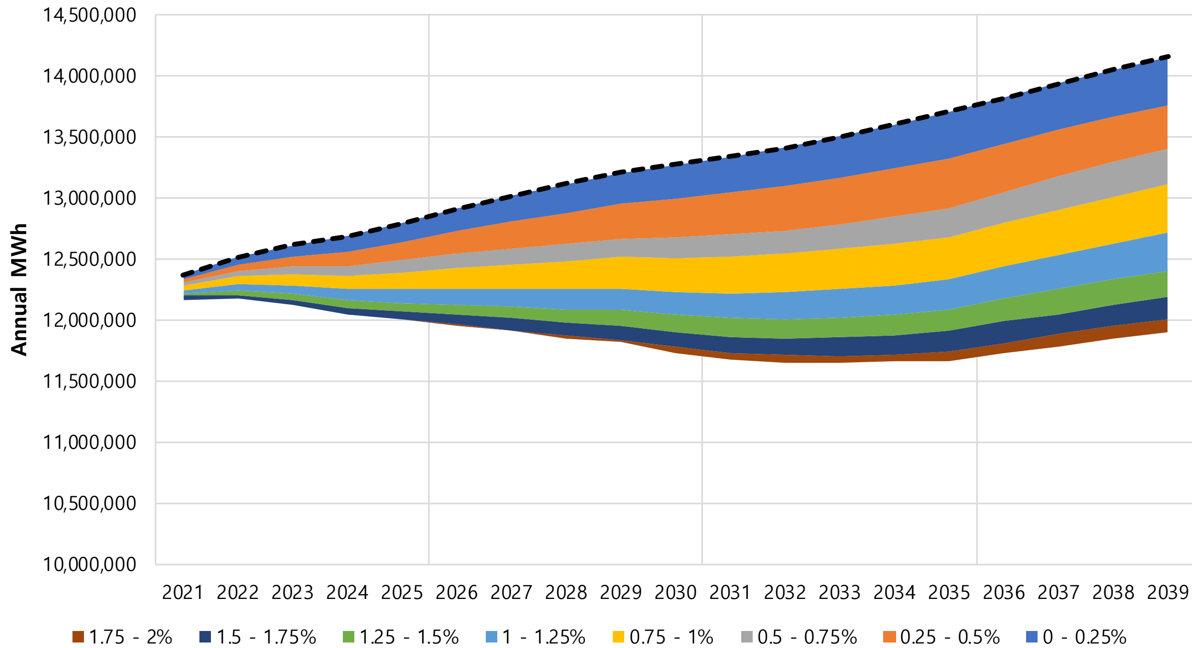


Figure 5.43 provides the cumulative savings and costs of layering on each additional DSM decrement.

Figure 5.43 | Decrement Analysis – Cumulative Savings and Costs

Decrement Bundle	Cumulative Savings		
	2021	2022	2023
1	30,814,371	31,103,684	31,531,181
2	60,658,921	59,378,674	60,844,869
3	92,528,755	92,307,819	93,566,503
4	119,719,071	124,673,163	125,425,014
5	141,300,182	140,748,140	144,427,177
6	185,443,755	186,853,815	189,209,272
7	201,245,927	196,461,290	200,408,981
8	0	0	0
Decrement Bundle	**Cumulative Cost**		
	2021	2022	2023
1	$ 2,332,292	$ 2,467,717	$ 2,622,880
2	$ 7,196,788	$ 7,184,013	$ 7,820,975
3	$ 10,269,242	$ 12,475,433	$ 13,319,451
4	$ 17,272,179	$ 19,666,137	$ 21,028,804
5	$ 23,817,857	$ 26,735,711	$ 29,199,022
6	$ 32,392,949	$ 41,791,240	$ 43,555,236
7	$ 44,232,408	$ 49,636,535	$ 54,343,744
8	$ -	$ -	$ -
Decrement Bundle	**Cost/kWh**		
	2021	2022	2023
1	$ 0.076	$ 0.079	$ 0.083
2	$ 0.119	$ 0.121	$ 0.129
3	$ 0.111	$ 0.135	$ 0.142
4	$ 0.144	$ 0.158	$ 0.168
5	$ 0.169	$ 0.190	$ 0.202
6	$ 0.175	$ 0.224	$ 0.230
7	$ 0.220	$ 0.253	$ 0.271
8	$ -	$ -	$ -

Demand Response

IPL included two Demand Response bundles as inputs into the Resource Selection Model. The first bundle was comprised of residential and commercial air conditioner load management measures with all load impacts occurring during the summer. The second bundle was comprised of residential and commercial water heater control measures with both summer and winter load impacts. Like the EE bundles, each bundle ran the duration of the study period (2021 – 2039) and had a levelized cost and 8760 load shape as model inputs.

IPL has implemented its Air Conditioner Load Management program since 2003. Currently, the company has roughly 55,000 Landis and Gyr switches, Cannon switches and smart thermostats with the capability of shedding approximately 35MW of air conditioner load during peak summer hours. IPL plans to maintain this existing device population over the IRP planning period. As such, annual maintenance costs to replace switches that have reached the end of their effective useful life and incentives to pay customers for program participation were included as costs in the IRP planning model.

5.5.4 DSM Bundles in Model

The eight DSM decrements were loaded into PowerSimm as negative load items with hourly energy profiles for the twenty years of the IRP study window. Each decrement was tied to a price ($/MWh) composing the decrement's levelized cost. Because the decrements are *negative* load, PowerSimm calculates a positive energy revenue stream where they are paid the IPL Load Zone Locational Marginal Price ("LMP") for every MWh of their profile. This is done because the decrement effectively offsets purchasing IPL load at that same price for the MWh in the decrement's profile. A cost is applied to the decrement at its levelized cost. If the IPL Load Zone LMP is greater than the levelized cost, then the decrement is a net benefit to the portfolio based on its energy savings.

The capacity credit for each DSM decrement was established by determining its contribution to IPL's peak load which is forecasted to occur in July each year between HE15 and HE18. Each decrement's hourly contribution across these four hours for all thirty-one days of July were averaged together to arrive at the decrement's capacity credit. The capacity credit increases with time as the decrement energy savings accumulate but is held constant within a year. The capacity credit from each of the decrements counted towards meeting IPL's Planning Reserve Margin Requirement.

5.5.5 Avoided Cost Calculation

170 IAC 4-7-4(29) 170 IAC 4-7-6(b)(1)

Avoided cost is defined in 170 IAC 4-7-1(b) as "the incremental or marginal cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility's IRP".

The avoided cost used in the MPS are shown in Confidential Attachment 5.4. The energy and generation capacity costs are from the Wood Mackenzie H1 2018 No Federal Carbon Case.

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

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

The aggregate avoided costs were used in the DSM MPS by GDS to calculate the NPV of DSM lifetime benefits.

5.6 Rate Design

IPL considers and reviews rate design options which include appropriate cost of service and recovery mechanisms and encompass innovative approaches. Through its energy efficiency programs, demand response programs, Rate CGS, curtailable energy riders, and load displacement rider, IPL employs a range of rate options.

Section 6: Environmental Considerations

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

6.1 Environmental Overview

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

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

- In August 2014, EPA finalized a revised regulation requiring utilities to reduce the adverse impacts to fish and other aquatic life caused by cooling water intake structures.
- In April 2015, EPA finalized revised regulations for Coal Combustion Residuals ("CCRs") regulating CCRs as a solid waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). Revisions to the rule have followed and remain under development.
- In July 2016, EPA published the final updated chronic aquatic life criterion for the pollutant selenium (Se) in freshwater per Clean Water Act section 304(a). The revised criterion is a recommendation to states authorized to establish water quality standards under the Clean Water Act.
- In July 2019, EPA published the final Affordable Clean Energy (ACE) Rule, regulating GHGs from existing coal-fired electric generating units, and replacing the 2015 Clean Power Plan.

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

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

6.2 Existing Environmental Regulations

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

6.2.1 Air Emissions

170 IAC 4-7-4(21)

IPL is subject to various regulations related to air emissions.

Sulfur Dioxide (SO_2)

In response to Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), IPL developed an Acid Rain Compliance Plan that was submitted to the IURC on July 1, 1992, (IURC Cause No. 39437) and subsequently approved on August 18, 1993 ("39437 Order").[22] This plan called for the installation of SO_2 retrofit Flue Gas Desulfurization ("FGD") units on Pete Unit 1 and Pete Unit 2. These FGD units were placed in-service in 1996. FGD is the technology used for removing SO_2 from the exhaust flue gases from coal-fired power plants.

The SO_2 regulations remained relatively unchanged as did the IPL compliance plan until March 10, 2005, when the EPA issued Clean Air Interstate Rule ("CAIR") which established a regional cap-and-trade program for SO_2 and NO_x. Phase I of CAIR for SO_2 had an effective date of January 1, 2010 and Phase II of CAIR was scheduled to become effective on January 1, 2015.

In anticipation of this CAIR regulatory program and to help meet the existing CAAA regulatory requirements, IPL developed a Multi-Pollutant Plan ("MPP") that was submitted to the IURC on July 29, 2004, (IURC Cause No. 42700) requesting approval of certain core elements of the plan which were approved on November 30, 2004. In order to reduce SO_2 emissions, IPL completed the Petersburg Generating Station ("Pete") Unit 3 FGD enhancement (May 2006) and the new Harding Street Generating Station ("HSS") Unit 7 FGD (September 2007). IPL also identified the enhancement of the Pete Unit 4 FGD as a core element of its MPP and completed the Pete Unit 4 FGD upgrade project (IURC Cause

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

No. 43403 approved April 2, 2008) in 2011 to help meet the additional SO_2 emission reduction requirements. IPL met the CAIR requirements for SO_2 upon completion of these projects and by supplementing its compliance plan with the purchase of emission allowances on the open market as needed.

As a result of legal proceedings related to CAIR, the EPA issued a final replacement rule, known as Cross State Air Pollution Rule ("CSAPR") in July 2011. Finally, following resolution of legal proceedings, CSAPR became effective on January 1, 2015, and CAIR ceased to apply at that time. Phase II of CSAPR became effective on January 1, 2017. IPL meets CSAPR requirements through the operation of our existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and plans to continue to comply with Phase II CSAPR using these measures.

Additional SO_2 requirements and compliance plans are discussed below under NAAQS.

Oxides of Nitrogen (NOx)

In order to meet more stringent NO_x emission reduction requirements which became effective in 2004 related to the NOx State Implementation Plan ("SIP") Call, IPL installed Selective Catalytic Reduction ("SCR") equipment on Pete Unit 2, Pete Unit 3 and HSS Unit 7 along with several low NO_x clean coal technology ("CCT") projects on other units. The Pete SCR units commenced operations in May 2004, whereas the HSS Unit 7 SCR came online in May 2005.

As previously discussed, the EPA issued CAIR in May 2005, which was subsequently replaced by CSAPR requirements. On September 7, 2016, EPA finalized the CSAPR Update Rule which established NOx reductions during ozone season for 22 states, including Indiana, to address downwind attainment with the 2008 Ozone NAAQS of 75 parts per billion (ppb). On September 13, 2019, the D.C. Circuit remanded a portion of the CSAPR Update Rule to EPA because it did not set a deadline by which upwind states must eliminate their significant contribution to downwind states' NAAQS nonattainment. At this time, it is uncertain whether future revisions to CSAPR resulting this decision could further impact IPL's NOx emissions limits. IPL currently meets requirements for NO_x through the operation of existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and currently plans to continue to comply using these measures.

Regional Haze

A Regional Haze Rule established planning and emissions reduction timelines for states to use to improve visibility in national parks throughout the U.S. The rule sets guidelines for states in setting

Best Available Retrofit Technology ("BART") at older power plants. Following rulemaking and litigation related to CAIR described above, EPA promulgated a final rule in 2012, finding CSAPR is "better than BART" in states participating in the CSAPR trading program, including Indiana. EPA published a rule reaffirming this determination on September 29, 2017.

State Implementation Plans addressing the second implementation period (2018-2028) for the Regional Haze Rule will be due to EPA by July 31, 2021 and EPA released guidance to assist states in developing revised SIPs on August 20, 2019. It remains uncertain whether a future revised Regional Haze SIP could result in more stringent emissions limitations for IPL.

Mercury and Air Toxics Standard ("MATS")

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

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

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

National Ambient Air Quality Standards ("NAAQS")

EPA is required under the CAA to set NAAQS for air pollutants that endanger public health or welfare. There are several NAAQS, but typically only three directly impacting coal-fired power plants: SO_2, ozone, and particulate. NAAQS do not directly limit emissions from utilities, but states must develop State Implementation Plans ("SIPs") to achieve emissions reductions to address each NAAQS when an area is designated as nonattainment. EPA reviews NAAQS and the science on which they are based on a five-year basis. This review process includes gathering input from the scientific community and the public, an integrated science assessment, a risk and exposure assessment, and a policy assessment.

The counties in which IPL operates power generation facilities are all currently designated as attainment for all air pollutants, except sulfur dioxide. On June 22, 2010, EPA revised the NAAQS for SO_2 from 140 parts per billion ("ppb") on 24-hour basis to 75 ppb on a one-hour basis. The areas in which IPL Harding Street, Eagle Valley, and Petersburg operate were designated as nonattainment with the lowered standard. As a result, IDEM developed a SIP to address the 2010 SO_2 NAAQS, and on September 30, 2015, published revisions to 326 IAC 7-4-15 establishing new and more stringent emission limits for Pete Units 1-4 with compliance required by January 1, 2017 as shown in Figure 6.1.

Measures needed to enhance the performance and integrity of the FGD systems at Petersburg in order to meet these limits were approved by the IURC in Cause No. 44794. As required, IPL has been complying with these limits since January 1, 2017 through the operation of pollution controls equipment.

On August 7, 2019 IDEM issued a Notice and Order of the Commissioner, as a result of an updated evaluation implementing the revised SO_2 emissions limitations (30-day rolling average) which became effective on September 24, 2019

Figure 6.1 | NAAQs Emission Limits for IPL Petersburg Units

Emission Unit Description	Beginning January 1, 2017		Beginning September 24, 2019
	Emission Limit (lbs/hour – 30 day rolling average)	Emission Limit (lbs/MMBtu – 30 day rolling average)	Emission Limit (lbs/MMBtu – 30 day rolling average)
Unit 1	263.0	0.12	0.10
Unit 2	495.4	0.12	0.10
Unit 3	1,633.7	0.29	0.25
Unit 4	1,548.2	0.28	0.24

IPL meets these emission limits through the operation of existing pollution control equipment.

Greenhouse Gas

On October 23, 2015, the EPA finalized CO2 emission rules for existing power plants under CAA Section 111(d), called the Clean Power Plan ("CPP"). On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the CPP pending resolution of legal challenges to the rule. On July 8, 2019, EPA published the final Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, known as the Affordable Clean Energy ("ACE") Rule along with associated revisions to implementing regulations. The final ACE Rule replaced the 2015 CPP and determined that heat rate improvement measures are the Best System of Emissions Reductions ("BSER") for existing coal-fired electric generating units. The final rule requires the State of Indiana to develop a State Plan to establish CO2 emission limits for designated facilities, including IPL Petersburg's coal-fired electric generating units. States have three years to develop their plans under the rule (until September 2022) and are required to consider candidate technologies identified in the rule to establish CO2 emission rate limits. States may consider remaining useful life and other factors when establishing emission limits. Compliance with CO2 emission rate limits will be required within 24 months of State Plan deadline or additional time may be allowed with establishment of a compliance schedule. Impacts remain largely uncertain because a State Plan has not yet been developed.

Existing Controls to Reduce Air Emissions

As shown in Figure 6.2, IPL has already installed environmental pollution control equipment at its facilities.

Figure 6.2 | IPL Generating Units: Environmental Controls

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

Note: Acronyms used in Figure 6.2 – ACI (Activated Carbon Injection), ESP (Electrostatic Precipitator), FGD (Flue Gas Desulfurization), LNB (Low NO_x Burner), NN (Neural Net), Overfire Air (OFA), SCR (Selective Catalytic Reduction), SNCR (Selective Non-Catalytic Reduction)

6.2.2 Water

The National Pollution Discharge Elimination System ("NPDES") permit system obtains its authority from Clean Water Act ("CWA"). Section 402 requires permits for the direct discharge of pollutants to the waters of the U.S. These permits, which IPL maintains for each of its power plants, have three main components: technology based and water quality based effluent limitations; monitoring requirements; and reporting requirements.

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

On August 28, 2012, the IDEM issued NPDES permit renewals to Petersburg and Harding Street. These permits contained new Water Quality Based Effluent Limits ("WQBELs") and Technology-Based Effluent Limits ("TBELs") for the regulated facility NPDES discharges with a compliance date of October 1, 2015, for the new WQBELs, which was later extended. New metal limits drove the need for additional wastewater treatment technologies at Petersburg and Harding Street. However, IPL determined that installation of the necessary wastewater treatment technologies and other potential future environmental requirements in addition to the necessary Mercury and Air Toxic Standard ("MATS") controls described in IPL's case-in-chief Cause No. 44242 were no longer the reasonable least cost plan for HSS. Instead, IPL obtained approval in Cause No. 44540 to refuel HSS Unit 7 to operate on natural gas which reduces the cost to comply with environmental regulations and reduces the impact on the environment. IPL also received approval of wastewater treatment systems necessary to comply with the new limits in the 2012 NPDES permit renewals in IPL's Cause No. 44540. For Petersburg Generating Station, this included dry fly ash handling, zero liquid discharge systems for FGD wastewater, and a tank-based treatment system of other wastewaters generated at Petersburg.

On November 3, 2015, EPA published the final revisions to the Effluent Limitations Guidelines ("ELG") Rule. The revised ELG regulations require dry fly ash handling, dry or closed-loop bottom ash handling, and apply numerical limits on FGD Wastewater. Eagle Valley and Harding Street Generating Stations no longer generate these wastewater streams as they have ceased coal combustion. Petersburg Generating Station will comply with the dry fly ash handling and limits on FGD Wastewater as a result of the NPDES Wastewater treatment project in Cause No. 44540. In addition, the ELG will require dry or closed-loop bottom ash handling at Pete with compliance required by a date to be specified by the NPDES permitting authority that is between November 1, 2018, and December 31, 2023. Pete will comply with this ELG requirement as a result of the closed-loop bottom ash dewatering system included in the Compliance Project proposed in Cause No. 44794 and described below for compliance with the Coal Combustion Residuals ("CCR") Rule. On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated and remanded portions of EPA's 2015 ELG Rule related to legacy wastewaters and combustion residual leachate.

On November 22, 2019, EPA published proposed revisions to the ELG Rule, specifically for FGD wastewater and bottom ash transport water.

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

Clean Water Act Section 316(a)

327 IAC 5-7 and Section 316(a) of the CWA authorizes the NPDES permitting authority to impose alternative effluent limitations for the control of the thermal component of a discharge in lieu of the effluent limits that would otherwise be required under sections 301 or 306 of the CWA. Regulations implementing section 316(a) are codified at 40 CFR Part 125, subpart H. These regulations identify the criteria and process for determining whether an alternative effluent limitation (i.e., a thermal variance from the otherwise applicable effluent limit) may be included in an NPDES permit and, if so, what that limit should be. This means that before a thermal variance can be granted, the permittee must demonstrate that the otherwise applicable thermal discharge effluent limit is more stringent than necessary to assure the protection and propagation of the waterbody's balanced, indigenous population ("BIP") of shellfish, fish and wildlife. If the variance study determines there is an impact, IPL Petersburg may need to employ additional thermal reduction technology such as closed cycle cooling in order to meet the temperature water quality standards. IPL is currently in the process of conducting thermal studies at the Petersburg and Harding Street facilities based on guidance developed by the Indiana Department of Environmental Management ("IDEM") which includes conducting comprehensive monitoring programs for temperature in the waterbody, conducting comprehensive monitoring programs to delineate the thermal discharge plume in the receiving waterbody, and conducting biological community assessments. The results of these studies will be included in the 316(a) demonstration and the demonstration is required to be submitted to IDEM. Petersburg submitted their 316(a) demonstration to IDEM in December 2017. Harding Street is required to submit their 316(a) demonstration to IDEM in December 2019. If IPL is unable to obtain an acceptable 316(a) variance based on the submitted demonstrations, Indiana thermal water quality standards would apply. In this scenario, the potential s could be similar to the range of impacts described under 316(b) and will be included in subsequent IRP analyses.

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

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of Cooling Water Intake Structures ("CWIS") reflect the best technology available for minimizing adverse environmental impact. Specifically, the 316(b) Rule is intended to reduce the impacts to aquatic organisms through impingement and entrainment due to the withdrawal of cooling water by facilities.

On August 15, 2014, EPA published a final rule which would set requirements that establish the Best Technology Available ("BTA") to minimize these impacts.

The entrainment BTA could be determined to be closed cycle cooling systems. Alternatively, utilities could be faced with installing less costly controls, like modified travelling screens and fish handling and return systems to address impingement BTA. Another is equipped with a cooling tower which dissipates approximately one-half of the waste heat generated by that unit. One of the three IPL coal-fired units at Harding Street is currently equipped with closed cycle cooling systems. The impact of this rule will be dependent upon IDEM's determination for impingement and entrainment BTAs for both Petersburg and Harding Street.

6.2.3 Solid Waste

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

Hazardous Waste

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

The three categories of hazardous waste are: 1) large quantity generator ("LQG"); 2) small quantity generator ("SQG"); and 3) conditionally exempt small quantity generator ("CESQG"). IPL plants are historically categorized as SQG and CESQG. As such, IPL faces minimal regulations and risk in this area.

Non-Hazardous Waste

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

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

On April 17, 2015, EPA published the final Coal Combustion Residuals ("CCR") Rule, which regulates CCR as non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The CCR Rule establishes national minimum criteria for existing CCR surface impoundments (ash ponds), including location restrictions, structural integrity, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care. Failure to demonstrate compliance with the national minimum criteria results in the requirement to cease use of and close existing active ponds within five years, with some potential for extensions, as needed. In 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act authorized states to establish CCR permitting programs and required EPA to establish a program for states that do not adopt one. On July 30, 2018, EPA finalized Phase One Part One CCR Rule Amendments in response to CCR litigation settlement and the WIIN Act. The revisions extended the deadline to cease placement of waste and commence closure of certain existing surface impoundments to October 31, 2020, established health-based groundwater protection standards for constituents with no Maximum Contaminant Levels, and added certain authorizations for Participating State Agencies or US EPA. EPA has proposed two additional revisions to the CCR Rule published on August 14, 2019 and December 2, 2019, respectively primarily to address matters at issue in litigation associated with the CCR Rule.

IPL Petersburg was unable to successfully demonstrate compliance with certain safety factor requirements set forth in the CCR rule at Petersburg, which are required to maintain operation of the ponds. As a result, IPL has removed the ponds from service, and made modifications to handle the material that was previously sent to the ash ponds. Specifically, as approved in Cause No. 44794, IPL installed a closed-loop bottom ash handling system to dewater the bottom ash which would otherwise have been sluiced to the active ponds.

IPL Harding Street and Eagle Valley have ceased coal combustion and must close their ponds in accordance with applicable local, state, and federal regulations. These ponds are currently being used on a very minimal basis to manage water not related to coal combustion.

IPL Petersburg, Harding Street and Eagle Valley Stations are collecting groundwater monitoring data as required by the CCR Rule. The data indicates exceedances of certain groundwater protection standards in the groundwater on IPL's property. As a result, IPL has completed Corrective Measures Assessment reports and is currently in the process of evaluating nature and extent. IPL will hold a public meeting prior to selection of a remedy. Any remedy selected will be protective of human health and the environment and will ensure that groundwater protection standards are achieved. Post-closure groundwater monitoring results could be different than past results due to the benefit of a waterproof cap included in IPL's ash pond closure plans[23]. IPL's closure plans include installation of a 30-inch protective layer over a waterproof liner on the pond preventing rainwater from carrying coals ash constituents into groundwater. Additionally, six inches of top soil will be laid on top and seeded with vegetative cover.

6.3 Pending and Future Environmental Regulations

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

There are a number of environmental initiatives that are being considered at the federal level that may impact the cost of electricity. This includes, but is not limited to more stringent regulations requiring:

- Additional SO_2 emission reductions;
- Additional NO_x emissions reductions;
- More stringent CCR requirements.

6.3.1 National Ambient Air Quality Standards

As discussed above, NAAQS are routinely reviewed, and potentially lowered by EPA. It is also possible that revised NAAQS may result in future revisions to CSAPR. As a result, future required reductions of SO_2 and NO_x are possible.

6.3.2 Coal Combustion Residuals

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

[23] IPL submitted Ash Pond Closure Plans for IPL Harding Street and Eagle Valley Stations to IDEM in 2016 which are under review. IPL Petersburg's Ash Pond Closure Plan was approved by IDEM in 2013.

6.3.3 Selenium Water Quality Criteria

On July 13, 2016, EPA published the final updated chronic aquatic life criterion for the pollutant selenium (Se) in freshwater per Clean Water Act section 304(a). The 2016 criterion is based on aquatic life selenium toxicity driven by organisms consuming selenium-contaminated food rather than by being exposed only to selenium dissolved in water. The revised criterion is a recommendation to states authorized to establish water quality standards under the Clean Water Act. Selenium criterion is expressed as four elements: fish egg-ovary, fish whole body or muscle, water column monthly, and water column intermittently. The federal rule will be implemented after the Indiana Department of Environmental Management finalizes the proposed Metals Criteria Revisions Rule. These final revised criteria will be incorporated into NPDES permits with compliance schedules in some cases. Currently, uncertainty remains around impacts to IPL.

6.3.4 New Source Review ("NSR")

In October 2009, IPL received a Notice of Violation and Finding of Violation (NOV) from the United States Environmental Protection Agency (EPA) under Section 113(a) of the Clean Air Act (CAA). The NOV alleges violations of the CAA at IPL's three primarily coal-fired electric generating facilities at the time, dating back to 1986. The alleged violations primarily pertained to the Prevention of Significant Deterioration (PSD) and nonattainment New Source Review requirements under the CAA. On October 1, 2015, IPL received an NOV from EPA alleging violations of opacity requirements at IPL Petersburg Unit 3 under the CAA, Indiana State Implementation Plan (SIP), and Petersburg Title V operating permit. Also, on February 5, 2016, the EPA issued a NOV alleging violations of PSD, non-attainment New Source Review and other CAA regulations, the Indiana SIP, and the Petersburg Title V permit.

Since receiving these NOVs, IPL management has met with staff from EPA and the Department of Justice (DOJ) to discuss a possible settlement of the NOVs. Settlements of similar claims have required companies to pay civil penalties, install additional pollution control technology on coal-fired electric generating units, retire existing generating units, and invest in additional environmental projects. At the time of this filing, IPL is now close to concluding a settlement to resolve the NOVs, pending required approvals by management at EPA and DOJ. Unless and until a settlement is approved and made public by DOJ, the discussions and proposed terms are confidential. By law, the settlement would be in the form of a judicial consent decree, and thus if approved by EPA and DOJ, any settlement would be subject to a public comment period and would have to be reviewed and approved by a federal district court judge before it would be final and effective

6.4 Summary of Potential Impacts

These regulations would potentially require IPL to incur additional expenses for compliance in the future. Figure 6.3 provides a summary of these potential regulations including potential timing and preliminary cost estimates available at this time.

Figure 6.3 | Estimated Cost of Potential Environmental Regulations

Rule	Expected Implementation Year	Capital Cost Range Estimate ($MM)	Assumed Technology
CWIS 316(b)*	2022	$13.8	Modified traveling screens
ELG	2018	$0	None
ACE Rule	2024	$8-27	Varies across portfolio

Section 7: Resource Portfolio Modeling

170 IAC 4-7-4(11) 170 IAC 4-7-4(22) 170 IAC 4-7-8(a)

Key Highlights
• IPL utilized the Ascend Analytics' PowerSimm modeling platform to develop a robust stochastic capacity expansion and production cost modeling framework • Systematic evalution of coal unit retirements modeled across a wide range of futures provided insight into coal unit viability now and in the future • Fundamentals-based forward curves from Wood Mackenize, a global market intelligence leader, provided a fresh look at forward-looking factors that could shape power and fuel markets • Deterministic sensitivities for key variables performed to stress portfolios and identify the impacts on sources of future uncertainty

7.1 Modeling Overview for the 2019 IRP

170 IAC 4-7-4(8) 170 IAC 4-7-8(c)(4)

After the 2016 IRP, IPL engaged in a comprehensive review of modeling capabilities, processes, and tools to prepare for the 2019 IRP. The 2019 IRP modeling process is a culmination of two years of work and process improvement from assumption development to the model itself. Figure 7.1 summarizes modeling done in 2016 versus 2019.

Figure 7.1 | Modeling Comparison: 2016 IRP vs. 2019 IRP

2016 IRP Modeling	2019 IRP Modeling
Six (6) candidate portfolios created from scenarios with deterministic, "typical week" capacity expansion runs	Fifteen (15) candidate portfolios created from stochastic capacity expansion runs with 8760 chronological commitment and dispatch across 100 iterations varying weather, load, and commodity prices
Six (6) deterministic production cost runs with base case assumptions	Seventy-five (75) stochastic production cost runs for each scenario with deterministic scenario drivers (15 portfolios * 5 scenarios)
One (1) 50 iteration stochastic study with base case assumptions	Each scenario conducted stochastically with 100 iterations to widen the range of uncertainty considered. A combined total of 7,500 iterations across all model runs.
Two (2) deterministic sensitivities for one portfolio (Base Case) on timing and magnitude of Clean Power Plan	Four (4) deterministic sensitivities for two scenarios and all portfolios evaluating (1) renewable and storage capital costs, (2) capacity prices, (3) wind capacity factors, and (4) wind LMP basis.

7.2 Modeling Tools

170 IAC 4-7-4(5) 170 IAC 4-7-4(19) 170 IAC 4-7-4(28)

IPL began a transition to Ascend Analytics' PowerSimm software in mid-2017. The PowerSimm platform provides a comprehensive suite of modeling products that cover short-term optimization (1-14 days) and long-term planning (20+ years).

IPL used three PowerSimm modules for the 2019 IRP:

PowerSimm Module #1: Automatic Resource Selection ("ARS")

ARS is the capacity expansion module in the PowerSimm platform that allows utilities to perform long-term resource optimization and selection subject to a set of constraints. ARS uses hourly dispatch modeling to make optimal resource decisions across the planning horizon subject to constraints. ARS used mixed integer programming (MIP) techniques to optimize resource decisions, with the objective of minimizing the present value of portfolio costs, subject to physical and financial constraints. The differentiating factor of PowerSimm is the ability to perform stochastic capacity expansion to provide a robust plan across a wide range of futures.

PowerSimm Module #2: Portfolio Manager

Portfolio Manager is the mid-term production cost module that was the foundation of the hourly portfolio runs. The back-end dispatch optimization, forward curve simulation, renewable simulation, and load simulation are the same as ARS and are run through the same software. Optimized portfolios from ARS were created as distinct portfolios in Portfolio Manager, which gave us the full reporting functionality required for the portfolio comparison and metric evaluation.

PowerSimm Module #3: BatterySimm

The BatterySimm module enables dynamic, hourly and sub-hourly optimization in PowerSimm. This was effectively a back-end code enhancement that conducted the hourly optimization of storage separately in a GAMS-based model and seamlessly integrated the results for ARS and Portfolio Manager. IPL did not use sub-hourly modeling in the 2019 IRP, but sub-hourly modeling is being explored as an improvement for future IRPs.

IPL also used a spreadsheet financial model to calculate PVRR for the 2019 IRP:

Financial Model outside of PowerSimm

IPL utilized a spreadsheet-based set of financial models to build the revenue requirement. The revenue requirement calculation outside of PowerSimm provides a transparent, flexible method to calculate PVRR, compare scenarios and portfolios, and build customized outputs for stakeholders. Consultants with Concentric Energy Advisors helped develop the model, linked the PowerSimm results to the financial model, and created a set of quality control measures to validate information was accurately linked.

In previous IRPs, PVRR was an output of the model, and it was difficult to trace the individual components to see how it was calculated. This methodology provides a set of transparent modeling files and provides a tool for performing other sensitivities on the portfolios. This allows greater visibility into the modeling and provides transparency to IPL stakeholders.

7.3 Modeling Framework

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7.3.1 Retirement Analysis

The modeling framework in the 2019 IRP centered on a systematic evaluation of IPL's existing resources compared with alternatives. IPL evaluated a set of fixed retirement dates on the Petersburg units based on age, existing technology, expected maintenance, and cost.

Most capacity expansion models, including PowerSimm, have the capability of co-optimizing new build decisions with retirement decisions for existing resources. This type of optimization can be useful, but it introduces modeling complexities and forces the modeler to make up front decisions about constraints for retirements.

IPL established the retirement dates instead of allowing the model to select dates for several reasons:

1. **Fixed cost allocation**: Petersburg is a large plant with interconnected systems and processes. As a result, allocating fixed costs to specific units presents a challenge because the model cannot dynamically evaluate changes to fixed costs as a result of the order of retirements. The timing and order of retirements, if any units are selected for retirement, would require an iterative modeling process that could quickly increase the number of required runs.
2. **Capacity valuation and Reserve Margin Constraints**: IPL's net long capacity position creates unique challenges for capacity expansion modeling. PowerSimm, like other models, is designed to find the lowest cost portfolio by maximizing resource profitability (total revenue minus total cost) subject to meeting a set of specified constraints. The PowerSimm model is designed to impose a "penalty" to portfolios that exceed the reserve margin target or are short of the reserve margin target. Because IPL is long 300 – 400 MW for our "going in" position, the model could prematurely retire units to avoid exceeding the reserve margin target. Allowing the model to "overbuild" in order to compensate for this could result in more capacity being selected than needed.
3. **Stakeholder input**: IPL received several requests to evaluate retirement of the entire plant by at least 2030, and in some cases sooner.

Several factors helped IPL establish the decision window on retirement dates of the coal units:

- **Unit Age:** Petersburg Units 1 and 2 are 52 and 49 years old, respectively, and have age-based retirement dates of 2033 and 2035. Costly unit overhauls and maintenance are required on the units to maintain performance and safety targets, so IPL wanted to evaluate the economics of the ongoing, all-in costs and net benefits of operating those units through the early 2030s compared to alternatives.
- **Renewable Tax Credits**: the pending phase out of the PTC and ITC also provided a short-term action window in which to evaluate retirement dates.
- **Scale and Timing of Replacement Capacity**: even if IPL let the model co-optimize retirement dates of existing resources with new resources, we would still need to constrain the model to generate portfolios that are reasonable and provide enough time for IPL to build, acquire, or contract for replacement capacity. We identified retirement dates for Pete 3 and 4 based on expectations for the lead time to integrate replacement capacity on the scale of those units.

This modeling framework allowed IPL to effectively evaluate a range of transition portfolios across a wide range of futures while clearly defining key drivers of portfolio risk and opportunity. The probabilistic nature of the model combined with scenario analysis and targeted sensitivities on key variables led IPL to a well-defined decision framework.

Figure 7.2 | IRP Portfolios with Retirements

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

7.3.2 Scenarios

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In the 2019 IRP, IPL set out to define a set of high-impact drivers to define scenarios rather than focus on narrative-themed scenarios as done in the 2016 IRP. The scenarios developed and presented in the second public stakeholder meeting in March 2019 provide a range of futures with variations and combinations of three key variables: natural gas prices, potential carbon legislation, and load forecasts.

All scenarios were modeled stochastically, which means that volatility was applied probabilistically to the forecasts in each specific scenario. The combination of scenarios with deterministic drivers and stochastic production cost modeling widens the range of uncertainty considered and enables us to fully account for risk and uncertainty as part of the modeling process. Figure 7.3 contains a description of the scenarios in the 2019 IRP and the key drivers for each scenario.

Figure 7.3 | IPL 2019 IRP Scenarios and Drivers

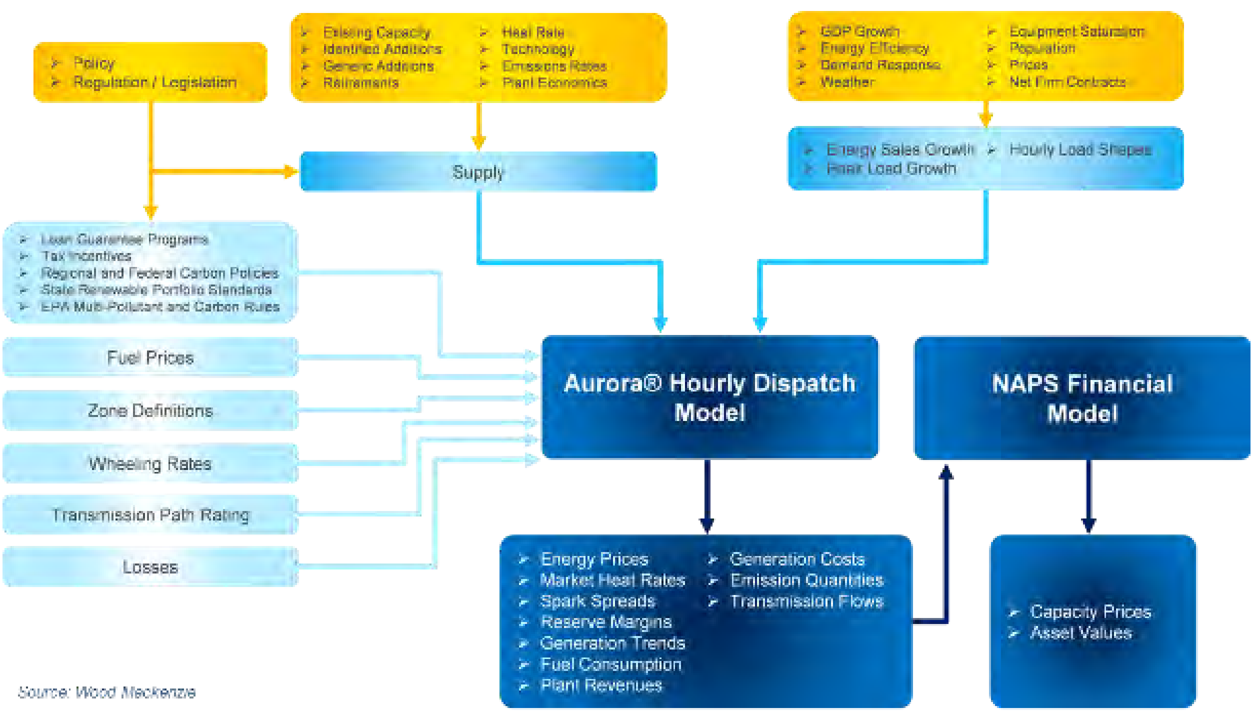
	Reference Case	Scenario A: Carbon Tax	Scenario B: Carbon Tax + High Gas	Scenario C: Carbon Tax + Low Gas	Scenario D: No Carbon Tax + High Gas
Natural Gas Prices	Base	Base	**HIGH ↑**	**LOW ↓**	**HIGH ↑**
Carbon Tax	No Carbon Price	**Carbon Tax (2028+)**	**Carbon Tax (2028+)**	**Carbon Tax (2028+)**	No Carbon Price
Coal Prices	Base	Base	Base	Base	Base
IPL Load	Base	Base	Base	**LOW ↓**	**HIGH ↑**

Capital Costs for Wind, Solar, and Storage	Base	Base	Base	Base	Base

IPL utilized the 2018 H1 Wood Mackenzie Long Term Outlook for the 2019 IRP. Wood Mackenzie's North American Power & Renewables Service provides a forward view using their fully integrated fundamentals-based forecast. The detailed power market analysis covers all NERC regions and includes deliverables on supply, demand, generating fuel pricing, wholesale power price projections, and analysis of other key fundamental drivers. In addition to the core forecast cases, Wood Mackenzie provided a set of natural gas sensitivities to IPL for use in the IRP.

Wood Mackenzie's two core cases are fully optimized cases – this means that they conducted a full zonal, hourly unit commitment and dispatch and capacity expansion to develop the underlying resource mix and market prices. Figure 7.4 contains a flow chart for Wood Mackenzie's North American fundamental modeling process.

Figure 7.4 | Wood Mackenzie North America Model



Source: Wood Mackenzie

Detailed reports on the H1 2018 Long Term Outlooks from Wood Mackenzie can be found in Confidential Attachments 7.1, 7.2, 7.3, 7.4, and 7.5.

Reference Case

The Reference Case is based on the Wood Mackenzie H1 2018 "No Federal Carbon Case". This fully optimized case represents the absence of any federal carbon policy but contains a forward-looking view on the underlying fundamentals of fuel, renewable, and power markets.

Scenario A: Carbon Tax Case

The Carbon Tax Case is based on the Wood Mackenzie H1 2018 "Federal Carbon Case" underlying assumptions. This includes a federal carbon tax of $2.45/ton starting in 2028 and escalating to $36/ton by 2039.

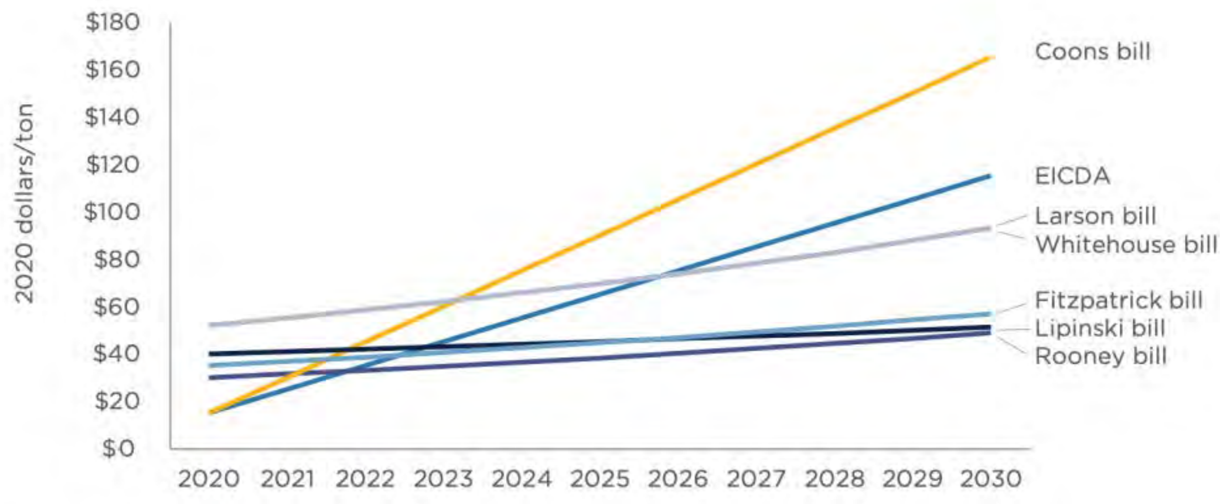
Wood Mackenzie's narrative on the Carbon Tax Case is as follows:

> Despite dim prospects for any federal carbon regulation under the current administration, broad-based sustainability efforts are likely to create a push towards a carbon framework in the US. We assume this does not materialize into policy goals until 2028, reflecting political inertia that has hounded any such policy efforts. Specifically, legislative proposals start emerging by 2022, and then it takes years before laws are passed with actual implementation goals set for 2028. Source: Wood Mackenzie

IPL recognizes the uncertainty surrounding any assumption for future carbon legislation. The timing, scale, and structure of any price on carbon is difficult to forecast. At the time this report was developed, seven different carbon tax legislative proposals have been introduced to Congress in 2019. Figure 7.5 shows a summary of the carbon prices proposed in these bills. Each bill has a different structure and timeline, and there are significant political headwinds facing these bills until after the 2020 Federal Election.

IPL believes that including a federal price on carbon in scenarios is a prudent planning exercise considering the national and global efforts for carbon reduction. Carbon legislation has an outsized impact on the electric power sector and ignoring the potential for future carbon pricing could introduce significant risk to IPL customers.

Figure 7.5 | Snapshot of Carbon Prices in Bills Introduced to Congress in 2019[24]



Source: CGEP analysis

Scenario B: Carbon Tax Case + High Gas

The Carbon Tax Case plus High Gas scenario is a natural gas sensitivity case provided by Wood Mackenzie. The high gas sensitivity includes a natural gas price forecast that is 30-40% higher than the base forecast, and power prices were developed by Wood Mackenzie through their fundamental model. Factors that could lead to this scenario:

- Increased regulation on fracking and natural gas production, which could include regulations on methane and/or water regulation
- A carbon tax driving more demand for natural gas as a "bridge fuel" to firm up intermittent renewable resources
- Higher than expected natural gas exports driving higher demand and prices for natural gas

Scenario C: Carbon Tax Case + Low Gas + Low Load

The power and natural gas prices in this case are from a sensitivity from Wood Mackenzie on their Federal Carbon Tax Case. This scenario also includes a low load forecast for IPL. Factors that could lead to this scenario:

[24] https://energypolicy.columbia.edu/sites/default/files/file-uploads/EICDA_CGEP-Report.pdf

- Carbon legislation combined with a national effort to decarbonize the grid could push out incremental natural gas power plant build as storage and other firm resources fill the gap from coal. This decrease in demand could drive prices lower
- Worldwide shifts toward renewables lowers demand for U.S. LNG exports, resulting in a glut of natural gas
- Overall lower power demand due to economics and energy efficiency results in less power demand for natural gas

Scenario D: No Carbon Tax Case + High Gas + High Load

Natural gas and power prices were from a Wood Mackenzie high gas sensitivity run on their No Carbon Tax Case. This scenario also includes a high IPL load forecast.

Factors that could lead to this scenario:

- Global demand for natural gas could increase U.S. LNG exports beyond current forecasted trajectories.
- Despite a lack of federal carbon legislation, market economics, the desire for decarbonization, and accelerated renewable deployment drives demand for natural gas power plant development as a replacement for coal.
- A change in administration in the 2020 election results in increased regulation on natural gas production, but comprehensive carbon legislation remains stalled at the federal level.

7.3.3 Fundamental Forecasts

The fuel prices for IPL’s existing generating units can be found in Confidential Attachment 7.6.

Power Prices

Wood Mackenzie forecasts for MISO Indiana Hub were utilized in all the IRP models. Through 2024, a blend of forward curves and fundamental curves was used for both power and natural gas, as noted in Figure 7.6. Starting in 2024, the fundamental curves were used in the model.

Figure 7.6 | Illustrative Example: Forward Curve and Fundamental Forecast Blend

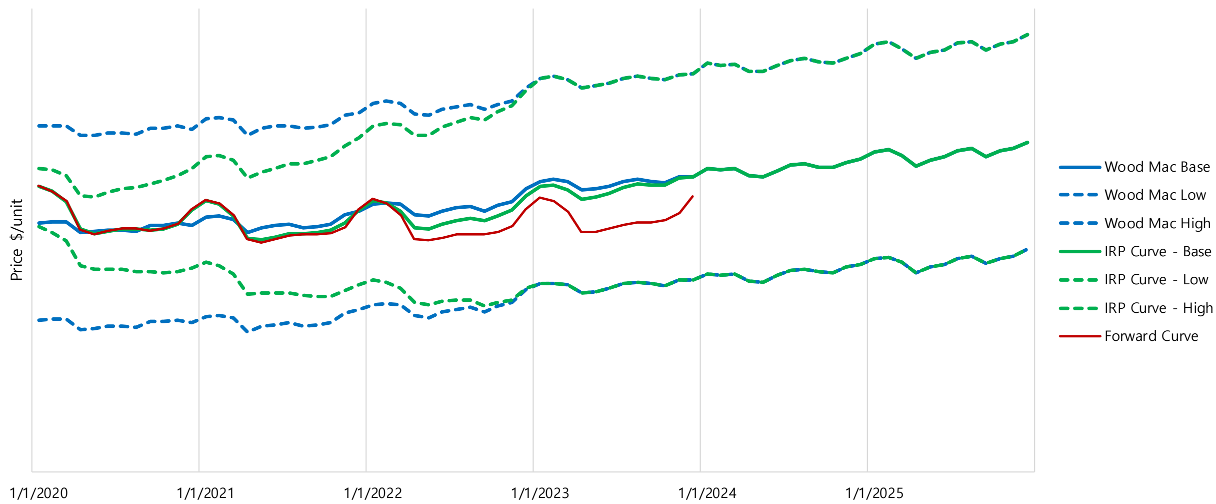
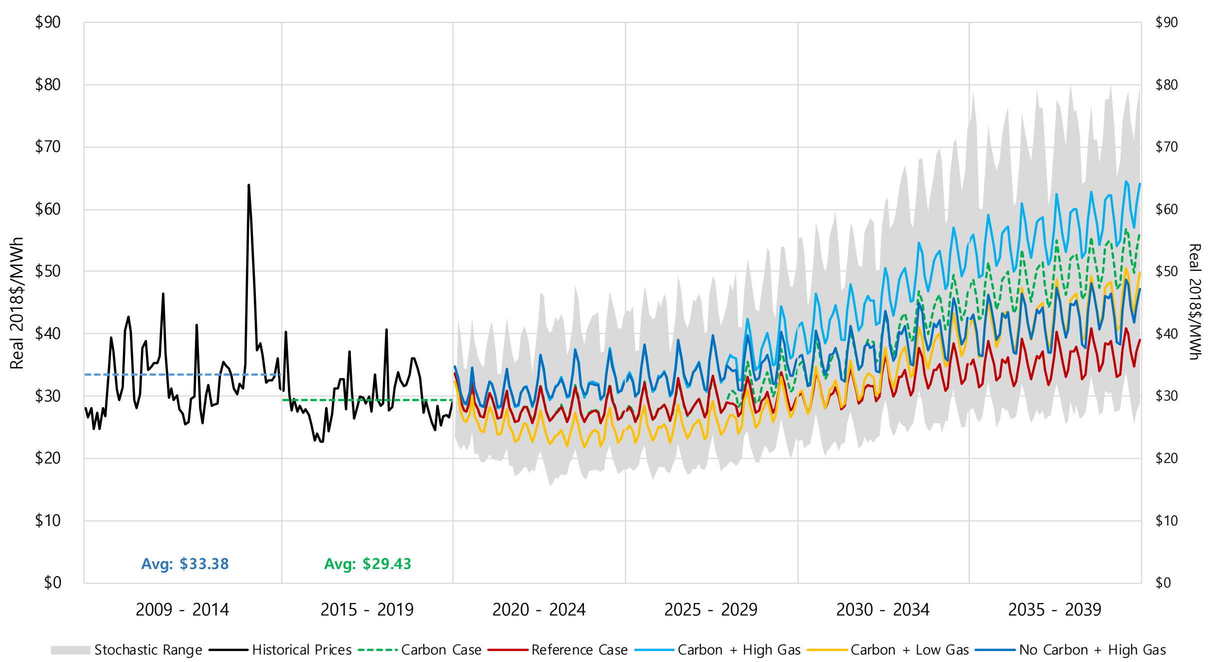


Figure 7.7 shows the distribution of 7x24 power prices in the 2019 IRP. The stochastic range shown is the difference between the 95th and 5th percentiles for all modeled scenarios, and the base curve for each scenario is also shown.

Figure 7.7 | MISO Indiana Hub 7x24 Power Prices in 2019 IRP (2018$/MWh)



IPL also included a locational marginal price (LMP) basis adjustment to existing and new supply-side resources (Figure 7.8). In the model, market revenues for supply-side resources are a function of the energy production and the wholesale market price, represented by market locational marginal prices (LMPs) in that hour. In MISO, LMPs at individual nodes can separate due to congestion, which is caused when transmission constraints cause re-dispatch of units that raises system production costs. To more accurately reflect the locational aspect of resources, IPL included an estimate for the LMP basis differential for existing and new resources. Forecasting congestion is difficult and is subject to uncertainty. A detailed congestion study will be conducted for any actual projects that IPL pursues.

Figure 7.8 | Modeled LMP Basis from MISO Indiana Hub

	On-Peak	Off-Peak
IPL Load	-2%	-1%
Petersburg	-9%	-6%
Eagle Valley	-5%	-4%
Harding Street	-3%	-2%
Georgetown	-2%	-1%
IPL Existing Solar	0%	0%
Hoosier Wind Park	-20%	-18%
Lakefield Wind	-21%	-21%
New Combined Cycle	-5%	-4%
New Gas Peaker	-3%	-2%
New Wind	-20%	-18%
New Solar	0%	0%
New Storage	0%	0%

IPL receives Annual Revenue Rights ("ARRs") from historical generator locations from MISO. ARRs were designed to compensate owners of transmission lines from generators to their load for the use of the transmission system with the advent of open access and the formation of MISO. ARRs can be monetized in the Annual Financial Transmission Right (FTR) auction or ARR holders can convert all or a portion of their ARRs into FTRs whose value will "float" in the Day-Ahead market throughout the planning year. IPL assumed that ARRs are retained in all retirement scenarios, which is consistent with the MISO Business Practice Manual for FTRs, and that the value of ARRs does not change when units are retired. The value of the ARRs was the same in all portfolios and scenarios and therefore was not included in the revenue requirement calculation. IPL will continue to value ARRs and optimize the value of ARRs and FTRs to the customer's benefit through time and will adjust strategies and valuations accordingly to changes to the underlying fundamentals of the system.

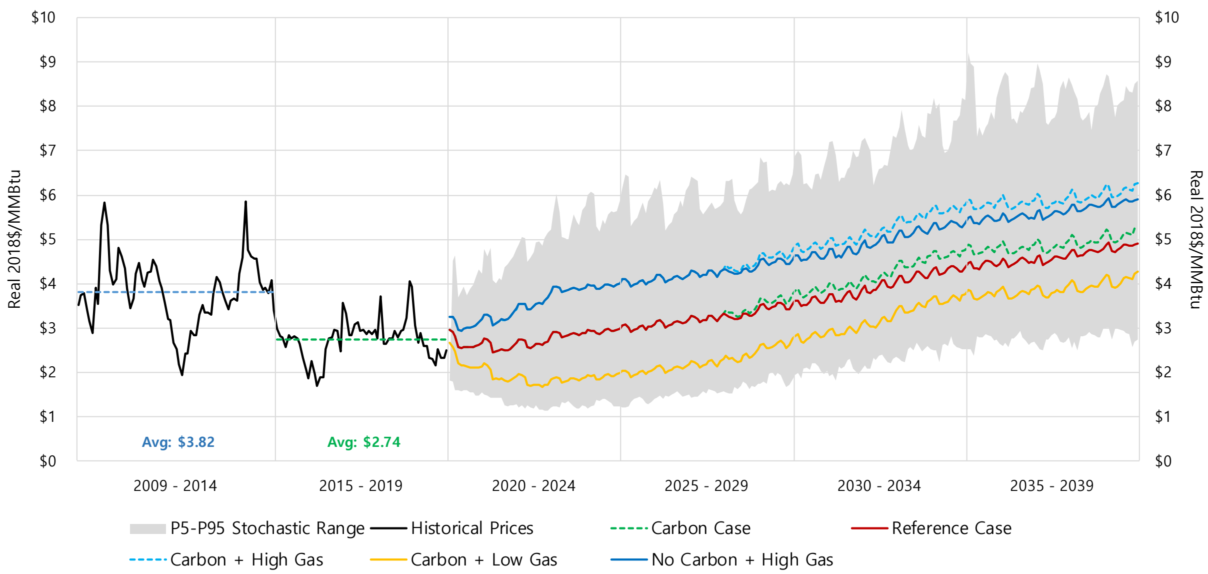
A sensitivity analysis was conducted to estimate the impacts of an improved basis assumption for new wind assets. This analysis is described in Section 7.4.4, and results are shown in Section 8.4.4.

Natural Gas Prices

Figure 7.9 contains the modeled range of natural gas prices in the 2019 IRP. Henry Hub was the benchmark used for simulations, and a basis or delivery adder or discount was included for existing resources as well as any new natural gas resources.

The fuel prices for IPL's existing generating units can be found in Confidential Attachment 7.6.

Figure 7.9 | Henry Hub Natural Gas Prices



Carbon Prices

For scenarios with a carbon tax, a price on carbon was included in the model and is added to the variable dispatch cost of thermal units. To the extent thermal units are economically dispatched in these scenarios, carbon emissions are a cost that is reflected in the PVRR calculation. Figure 7.10 contains an illustrative example of how different levels of a carbon tax impact the variable cost of a typical coal plant and a typical combined cycle plant.

Figure 7.10 | Carbon Price Impact on Dispatch Cost

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

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

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

Figure 7.11 depicts the carbon price curve utilized in Scenarios A, B and C.

Figure 7.11 | Federal U.S. Carbon Price in Carbon Scenarios

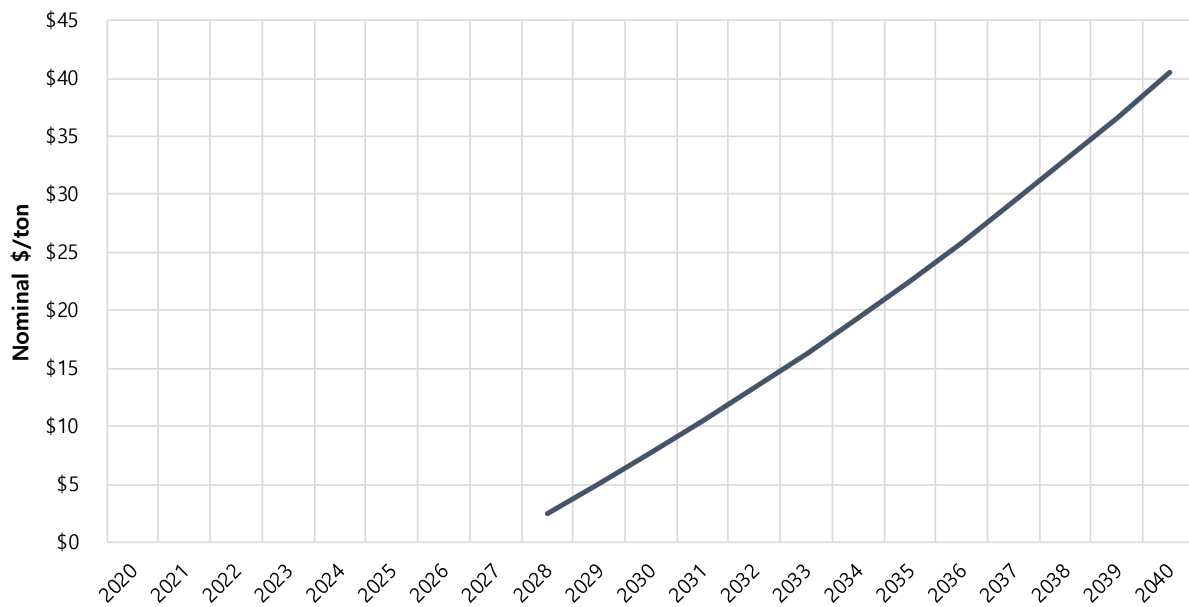
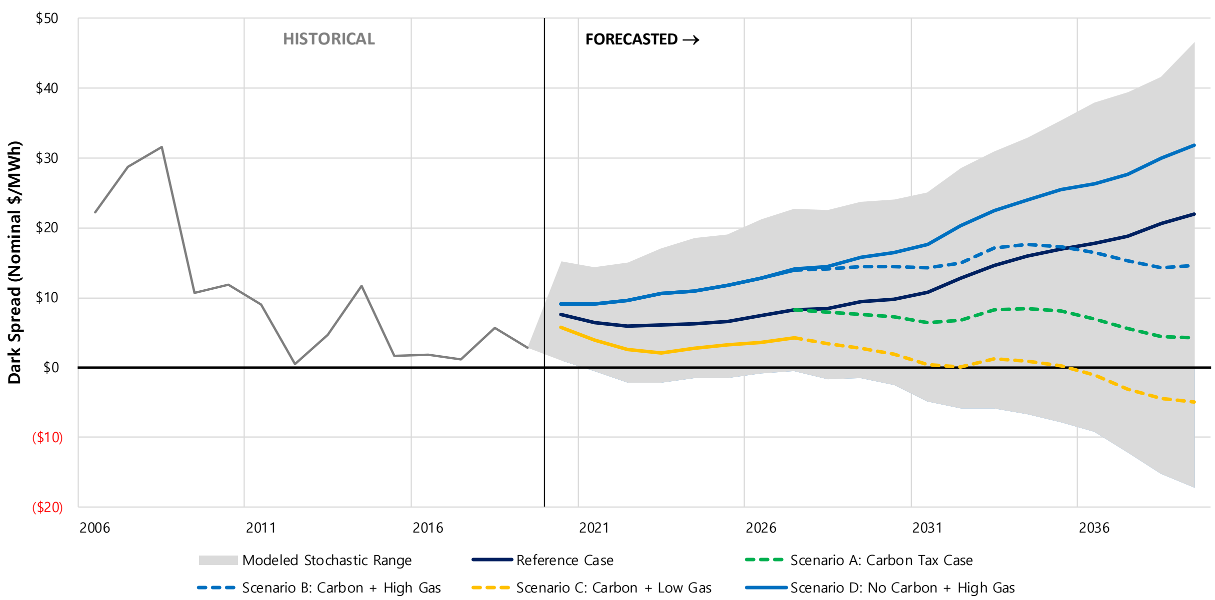


Figure 7.12 shows the distribution of 7x24 clean dark spreads[25] for the base curves from each scenario included in the IRP. The dark spread, which is the market power price minus the variable production cost, is indicative of the economic positioning of coal in MISO relative to other units. A dark spread of $0/MWh means that market prices on average are at the cost of the coal unit's variable cost, so dispatch hours and therefore energy margin will be limited. In reality, dark spreads vary throughout the year, and the dispatch of the unit can change the captured or realized dark spread because it can cycle down or off during low price times and dispatch up during high price times.

As Figure 7.12 shows, the modeled scenarios captured a wide range of potential futures for underlying power price fundamentals that could impact coal's economic viability. A carbon price is a significant variable impacting dark spreads, and natural gas will continue to be a driver of risk and opportunity for coal assets in the short term and long term. In addition to this distribution represented by the scenarios, each scenario was modeled stochastically, so the range of uncertainty captured was expanded to more potential futures.

Figure 7.12 | IPL Petersburg 7x24 Clean Dark Spreads for Scenarios (Nominal $/MWh)

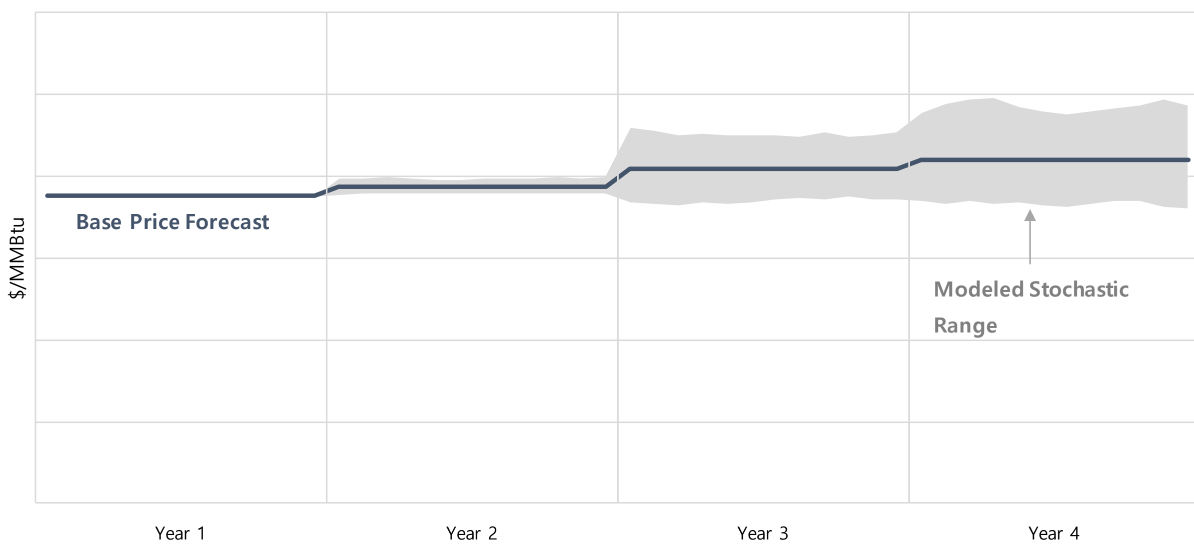


25 Clean Dark Spread = Power Price – (Fuel Price * Heat Rate + Variable O&M + Emission Cost); does not contain market dispatch results, just 7x24 power prices with LMP basis and base variable costs per year of the analysis

Coal Prices

The coal curve for Petersburg is an internally developed curve based on contracted fuel positions, forward-looking analysis for spot market coal, and market intelligence for the Indiana coal market. Coal prices were modeled stochastically, with volatility applied to the base coal curve to simulate a range of prices that varied monthly. Any hedged or contracted coal was accounted for, which primarily affected the range of coal prices modeled in the early years of the study. Figure 7.13 contains an illustrative chart showing how contracted coal was accounted for in the stochastic simulations.

Figure 7.13 | Coal Price Volatility Tied to Hedge Percentage in Early Years of Study



The fuel prices for IPL's existing generating units can be found in Confidential Attachment 7.6.

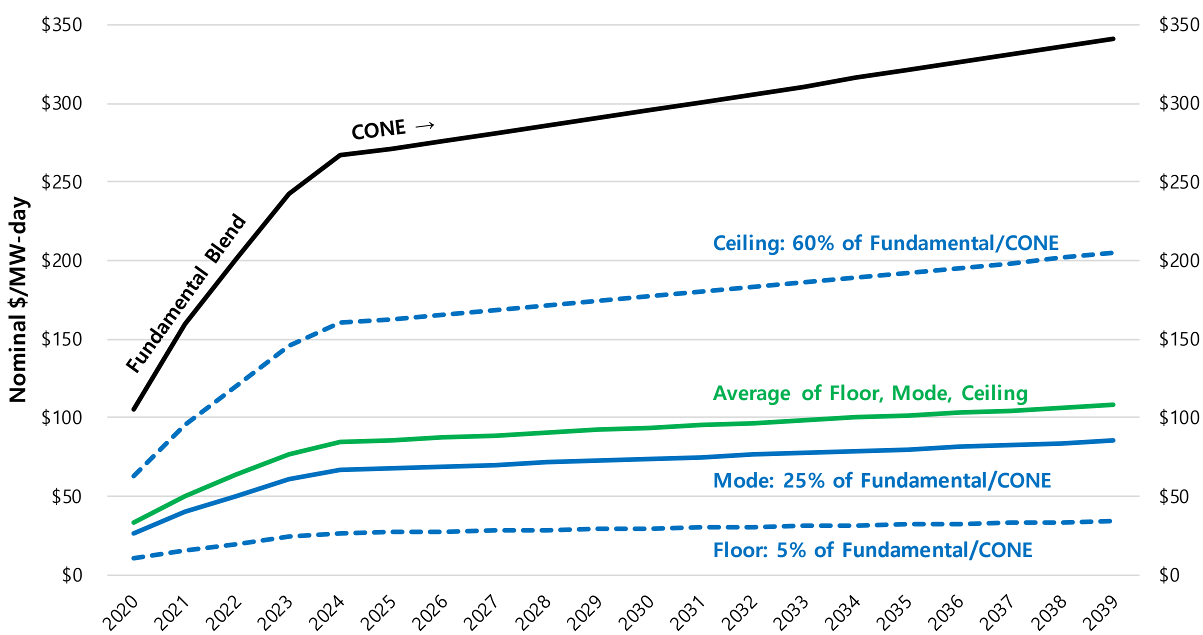
Capacity Prices

MISO runs a voluntary, administrative capacity auction process called the Planning Resource Auction ("PRA"). The MISO capacity market is a residual market for balancing prompt year capacity positions, as opposed to a long-term capacity construct like PJM's three-year forward market. Because of the residual nature of MISO's capacity construct, there has historically been volatility in both the auction clearing prices as well as the bilateral market. IPL chose to account for this uncertainty by simulating a range of capacity prices stochastically using a triangular distribution. The minimum, mode, and maximum values were established as percentages of the fundamental forecast, which approaches the Cost of New Entry ("CONE") for a combustion turbine by 2024.

Figure 7.14 contains a graphical depiction of this modeling setup. For each year of the study, the average of all simulated prices will equal the average of the minimum, mode, and maximum values established. The value of capacity only applies to portfolio imbalances, meaning capacity purchases and sales. For example, IPL's "going-in" capacity position is a net long capacity position of approximately 400 MW. The net capacity length in MW is multiplied by the annual capacity price in each iteration and valued as a net revenue in the revenue requirement calculation.

In addition to this modeling approach, we also ran deterministic sensitivities on the capacity price for each portfolio for the Reference Case and Carbon Tax Case. The setup is in Section 7.4.2, and results are in Section 8.4.2.

Figure 7.14 | MISO Zone 6 Capacity Price Range



Load

Base, low, and high IPL load forecasts were used in the scenarios. The Reference Case, Scenario A, and Scenario B used the base forecast. Scenarios C and D introduced low and high load forecasts in combination with other scenario drivers. PowerSimm uses weather simulations to create variation in load, and all load simulations are scaled to match forecasted levels and shaped hourly based on historical hourly IPL load data.

Candidate resource portfolios were created to meet the load obligation for the base load forecast. For the low and high load forecast scenarios, any incremental capacity shortfall was filled with capacity market purchases and excess capacity was sold at the modeled range of capacity prices.

Figure 7.15 and Figure 7.16 contain the modeled distribution of annual peak and energy forecasts for IPL.

Figure 7.15 | IPL Annual Energy Simulated Range and High/Low Cases

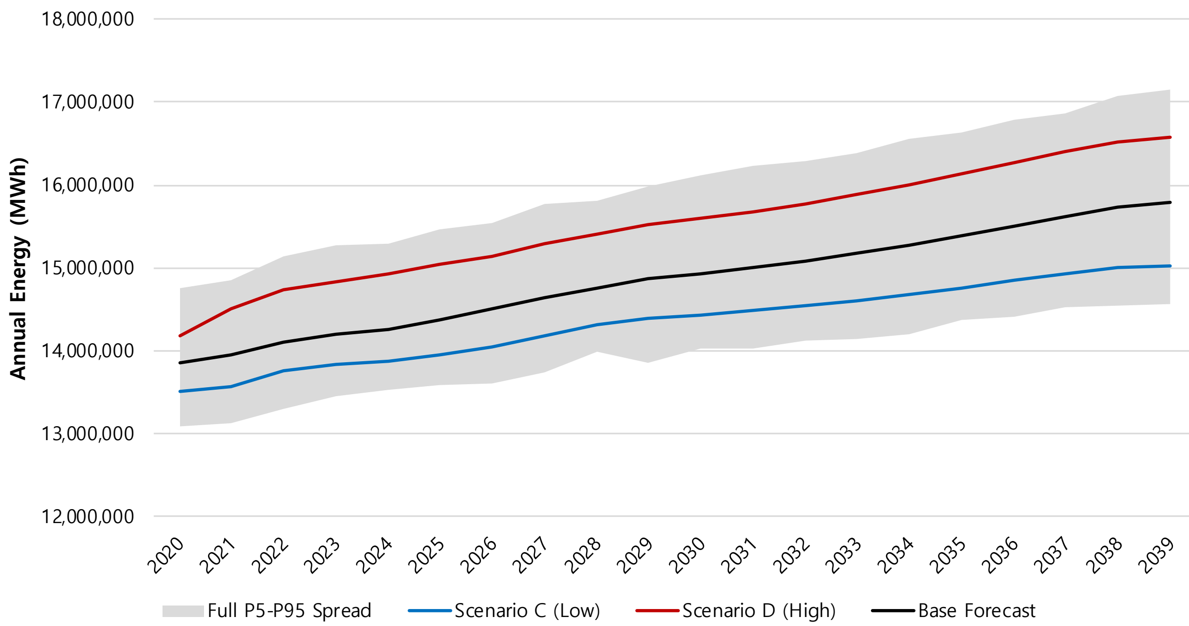
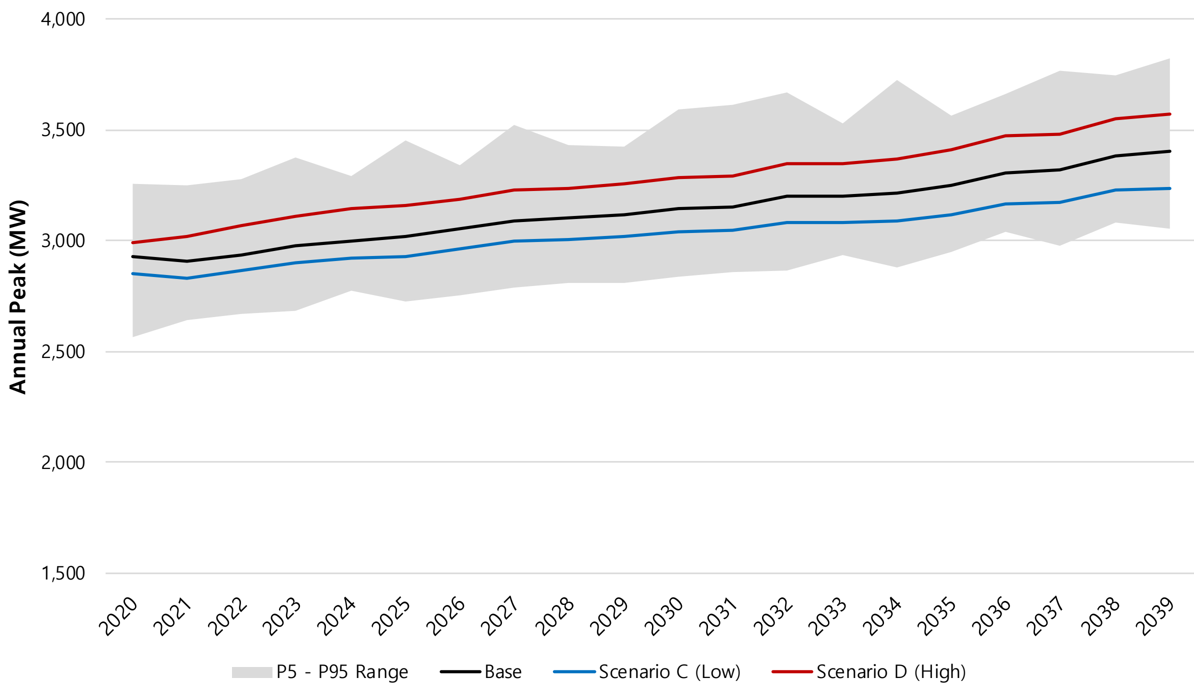


Figure 7.16 | IPL Annual Peak Load Simulated Range and High/Low Cases



7.3.4 Stochastic Parameters

This section describes the setup of the stochastic parameters required in all IRP models. The two primary inputs are volatility and correlation of key variables.

Volatility

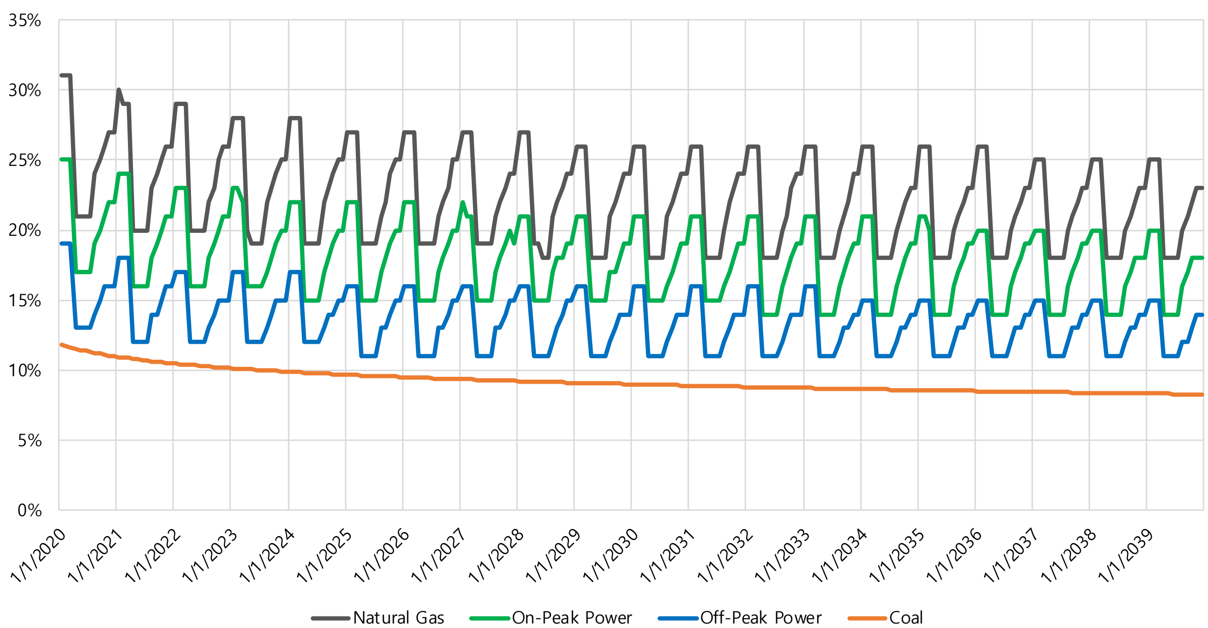
Volatility in the context of this type of modeling is defined as the annualized standard deviation of daily changes in forward market prices based on historical volatility of forward markets. Two dynamics are typically present when looking at forward-looking volatility measures: term structure and seasonality. A basic definition of the term structure of volatility is that volatility is typically higher the closer you are to contract expiration. This is driven by several factors, including the fact that closer contracts are more liquid and actively traded as well as the fact that short-term weather forecasts can drive sharper changes in power and gas markets more for the next month or two compared to 6 months or a year out. Seasonality is simply driven by more uncertainty in winter for natural gas, which therefore impacts power prices.

Volatility is used in the model to determine the range of outcomes, or the spread between the lowest and the highest priced iterations. A lower volatility input would result in a tighter range of prices, whereas higher volatility would result in a wider dispersion of outcomes.

Coal prices typically experience lower volatility on a forward-looking basis due to the nature of the commodity – the production cycle is longer, contracting is often longer term, and the transportation of the product is done on a longer time scale. Therefore, it takes longer for underlying market fundamentals to impact coal markets.

Figure 7.17 contains monthly volatility for natural gas, power, and coal that was used in PowerSimm. These volatility curves were used for all stochastic runs – this means that the volatilities stayed constant, but the underlying curves to which the volatilities were applied changed.

Figure 7.17 | Monthly Annualized Volatility for Gas, Power, and Coal in 2019 IRP



Correlation

The monthly correlation of forward prices is another input in PowerSimm for developing stochastic forward price ranges. The only correlation entered was for power and natural gas. The role of natural gas as a marginal fuel has long been observed, and as a result there has historically been a high correlation between natural gas prices and power prices on a monthly and daily basis.

IPL expects natural gas units to continue to drive the marginal price of power as more coal is retired, and therefore we included a high correlation (90%) for monthly power and natural gas prices. This correlation input only affects simulation of monthly forward power and gas prices – there is still separation of these commodities in the daily and hourly spot price simulations. The daily and hourly relationship between power and natural gas is preserved in the PowerSimm simulation framework.

In the 2018 State of the Market Report, the MISO Independent Market Monitor (IMM) describes the price-setting nature of natural gas and produced Figure 7.18 also presented in the report:

> *Price-Setting Shares.* Coal resources set system-wide prices in 46 percent of hours, down from 55 percent in 2017. Although natural gas units produce a modest share of the energy in MISO, they play a pivotal role in setting energy prices. Gas-fired units set the system-wide price in more than half of all intervals for the year, including almost all peak hours when prices are highest. In addition, congestion often causes gas-fired units to set prices in local areas when lower-cost units are setting the system-wide price. This is why they set local LMPs in 87 percent of intervals and why they are a key driver of energy prices.

Figure 7.18 | 2018 MISO State of the Market: Price-Setting by Fuel Type

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2017	2018	2017	2018	2017	2018	2017	2018	2017	2018
Nuclear	12,420	12,225	10%	10%	16%	16%	0%	0%	0%	0%
Coal	50,843	48,775	39%	38%	47%	46%	55%	46%	84%	78%
Natural Gas	55,794	55,240	43%	43%	23%	27%	44%	53%	85%	87%
Oil	1,904	1,691	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,929	3,966	3%	3%	1%	1%	0%	1%	1%	1%
Wind	2,610	3,005	2%	2%	8%	8%	0%	0%	30%	31%
Other	2,273	2,678	2%	2%	4%	2%	0%	0%	4%	2%
Total	**129,773**	**127,580**								

Other studies also indicate a continued strong correlation between power and natural gas prices. The NREL *2018 Standard Scenarios Report*[26] evaluated the relationship between power and natural gas which led them to provide the following key insight:

> **Marginal electricity prices continue to be impacted primarily by natural gas prices.** The modeled scenarios showed a linear relationship between natural gas prices and marginal electricity prices across most scenarios. Scenarios with higher or lower renewable energy

[26] https://www.nrel.gov/analysis/standard-scenarios.html

deployment tended to impact the electricity prices by changing the demand for natural gas, which in turn impacts the price.

No correlation was included for forward coal prices. In the short- to mid-term (1-5 years), there is low correlation between coal and natural gas prices as coal markets do not typically respond as quickly to changes in gas prices. Over the long term there could be correlation between coal and natural gas, but it has not been a consistent historical trend and therefore was not included.

7.3.5 Capacity Expansion Setup and Constraints

The capacity expansion optimization was set up to find the lowest cost resources subject to meeting IPL's annual reserve margin constraint using the base load forecast. While load was simulated stochastically, this did not affect the reserve margin target.

Figure 7.19 contains modeled constraints for new supply-side resources. Constraints on the first year available and number of projects per year are based on expected timeline for construction and/or procurement of projects under development, including the time for regulatory approval.

Figure 7.19 | Supply-Side Resource Capacity Expansion Constraints

	Gas CC	Gas CT - Frame	Gas CT - Aero	Gas Recip	Wind	Utility Solar	4-Hour Battery Storage
First Year Available	2023	2023	2023	2023	2022 (2021 pricing)	2023	2023
Generic Project Size (ICAP MW)	325	100	126	108	50	25	20
Number of Projects Allowed Per Year	4	5	1	1	10 in 2022 4 in 2023+	20	20
MW Allowed Per Year	1,300	500	126	108	500 in 2022 200 in 2023+	500	400
Number of Total Projects Allowed	8	10	5	5	30	60	100
Total MW Allowed	2,600	1,000	630	540	1,500	1,500	2,000

Several factors were taken into consideration for constraints on new wind:

1. Timing: the first year new wind was available was January 1, 2022. The PowerSimm model operates on a calendar year basis, which means that new build decisions will occur on January 1st. Because of the expected contracting and construction lead time required for new wind, it is expected that the in-service date for new wind in 2021 would be at the end of the calendar year. Therefore, the first year new wind is available is 2022, but the cost of the new wind is based on 2021 in-service with 80% PTC.
2. Number of projects per year: IPL allowed up to 500 MW of wind to be built in 2022 and 200 MW per year for every year after that. Wind pricing with 80% PTC eligibility provides a significant cost advantage, and because IPL is in net long position, the model was limited in capacity additions for 2022. Beyond 2022, IPL limited annual wind build to 200 MW due to concerns over the availability of wind projects after the phaseout of the PTC. As shown in Figure 7.20, the amount of wind in Indiana in the MISO Generation Interconnection Queue decreases significantly after 2020 as many developers are shifting focus to meeting solar ITC safe harbor deadlines.

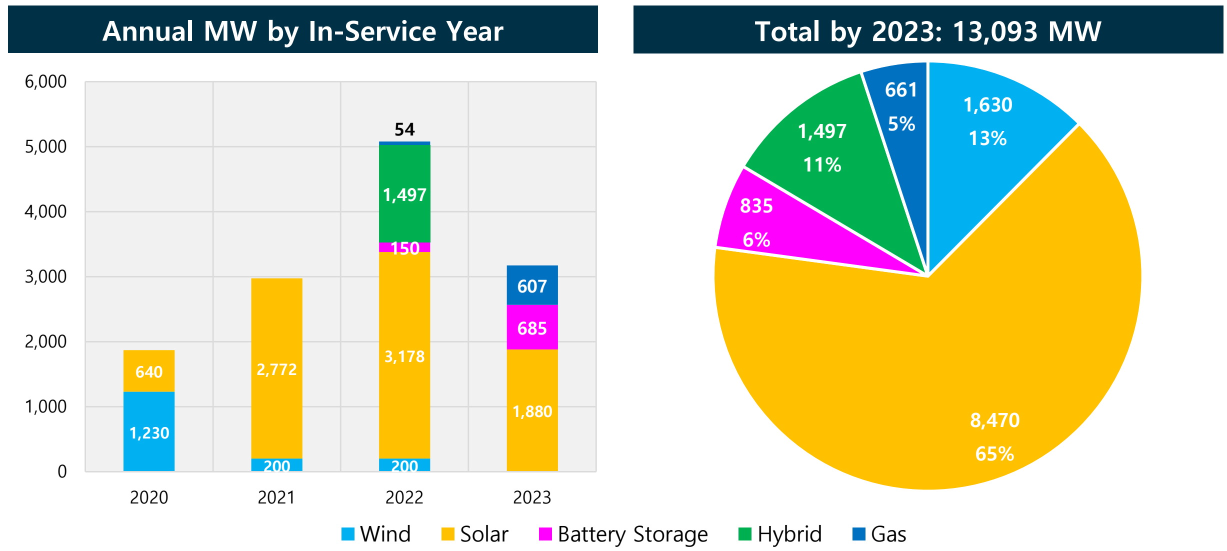
NREL's *2018 Standard Scenarios Report*[27] confirms the overall trend in lower expectations for wind development after the PTC expires. In their analysis of national wind installations over time, NREL concluded:

> Following the expiration of the PTC, most scenarios show little to no growth in wind capacity for several years (see Figure 29). Some scenarios show wind capacity stagnant or even declining for many years. Drivers of this slow wind growth are as expected, with low natural gas prices, high wind costs, and low demand, which all push demand for new wind downward.

IPL will continue to closely monitor market developments, MISO queue positions (Figure 7.20), and other factors through time and will adjust wind availability in the model accordingly.

[27] https://www.nrel.gov/analysis/standard-scenarios.html

Figure 7.20 | MISO Generation Interconnection Queue[28] for Indiana Projects



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

7.3.6 Financial Assumptions

Figure 7.21 and Figure 7.22 contain assumptions on IPL's capital structure, the discount rate used in the model, and other relevant financial assumptions used in the revenue requirement financial model.

Figure 7.21 | Capital Structure and Discount Rate in 2019 IRP

	Cap. Mix	Cost of Capital	WACC	Discount Rate
Debt	54.73%	4.98%	2.726%	2.048%
Preferred	1.82%	5.37%	0.098%	0.098%
Equity	43.45%	9.99%	4.341%	4.341%
Total	100.00%		7.164%	6.486%
			Actual	Effective
		State Tax	4.90%	4.90%
		Federal Tax	21.00%	19.97%
		Effective Tax Rate		24.87%

[28] https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

Figure 7.22 | Financial Model Assumptions

	2020
Property Tax Rate (%)	1.30%
Working Capital Factor ($M/MW)	0.0023
Gross Revenue Conversion Factor (Bad Debt and Expense)	1.02
Gross Revenue Conversion Factor (Capital)	1.23
Inflation	2.00%

7.4 Sensitivity Analysis

A sensitivity measures how a candidate resource portfolio performs across a range of possibilities for a specific risk or variable. IPL used both deterministic and probabilistic sensitivities to examine risks of the portfolios.

IPL identified four key drivers of uncertainty impacting candidate resource portfolios:

1. Future projections of wind, solar, and storage costs
2. MISO capacity prices
3. Modeled wind capacity factors
4. Wind LMP Basis and Captured Revenue

These sensitivities did not require additional production cost model runs because the sensitivity analysis is conducted in the financial revenue requirement model.

7.4.1 Capital Cost Sensitivities

IPL conducted a thorough research process to develop a base set of capital cost assumptions for alternative resources. This included a wide range of forecasts benchmarked to recent pricing seen in Indiana. However, there is still uncertainty for capital cost projections for wind, solar, and storage, especially past the 5-year window. NREL and other vendors use a variety of methods to estimate learning curves and cost trajectories for those technologies, but as recent history has shown, long term cost estimates for these technologies have been off the mark.

Therefore, IPL developed a set of sensitives around the capital costs and applied them to all five portfolios for the Reference Case and Carbon Tax Case. Cost adjustment curves were applied to capital costs for wind, solar, and storage. Adjustments were made to all three technologies together – this means that for a specific sensitivity, capital costs for wind, solar, and storage were moved by the same percentage and applied to the new build in each candidate resource portfolio.

For this exercise, IPL assumed that uncertainty increases through time. For example, we have more certainty about the cost of solar in Year 3 than we do in Year 15, so the range of costs should be greater in the later part of the study. Figure 7.23, Figure 7.24 and Figure 7.25 illustrate the range of capital costs for wind, solar and storage analyzed through the study period for this sensitivity analysis.

Figure 7.23 | Wind Capital Cost Sensitivity Range (2018$/kW; includes PTC)

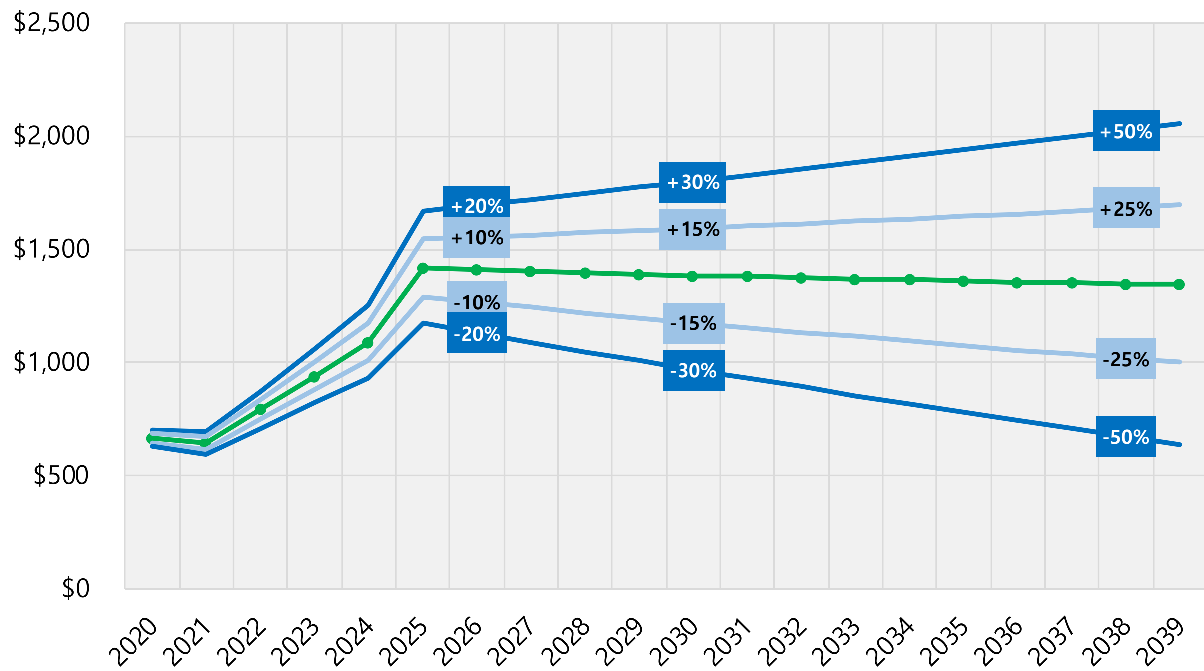


Figure 7.24 | Solar Capital Cost Sensitivity Range (2018$/kW$_{AC}$; includes ITC)

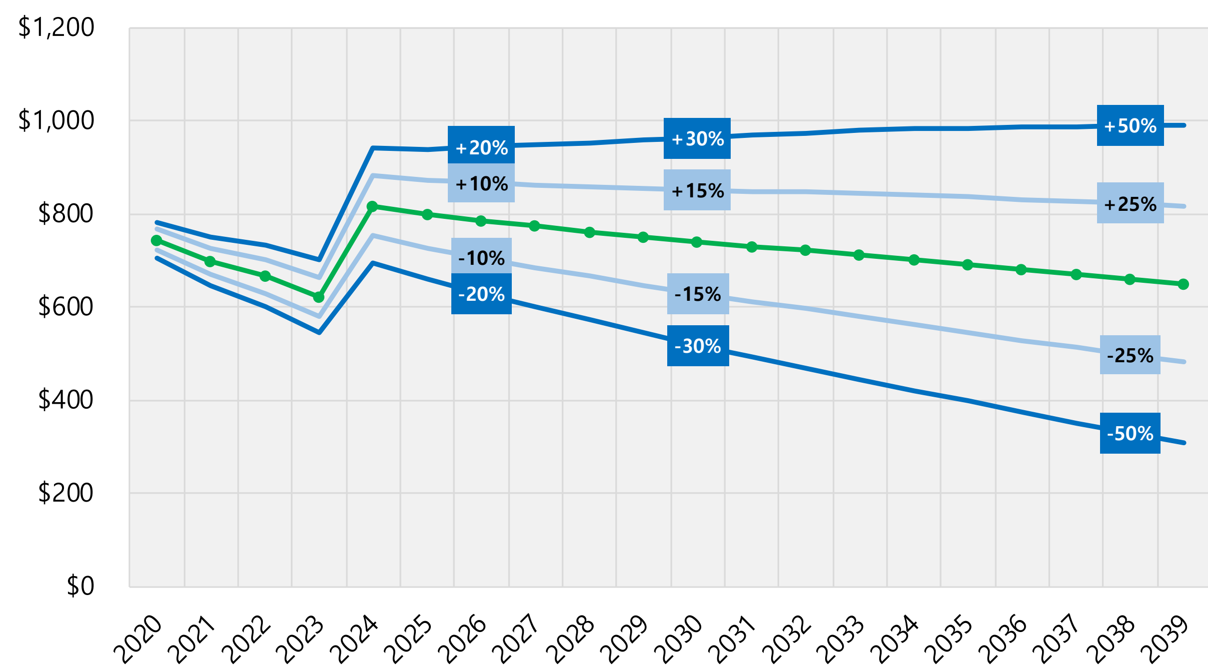
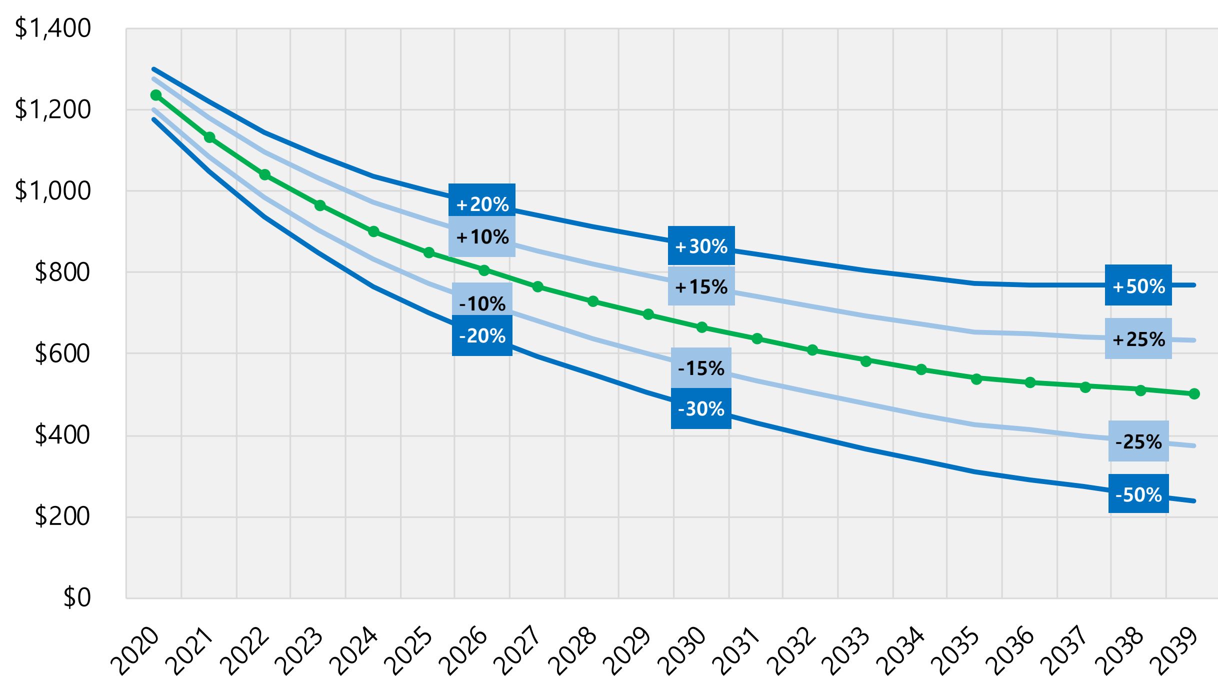


Figure 7.25 | Storage Capital Cost Sensitivity Range (2018$/kW)



7.4.2 Capacity Price Sensitivity

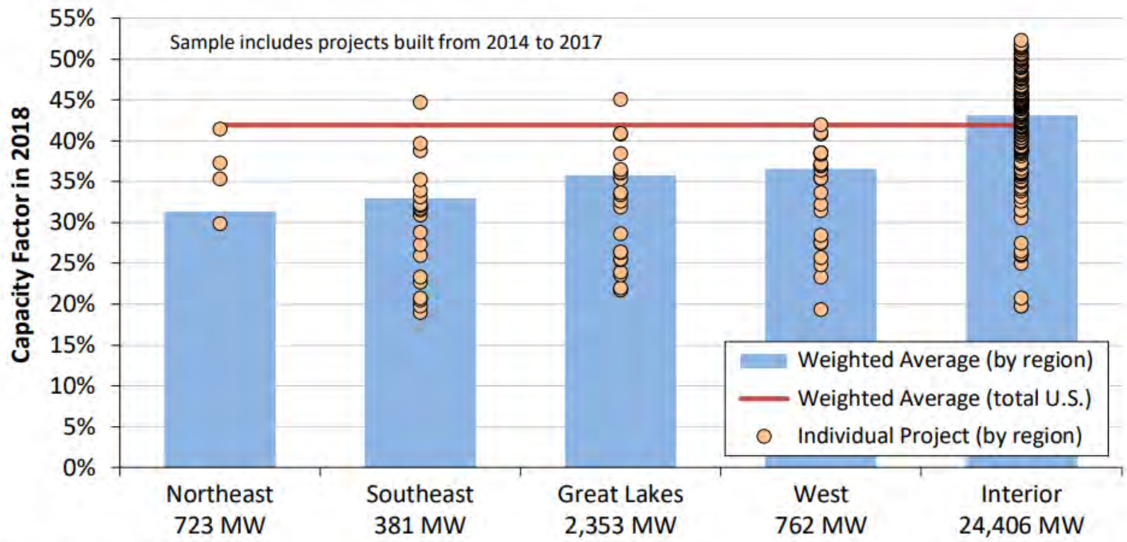
Capacity prices were simulated using a triangular distribution in PowerSimm for production cost runs as described in Section 7.3.3. IPL also conducted a deterministic sensitivity analysis to evaluate the impact of capacity prices on portfolio cost for the Reference Case and the Carbon Tax Case (Scenario A). The capacity position (MW) was fixed for each candidate resource portfolio and was the same for both scenarios, and annual capacity prices were applied to the capacity length to generate a set of PVRRs for comparison.

7.4.3 Wind Capacity Factor Sensitivity

As described in Section 5.3.1, IPL utilized the NREL Wind Toolkit to develop wind production profiles for generic new wind projects. IPL selected a midpoint 42% net capacity factor for simulated wind sites in Benton County, IN. Wind capacity factors are a function of the strength of the wind resource in a region, turbine size and technology, hub height, and other factors such as localized congestion and curtailment patterns. Additionally, while newer wind projects in the Midwest have achieved capacity factors greater than 40%, most projects installed in the Great Lakes region in the past five years have seen net capacity factors closer to 35%. The U.S. Department of Energy 2018 Wind Technologies Market Report[29] (Figure 7.26) shows 2018 calendar year capacity factors by U.S. region. The Great Lakes region, which includes Indiana, shows capacity factors in the range of about 20% to 45% with a weighted average of just over 35%.

[29] U.S. Department of Energy, *2018 Wind Technologies Market Report.* Retrieved from: https://emp.lbl.gov/sites/default/files/wtmr_final_for_posting_8-9-19.pdf

Figure 7.26 | Calendar year 2018 capacity factors by region: 2014–2017 projects only



Source: Berkeley Lab

Because of the uncertainty of what a potential new Indiana wind farm could produce, IPL conducted a sensitivity on the MWh produced by the modeled generic wind project for each portfolio. Figure 7.27 shows an example of how the sensitivity was set up. The "captured revenue", which is the generation-weighted revenue in $/MWh, was fixed, but the annual MWh of wind production was varied to estimate the impact of a different capacity factor than what we modeled in the base wind asset. The result is a different revenue value received by wind in the model. It is possible that re-simulating the wind units with different capacity factors at the same location could yield a different captured revenue, but the impact would likely be insignificant and would not change the insight this sensitivity provides.

Results from this sensitivity analysis can be found in Section 8.4.3.

Figure 7.27 | Wind Capacity Factor Sensitivity: Example Setup

Annual Capacity Factor	Percent Difference from Base	Annual MWh from 50 MW Project	Portfolio 3 2022 Build: 250 MW	2022 Captured Revenue ($/MWh)	2022 Portfolio 3 Wind Revenue ($MM)
46%	9%	201,480	1,007,400	$23.29	$23.46
44%	4%	192,720	963,600	$23.29	$22.44
[Base] 42.3%	-	185,447	927,235	$23.29	$21.60
40%	-6%	175,200	876,000	$23.29	$20.40
38%	-10%	166,440	832,200	$23.29	$19.38
36%	-15%	157,680	788,400	$23.29	$18.36
34%	-20%	148,920	744,600	$23.29	$17.34
32%	-24%	140,160	700,800	$23.29	$16.32
30%	-29%	131,400	657,000	$23.29	$15.30

7.4.4 Wind LMP Basis Sensitivity

IPL assumed the LMP basis from Indiana Hub to a generic new wind farm was approximately a 20% discount to the hub. As mentioned in Section 7.3, estimating future congestion is difficult because of the myriad of factors that could impact an individual location's LMP. A sensitivity analysis on the captured revenue of wind was included to estimate the impact of an improved LMP basis for new wind build across the portfolios. In this sensitivity analysis, wind production in MWh was fixed, and the captured revenue rate ($/MWh) was changed in increments of 5% to remove the basis assumption for new wind assets in the model.

Figure 7.28 and Figure 7.29 contain the base-modeled wind-captured revenue, which includes the LMP basis discount to Indiana Hub, as well as the sensitivity range and the LCOE by year. Results from this sensitivity analysis can be found in Section 8.4.4.

Figure 7.28 | Reference Case Wind Basis/Captured Revenue Sensitivity

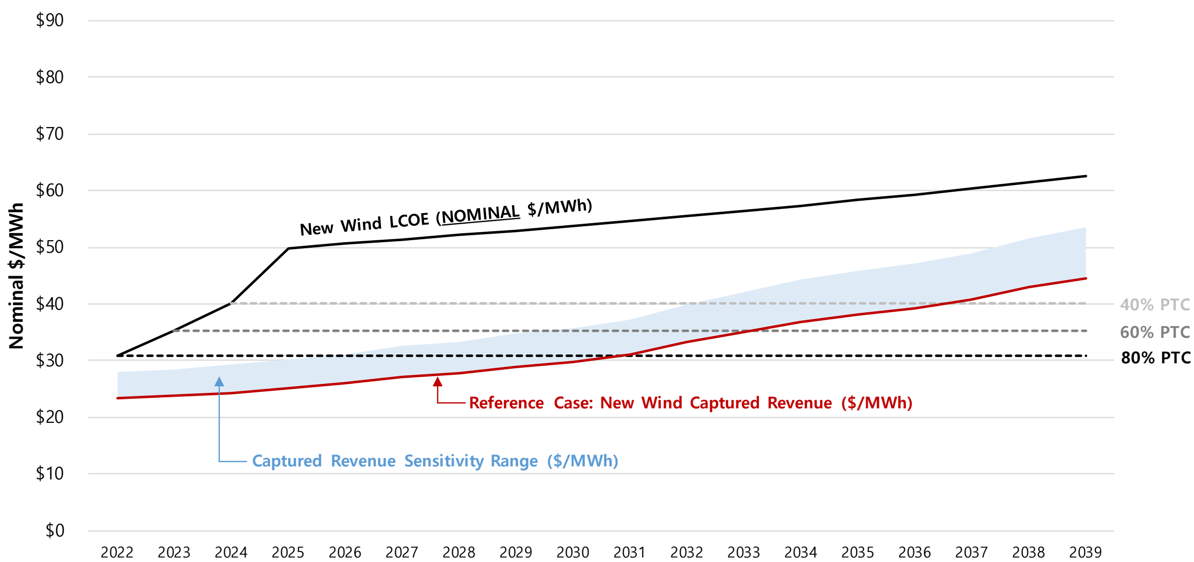
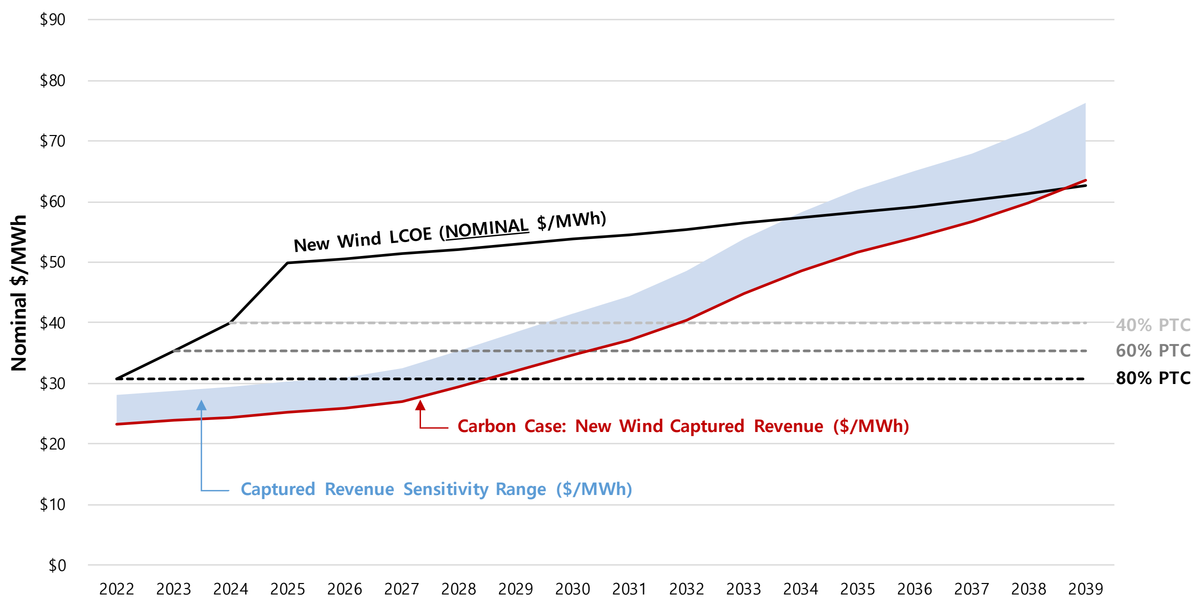


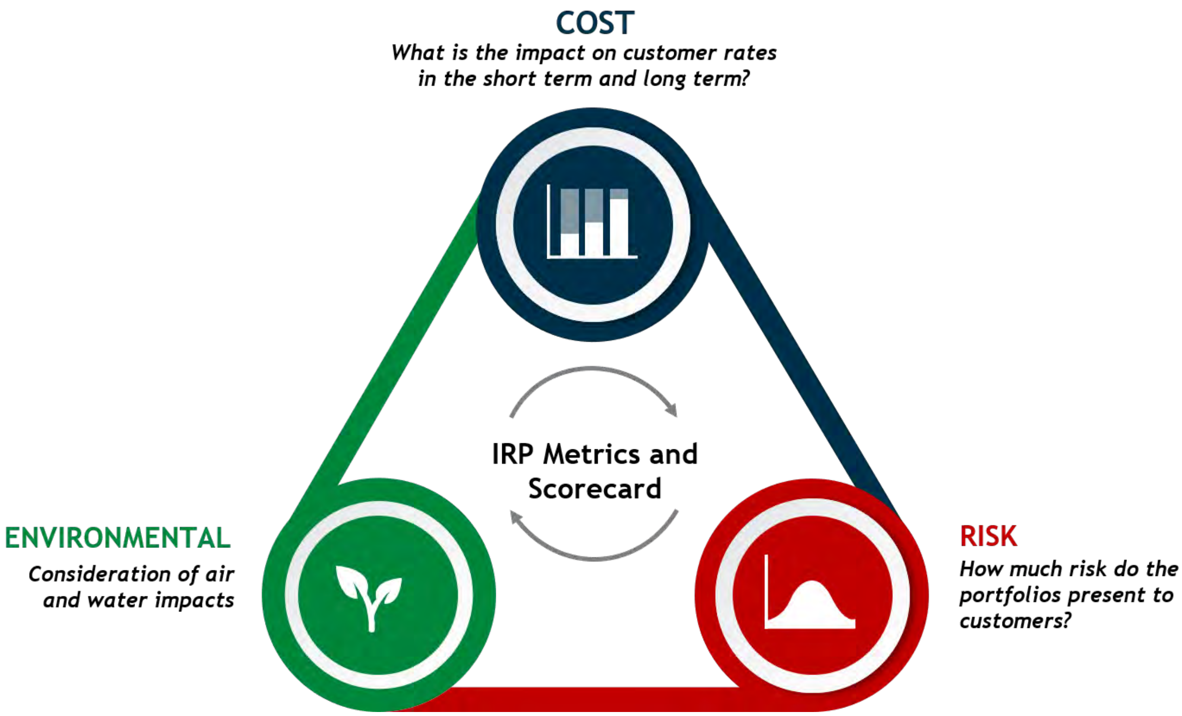
Figure 7.29 | Carbon Tax Case Wind Basis/Captured Revenue Sensitivity



7.5 Portfolio Metrics

As shown in Figure 7.30, IPL identified three primary categories of metrics for this IRP: cost, risk, and environmental. For all metrics, stochastic modeling results were used for each portfolio and scenario.

Figure 7.30 | 2019 IRP Metric Categories



7.5.1 Cost

IPL identified three primary cost metrics:

1. 20-year Present Value Revenue Requirement (PVRR)
2. Annual revenue requirement
3. Levelized $/kWh rate

PVRR is the standard portfolio metric that compares the present value cost to customers. PVRR is evaluating the incremental impact on the cost to generate and does not include transmission and distribution revenue requirement. IPL assumed that cost recovery for all approved and in-service generation does not change across portfolios or scenarios. Any change to existing depreciation schedules would be considered in a future regulatory filing, and IPL's primary objective in this IRP was to focus on the economic value of existing resources versus alternatives.

Figure 7.31 contains a table with the main components of PVRR. As described at the beginning of this section, IPL used PowerSimm for capacity expansion (PowerSimm Module #1) and hourly production cost runs (PowerSimm Module #2) and loaded that output into a financial model to calculate the revenue requirement.

Figure 7.31 | Building Blocks for Revenue Requirement

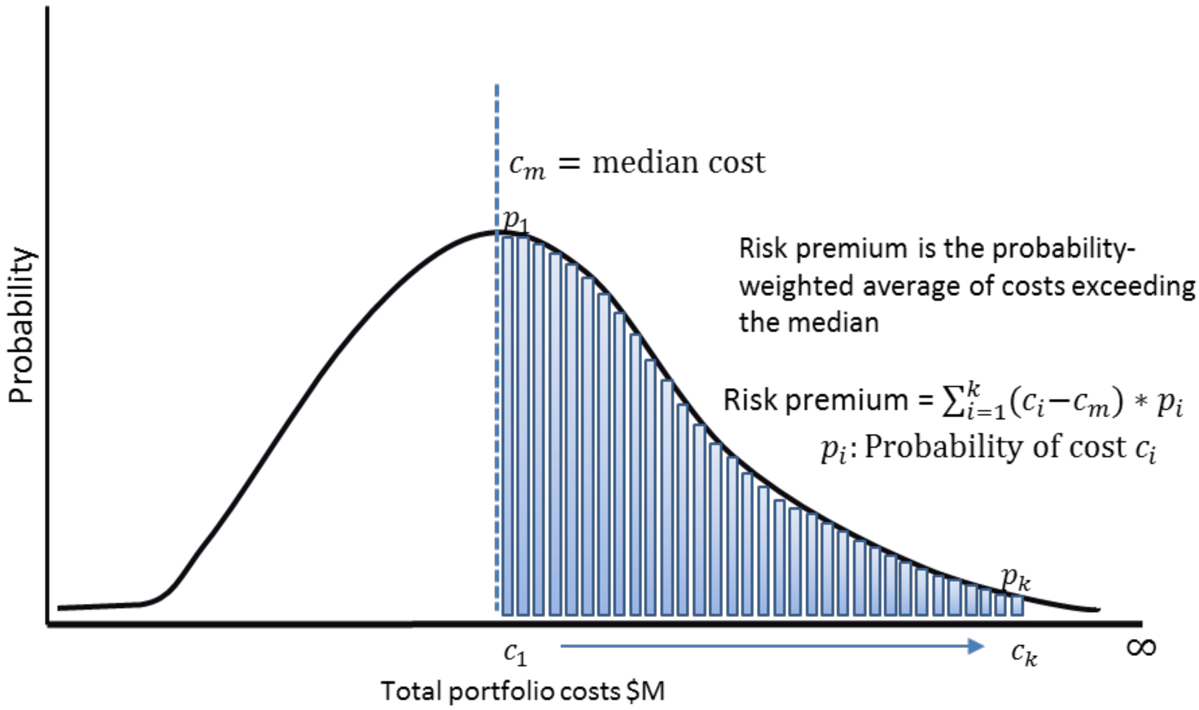
VARIABLE	DATA SOURCE	DESCRIPTION
OPERATING EXPENSES		
Energy Purchases	PowerSimm	IPL Load cost in MISO market (MW * LMP each hour)
Fuel	PowerSimm	Coal, natural gas, oil, and battery charging cost
Variable O&M	PowerSimm	Variable O&M for each technology - dependent on run time in each scenario
Fixed O&M	PowerSimm	Fixed O&M - constant across iterations and scenarios for specific portfolio
Emissions	PowerSimm	NOX, SO2, and CO2 cost - specific for each scenario
RECOVERY OF AND RETURN ON NEW CAPITAL		
Book Depreciation	Financial Model	Recovery of new capital spent; tied to capacity expansion results
Return on Rate Base	Financial Model	Rate Base * Rate of Return, grossed up for taxes
Property Taxes	Financial Model	Incremental property taxes for new capital
MARKET REVENUES		
MISO Energy Revenue	PowerSimm	MW * basis adjusted-LMP each hour for each resource, varies by scenario
Net Capacity Revenue	PowerSimm	Annual capacity length * capacity price
CALCULATION: REVENUE REQUIREMENT		
Expenses + Recovery of New Capital - Market Revenues = Revenue Requirement	PowerSimm/ Financial Model	Incremental revenue requirement for portfolio PVRR = Net present value of annual revenue requirement discounted @ IPL cost of capital

7.5.2 Risk

Not only does PowerSimm aid in the selection of the optimal energy portfolio over a wide range of future conditions, PowerSimm also identifies the risk associated with each energy portfolio option, quantifying this as the "risk premium." The risk premium is defined as the probability-weighted average of costs above the median. This concept is illustrated below in Figure 7.32.

Since different energy portfolios have different simulated cost distributions, the risk premium will be larger for wider cost distributions, or riskier portfolios, and smaller for narrower cost distributions, or less risky portfolios. After calculating the risk premium, IPL added the risk premium variable to the expected value, creating a risk-adjusted PVRR, in order to put all portfolios on the same playing field.

Figure 7.32 | Risk Premium



Risk vs Uncertainty

There are many definitions used for risk and uncertainty, but the following description from Dr. Jonathan Mun from *Modeling Risk* provides a concise summary that is relevant to how IPL is considering risk in this IRP:

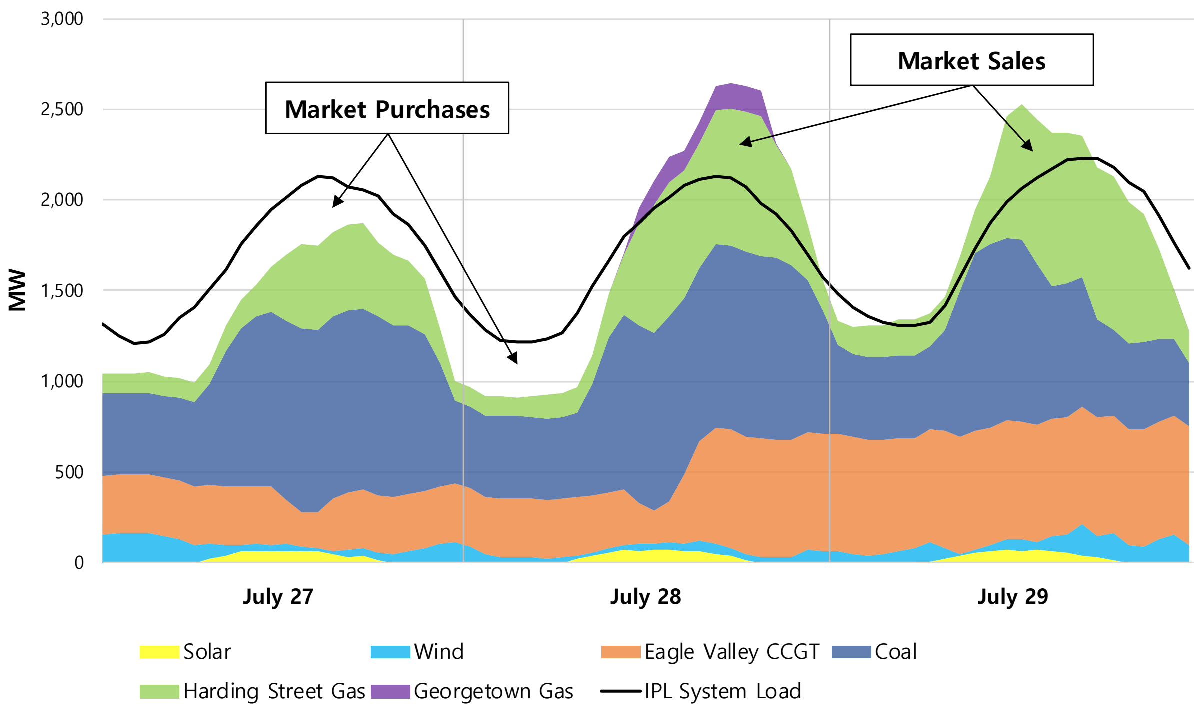
> The concepts of risk and uncertainty are related but different. Uncertainty involves variables that are unknown and changing, but its uncertainty will become known and resolved through the passage of time, events, and action. Risk is something one bears and is the outcome of uncertainty. Sometimes, risk may remain constant while uncertainty increases over time.[30]

In the context of the IPL modeling framework in the IRP, uncertainty in future natural gas prices, power prices, coal prices, weather, and load are simulated in a stochastic framework across scenarios with deterministic drivers. These variables are "unknown and changing", but we will know what the actual values are as time progresses. By simulating a range of uncertainty going forward, IPL can quantify the actual impact across many possible futures, not just a base case or future of our liking. Risk in the IRP is defined as the actual cost to customers in the face of uncertainty in these key variables. IPL has chosen the risk premium metric as the way to compare all portfolios on an equal footing that incorporates risk into the decision-making process.

[30] Mun, J. (2006). Modeling Risk: Applying Monte Carlo Simulation, Real Options Analysis, Forecasting, and Optimization Techniques. Germany: Wiley.

The second risk metric IPL considered was a market interaction variable. This metric is based on annual market purchases and sales for each portfolio across the different scenarios. Due to hourly fluctuations in load, wholesale market prices, and unit availability, IPL can be net long or short energy throughout the year, which as a MISO market participant is characterized as market purchases and market sales. Figure 7.33 provides an example from three days in July 2019 using IPL load and generation. Across these three days, IPL was both long and short in hours as load moved, and units were committed and dispatched.

Figure 7.33 | Market Purchases and Sales Fluctuate Hourly



IPL included market interaction as a risk metric because heavy reliance on the market could introduce market price and volume risk going forward if IPL does not have a balanced portfolio. Overreliance on market purchases to serve load or overreliance on market energy sales to create value equally present risk to customers.

7.5.3 Environmental

IPL included the following environmental metrics in the 2019 IRP:

Air Emissions

- Annual CO_2 Emissions
- Annual CO_2 Intensity (tons/MWh)
- Annual SO_2 Emissions
- Annual NOx Emissions

For all air emissions, forecasted data is based on the economic dispatch of existing and new thermal units in PowerSimm across the scenarios. All metrics are based on the stochastic mean air emission output data for each portfolio and scenario.

Non-Air Emissions (Water):

IPL estimated water intake and discharge at Petersburg for the portfolios. Precise forecasts for water usage at the plant is difficult because there is not a consistent rate that can be tied to unit MWh production. For the estimate, the IPL environmental team developed a high-level estimate for the change in water usage at Petersburg for the retirement dates established in Portfolios 1-5.

Section 8: Results

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8.1 Executive Summary

170 IAC 4-7-4(8)

The modeling framework in the 2019 IRP produced a set of candidate portfolios optimized stochastically over a wide range of simulated futures. Each candidate portfolio was run through stochastic production cost modeling runs for each scenario, further expanding the range of uncertainty considered. This methodology allowed IPL to see how the portfolios performed in multiple scenarios, which provides insight into the risk, benefits, and overall robustness of portfolios across time and across a range of market conditions.

To ensure that the optimal level of DSM is targeted, IPL directly tested increasing DSM decrements or bundles included in the list of candidate portfolios. This was done until the PVRR increased as an incremental decrement was added. The result was fifteen (15) distinct candidate resource portfolios optimized with increasing levels of DSM. Each portfolio was locked and then run through each scenario stochastically, yielding seventy-five (75) production cost model results simulated across a range of probabilistic futures. Figure 8.1 contains a summary of the modeling structure and the naming convention that will be used throughout this section.

The technical appendix includes confidential information, most of which is in electronic format, and is available as part of the Confidential IRP.

Figure 8.1 | Portfolio Naming Convention

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

8.2 Capacity Expansion Results

8.2.1 Candidate Resource Portfolios

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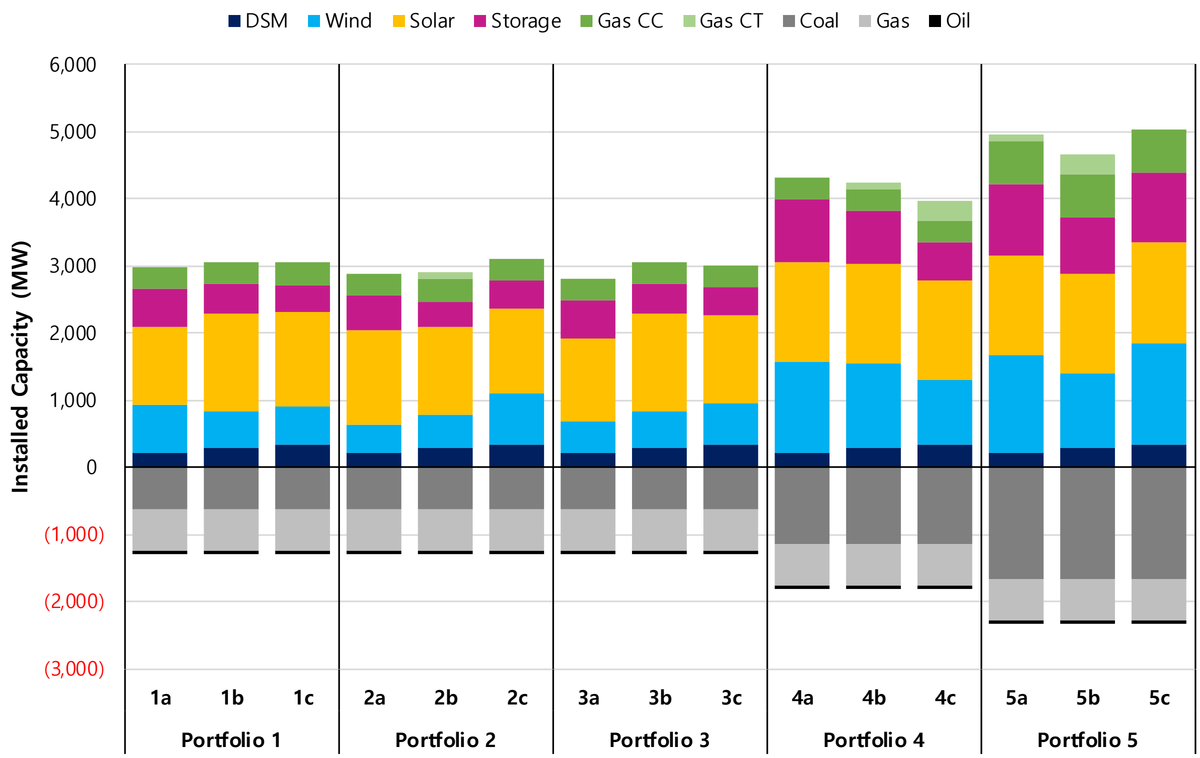
Several portfolio changes are consistent across all portfolios:

- Harding Street Retirements:
  - Harding Street Oil 1-2, 40 MW, 2024
  - Harding Street Gas ST5: 100 MW, 2030
  - Harding Street Gas ST6: 98 MW, 2030
  - Harding Street Gas ST7: 420 MW, 2034
- A 1x1, 325 MW (ICAP) combined cycle was added to all portfolios in 2034 to provide firm, dispatchable capacity on the IPL 138 kV transmission system after the Harding Street steam units retire. IPL has not performed a detailed engineering or reliability study to determine if a combined cycle is the required solution. This combined cycle addition is a placeholder to represent the firm capacity needed for the IPL distribution system, a need that is currently fulfilled by a combination of natural gas units (Eagle Valley, Harding Street, Georgetown). The cost and dispatch were consistent across all portfolios, so there is no difference in PVRR attributed to the addition of this resource. The actual firm capacity need and solution will likely change through time and could be a different technology.
- Load contribution to peak and energy from electric vehicles is the same across all portfolios.
- Distributed solar was modeled as a fixed supply-side resource and was the same across all portfolios and scenarios.

Figure 8.2 contains a summary of the installed capacity changes through 2039 for all 15 candidate resource portfolios.

Figure 8.2 | Cumulative Installed Capacity Changes through 2039 (ICAP MW)



Portfolio 1 Capacity Expansion Results

Portfolio 1 is based on age-based retirement dates for all Petersburg units. No resource additions are required in this portfolio until 2033. DSM decrements were set up starting in 2021 and had to be "in-service" through the end of the study period, so additional DSM capacity was the only resource that was added before 2033 in Portfolio 1. Any incremental capacity length created from new DSM led to capacity sales at the MISO market price in the model.

Retirements in all Portfolio 1 runs were as follows:

- Petersburg Unit 1: 220 MW, 2033
- Petersburg Unit 2: 410 MW, 2035
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.3 contains annual installed capacity additions (ICAP MW) for Portfolio 1a, 1b, and 1c and Figure 8.4 shows cumulative capacity changes (additions and retirements) through the end of the study period (2039).

Figure 8.3 | Portfolio 1 Installed Capacity Additions (MW)

Portfolio 1a: Includes Decrements 1-3

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

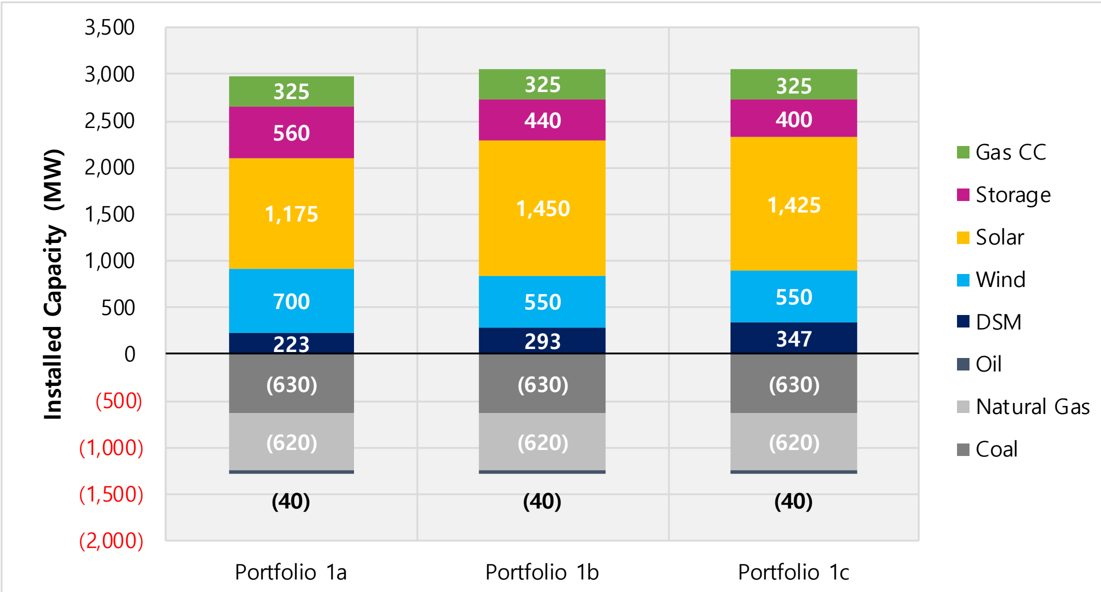
Portfolio 1b: Includes Decrements 1-4

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

Portfolio 1c: Includes Decrements 1-5

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

Figure 8.4 | Portfolio 1 Cumulative Installed Capacity Changes through 2039 (MW)



Portfolio 2 Capacity Expansion Results

Portfolio 2 included early retirement of Petersburg Unit 1 in 2021. Even with the retirement of Pete 1, no capacity additions are needed until 2031 in this portfolio and DSM was the only resource added before 2031.

Retirements in all Portfolio 2 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2035
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.5 contains annual installed capacity additions (ICAP MW) for Portfolio 2a, 2b, and 2c and Figure 8.6 shows cumulative capacity changes (additions and retirements) through the end of the study period (2039).

Figure 8.5 | Portfolio 2 Installed Capacity Additions (MW)

Portfolio 2a: Includes Decrements 1-3

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

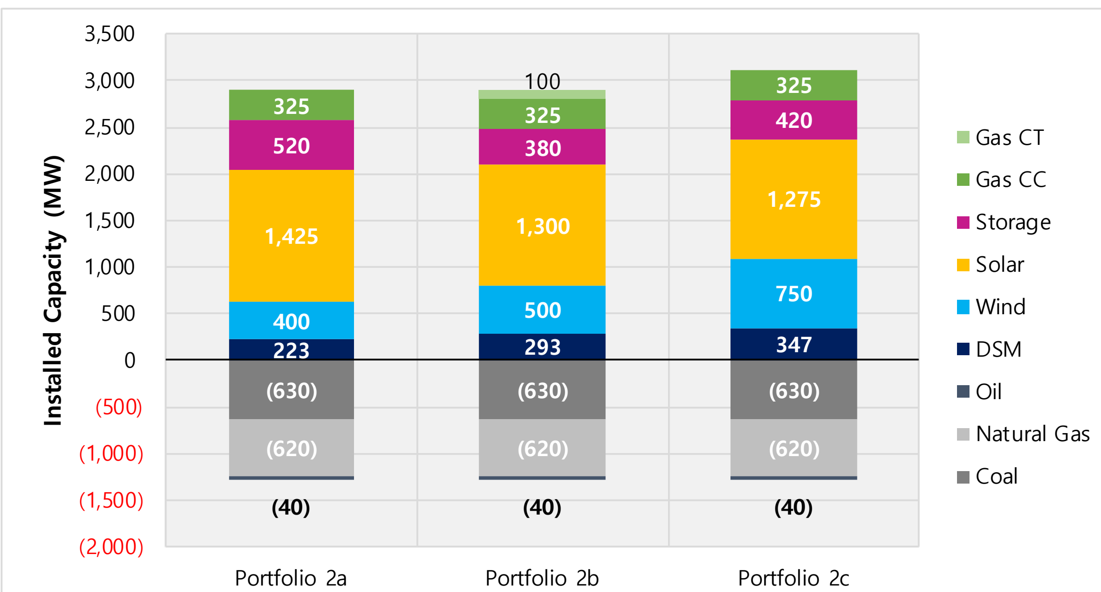
Portfolio 2b: Includes Decrements 1-4

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

Portfolio 2c: Includes Decrements 1-5

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

Figure 8.6 | Portfolio 2 Cumulative Installed Capacity Changes through 2039 (ICAP MW)



Portfolio 3 Capacity Expansion Results

Portfolio 3 included the retirement of Pete 1 in 2021 and Pete 2 in 2023. Before new capacity additions, this results in a capacity shortfall starting in 2023. Even without a capacity need until 2023, DSM was made available starting in 2021 and wind in 2022.

Retirements in all Portfolio 3 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2023
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.7 | Portfolio 3 Installed Capacity Additions (MW)

Portfolio 3a: Includes DSM Decrements 1-3

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

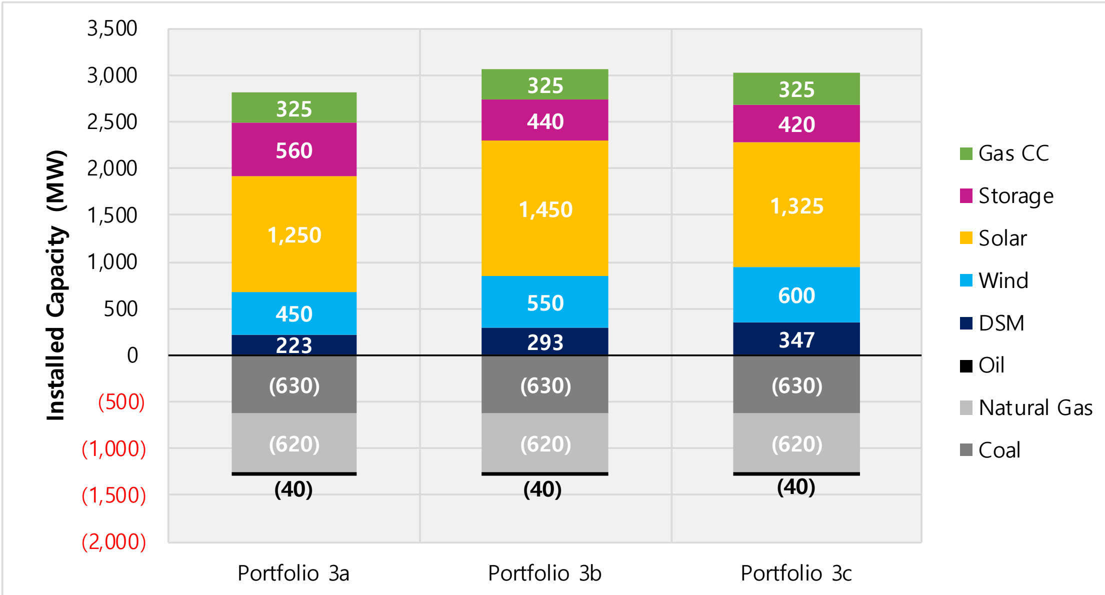
Portfolio 3b: Includes DSM Decrements 1-4

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

Portfolio 3c: Includes DSM Decrements 1-5

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

Figure 8.8 | Portfolio 3 Cumulative Installed Capacity Changes through 2039 (MW)



Portfolio 4 Capacity Expansion Results

Portfolio 4 included the retirement of Pete 1 in 2021, Pete 2 in 2023, and Pete 3 in 2026. This results in a capacity shortfall of approximately 258 MW in 2023, 900 MW in 2026. Capacity expansion was run to allow the model to optimally fill that capacity shortfall.

Retirements in all Portfolio 4 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2023
- Petersburg Unit 3: 520 MW, 2026
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.9 | Portfolio 4 Installed Capacity Additions (MW)

Portfolio 4a: Includes Decrements 1-3

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

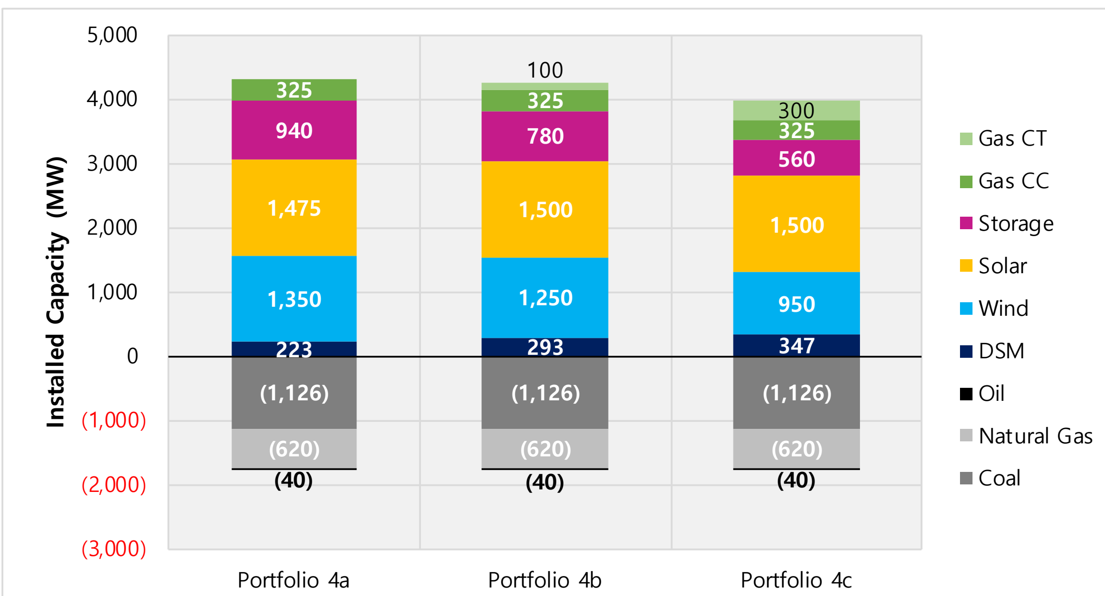
Portfolio 4b: Includes Decrements 1-4

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

Portfolio 4c: Includes Decrements 1-5

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

Figure 8.10 | Portfolio 4 Cumulative Installed Capacity Changes through 2039 (MW)



Portfolio 5 Capacity Expansion Results

Portfolio 4 included the retirement of Pete 1 in 2021, Pete 2 in 2023, Pete 3 in 2026, and Pete 4 in 2030. The retirement of these units leaves IPL with a sizeable capacity shortfall with retirements:

- Capacity Shortfall before any new resources:
  - o 2023: 258 MW UCAP
  - o 2027: 900 MW UCAP
  - o 2031: 1,700 MW UCAP

Retirements in all Portfolio 5 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2023
- Petersburg Unit 3: 520 MW, 2026
- Petersburg Unit 4: 520 MW, 2030
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.11 | Portfolio 5 Installed Capacity Additions (MW)

Portfolio 5a: Includes Decrements 1-3

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

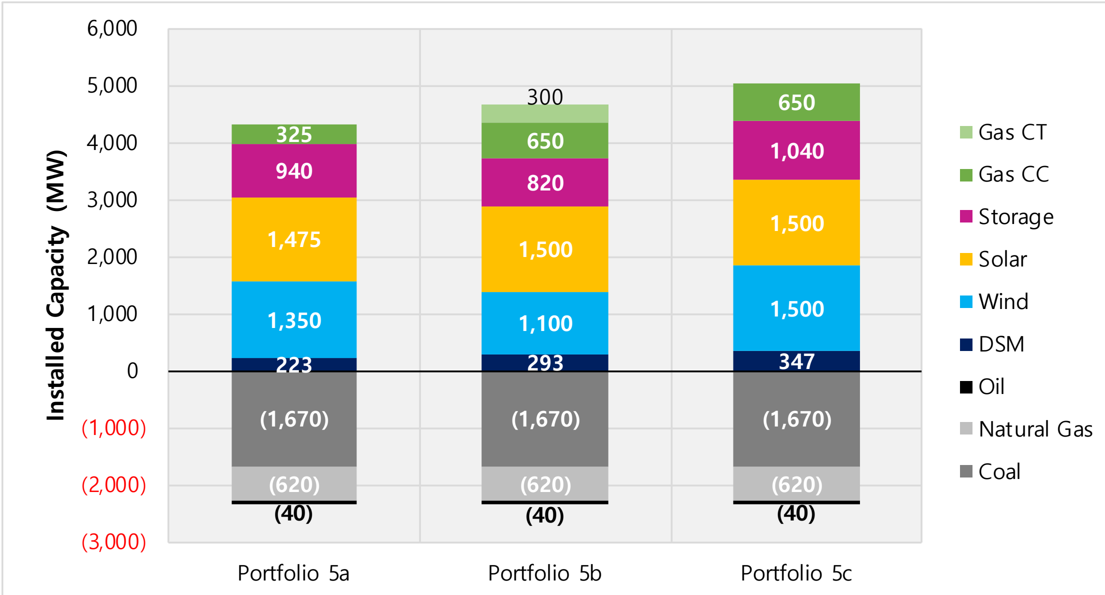
Portfolio 5b: Includes Decrements 1-4

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

Portfolio 5c: Includes Decrements 1-5

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

Figure 8.12 | Portfolio 5 Cumulative Installed Capacity Changes through 2039 (MW)



IPL produced Annual Energy Charts (Attachment 8.1) and Load Resource Balance charts (Attachment 8.2) for all portfolios and scenarios. These show how the model selected portfolios that could meet IPL's energy requirements, as well as IPL capacity requirements to reliably serve demand throughout the study period.

Figure 8.13 contains cumulative CAPEX spending (plant entering service) for new and existing assets for each portfolio. The timing of coal unit retirements and need for replacement capacity is the largest driver of differences between portfolios. Portfolio 1 would require approximately $630 million in capital expenditures at Petersburg for environmental and maintenance capital through 2030, and most of the capital is required 2031 – 2039 with the retirement of Pete 1, Pete 2, and the Harding Street steam units. Portfolio 5 requires the largest capital expenditure, with $3-4 billion required by 2030 to replace the capacity from Petersburg Units 1-4.

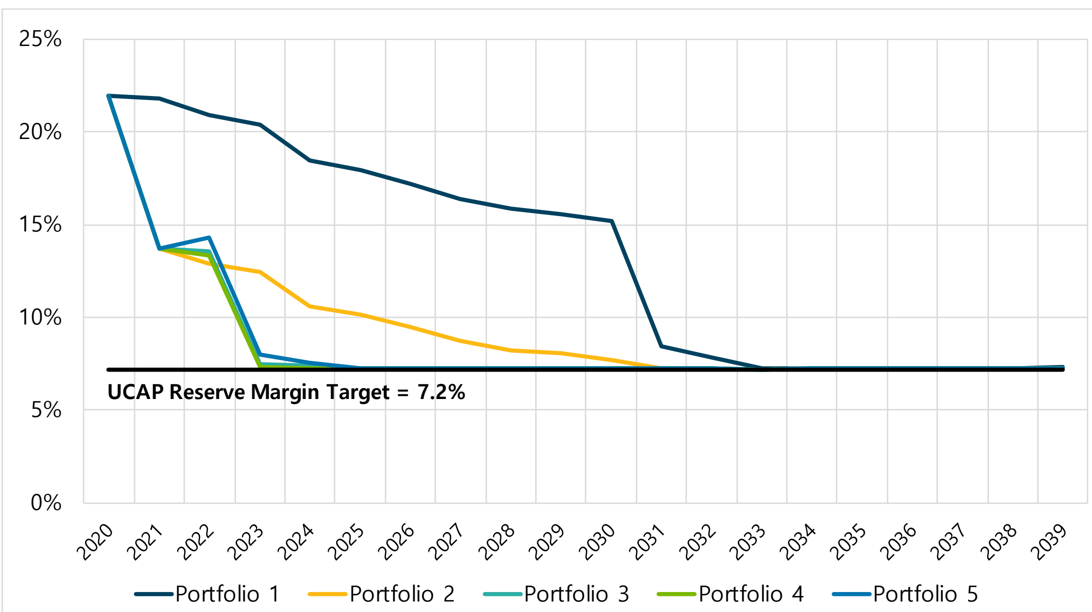
Figure 8.13 | Cumulative CAPEX Spend by Portfolio (Nominal $Billion)

		2025	2030	2035	2039
Portfolio 1	1a	$0.4	$0.6	$2.7	$4.4
	1b	$0.4	$0.6	$2.8	$4.3
	1c	$0.4	$0.6	$2.9	$4.2
Portfolio 2	2a	$0.4	$0.5	$2.4	$3.9

	2b	$0.4	$0.5	$2.6	$3.9
	2c	$0.4	$0.5	$2.9	$4.3
Portfolio 3	3a	$1.0	$1.3	$2.5	$3.3
	3b	$0.9	$1.3	$2.6	$3.7
	3c	$0.9	$1.3	$2.5	$3.7
Portfolio 4	4a	$1.2	$2.7	$4.1	$5.2
	4b	$1.1	$2.6	$4.0	$5.1
	4c	$1.0	$2.1	$3.7	$4.5
Portfolio 5	5a	$1.3	$3.6	$4.9	$5.8
	5b	$1.0	$2.9	$4.1	$5.3
	5c	$1.1	$3.5	$5.1	$5.7

Figure 8.14 shows the annual reserve margin target for each portfolio. There are small variations in reserve margins for the portfolios optimized with Decrements 1-4 and 1-5, but the changes are negligible and not shown in this figure.

Figure 8.14 | Annual Reserve Margin by Portfolio (UCAP Reserve Margin %)



8.3 Scenarios and Metrics

170 IAC 4-7-8(b)

Capacity expansion portfolios were locked and simulated stochastically through all scenarios. This allowed IPL to see how portfolios performed across many futures, not just the set of assumptions used to optimize the portfolio. Frequently stochastic modeling is used only for the "base case" or "reference case" scenario. While this analysis can be valuable, modeling each scenario stochastically effectively widens the range of uncertainty, which is particularly valuable in capturing fundamental or systemic changes to fundamental forecasts.

Figure 8.15 contains PVRR results for all seventy-five model runs. PVRRs are based on mean (average) PowerSimm model results, and portfolio builds are fixed across all scenarios. Color gradients reflect the ranking of portfolios within each specific scenario, with the lowest PVRR in white and the highest portfolio shaded the darkest color.

Figure 8.15 | Expected Value 20-Year PVRR ($MM)

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

8.3.1 Reference Case

170 IAC 4-7-4(25)

The Reference Case includes IPL's view of the future based on the current trajectory. This means commodity prices for power and gas reflect the base case forecasts. More importantly, the Reference Case does not include any carbon tax. Figure 8.16 shows the 20-year PVRR for each portfolio from the Reference Case.

Figure 8.16 | Reference Case 20-Year PVRR by Portfolio ($B)

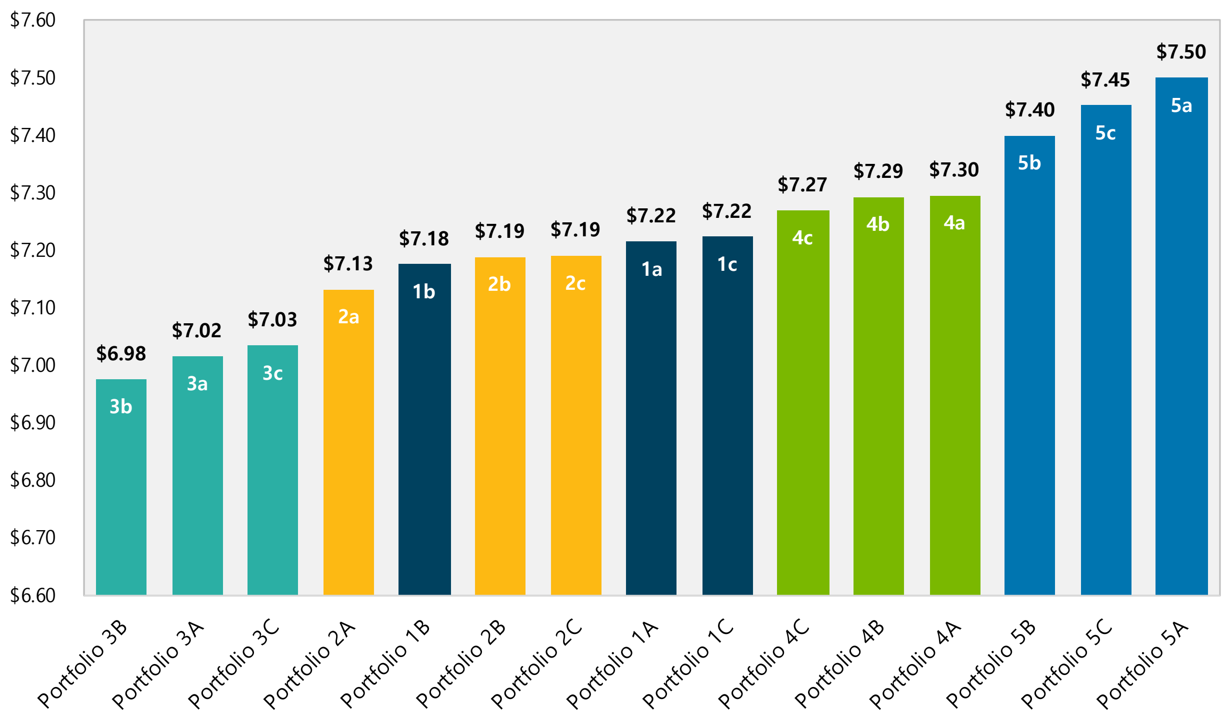
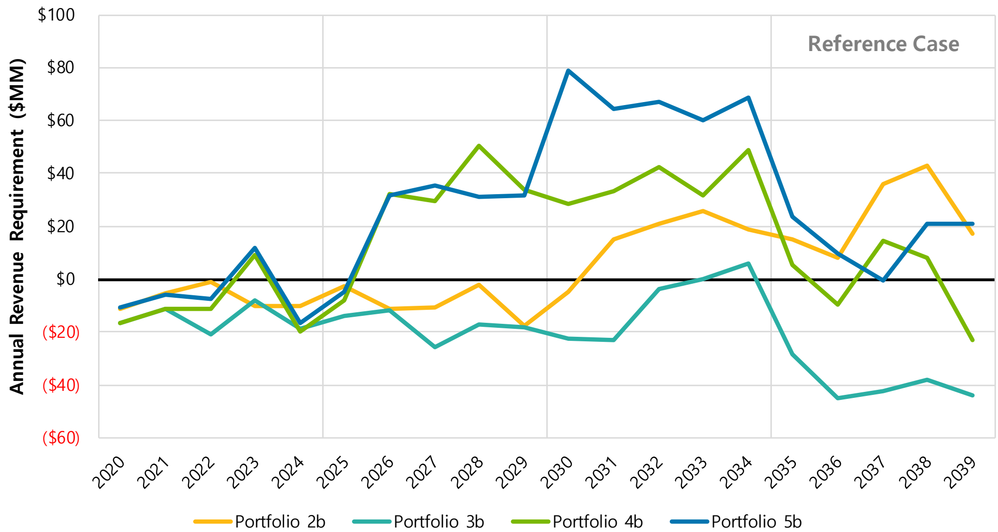


Figure 8.17 shows annual revenue requirement differences from Portfolio 1b. There are only slight differences between Portfolios a-c when looking at annual portfolio costs, so only Portfolio 2b-5b are shown. The annual revenue requirement for Portfolio 3 remains at or below Portfolio 1 for almost every year of the study, even when capacity additions are required by 2023. This is primarily because new capital spent for replacement capacity is generally offset by capex and O&M savings at Petersburg 1 and 2. Portfolios 4 and 5 require significant capital expenditures to replace all four Petersburg units, and that drives a higher revenue requirement in the 2026 – 2033 time frame.

Figure 8.17 | Annual Difference from Portfolio 1b (Nominal $MM)



8.3.2 Scenario A: Carbon Tax

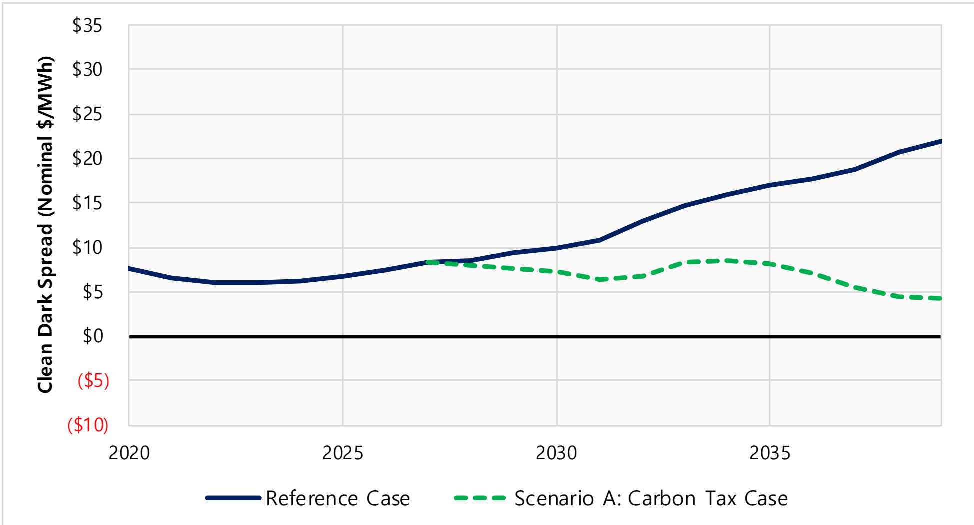
170 IAC 4-7-4(26)

Scenario A used forward curves that incorporated a federal carbon tax beginning in 2028. Portfolio costs increased for all portfolios in this scenario, as the Carbon Tax Case has higher wholesale power price and natural gas prices compared to the Reference Case when the carbon tax is implemented.

The carbon tax is a significant driver of changes in portfolio cost and performance. Portfolio 5, which aggressively transitions the portfolio away from coal by 2030, moves into the top five for PVRR ranking in this scenario, and Portfolios 1 and 2 are among the highest cost portfolios.

The carbon tax impacts portfolios in two key ways. First, clean dark spreads, which are indicative of the marginal economic value of coal units relative to other resources in MISO, shrink as the cost of carbon is added to the variable cost of production of coal. The impact on PVRR is that net margin (energy revenue less fuel, variable O&M, and emission costs) for existing coal assets decreases significantly (30-50%) in the Carbon Tax Case compared to the Reference Case. Figure 8.18 shows the comparison of 7x24 dark spreads in the Reference Case and Carbon Tax Case.

Figure 8.18 | 7x24 Clean Dark Spreads (Nominal $/MWh)



Second, because the grid is not fully decarbonized when the carbon tax is implemented and coal and natural gas units are the marginal price-setting units, wholesale power prices increase in the presence of a carbon tax. Renewable resources benefit from this as their production (MWh) are relatively fixed, but their market revenues will increase with higher prices, all other things equal. Figure 8.19 shows captured energy revenue, which is the generation-weighted average LMP received in the energy market, for the Reference Case and the Carbon Tax Case (Scenario A). The increase in energy revenue in the carbon tax case directly provides benefit to the PVRR in case where new wind and solar is built.

Figure 8.19 | Wind and Solar Captured Revenue, Reference Case vs Carbon Tax Case

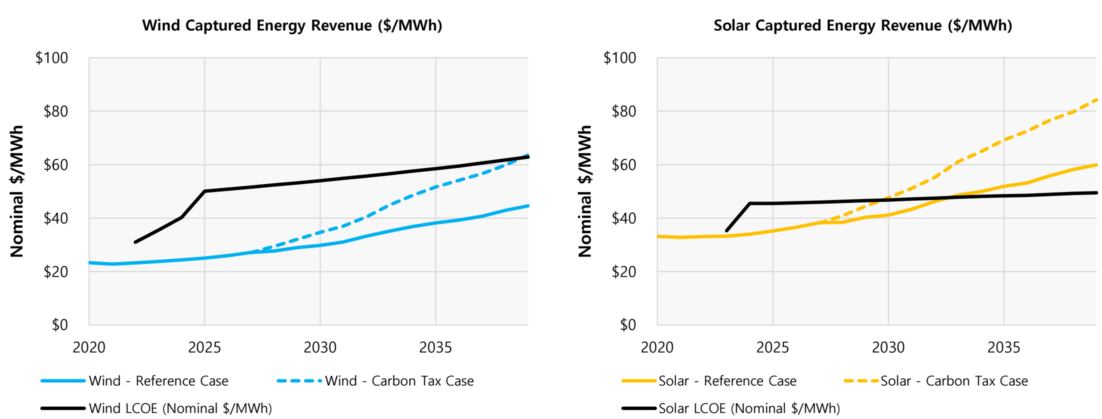


Figure 8.20 shows 20-year PVRR results for all portfolios in Scenario A. Portfolio 3b is the lowest cost portfolio and represents about a $300 million savings from Portfolio 1. Portfolios 5b and 5c, which add

about 2,000 MW of wind and solar through 2030 to replace capacity from coal retirements, benefits from the carbon tax and are in the top 5 lowest cost portfolios in this scenario.

Figure 8.20 | Scenario A PVRR Summary ($Billion)

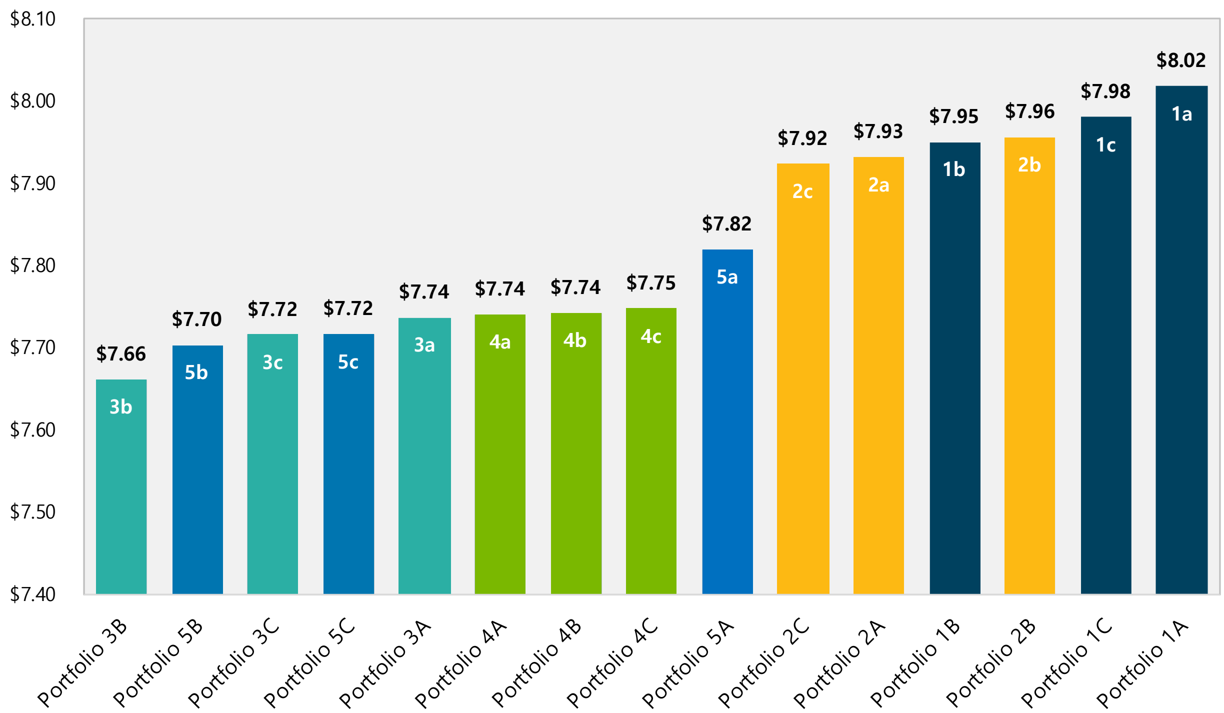
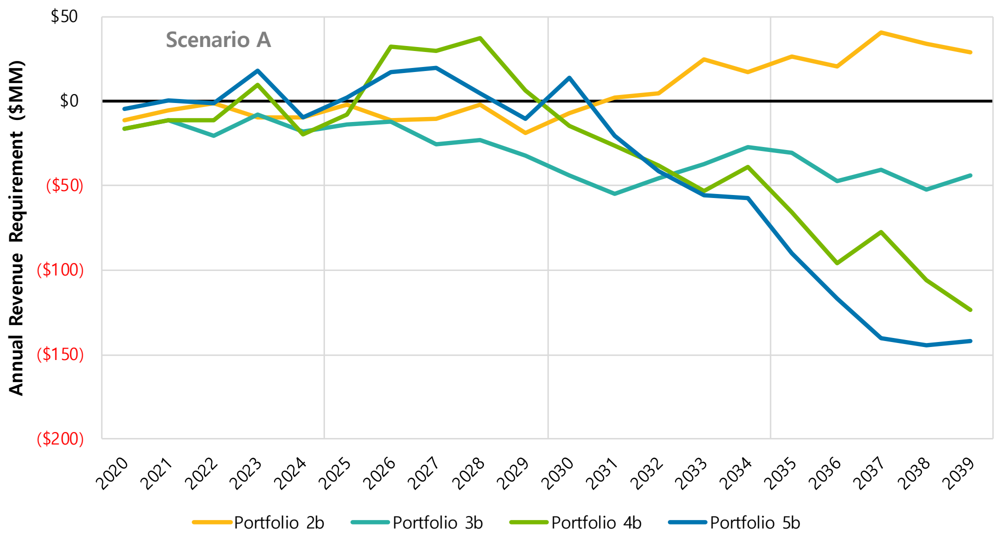


Figure 8.21 shows the annual revenue difference for Portfolios 2b-5b from Portfolio 1b. The revenue requirement increases for Portfolio 5 in the middle of the study when new capacity is added, but the large renewable build benefits from the carbon tax environment and produces annual portfolio cost savings of approximately $200 million (nominal) by the end of the study.

Figure 8.21 | Annual Difference from Portfolio 1b (Nominal $MM)



8.3.3 Scenario B: Carbon Tax + High Gas

170 IAC 4-7-4(26)

Scenario B includes a carbon tax in 2028 and stresses natural gas prices higher (+30-40% per year) starting in the first year of the study. This scenario provides a useful look at whether high natural gas prices, which improve coal net margins, are enough to offset the dispatch cost a carbon tax adds to coal units.

Figure 8.22 contains PVRR results for Scenario B. The results from this scenario show that high gas prices increase the relative cost of Portfolio 5 to other portfolios as the opportunity cost of higher dark spreads 2028 – 2035 outweighs the additional renewable captured revenue in this scenario. Portfolio 1 and 2 remain the highest cost portfolios in this scenario, which indicate that while higher dark spreads in the short term are higher, the long-term impacts of a carbon tax negatively affect a coal-heavy portfolio. Portfolio 3 remains the lowest cost portfolio, showing that portfolio diversification benefits of a mix of resources and locking in low renewable costs early in the study provide long-term benefits in a scenario with a carbon tax and high natural gas prices. Figure 8.23 contains the annual revenue requirement difference from Portfolio 1b for Portfolios 2b – 5b.

Figure 8.24 shows wind and solar captured revenue in $/MWh for the Reference Case and Scenario B. Figure 8.25 shows that dark spreads are higher in Scenario B compared to the Reference Case through 2035, when the carbon tax impact outweighs the benefit coal units see from higher natural gas prices.

Figure 8.22 | Scenario B PVRR Results ($Billion)

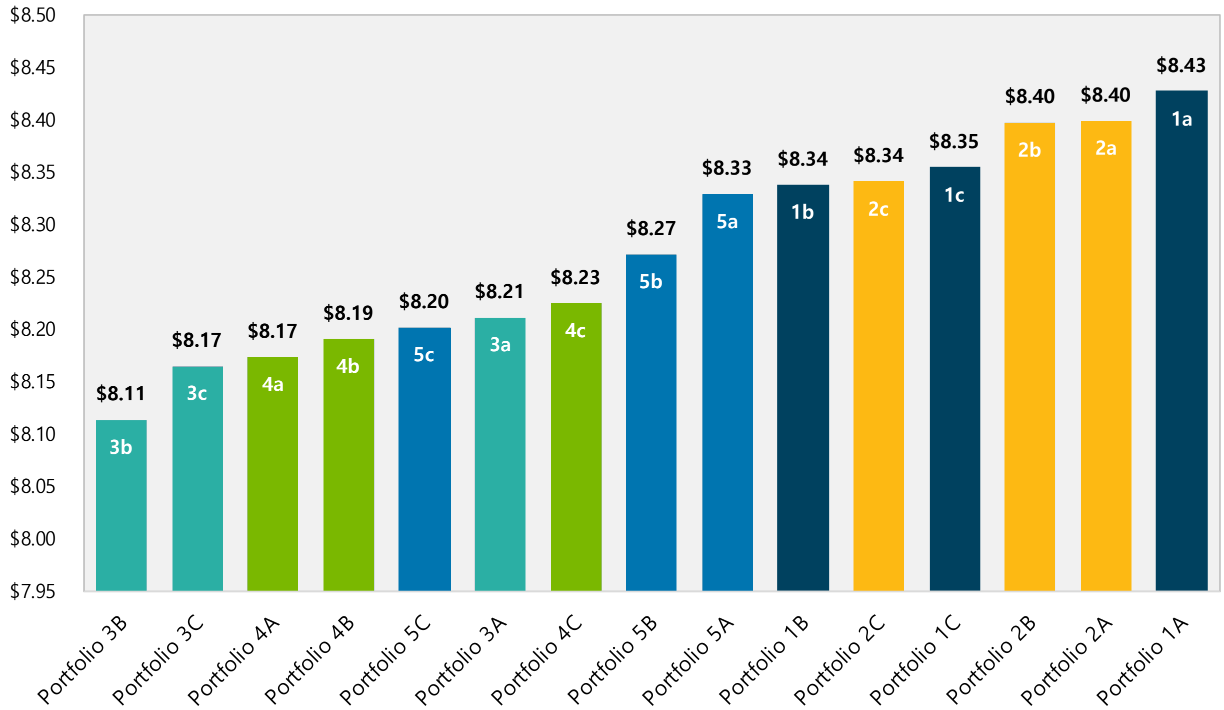


Figure 8.23 | Annual Difference from Portfolio 1b (Nominal $MM)

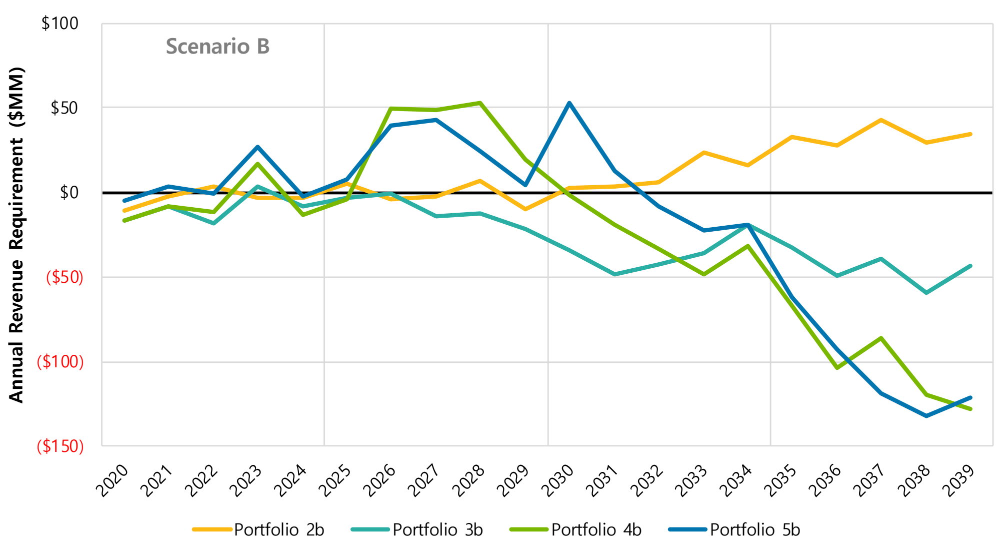


Figure 8.24 | Wind and Solar Captured Revenue, Reference Case vs Scenario B

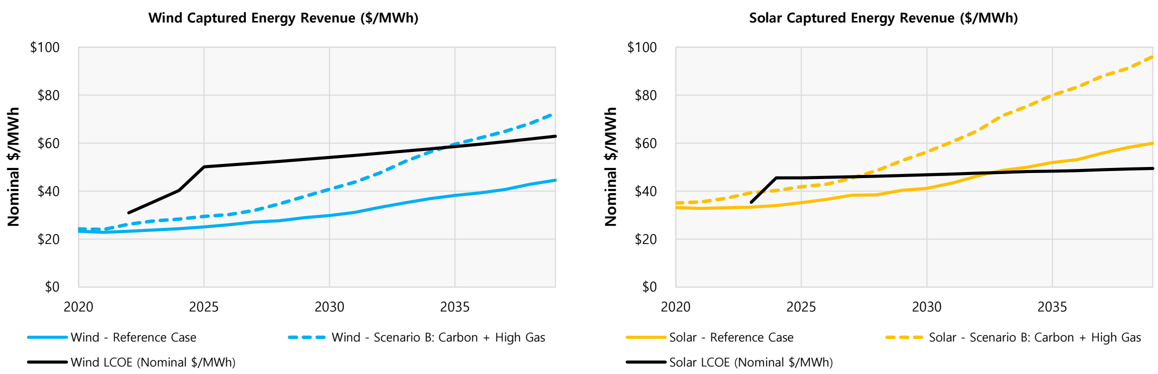
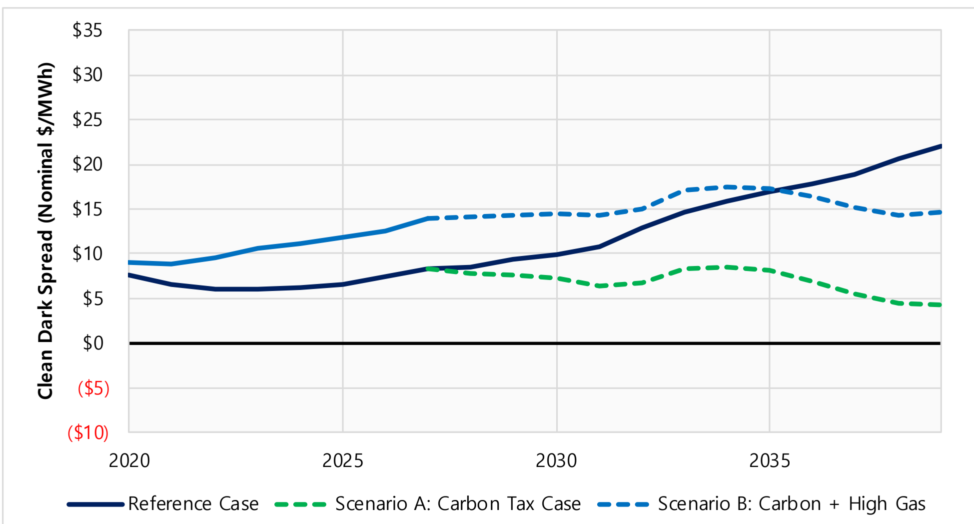


Figure 8.25 | 7x24 Clean Dark Spreads ($Nominal $/MWh)



8.3.4 Scenario C: Carbon Tax + Low Gas + Low Load

170 IAC 4-7-4(26)

Scenario C includes a carbon tax in 2028 and stresses natural gas prices lower (+30-40% per year) starting in the first year of the study. This scenario also includes a low IPL load forecast, which lowers the peak and energy load forecasts. IPL assumed that any excess capacity was sold at the MISO bilateral price estimate.

Figure 8.26 contains PVRR results for Scenario C. The combination of low load, low natural gas prices, and a carbon tax negatively impacts portfolios with coal generation and generally improves the economics of portfolios that contain a balance of natural gas and renewables. Portfolio 5b, which included a fourth DSM bundle and added a 1x1 CCGT in 2026 was the lowest cost portfolio in this scenario, followed by Portfolios 3a-3c. Figure 8.27 contains annual 7x24 clean dark spreads and shows that the combination of low natural gas prices and a carbon tax significantly reduce the economics of any coal in the candidate portfolios.

Figure 8.26 | Scenario C PVRR Summary ($Billion)

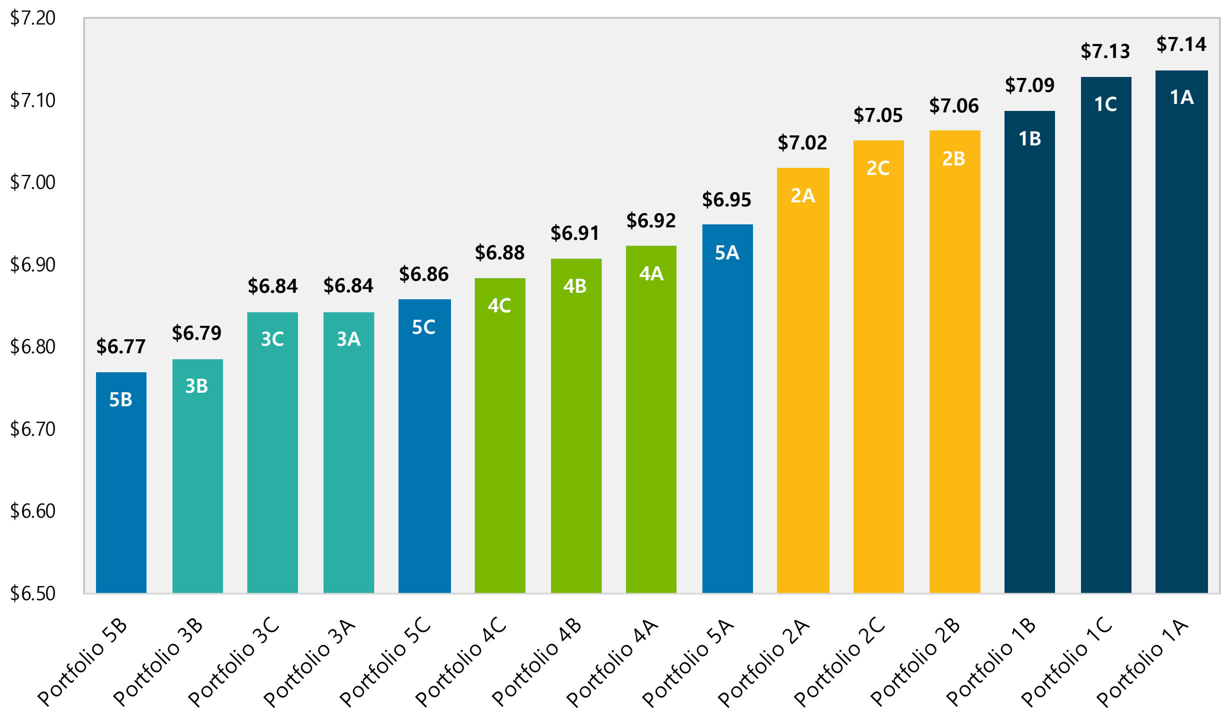
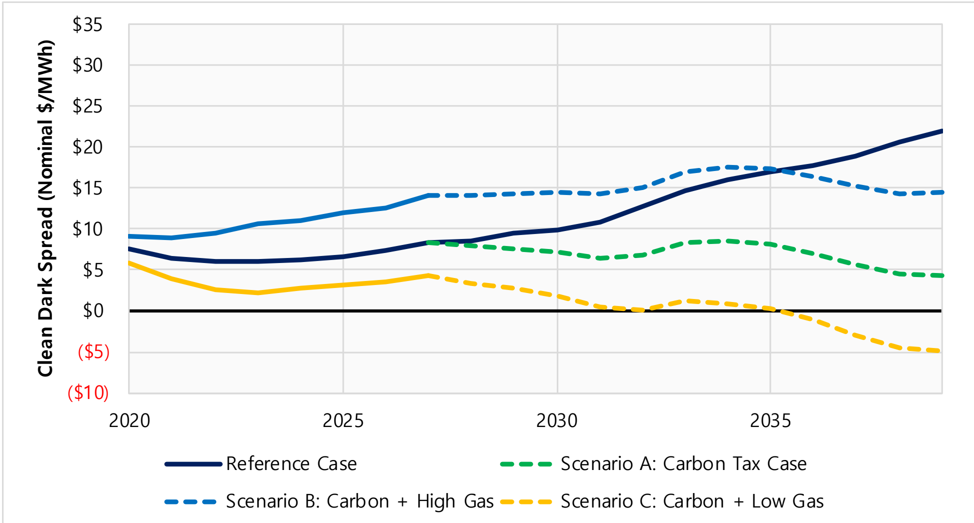


Figure 8.27 | 7x24 Clean Dark Spreads (Nominal $/MWh)



8.3.5 Scenario D: No Carbon Tax + High Gas + High Load

170 IAC 4-7-4(26)

Scenario D represents an increase of 30-40% per year in natural gas prices relative to the Reference Case but does not contain a federal carbon tax. This scenario also includes a high load forecast, which includes higher peak and energy forecasts. New build and retirement decisions were fixed, so any incremental capacity shortfall was covered with capacity market purchases when needed.

This scenario was designed to represent a bookend scenario to evaluate a best-case scenario for the future economics of IPL's coal units. Figure 8.28 contains summary PVRR data for Scenario D. While the cost gap between Portfolios 1 and 3 closes in this scenario, Portfolio 3 remains the lowest cost portfolio as it benefits from a diverse portfolio and retains some coal to hedge against high gas prices. Overall, it highlights the inability of Pete 1 and 2 to earn enough energy and capacity margin to cover operating costs over the remaining life of the assets. Figure 8.29 contains the annual revenue requirement difference from Portfolio 1b for Portfolios 2b – 5b.

Figure 8.28 | Scenario D PVRR Summary ($Billion)

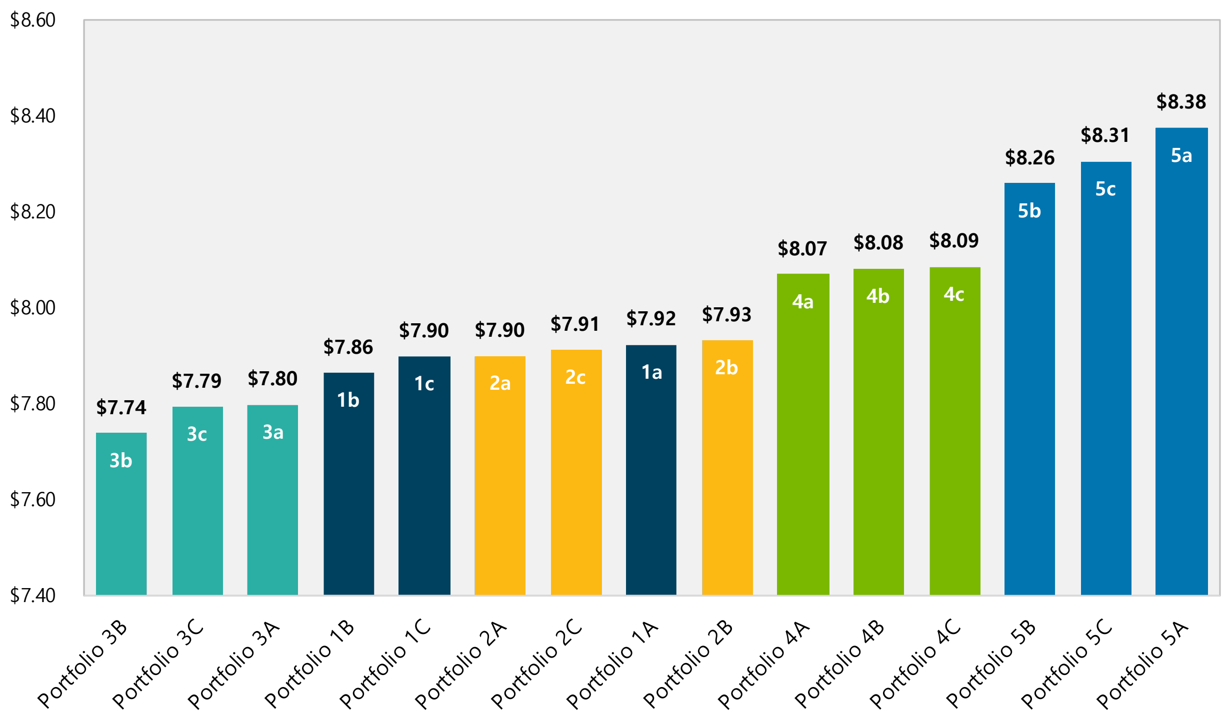


Figure 8.29 | Scenario D: Annual Difference from Portfolio 1b (Nominal $MM)

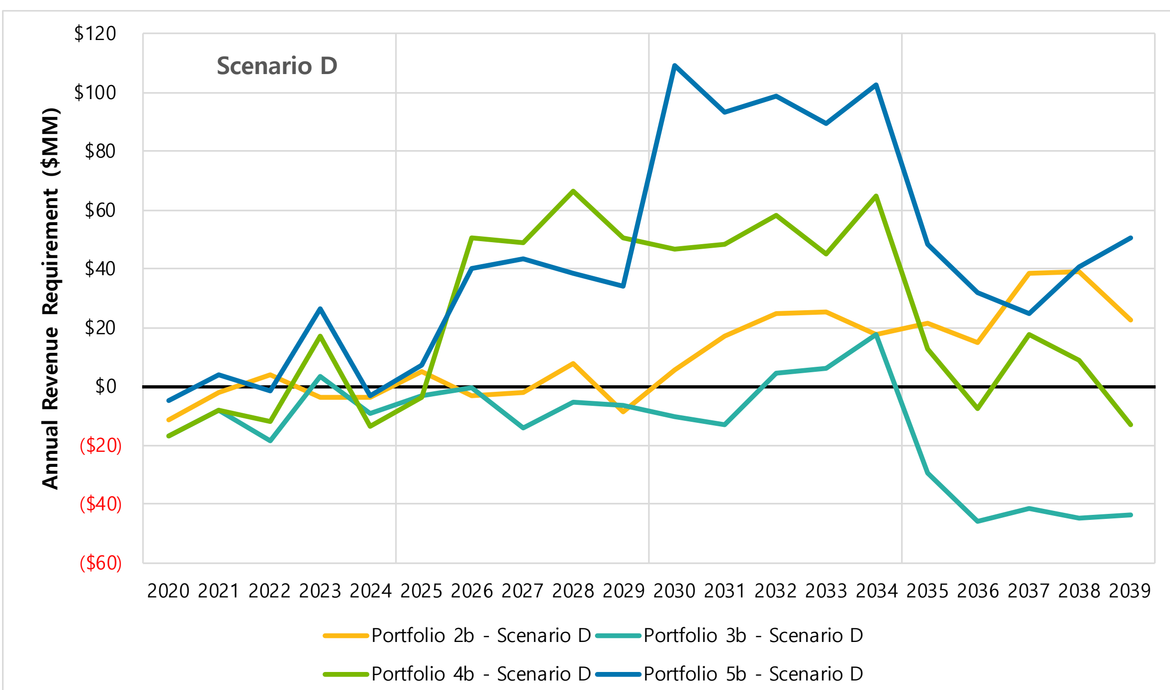


Figure 8.30 contains wind and solar captured revenue for the Reference and Scenario D. As the two charts show, all other things equal, higher natural gas prices benefit renewables with higher priced natural gas units setting the market price in most hours throughout the year. This provides a type of fuel hedge and shows how renewables can provide some level of risk mitigation for long term increases in natural gas prices.

Figure 8.30 | Wind and Solar Captured Revenue, Reference Case vs. Scenario D

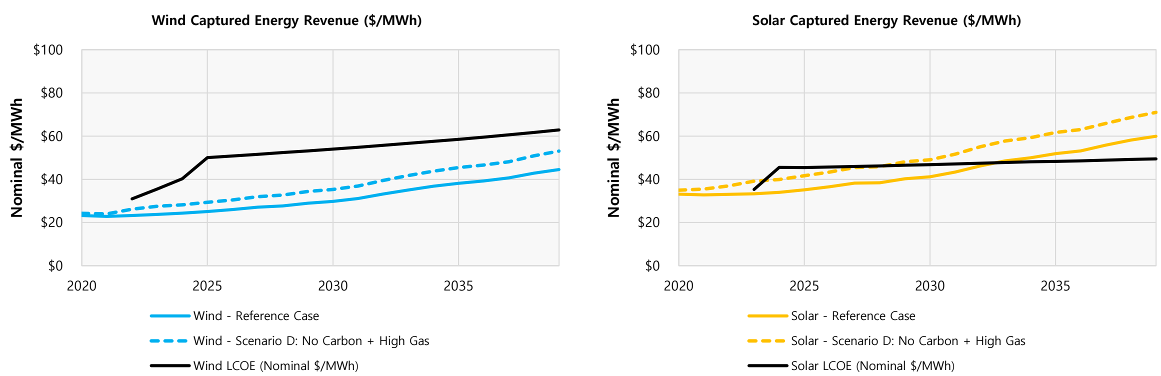
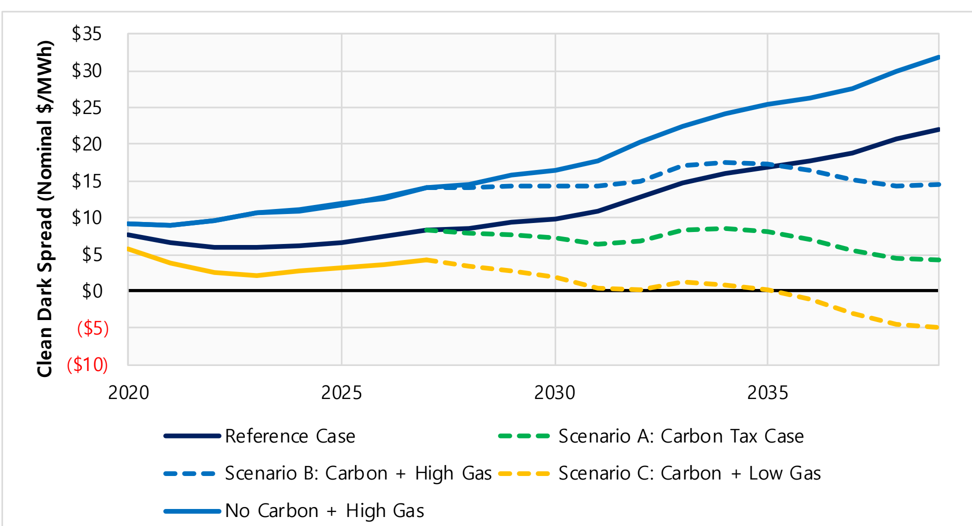


Figure 8.31 shows the 7x24 annual clean dark spreads for all scenarios modeled in this IRP. As the chart shows, Scenario D is effectively the "best case" scenario for coal as coal units are more in the money in this scenario compared to all other alternative scenarios.

Figure 8.31 | 7x24 Clean Dark Spreads



IPL had several key takeaways from analyzing PVRR for each portfolio across the scenarios:

1. **A carbon tax had the single largest impact on changes in PVRR for the portfolios.** As demonstrated from the scenario results, the assumption for a carbon tax resulted in significant changes in the ordering of portfolios on cost. The impact is due to the simultaneous impact of penalizing coal and natural gas generation and increasing the value of renewables, all other things equal. IPL believes that reducing customer exposure to future carbon legislation is an important considering for long term planning. As stated before, the timing and scale of any future carbon legislation could take many forms.

2. **The price of natural gas will continue to be a high impact variable to assess the future viability IPL coal units.** The fundamental shift downward in natural gas prices over the past 10 years due to shale production has put immediate economic pressure on coal assets in MISO and in Indiana. There are market uncertainties and policy uncertainties that play into the forecasted range of natural gas prices in this IRP.

3. **In the short- to mid-term, continuing to pursue a balanced portfolio that is not too reliant on one resource type provides value to customers.** Portfolio 3b, which continues to decrease IPL's reliance on coal, maintains existing natural gas units in the first ten years, and adds wind, renewables, storage, and DSM early performs the best across a wide range of futures and provides opportunities for continued evaluation of the market as the portfolio is implemented.

8.3.6 Cost Metrics

IPL evaluated three (3) specific cost metrics: the 20-year PVRR, Annual Revenue Requirement and a Levelized Rate. The 20 Year PVRR is presented in Figure 8.15 and the Annual Revenue Requirements as compared to Portfolio 1 are shown for each Scenario's result sections (Sections 8.3.1 – 8.3.5). Annual rate impacts for each of the portfolios are driven by the change in annual costs as shown for each of the scenarios above in the annual revenue requirement graphs. The cumulative 20-year rate impact for each portfolio and scenario is summarized in Figure 8.32.

Figure 8.32 | Levelized Rate Impact at 6.486% Discount Rate ($/kWh)

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

8.3.7 Risk Metrics

The risk premium metric evaluates the probability weighted average of high cost outcomes less the median. This is an indicator of tail risk for each portfolio. The risk premium was calculated for each production cost run and is summarized in Figure 8.33.

The risk premium trends higher as coal is retired, which can be attributed to several factors. First, coal prices are relatively stable compared to power and natural gas prices, so coal can potentially reduce overall portfolio risk. Second, coal units are dispatchable units and will increase output during high price times and reduce output during low price hours.

Figure 8.33 | Net Present Value of Annual Risk Premium ($MM)

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

Figure 8.34 contains risk-adjusted PVRRs, which means that the risk premium in Figure 8.33 was added to the mean expected value PVRR. Adding the risk premium puts all portfolios on equal footing and allows IPL to directly incorporate risk into the decision-making process. When adjusted for risk, Portfolio 3 is the lowest cost option on a risk-adjusted basis.

Figure 8.34 | Risk-Adjusted PVRR: Expected Value (Mean) + Risk Premium ($MM)

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

IPL evaluated "potential downside", which represents the median minus the probability-weighted average of outcomes below the median (left side of distribution), along with high cost tail risk across all scenarios. Figure 8.35 to Figure 8.39 contain the expected value (mean/average) PVRR, the risk premium, and the downside potential. Considering the full distribution of outcomes provides a balanced view of the variability of PVRR results across scenarios.

Figure 8.35 | PVRR Range: Reference Case ($MM)

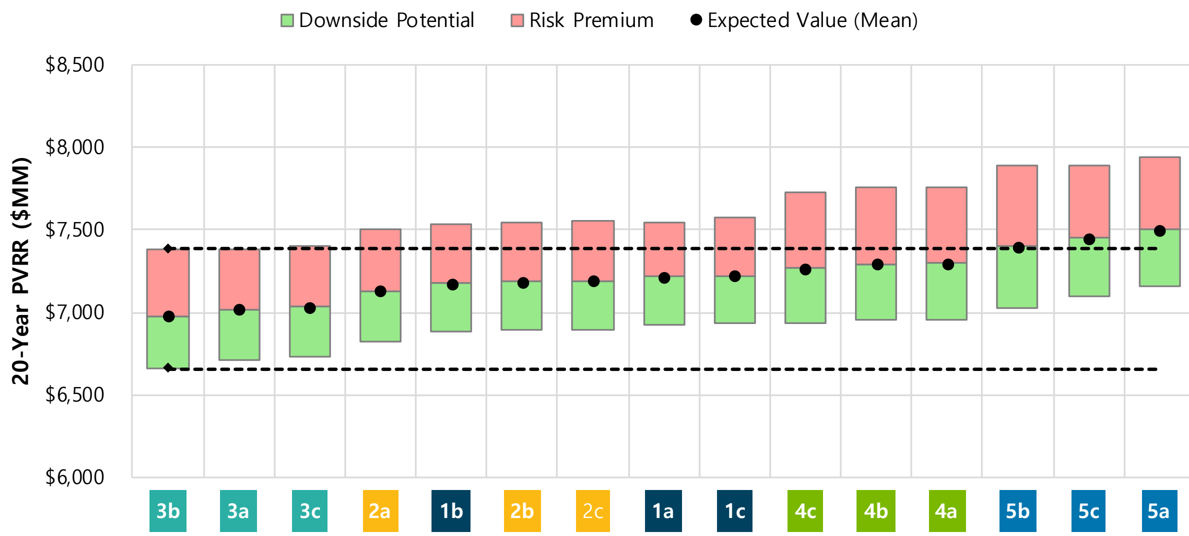


Figure 8.36 | PVRR Range, Scenario A: Carbon Tax Case ($MM)

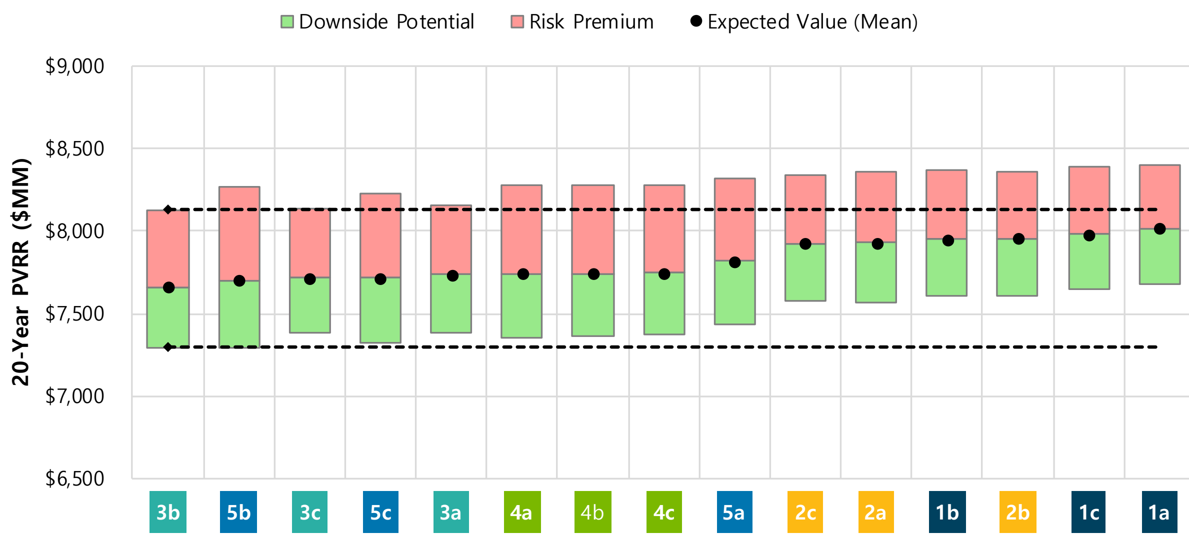


Figure 8.37 | PVRR Range, Scenario B: Carbon Tax + High Gas ($MM)

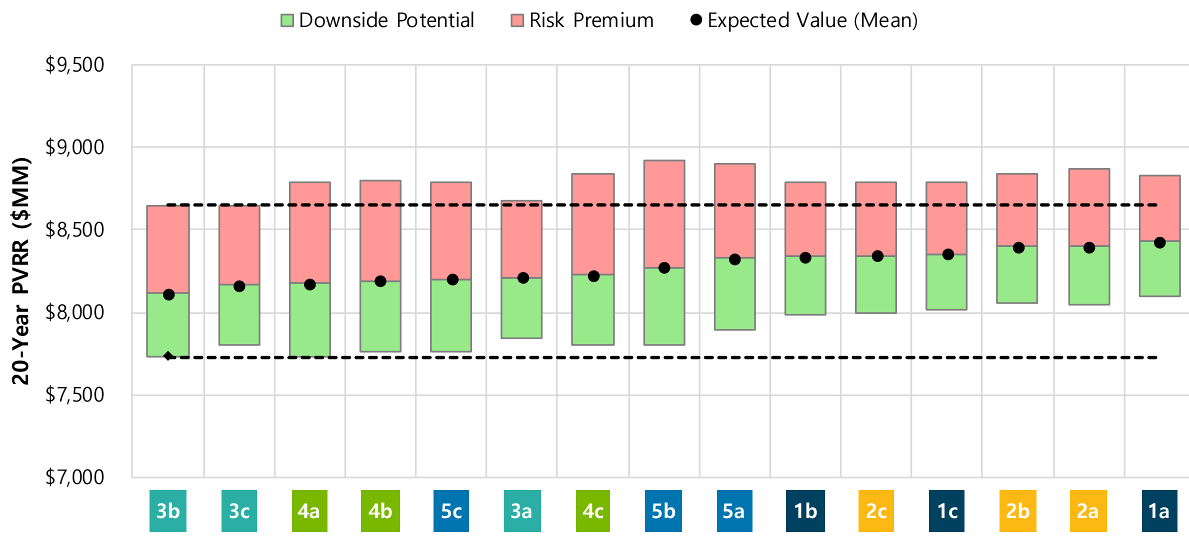


Figure 8.38 | PVRR Range, Scenario C: Carbon Tax + Low Gas + Low Load ($MM)

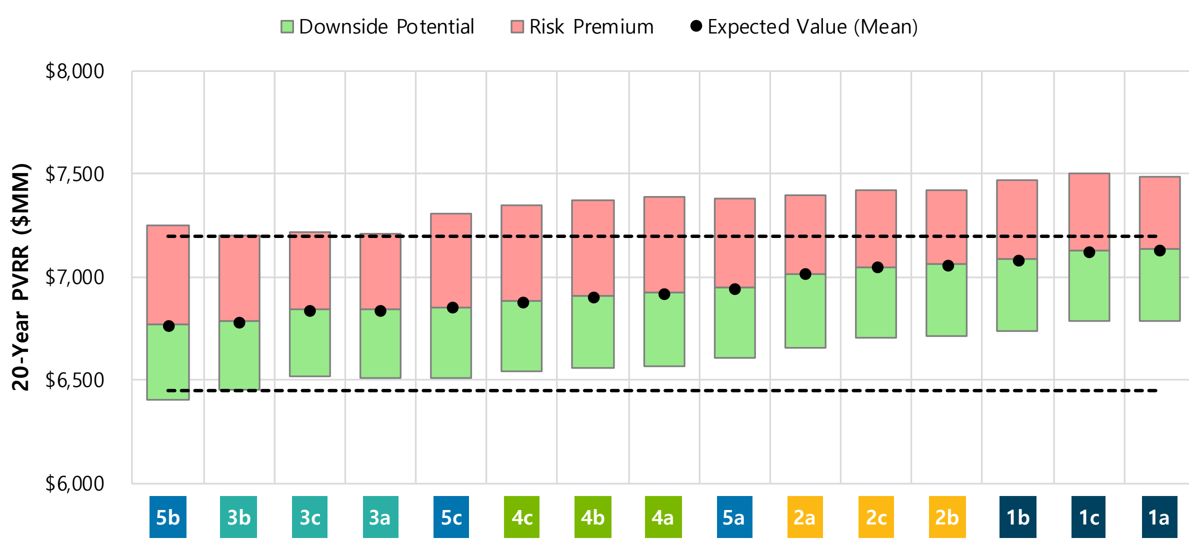
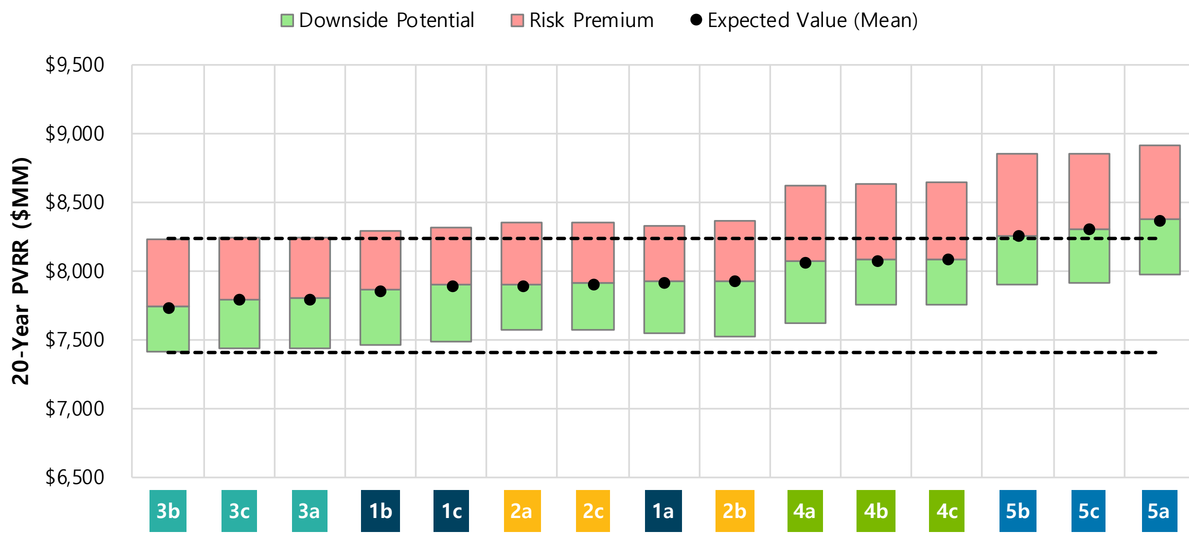
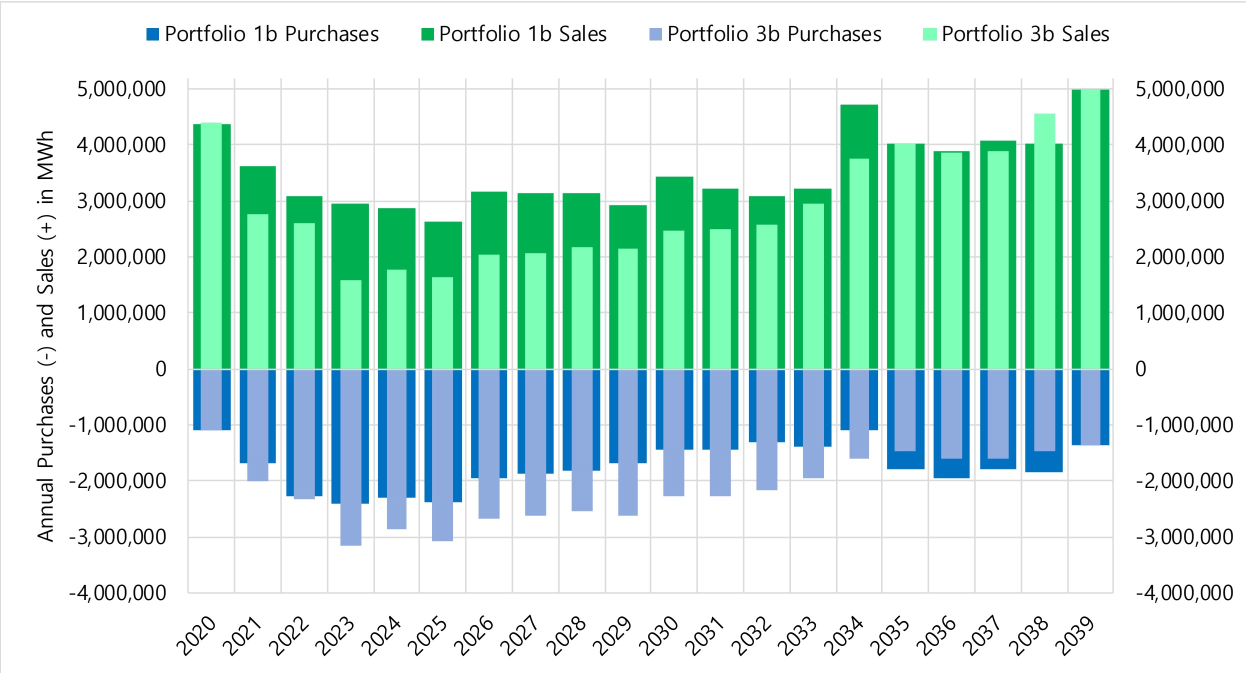


Figure 8.39 | PVRR Range, Scenario D: No Carbon Tax + High Gas + High Load ($MM)



Looking at market purchases and sales, or total market interaction, provides another perspective on risk exposure. While there is not a "correct" level of market interaction, this is a useful metric to compare the relative risk of portfolios and the ability to serve hourly load and not simply produce enough energy on an annual basis. Figure 8.40 is an example of hourly market interactions summed up annually. It compares Portfolio 3b to Portfolio 1b in the Reference Case. The portfolios are identical in the first year, but by 2021 Portfolio 3b has slightly more energy purchases and notably less energy sales due to the early retirement of Pete 1. Similar market interactions charts for each portfolio and scenario can be found in Attachment 8.3.

Figure 8.40 | Annual Market Interaction of Portfolio 3b Compared to Portfolio 1b for the Reference Case



Averaging the annual purchases and sales and summing the absolute value of those averages provides a simplified single number representing market interaction that can be used for comparison between portfolios. Figure 8.41 displays this metric for each portfolio and highlights the lowest risk portfolio in each group for each scenario. Less market interaction implies less risk. Portfolios 2 and 3 have the least market interaction, and Portfolios 1 or 5 tend to the have most market interaction.

Figure 8.41 | Average Market Interaction by Portfolio and Scenario

	Market Interaction in Millions of MWh, |Purchases| + |Sales|				
	20-Year Average (2020 - 2039)				
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1a	5.1	5.4	4.7	5.8	4.4
Portfolio 2a	4.8	5.4	4.6	5.7	4.3
Portfolio 3a	4.7	5.1	4.6	5.1	4.4
Portfolio 4a	5.4	5.5	5.3	5.5	5.3
Portfolio 5a	5.4	5.4	5.3	5.6	5.4
Portfolio 1b	5.2	5.7	5.0	5.9	4.6
Portfolio 2b	4.9	5.3	4.6	5.5	4.4
Portfolio 3b	5.0	5.4	4.9	5.4	4.7
Portfolio 4b	5.5	5.4	5.2	5.5	5.3
Portfolio 5b	5.6	5.6	5.5	5.6	5.7
Portfolio 1c	5.4	5.7	5.0	5.9	4.6
Portfolio 2c	5.1	5.4	4.8	5.5	4.5
Portfolio 3c	4.9	5.1	4.7	5.1	4.6
Portfolio 4c	5.4	5.5	5.2	5.4	5.2
Portfolio 5c	5.7	5.7	5.5	5.9	5.5

8.3.8 Environmental Metrics

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Air Emissions

Figure 8.42 contains a comparison of metrics for air emissions for all portfolios in the Reference Case. Metrics for all portfolios are shown as 20-year averages for the study period (2020 – 2039). Coal generation produces the most emissions in IPL's fleet, so average emissions decrease from Portfolios 1 to 5 as more coal units are retired and replaced with renewables, storage, and gas. Each portfolio, including Portfolio 1 with age-based retirements, shows a significant reduction in all air emissions compared to the historic baseline.

Figure 8.42 | Portfolio Air Emissions from Reference Case Scenario

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

Figure 8.43 shows the air emissions of the portfolios in Scenario A, the Carbon Case. A carbon tax results in lower coal capacity factors which further reduces air emissions relative to the Reference Case.

Figure 8.43 | Portfolio Air Emissions from Scenario A: Carbon Case

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

Non-Air Impacts (Water)

Retiring Pete Units 1 and 2 reduces the actual intake flow of water more than 67%. Retiring all four Pete Units results in the elimination of 354 million gallons per day ("MGD") of water withdrawal from the river (100% reduction).

8.4 Sensitivities

8.4.1 Capital Cost Sensitivity

The capital cost sensitivity analysis was designed to evaluate the impact of changing costs for renewables and storage for each portfolio relative to the base set of cost estimates. The deterministic sensitivity uses the financial revenue requirement model to provide insight into how portfolio costs change if resource decisions are made and if the actual cost is higher or lower than expected.

This analysis can help answer two questions:

1. How low would capital costs need to be to make Portfolio 5, the most aggressive transition case, the lowest cost portfolio in the Reference Case and Carbon Tax Case (Scenario A)?
2. For the lowest cost portfolio, would higher than expected renewable and storage costs cause that portfolio to be higher cost than Portfolio 1 with no economic retirements of coal units?

Figure 8.44 shows that even with a significant decrease in capital costs for renewables and storage, Portfolio 5 is not the lowest cost portfolio in the Reference Case. The figure also shows that even with a significant increase in capital costs, the PVRR for Portfolio 3 is lower than or equal to the PVRR of the mean PVRR for Portfolio 1 using base cost assumptions. Figure 8.45 shows the detailed PVRR results for the sensitivity analysis for the Reference Case scenario.

Figure 8.44 | Capital Cost Sensitivity, Reference Case PVRR Range ($MM)

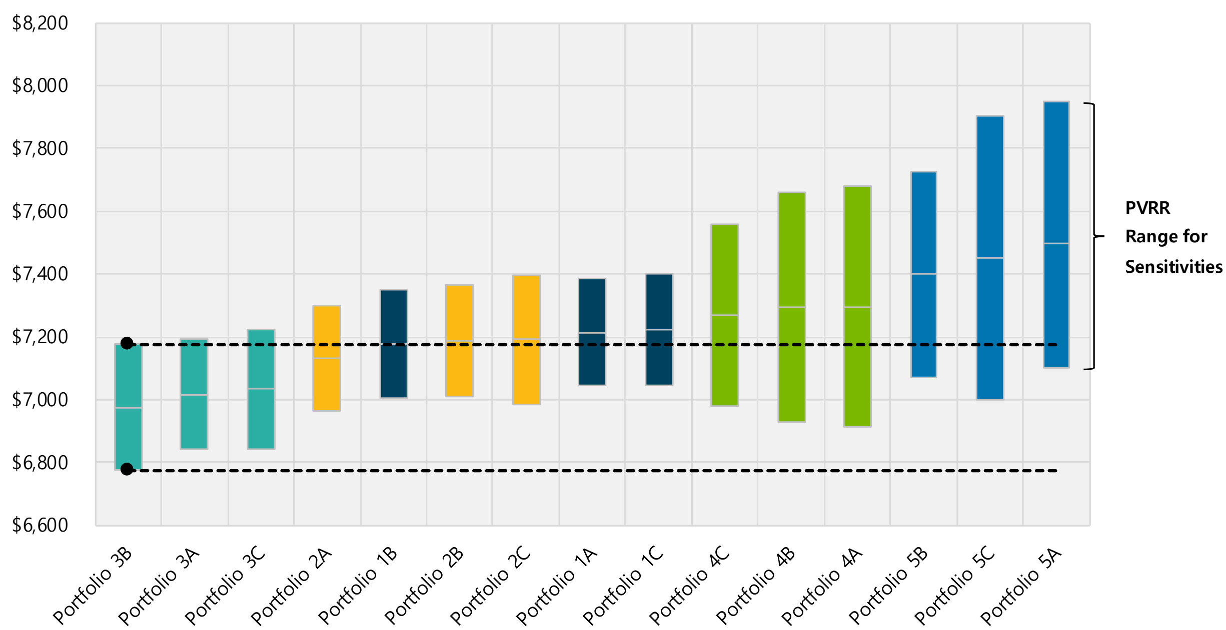


Figure 8.45 | Capital Cost Sensitivity, Reference Case PVRR Summary ($MM)

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

Figure 8.46 shows results of the sensitivity analysis for Scenario A, which is the Carbon Tax Case. The results from this scenario indicate two important takeaways. First, the results show that decreases in capital costs relative to base forecasts show that even small decreases in capital costs would make Portfolios 4 and 5 the lowest cost portfolios in this scenario. This combination of scenario analysis and sensitivity analysis effectively identifies market indicators or "sign posts" that IPL can monitor to see how portfolio strategies could change through time. A federal tax on carbon combined with capital costs beating expectations could cause IPL to move retirement dates for Pete 3 and 4 forward. Figure 8.46 also shows the robustness of Portfolio 3 compared to Portfolios 1 and 2, as the upper end of the PVRR range for Portfolio 3 is still lower than the expected PVRR for Portfolios 1 and 2. Figure 8.47 contains the detailed PVRR results from this analysis.

Figure 8.46 | Capital Cost Sensitivity, Scenario A (Carbon Case) PVRR Range ($MM)

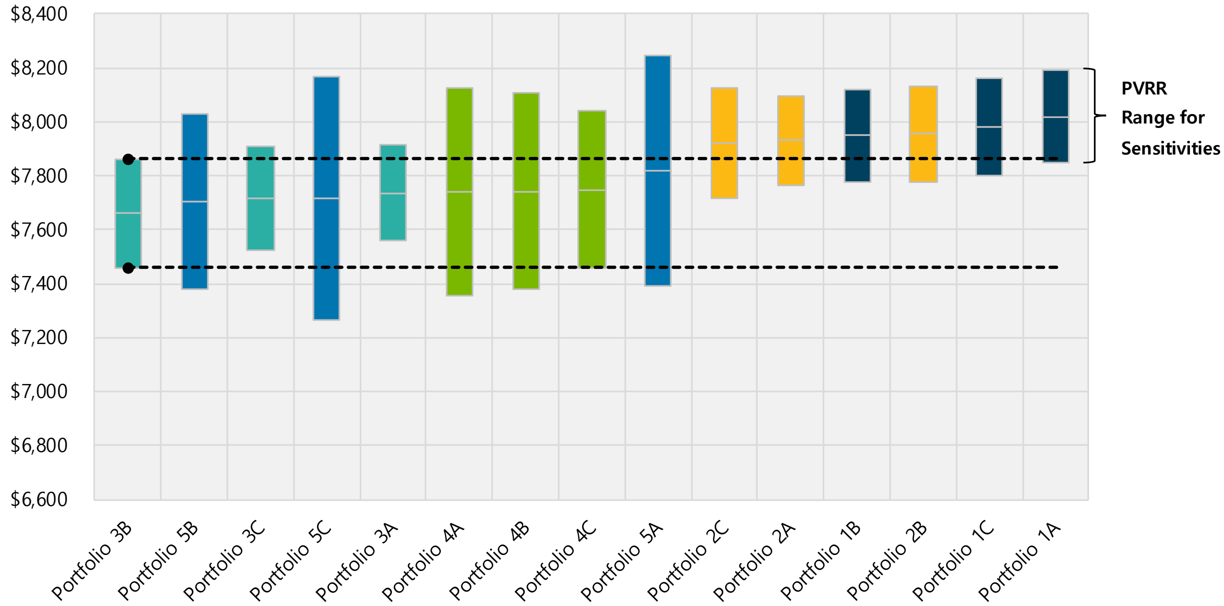


Figure 8.47 | Capital Cost Sensitivity, Scenario A (Carbon Case) PVRR Summary ($MM)

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

8.4.2 MISO Capacity Price Sensitivity

In addition to capturing uncertainty in future MISO capacity prices via stochastic simulation, IPL also ran a deterministic sensitivity analysis on capacity prices with predefined price curves against the fixed net capacity position for each portfolio.

This sensitivity analysis can assess two kinds of risk:

(1) If IPL does not retire units early and maintains a net long position through 2031, what is the risk to customers that bilateral and MISO auction clearing prices for capacity remain low?

(2) If IPL does retire units early and capacity prices increase significantly due to market rule changes, accelerated retirements in Indiana by multiple utilities, or other factors, what opportunity cost for capacity market sales is the company giving up by retiring units? And does this risk result in Portfolio 1 being the lowest cost portfolio?

Figure 8.48 contains results of the analysis for Portfolios 1a-3a from the Reference Case. The results show that even if IPL values the excess capacity position in Portfolio 1 at CONE for a new CT, Portfolio 3 is still the lower cost portfolio. Additionally, a low capacity price forecast adds an additional $45 million to the PVRR of Portfolio 1.

Overall, the results indicate that even at a very high valuation of excess capacity, Portfolio 1 remains a higher cost portfolio compared to Portfolio 3.

Figure 8.48 | Reference Case PVRR with Capacity Price Sensitivities (PVRR, $MM)

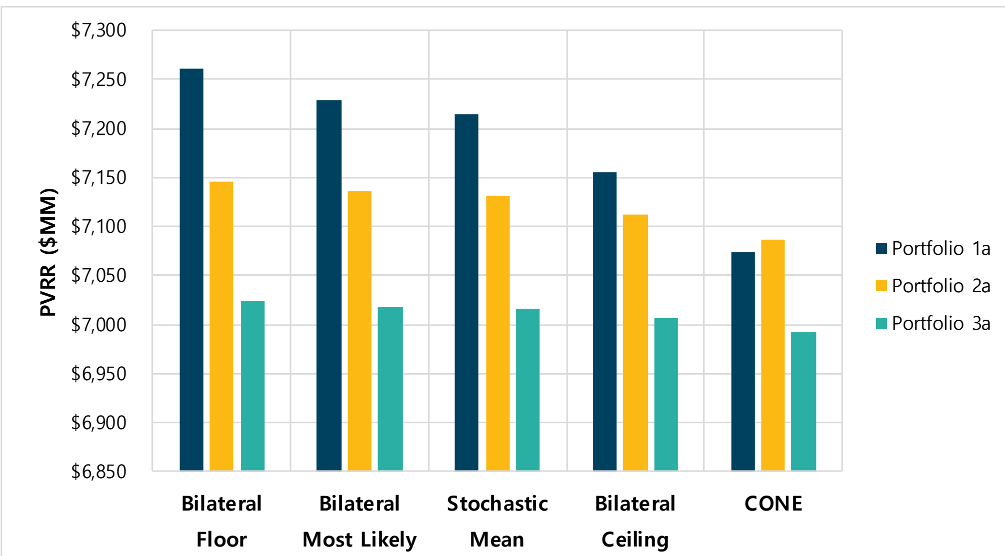


Figure 8.49 | Capacity Price Sensitivity, Reference Case (PVRR, $MM)

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

Figure 8.50 | Carbon Tax Case PVRR with Capacity Price Sensitivities (PVRR, $MM)

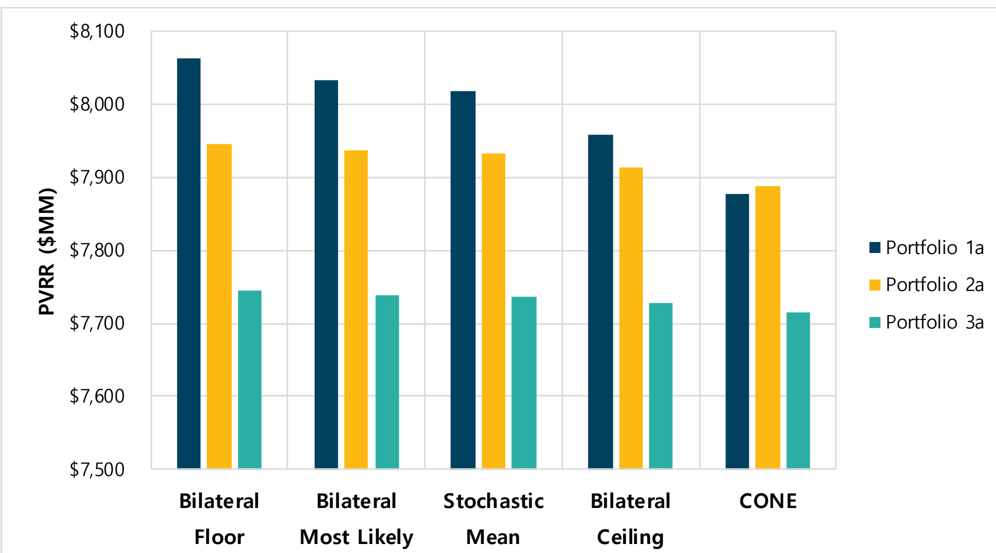


Figure 8.51 | Capacity Price Sensitivity, Carbon Tax Case (PVRR, $MM)

	Bilateral Floor	Bilateral Most Likely	[Base] Stochastic Mean	Bilateral Ceiling	CONE
Portfolio 1a	$8,063	$8,032	$8,018	$7,959	$7,877
Portfolio 2a	$7,946	$7,936	$7,932	$7,913	$7,887
Portfolio 3a	$7,745	$7,739	$7,737	$7,727	$7,714
Portfolio 4a	$7,749	$7,743	$7,740	$7,729	$7,715
Portfolio 5a	$7,828	$7,822	$7,819	$7,809	$7,795
Portfolio 1b	$7,995	$7,964	$7,950	$7,891	$7,809
Portfolio 2b	$7,970	$7,960	$7,956	$7,937	$7,911
Portfolio 3b	$7,669	$7,664	$7,661	$7,651	$7,638
Portfolio 4b	$7,751	$7,745	$7,742	$7,731	$7,717
Portfolio 5b	$7,712	$7,706	$7,703	$7,693	$7,679
Portfolio 1c	$7,980	$7,980	$7,980	$7,980	$7,980
Portfolio 2c	$7,923	$7,923	$7,923	$7,923	$7,923
Portfolio 3c	$7,716	$7,716	$7,716	$7,716	$7,716
Portfolio 4c	$7,747	$7,747	$7,747	$7,747	$7,747
Portfolio 5c	$7,716	$7,716	$7,716	$7,716	$7,716

8.4.3 Wind Capacity Factor Sensitivity

The wind capacity factor sensitivity analysis fixed the captured revenue rate ($/MWh from model results) and changed the volume based on a change to the assumed annual capacity factor. The goal is to evaluate the impact of lower production from actual wind farms relative to modeled wind in this IRP. Total energy market revenues from new wind impacts PVRR and is a significant source of uncertainty for any intermittent resource.

Figure 8.52 shows PVRR results from the Reference Case scenario. Results show that even if new wind was assumed to only have a 30% annual capacity factor, Portfolio 3 is still a lower cost portfolio compared to Portfolio 1. Because Portfolios 4 and 5 add up to 500 MW of wind starting in 2022, the PVRR is more sensitive to changes in capacity factor. Every 2% decrease in the annual wind capacity factor increases the PVRR by approximately $40-50 million for these portfolios.

Figure 8.52 | Wind Capacity Factor Sensitivity, Reference Case (PVRR, $MM)

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

Figure 8.53 contains results for Scenario A: Carbon Tax Case. The portfolio ordering on cost does not change significantly in this scenario. Portfolios 4 and 5, which add 600-1000 MW of wind by 2030, are impacted the most by changes in the assumption for wind production. This analysis helps identify inflection points that change the unit economics for wind through time. IPL will continuously monitor trends in wind technology performance through time as future IRPs are developed.

Figure 8.53 | Wind Capacity Factor Sensitivity, Carbon Tax Case (PVRR, $MM)

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

8.4.4 Wind LMP Basis Sensitivity

IPL modeled new wind assets with a 20% basis adjustment to the LMP at the project, which means that the assumed LMP is 20% lower than the modeled MISO Indiana Hub price on average. This adjustment was made to account for the fact that wind is typically located in areas not near a load center and often see congestion putting downward pressure on LMPs. Forecasting congestion is difficult due to the myriad of factors that affect it, but the basis adjustment is an estimate to more accurately model the revenues that an actual wind project could receive.

IPL conducted a sensitivity analysis to evaluate the impact on PVRR if the basis adjustment was gradually removed. This informs the preferred portfolio selection by highlighting and quantifying a key risk variable when considering new wind projects.

This analysis was conducted for all 15 candidate portfolios for the Reference Case and Scenario A (Carbon Tax Case). Figure 8.54 contains the results for the Reference Case. In the Refence Case, changing the LMP basis assumption does not change the PVRR ranking of portfolios. Portfolios 4 and 5, which add 500 MW of wind starting in 2022, benefit the most from the wind revenue increase as each 5% increase in the wind captured revenue lowers the PVRR by $40-50M. However, the improved PVRR is not enough to close the gap between Portfolio 3 and Portfolios 4 and 5.

Figure 8.55 contains results for the Carbon Tax Case are in. The PVRR ranking for portfolios does change with just a 5% improvement in the basis assumption. Portfolio 5c is the lowest cost portfolio in the Carbon Tax Case with a 10% increase in wind captured revenue. This highlights the importance of future wind farm siting and congestion analysis to inform any new wind projects.

Figure 8.54 | Wind LMP Basis Sensitivity, Reference Case (PVRR, $MM)

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

Figure 8.55 | Wind LMP Basis Sensitivity, Carbon Tax Case (PVRR, $MM)

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

This sensitivity highlights the importance of wind farm siting as it pertains to transmission interconnection, localized congestion trends, and the overall robustness of the regional transmission grid. A detailed nodal, security-constrained production cost study would need to be conducted to further evaluate any specific project that IPL would consider in the future.

8.5 Preferred Resource Portfolio

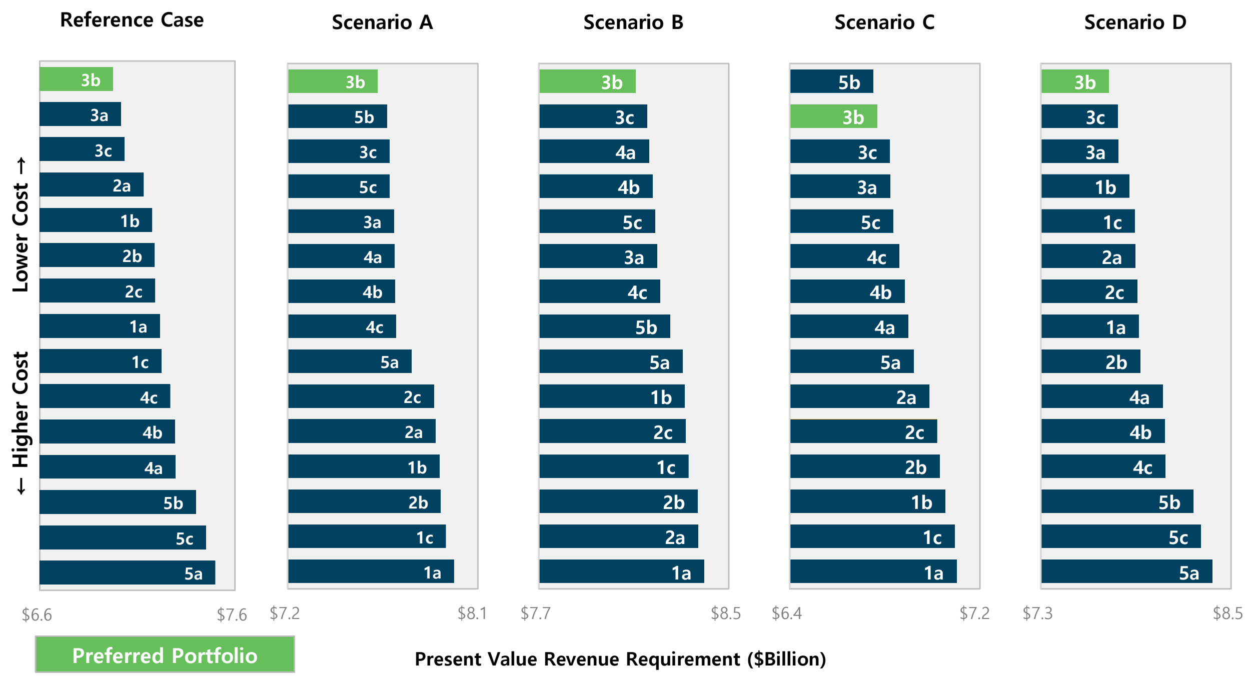
170 IAC 4-7-4(9) 170 IAC 4-7-6(a)(2) 170 IAC 4-7-8(c)(1) 170 IAC 4-7-8(c)(2) 170 IAC 4-7-8(c)(3)

1. **COST**

Portfolio 3b is the lowest-cost portfolio on a risk-adjusted basis across the widest range of futures. Short term costs are limited due to O&M and capital savings when Pete 1 and 2 retire, and IPL's net long position reduces the amount of firm capacity needed.

Pete 1 and 2 are the smallest, oldest units at Petersburg, and the model results strongly indicate that an earlier retirement date is the reasonable least cost plan for customers. Pete 1 and 2 require overhaul and maintenance cost over the next decade. The economic value as forecasted across many future scenarios shows that the retirement and replacement of these two units is the lowest cost options for IPL customers.

Figure 8.56 | Portfolio 3b: Lowest Cost Portfolio Across Wide Range of Futures



2. RISK

Identifying and quantifying risk in resource planning involves comprehensive evaluation of potential outcomes and testing different portfolios to see how robust they are if the world is different than expected. Portfolio 3b is the lowest cost portfolio on a risk-adjusted basis, provided a well-balanced portfolio in the short term while retaining flexibility to react to future market changes.

3. ENVIRONMENTAL

Portfolio 3b allows IPL to prudently and cost-effectively continue to decarbonize our portfolio over the next 5 years. Portfolio 3 would yield a reduction in carbon intensity of 50% compared to 2014 and 25% compared to Portfolio 1 that retains all coal units. In addition to a significant reduction in air emissions, the retirement of Petersburg Units 1 and 2 would decrease IPL's water intake at the plant by over 67%.

8.5.1 Financial Impact of Preferred Resource Portfolio

170 IAC 4-7-8(c)(7)(A) 170 IAC 4-7-8(c)(7)(B) 170 IAC 4-7-8(c)(7)(C) 170 IAC 4-7-8(c)(7)(D)

Figure 8.57 contains a breakdown of the portfolio cost for Portfolio 3b, the Preferred Resource Portfolio, compared to Portfolio 1b, which is the status quo portfolio with no change in retirement dates. Annual operating expenses are forecasted to decrease by approximately $104 million per year on average for the first ten years of the study, with most of those savings coming from fuel and O&M savings resulting from unit retirements. Recovery of and return on new capital expenditures, which includes the addition of new capacity to fill the expected capacity shortfall, is forecasted to increase $30-60 million per year from 2023 to 2029 for the Preferred Portfolio compared to the status quo. Because of the change in resource mix, annual energy market revenue and net capacity revenue is expected to decrease.

Figure 8.57 | 10-Year Portfolio Cost Difference: Preferred Portfolio vs. Status Quo

10-Year PVRR Breakdown (Nominal $MM)	Portfolio 3b vs. Portfolio 1b, Reference Case									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING EXPENSES	Positive = more cost = ↑ PVRR			Negative = less cost = ↓ PVRR						
Energy Purchases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel	$0	($25)	($20)	($77)	($76)	($80)	($89)	($90)	($92)	($98)
Variable O&M	$0	($3)	($2)	($8)	($8)	($9)	($10)	($10)	($10)	($10)
Fixed O&M	($13)	($16)	($22)	($25)	($44)	($38)	($34)	($46)	($36)	($36)
Emissions	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Expense Gross Up	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Subtotal: Operating Expenses	($13)	($44)	($45)	($113)	($130)	($129)	($134)	($148)	($141)	($147)
RECOVERY OF AND RETURN ON NEW CAPITAL	Positive = more cost = ↑ PVRR			Negative = less cost = ↓ PVRR						
Book Depreciation (New Capital)	($1)	($2)	$1	$13	$18	$19	$22	$23	$27	$28
Property Taxes	($0)	($0)	$0	$3	$3	$2	$1	$0	$0	$0
Return on Rate Base	($1)	($3)	($1)	$14	$29	$32	$32	$33	$34	$35
Subtotal: New Capital	($3)	($5)	$0	$30	$49	$52	$55	$56	$61	$64
MARKET REVENUES	Positive = less revenue = ↑ PVRR			Negative = more revenue = ↓ PVRR						
Energy Revenue ($MM)	($0)	$34	$19	$64	$51	$52	$58	$57	$54	$56
Capacity Revenue ($MM)	$0	$4	$5	$11	$10	$10	$10	$10	$9	$9
Subtotal: Market Revenue	($0)	$38	$24	$75	$62	$63	$68	$66	$63	$65
Annual Revenue Requirement [Line 7+11+14]	($17)	($11)	($21)	($8)	($19)	($14)	($12)	($26)	($17)	($18)

10-Year PVRR Difference @ 6.486% Discount Rate ($115)

The IRP is modeled at a snapshot in time with assumptions regarding numerous inputs including the cost for new replacement capacity. The annual revenue requirement calculation is not intended to be a precise forecast for the impact on rates based on the preferred portfolio. Any potential rate impacts of decisions stemming from this IRP will be considered in future regulatory filings.

Overall, the Preferred Resource Portfolio provides a measured transition period that enables IPL to efficiently finance any potential new projects in a timely and cost-effective manner for customers.

Section 9: Short Term Action Plan and Conclusion

170 IAC 4-7-4(24) 170 IAC 4-7-6(b)(4)(C) 170 IAC 4-7-9

9.1 IPL Short Term Action Plan

170 IAC 4-7-4(10)

9.1.1 2019 Short Term Action Plan (2020-2022)

- Continue implementation of approved 2020 DSM Plan (part of 2018-2020 plan)
- File for regulatory approval of a 2021-2023 DSM Plan consistent with the 2019 IRP
- Review and evaluate bids from all-source RFP facilitated by third-party (Sargent & Lundy).
- File for regulatory approval for replacement resources identified from the RFP
- Retire Petersburg Unit 1 by 2021
- Continue investment in grid modernization via proposed TDSIC Plan
- Retire Petersburg Unit 2 by 2023

Importantly, the Preferred Resource Portfolio preserves optionality because the short-term action plan is the same for Portfolios 3, 4 and 5. This means that even if IPL selected Portfolio 5 as the Preferred Portfolio, the company would not do anything different in the Short Term action window because of the lead time required to retire and replace large quantities of capacity.

The Short Term Action plan covering 2020 through 2022 includes offering DSM, replacing generation and completing transmission projects.

IPL will manage project costs and schedules and include a comparison of these short term IRP goals to what transpires in future IRPs.

Demand Side Management (DSM) Programs for 2021 – 2023

IPL has Commission approval to offer DSM programs for the 2018 to 2020 period (Cause No. 44945). IPL expects to file in late Q1 or early Q2 of 2020 for Commission authority to offer DSM programs for the three-year period 2021 through 2023. The proposed 2021-2023 DSM Plan will be consistent with the results of this IRP planning process.

The eight DSM bundles included in the IRP analysis represent the Realistic Achievable Potential (RAP) level of savings from the MPS which (all eight bundles) total approximately 2% of IPL sales. It is important to note that the MPS assumes that the RAP (2%) level of savings can only be achieved at a very high delivery cost under optimal market conditions. The DSM supply curve (Figure 5.41) demonstrates this – note the cost for measure delivery continues to escalate with each 0.25% of additional energy savings until costs are high for measures in the 1.75% - 2% decrement bundle. Therefore, it is important to use the IRP process to get to a level of savings that can be delivered under typical market conditions or to define a "Program Potential" level of savings. In the IRP modeling, the Present Value of Revenue Requirements (PVRR) continues to improve for each decrement of additional DSM through the selection of Decrement 4 or roughly 1% of annual sales. Including Decrements after Decrement 4 causes the PVRR to increase. Based on IPL's experience delivering programs in our service territory, the costs and savings at this 1% level are roughly consistent with our current offerings. However, this target will not be met without challenges.

The next step in developing the proposed 2021-2023 DSM Plan will be to collaborate with DSM implementation vendors and the IPL OSB to identify DSM programs that roughly align the cost and characteristics of the DSM measures that were identified in the Preferred Resource Portfolio by the IRP modeling. IPL has already initiated this process by initially targeting the IRP Decrement 4 results. IPL will face a significant challenge with the elimination of general service LED lighting measures from the residential program offerings. These lighting measures currently make up around 40% of residential energy savings. These measures have been removed starting in 2021 due to changes in the underlying baseline assumptions (LEDs are becoming the predominant lighting source). Preliminary forecasts for the Action Plan period indicate that the level of DSM in Decrement 4 will be challenging to achieve due to the removal of this general service LED lighting. As such, IPL plans to initially target a level of DSM between Decrement 3 and Decrement 4 for the 2021 – 2023 period as detailed in Figure 9.1 (these energy savings are net of free riders). Note that general service LED lighting will continue to be available through programs to the income qualified segment of customers where measure savings are still available.

Figure 9.1 | Net MWh DSM Target for the 2021 – 2023 Action Plan

Decrements 1 - 3 (Net MWh)	92,529	92,308	93,567
Decrement 1 - 4 (Net MWh)	119,719	124,673	125,425
DSM Action Plan Target (Net MWh)	92,529 - 119,719	92,308 - 124,673	93,567 - 125,425

***DSM level in Reference Case**

New demand response was not shown to be cost effective in the IRP; however, IPL will continue to maintain and use the existing load control devices as a load modifying resource. IPL included incentive and maintenance costs for the existing device population in the IRP analysis.

IPL expects to continue to offer income qualified programs and realize the current annual level of 1,500 – 2,000 MWhs of energy savings. Since IPL plans to offer these programs as a matter of policy, they were not included as selectable in the IRP analysis. Instead, the costs, energy savings and load shapes associated with these programs were non-selectable inputs in the analysis.

Supply Side (Generation) Plan for 2020 – 2022

IPL will release a Request for Proposals ("RFP") to procure replacement generation for needed capacity from the shortfall of Petersburg Units 1 & 2 retirements. IPL will evaluate the project bids to determine the appropriate replacement capacity for the retiring Petersburg units.

Transmission Short Term Action Plan for 2020 – 2022

The IPL transmission system projects listed below have been identified though annual transmission system performance assessments to establish baseline reliability projects or through MISO assessments.

- Rockville Substation 345 kV Ring Bus – 2020

The Rockville Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Rockville Substation to create a ring bus configuration. Cost Estimate: $3.6M.

- Petersburg – Gibson TMEP – 2020

The Petersburg to Gibson Targeted Market Efficiency Projects ("TMEP") was identified through an Interregional MISO and PJM process. The TMEP study looked to identify low-cost, quick implementation projects to relieve historically observed Market-to-Market congestion issues. This economic study identified an economic project with a B/C ratio of 4.5. To mitigate the congestion issue, IPL will replace two 345 kV breakers, relays, switches, and bus at the Petersburg substation. Cost Estimate: $4.3M.

- Guion Substation – 2023

The Guion Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To address this, IPL will add a 345/138 kV transformer and modify the existing substation configuration to include a 345 kV ring bus. This requires three new 345 kV breakers and two new 138 kV breakers. Cost Estimate: $14M.

- Stout Substation 345 kV Ring Bus – 2024

The Stout Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Stout Substation to create a ring bus configuration. Cost Estimate: $3.4M.

Timing of future projects are subject to change. See Section 3.2 of this IRP for a brief overview of IPL's TDSIC Plan.

9.1.2 Long Term Action Plan (2023 and Beyond)

Beyond the Short Term Action plan window, IPL's modeling and analysis efforts in this IRP have highlighted several key signposts, or market indicators, to evaluate as we move forward into the 2022 IRP.

First, the modeling clearly showed the potential impact of carbon legislation on influencing the optimal mix of technologies in our resource mix. The federal election in 2020 will be a major event to watch as federal climate and energy goals are formed over the next three years.

Second, the results from IPL's all-source RFP will provide first-hand market knowledge of the types of commercially available projects that are available today. The pricing and execution of new replacement capacity will be critical to understanding how to shape long-term forecasts for wind, solar, and storage.

Third, the evolution of the MISO market, including MISO's efforts with RIIA and RAN, could influence how we approach long term planning in the face of uncertainty on RTO policy and rules.

Overall, IPL will continue to evaluate existing resources, including Petersburg units 3 and 4, as we enter the 2022 IRP planning process.

9.2 Expectations for Future Improvements

170 IAC 4-7-4(16) 170 IAC 4-7-5(a)(9) 170 IAC 4-7-8(c)(9)

IPL plans to continue its effort to improve its IRP process and has identified the following items to do so.

- **IPL plans to improve load research and load forecasting by using AMI data.** Currently, IPL's load research sampling is performed through a statistically representative sample of load research meters installed throughout the service territory. This sample has become somewhat dated due to customer's changing locations. IPL plans to work with Itron to replace the load research meters with the AMI meters for load research. The changeover to AMI meters will eliminate load research meter deployment costs and result in more robust customer samples. Additionally, IPL has plans to work with an external consultant to explore load forecasting at the customer meter level using the AMI data. These forecasts will help IPL better understand usage trends which includes identifying customer deployment of DERs and EVs.
- **Seasonal capacity assessment:** Resource capacity credit can vary by season, requiring careful consideration of a portfolio used to serve load reliably. MISO continues to evaluate the existing capacity construct that IPL participates in through a stakeholder process. Changes to the capacity construct that include seasonality as opposed to an annual consideration could have a significant impact on the capacity credit for renewables.
- **Hourly and sub-hourly modeling:** Hourly and sub-hourly modeling allows IPL to evaluate its ability to meet load for all hours. Some resources such as batteries offer exceptional flexibility. This value may be more accurately captured by sub-hourly modeling, though this currently pushes the limits of many available models. IPL will continue assess whether the value of more granular modeling justifies the increase in complexity.
- **Explore modeling DSM, EE, and DR shapes hourly and sub-hourly to assess peak reduction, load shifting value:** Hourly and sub-hourly shapes for DSM, EE, and DR allow IPL to evaluate more accurately how these resources can contribute towards meeting load obligations.
- **Dynamic wind, solar, and storage ELCC:** Wind, solar, and storage's ability to meet reserve requirements is influenced by the penetration of each resource. Therefore, allowing for a dynamic ELCC value that provides feedback based on model selections could produce a more comprehensive optimization. IPL will continue to evaluate this consideration and its feasibility in available models.
- **"Bottom up" electric vehicle and distributed solar forecast integrated with generation, transmission, and distribution planning:** Electric vehicles and solar distribution are closely tied

to IPL's transmission and distribution system. As penetration of these resources increases, the need to incorporate grid infrastructure becomes more important and IPL will continue to evaluate the feasibility of doing so.

- **Scenario planning centered around decarbonization pathways that prioritize least cost, reliability, and effectiveness:** IPL's 2019 IRP has informed the importance of a carbon tax on influencing the optimal plan for customers. IPL will continue to monitor research and policies that influence the viability of resources.

9.3 Conclusion

170 IAC 4-7-8(c)(10)

The IRP is the foundation for future regulatory requests based upon a holistic view of IPL's resource needs and portfolio options. IPL has made strides to create a fair, balanced, transparent, and stakeholder informed IRP in the 2019 IRP Planning Process. The Preferred Portfolio provides a reasonable and balanced transition pathway that provides clear off-ramps for remaining coal units. The probabilistic assessment of risk and uncertainty that was embedded in the modeling and decision process provides a data-driven framework to build upon through the passage of time. IPL will continue to build the tools and capabilities that allow us to shape our long-term resource plan in the best interest of customers.

Section 10: Attachments & Rule Reference Table

Public Attachments are available in Volumes 2 & 3 of the Public IRP Report

Confidential Attachments & the Technical Appendix are available as part of the Confidential IRP

Attachment 1.1 (IPL 2019 IRP Non-Technical Summary)

Attachment 1.2 (Public Advisory Meeting Presentations) **170 IAC 4-7-4(30)**

Attachment 3.1 (Smart Grid 2017 & 2018 Annual Reports)

Attachment 3.2 (Rate REP Projects Map)

Attachment 4.1 (Test Year July 2016 through June 2017 Hourly Loads – MW) **170 IAC 4-7-4(12) 170 IAC 4-7-4(14) 170 IAC 4-7-5(a)(1) 170 IAC 4-7-5(a)(2)**

Attachments 4.2a – g (EIA End Use Data - Indices) **170 IAC 4-7-4(12)**

Attachment 4.3 (End Use Modeling Technique) **170 IAC 4-7-4(12)**

Confidential Attachment 4.4a (Moody's Q4 2018 Base) **170 IAC 4-7-4(12)**

Confidential Attachment 4.4b (Moody's Q4 2018 Exceptionally Strong) **170 IAC 4-7-4(12)**

Confidential Attachment 4.4c (Moody's Q4 2018 Lower Trend) **170 IAC 4-7-4(12)**

Attachment 4.5 (10 Yr. Energy and Peak Forecast) **170 IAC 4-7-4(12)**

Attachment 4.6 (20 Yr. High, Base and Low Forecast) **170 IAC 4-7-4(1) 170 IAC 4-7-4(3) 170 IAC 4-7-4(12) 170 IAC 4-7-6(a)(5) 170 IAC 4-7-5(b)(1) 170 IAC 4-7-5(b)(2) 170 IAC 4-7-5(b)(3)**

Attachment 4.7a (Energy Input Data–Residential) **170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(3)**

Attachment 4.7b (Energy Input Data–Small C&I) **170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(3)**

Attachment 4.7c (Energy Input Data–Large C&I) **170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(3)**

Attachment 4.8 (Peak–Forecast Drivers and Input Data) **170 IAC 4-7-4(12)**

Attachment 4.9 (Forecast Error Analysis) **170 IAC 4-7-4(2) 170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(6)**

Attachment 5.1 (IPL 2018 DSM MPS) **170 IAC 4-7-4(15) 170 IAC 4-7-6(b)(2)(B) 170 IAC 4-7-6(b)(2)(D) 170 IAC 4-7-6(b)(2)(E)**

Attachment 5.2a (MPS Appendix B – Residential Electric Measure Detail)

Attachment 5.2b (MPS Appendix C – Commercial Electric Measure Detail)

Attachment 5.2c (MPS Appendix D – Industrial Electric Measure Detail)

Attachment 5.3 (Decrement Load Shapes Summary) **170 IAC 4-7-6(b)(2)(D) 170 IAC 4-7-6(b)(2)(E)**

Confidential Attachment 5.4 (Avoided Cost) **170 IAC 4-7-4(29) 170 IAC 4-7-8(c)(6)**

Confidential 7.1 (Wood Mackenzie H1 2018 No Federal Carbon Case Report)

Confidential 7.2 (Wood Mackenzie H1 2018 Federal Carbon Case Report)

Confidential 7.3 (Wood Mackenzie H1 2018 Federal Carbon Case Report – MISO)

Confidential Attachment 7.4 (Wood Mackenzie - H1 2018 Supply, Demand Energy, Federal Carbon Case)

Confidential Attachment 7.5 (Wood Mackenzie - H1 2018 Supply, Demand Energy, No Carbon Case)

Confidential 7.6 (Annual Generator Fuel Prices) **170 IAC 4-7-6(a)(3)**

Attachment 8.1 (Annual Energy Charts) **170 IAC 4-7-8(c)(5)**

Attachment 8.2 (Load Resource Balance by Scenario)

Attachment 8.3 (Market Purchases and Sales)

Rule Reference Table

170 IAC 4-7 (Readopted Filed Verison 4/11/19)		
Regulatory Requirement	**Rule Reference**	**Section and/or Attachment in Indianapolis Power & Light Company 2019 IRP Report**
0.5 - Purpose and applicability	-	No Response Required
1 - Definitions	-	No Response Required
2 - Integrated resource plan submission	-	-
2.1 - Confidentiality	-	-
2.2 - Public comments and director's reports	-	No Response Required
2.3 - Resource adequacy assessment report	-	No Response Required
2.4 - N/A	-	-
2.5 - Effects of integrated resource plans in docketed proceedings	-	No Response Required
2.6 - Public advisory process	170 IAC 4-7-2.6	Section 1.4 & Attachment 1.2
2.7 - Contempory issues technical conference	-	-
3 - Waiver or variance requests	-	No Response Required
4 - Integrated resource plan contents		
(1) Twenty-year forecast	170 IAC 4-7-4(1)	Section 4.3, Attachment 4.6
(2) Analysis of historical and forecasted peak demand and energy usage	170 IAC 4-7-4(2)	Section 4.5, Attachment 4.9
(3) Alternative forecasts of peak demand and energy usage	170 IAC 4-7-4(3)	Section 4.3, Attachment 4.6
(4) Description of existing resources	170 IAC 4-7-4(4)	Section 5.1
(5) Process for selecting possible future resources	170 IAC 4-7-4(5)	Sections 7.2 & 7.3
(6) Description of possible future resources	170 IAC 4-7-4(6)	Sections 5.2, 5.3, & 5.4
(7) Screening analysis and resource summary table	170 IAC 4-7-4(7)	Section 5.2
(8) Candidate resource portfolios	170 IAC 4-7-4(8)	Sections 7.1, 8.1, & 8.2.1
(9) Preferred resource portfolio	170 IAC 4-7-4(9)	Section 8.5
(10) Short-term action plan	170 IAC 4-7-4(10)	Section 9.1
(11) Inputs, methods, and definitions used by the utility in this IRP	170 IAC 4-7-4(11)	Sections 4,5 & 7
(12) Data sets and sources	170 IAC 4-7-4(12)	Section 4 Attachments
(13) Efforts to develop a database of electricity consumption patterns	170 IAC 4-7-4(13)	Section 4.1
(14) Suggested methods for developing database in (13)	170 IAC 4-7-4(14)	Attachment 4.1
(15) Schedule for customer surveys	170 IAC 4-7-4(15)	Section 5.4.3, Attachment 5.1
(16) Usage of AMI data	170 IAC 4-7-4(16)	Sections 3.3.2, 4.1, & 9.2
(17) Contemporary issues designated	170 IAC 4-7-4(17)	Section 1.5
(18) Distributed generation	170 IAC 4-7-4(18)	Sections 3.2 & 3.4.1
(19) Model structure and applicability	170 IAC 4-7-4(19)	Section 7.2
(20) Fuel inventory and procurement planning	170 IAC 4-7-4(20)	Section 2.2
(21) Emission allowance inventory and procurement planning	170 IAC 4-7-4(21)	Section 6.2.1
(22) Generation expansion planning criteria	170 IAC 4-7-4(22)	Section 7
(23) Consideration of compliance costs	170 IAC 4-7-4(23)	Section 6
(24) Resource planning objectives	170 IAC 4-7-4(24)	Executive Summary and Sections 1.1, 8 & 9
(25) Base case scenario	170 IAC 4-7-4(25)	Section 8.3.1
(26) Alternative scenarios	170 IAC 4-7-4(26)	Sections 7.3.2, 8.3.2, 8.3.3, 8.3.4 & 8.3.5
(27) Description of power flow models and transmission planning criteria	170 IAC 4-7-4(27)	Sections 2.3.2 & 2.3.3
(28) List and description of methods	170 IAC 4-7-4(28)	Sections 4.3 & 7.2
(29) Avoided cost calculation	170 IAC 4-7-4(29)	Section 5.4.5 & Confidential Attachment 5.4
(30) Summary of public advisory process	170 IAC 4-7-4(30)	Section 1.4 & Attachment 1.2
(31) Assessment of resources considered	170 IAC 4-7-4(31)	Sections 5.2, 5.3 & 5.4
5 - Energy and demand forecasts		
(a)(1) Historical load shapes	170 IAC 4-7-5(a)(1)	Attachment 4.1
(a)(2) Disaggregation of data	170 IAC 4-7-5(a)(2)	Attachment 4.1
(a)(3) Actual and weather-normalized levels	170 IAC 4-7-5(a)(3)	Attachment 4.7 a-c
(a)(4) Methods to weather-normalize	170 IAC 4-7-5(a)(4)	Section 4.3
(a)(5) 20-year energy and demand forecasts	170 IAC 4-7-5(a)(5)	Attachment 4.6
(a)(6) 10-year historical analysis	170 IAC 4-7-5(a)(6)	Attachment 4.9
(a)(7) Impact of historical DSM programs on load forecast	170 IAC 4-7-5(a)(7)	Section 4.3
(a)(8) Justification for forecast methodology	170 IAC 4-7-5(a)(8)	Section 4.3
(a)(9) Potential improvements for forecasting	170 IAC 4-7-5(a)(9)	Section 9.2
(a)(10) Data sources for historical analysis	170 IAC 4-7-5(a)(10)	Section 4.5
(b)(1) Alternative forecasts - high	170 IAC 4-7-5(b)(1)	Attachment 4.6
(b)(2) Alternative forecasts - low	170 IAC 4-7-5(b)(2)	Attachment 4.6
(b)(3) Alternative forecasts - most probable	170 IAC 4-7-5(b)(3)	Attachment 4.6
(c) Suggested inputs for most probable forecast	-	No Response Required

6 - Description of available resources		
(a)(1) Net and gross dependable generating capacity	170 IAC 4-7-6(a)(1)	Section 5.1.1
(a)(2) Expected changes to existing capacity	170 IAC 4-7-6(a)(2)	Sections 5.1.1 & 8.5
(a)(3) Fuel price forecasts by existing generating unit	170 IAC 4-7-6(a)(3)	Confidential Attachment 7.1
(a)(4) Environmental effects at existing fossil generating units	170 IAC 4-7-6(a)(4)	Section 6
(a)(5) Analysis of existing transmission system	170 IAC 4-7-6(a)(5)	Section 2
(a)(6) Discussion of demand-side resources	170 IAC 4-7-6(a)(6)	Sections 4.3 & 5.4
(b)(1) Rate design as a resource	170 IAC 4-7-6(b)(1)	Section 5.4.5
(b)(2)(A) Description of potential DSM resources	170 IAC 4-7-6(b)(2)(A)	Section 5.4
(b)(2)(B) Methods by which DSM resource characteristics are determined	170 IAC 4-7-6(b)(2)(B)	Section 5.4.3 & Attachment 5.1
(b)(2)(C) Customer class affected by potential DSM resources	170 IAC 4-7-6(b)(2)(C)	Sections 5.4.2 & 5.4.3
(b)(2)(D) Annual and lifetime energy and savings for potential DSM resources	170 IAC 4-7-6(b)(2)(D)	Attachments 5.1 & 5.3
(b)(2)(E) Impact of potential DSM on load, capacity and T&D requirements	170 IAC 4-7-6(b)(2)(E)	Attachments 5.1 & 5.3
(b)(2)(F) Ability of all ratepayers to participate in DSM	170 IAC 4-7-6(b)(2)(F)	Section 5.4.1
(b)(3)(A) Description of supply-side resources considered	170 IAC 4-7-6(b)(3)(A)	Sections 5.2 & 5.3
(b)(3)(B) Description of efforts to coordinate planning with other utilities	170 IAC 4-7-6(b)(3)(B)	Section 2.3
(b)(3)(C) Environmental effects of supply-side resources considered	170 IAC 4-7-6(b)(3)(C)	Section 8.3.8
(b)(4)(A) Transmission resources considered	170 IAC 4-7-6(b)(4)(A)	Section 2.3
(b)(4)(B) For transmission resources, timing, types, and alternatives considered	170 IAC 4-7-6(b)(4)(B)	Section 2.3
(b)(4)(C) Cost of expected transmission projects	170 IAC 4-7-6(b)(4)(C)	Section 9.1
(b)(4)(D) Value of transmission upgrades	170 IAC 4-7-6(b)(4)(D)	Section 2
(b)(4)(E) How IRP affects RTO planning and RTO planning affects IRP	170 IAC 4-7-6(b)(4)(E)	Section 2
7 - Selection of resources		
8 - Resource portfolios		
(a) Process for selecting candidate portfolios	170 IAC 4-7-8(a)	Section 7
(b) Candidate portfolio performance across scenarios	170 IAC 4-7-8(b)	Section 8.3
(c)(1) Preferred resource portfolio	170 IAC 4-7-8(c)(1)	Section 8.5
(c)(2) Standards of reliability	170 IAC 4-7-8(c)(2)	Section 8.5
(c)(3) Assumptions having greatest effect on preferred resource portfolio	170 IAC 4-7-8(c)(3)	Section 8.5
(c)(4) Analysis showing that supply-side and DSM have been considered on a consistent basis	170 IAC 4-7-8(c)(4)	Sections 7 & 8
(c)(5) Analysis showing that portfolio meets demand	170 IAC 4-7-8(c)(5)	Attachment 8.1
(c)(6) Analysis of DSM deferring T&D investment	170 IAC 4-7-8(c)(6)	Confidential Attachment 5.4
(c)(7)(A) Operating and capital cost of preferred portfolio	170 IAC 4-7-8(c)(7)(A)	Section 8.5.1
(c)(7)(B) Avg. cost/kWh of future resources	170 IAC 4-7-8(c)(7)(B)	Section 8.5.1
(c)(7)(C) Avoided cost in each year for preferred portfolio	170 IAC 4-7-8(c)(7)(C)	Section 8.5.1
(c)(7)(D) Ability to finance preferred portfolio	170 IAC 4-7-8(c)(7)(D)	Section 8.5.1
(c)(8) How preferred portfolio balances cost, reliability, risk	170 IAC 4-7-8(c)(8)	Section 8
(c)(9) Discussion of potential improvements	170 IAC 4-7-8(c)(9)	Section 9.2
(c)(10) Strategy for adapting to change in assumptions	170 IAC 4-7-8(c)(10)	Section 9.3
9 - Short term action plan	170 IAC 4-7-9	Section 9
10 - IRP updates	-	-

Cause No. 45591

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

INDIANAPOLIS POWER & LIGHT COMPANY

2019 Integrated Resource Plan

Volume 2 of 3

December 16, 2019

Attachment 1.1

ipl an AES company

2019 Integrated Resource Plan (IRP) Non Technical Summary

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-2
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BACKGROUND

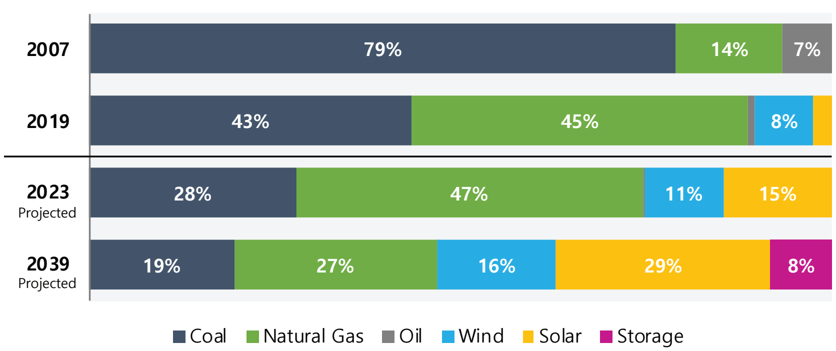
Indianapolis Power & Light Company ("IPL") is engaged primarily in generating, transmitting, distributing and selling electric energy to more than 500,000 retail customers in Indianapolis and neighboring areas; the most distant point being about 40 miles from Indianapolis. IPL's service area covers about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

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

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

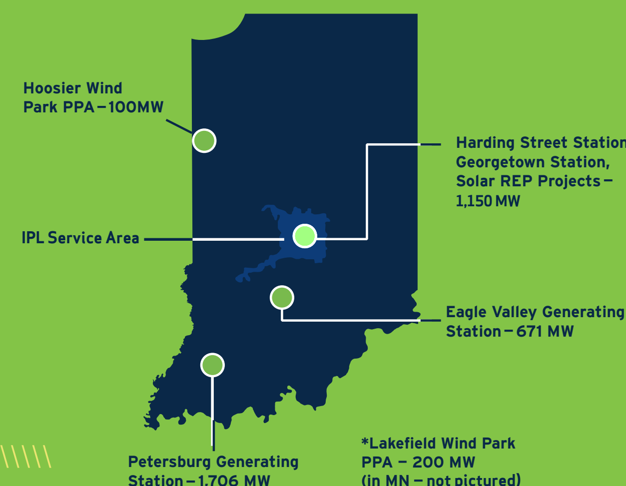
Figure 1 - ***IPL RESOURCE MIX***

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



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

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



IRP OBJECTIVE

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

IRP Process

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

Public Advisory Process

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

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

Public Advisory Meeting #1
January 29, 2019
Topics covered: 2016 IRP review, introduction to the 2019 IRP (timeline, mission, objectives), capacity discussion, 2019 IRP starting point, modeling replacement resources, DSM/EE modeling and load forecast update

Public Advisory Meeting #2
March 26, 2019
Topics covered: stakeholder presentations, detailed load forecast, IPL DSM market potential study and end use results, commodity prices and modeling, assumptions for replacement resources, scenario analysis framework and proposed scenarios

Public Advisory Meeting #3
May 14, 2019
Topics covered: electric vehicle and distributed solar forecast, stakeholder presentation, detailed load forecast, DSM bundles in IRP modeling, modeling and scenario recap

Public Advisory Meeting #4
September 30, 2019
Topics covered: modeling and scenario recap, preliminary model results, optimized portfolios, portfolio metrics

Public Advisory Meeting #5
December 9, 2019
Topics covered: summary of IPL 2019 short term action plan, 2019 IRP modeling insights, analysis of alternatives and preferred resource portfolio

IRP MODELING

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

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

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

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

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

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

PREFERRED RESOURCE PORTFOLIO

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

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

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

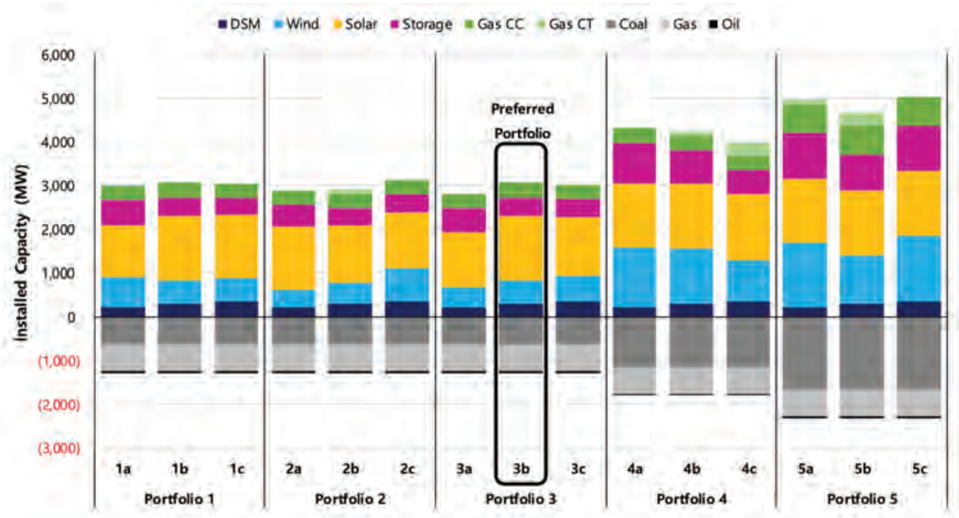
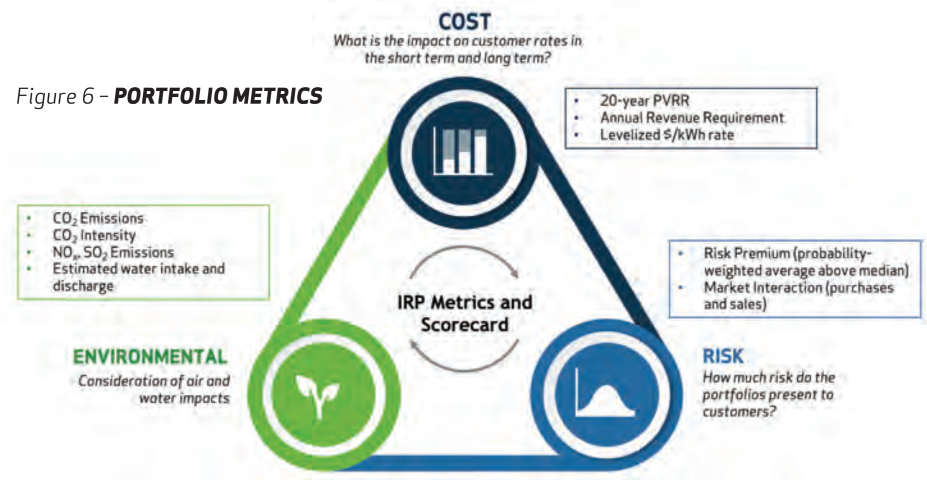


Figure 6 – ***PORTFOLIO METRICS***



SHORT TERM ACTION PLAN

RETIRE

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 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

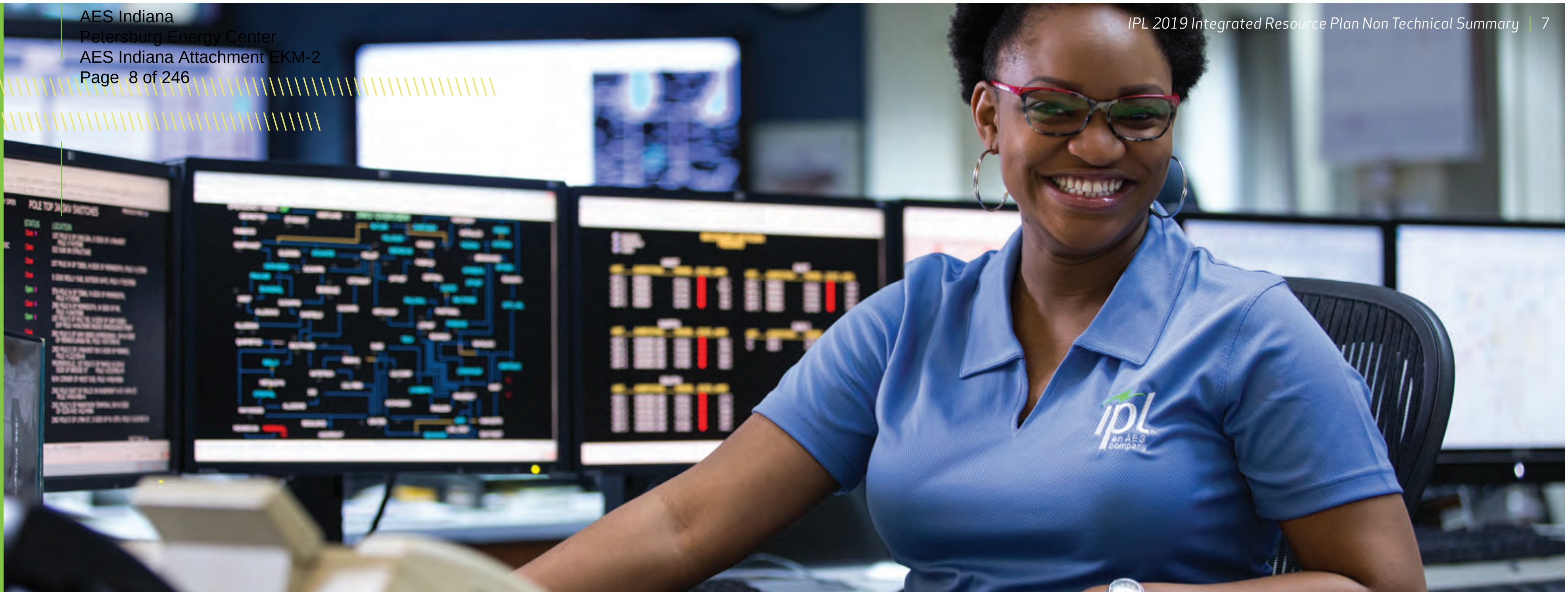
IPL intends to issue an all-source Request for Proposal ("RFP") to competitively procure replacement capacity by June 1, 2023, which is the first year IPL is expected to have a capacity shortfall. IRP modeling indicates that a combination of wind, solar and storage resources would be the lowest cost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

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Maintains generation optionality

Greener Energy Future
Moves the company to more renewables

2019 Integrated Resource Plan (IRP) Non Technical Summary

IPL 2019 IRP: PUBLIC ADVISORY MEETING #1

January 29, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

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

2016 IRP RECAP

Patrick Maguire

Director of Resource Planning

2016 IRP SUMMARY

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

Report Filed on November 1, 2016

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

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

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

2016 IRP: COMMENTS AND IMPROVEMENTS TARGETED

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

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

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

INTRODUCTION TO THE 2019 IRP

Patrick Maguire

Director of Resource Planning

IPL 2019 IRP

INTEGRATED RESOURCE PLAN (IRP):

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

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

What is a preferred resource portfolio?

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

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

2019 IRP STAKEHOLDER PROCESS

Dates to follow for meetings #3-5

January 29th
- 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
- 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.

IRP PROCESS OVERVIEW

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

Final Report filed on November 1, 2019

ipl an AES company

2019 IRP PARTNERS AND RESOURCES

Key Partners

Ascend Analytics — Better models. Better decisions.

Itron

GDS Associates, Inc. — ENGINEERS & CONSULTANTS

CONCENTRIC ENERGY ADVISORS

VANRY ASSOCIATES

Resources

IHS Markit

Wood Mackenzie — POWER & RENEWABLES

ABB

S&P Global Market Intelligence — Energy

NREL — NATIONAL RENEWABLE ENERGY LABORATORY

Bloomberg NEW ENERGY FINANCE

eia — Independent Statistics & Analysis — U.S. Energy Information Administration

ipl an AES company

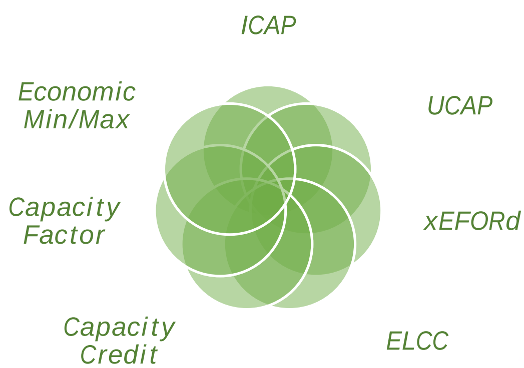
BREAK

CAPACITY: DEFINING COMMON IRP MODELING TERMS

Patrick Maguire
Director of Resource Planning

CAPACITY DEFINITIONS

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



ICAP

ICAP = INSTALLED CAPACITY

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

Examples:

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

XEFORD

xEFORd = Equivalent Demand Forced Outage Rate excluding some outages

Per MISO BPM-011, Section 3.5.4*:

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

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

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

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

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

Link: MISO PY 19/20 Resource Adequacy Documents

ELCC

ELCC = Effective Load Carrying Capability = Capacity Credit

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

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

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

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

UCAP

UCAP = UNFORCED CAPACITY = FIRM CAPACITY = PLANNING CAPACITY

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

THERMAL RESOURCE EXAMPLE

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

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

WIND AND SOLAR EXAMPLES

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

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

ICAP VS UCAP: EXAMPLES

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

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

ICAP VS UCAP: EXAMPLES

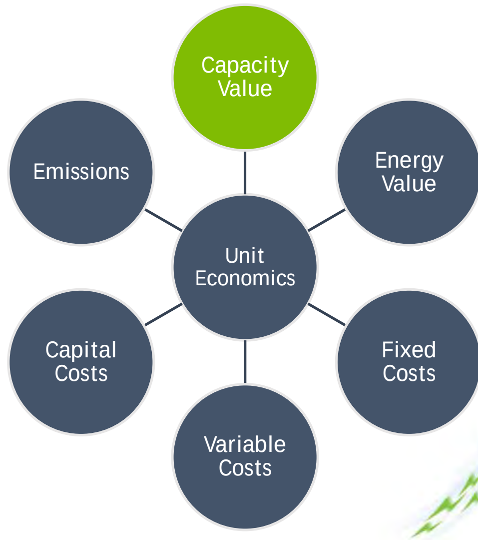
ICAP = Installed Capacity **UCAP = Unforced Capacity**

To Cover a 1,000 MW UCAP Shortfall:

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

CAPACITY: ONLY ONE PIECE OF RESOURCE VALUATION PUZZLE

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



ECONOMIC DISPATCH CAPACITY

Economic Minimum

<u>Minimum</u> amount of MW available for economic dispatch in the market

Economic Maximum

<u>Maximum</u> 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

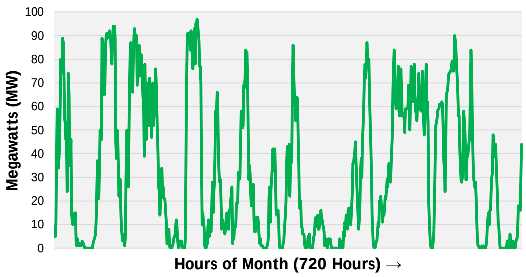
- Can be different than ICAP and UCAP
- Closely aligned with IPL Commercial Group that offers the units in MISO
- Can change daily due to ambient weather conditions, operational constraints at the plant, and other factors

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

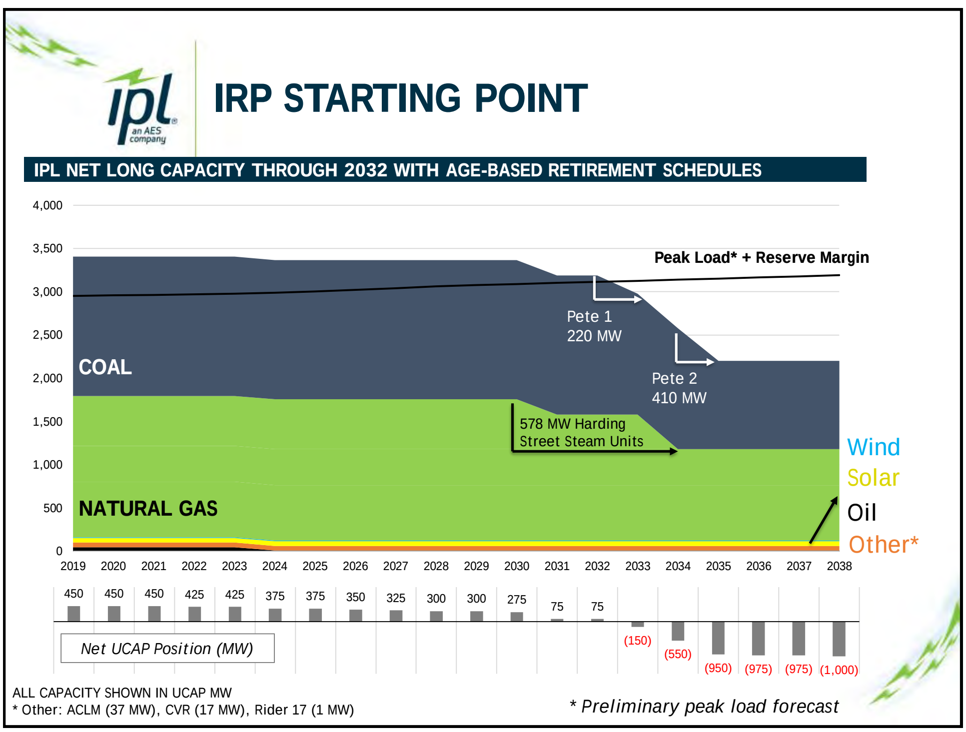
Monthly Capacity Factor = 23,500 / 72,000 = 32.6%

2019 IRP STARTING POINT: IPL LOAD AND RESOURCES

Patrick Maguire

Director of Resource Planning

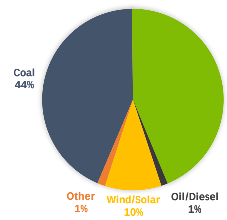

IPL'S CHANGING RESOURCE MIX
2009 - 2018
2009
Signed 100 MW PPA at Hoosier Wind Park in NW Indiana
2011
Signed 200 MW PPA at Lakefield Wind Farm in Minnesota
2013-2015
Signed 96 MW PPA for solar in Indianapolis through Rate REP
2016
Retired 260 MW of coal at Eagle Valley
2016
Finalized conversion of 630 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
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Peak Load* + Reserve Margin
Pete 1
220 MW
Pete 2
410 MW
COAL
578 MW Harding Street Steam Units
NATURAL GAS
Wind
Solar
Oil
Other*
2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038
450 450 450 425 425 375 375 350 325 300 300 275 75 75 (150) (550) (950) (975) (975) (1,000)
Net UCAP Position (MW)
ALL CAPACITY SHOWN IN UCAP MW
* Other: ACLM (37 MW), CVR (17 MW), Rider 17 (1 MW)
* Preliminary peak load forecast

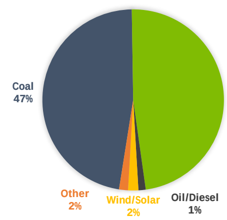
IPL RESOURCES: SUMMARY

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

% of ICAP



% of UCAP



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

IPL RESOURCES: NATURAL GAS

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

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

Total Natural Gas UCAP: 1,634 MW

IPL RESOURCES: WIND AND SOLAR

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

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

Total Renewable ICAP: 396 MW

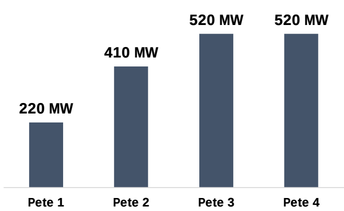
Total Renewable UCAP: 62 MW

IPL RESOURCES: COAL

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

Total Coal ICAP: 1,706 MW

Total Coal UCAP: 1,608 MW



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

INTRODUCTION TO ASCEND ANALYTICS

Patrick Maguire

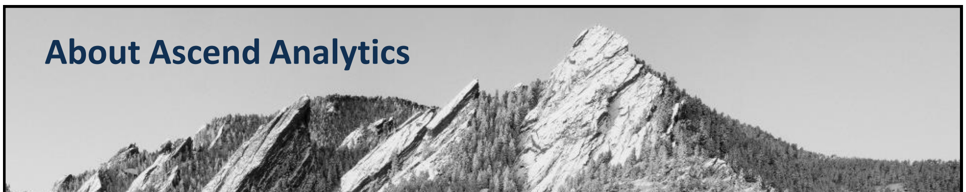
Director of Resource Planning

AGENDA

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

Ascend Analytics

About Ascend Analytics



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

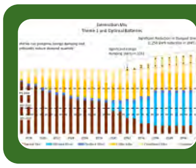
Proven and Broadly Adopted

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

Differentiated Value

PowerSimm OPS OPERATIONAL STRATEGY	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

Ascend Analytics

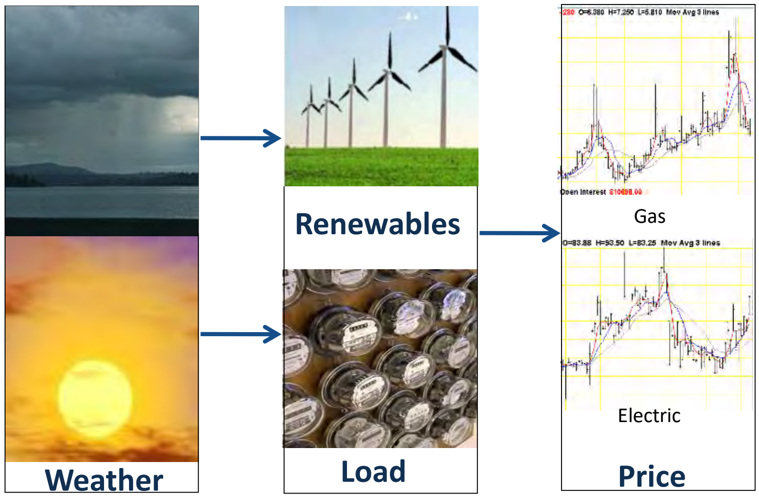
PowerSimm Suite: Short-, Intermediate, Long-term

A full, end-to-end solution

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

Ascend Analytics

Weather → Renewables/Load → Price Simulations



Ascend Analytics

Weather – Load – Delivery – Price Paradigm

Weather

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

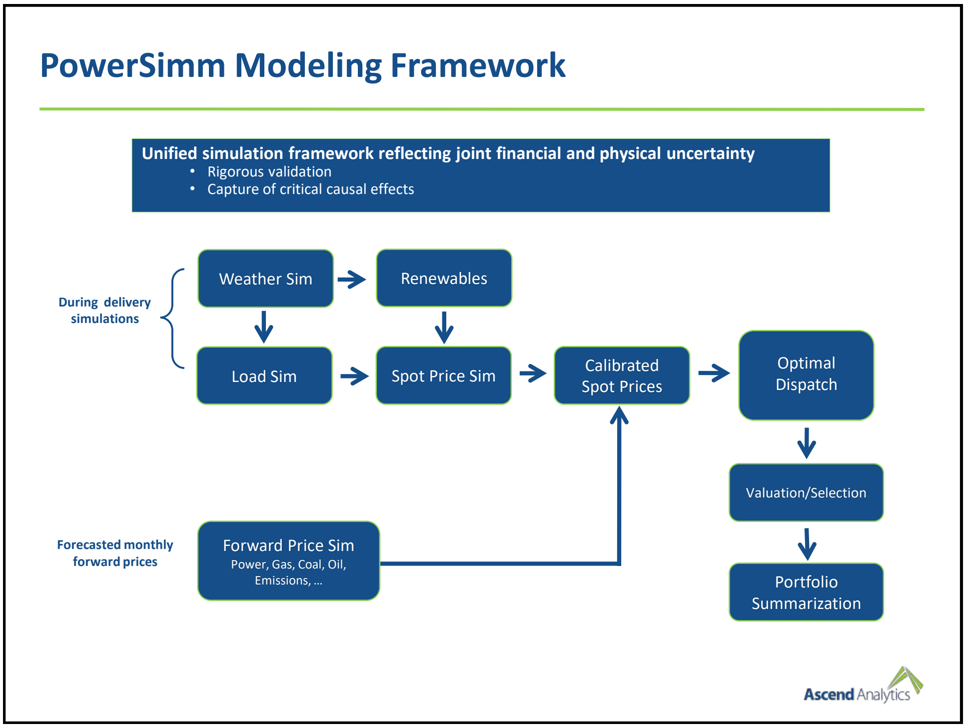
Load

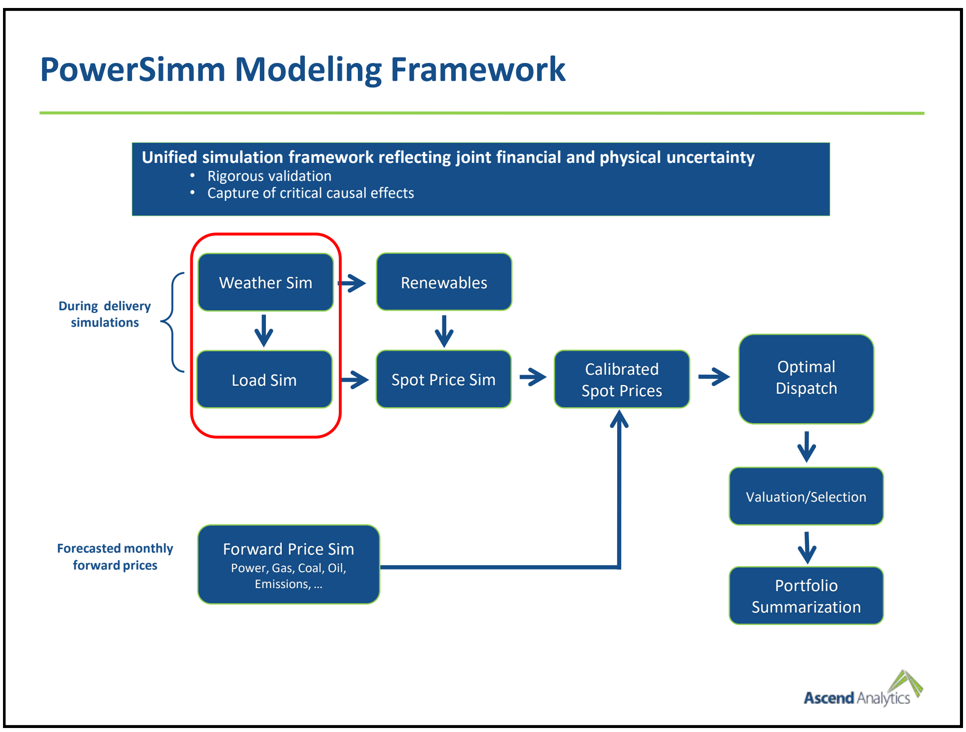
- Load is driven primarily by weather
- Key benefit is analysis of high and low temperatures produce more accurate energy expectations, and hourly demand

Delivery

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

Ascend Analytics


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
Valuation/Selection
Forecasted monthly forward prices
Forward Price Sim
Power, Gas, Coal, Oil, Emissions, ...
Portfolio Summarization
Ascend Analytics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Power, Gas, Coal, Oil, Emissions, ...
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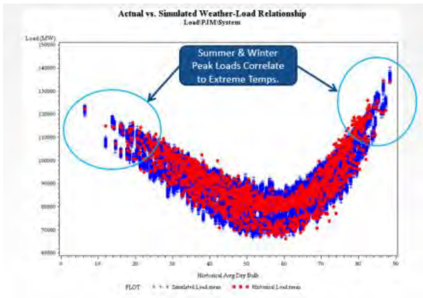
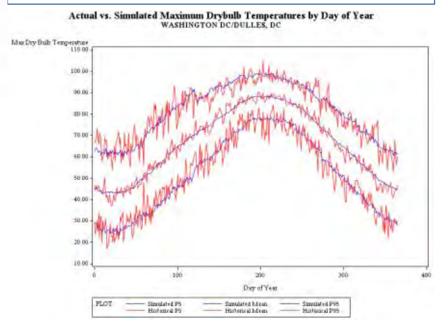
Ascend Analytics

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

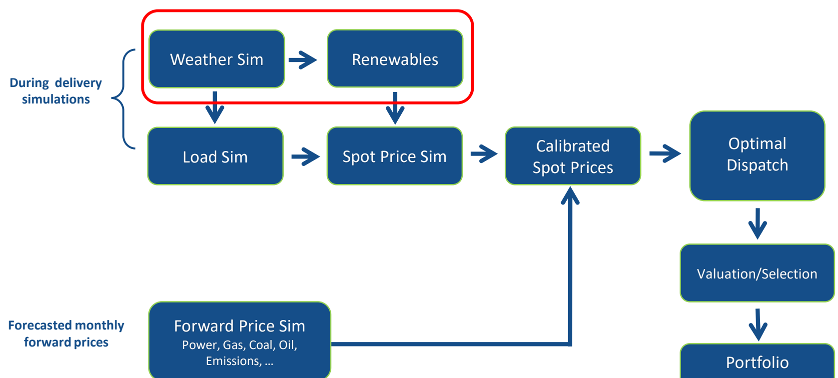
- Validate by capturing the weather – load relationship in the historical period and simulated back-cast
- The structural state space modeling captures the changes in shape with changes in load

Ascend Analytics

PowerSimm Modeling Framework

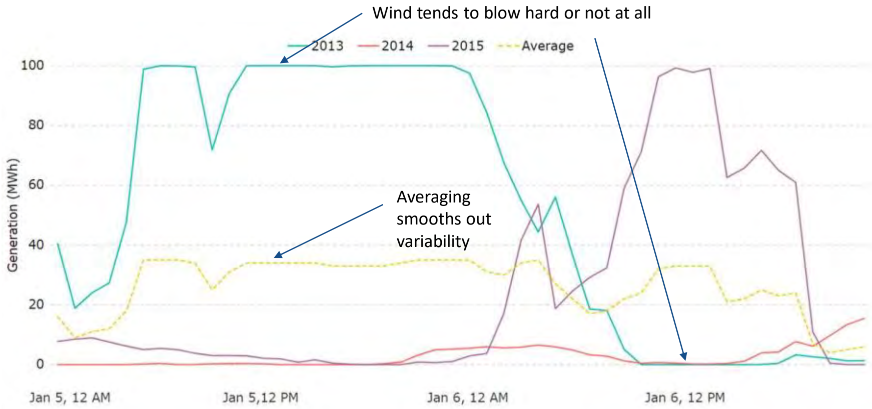
Unified simulation framework reflecting joint financial and physical uncertainty

- Rigorous validation
- Capture of critical causal effects



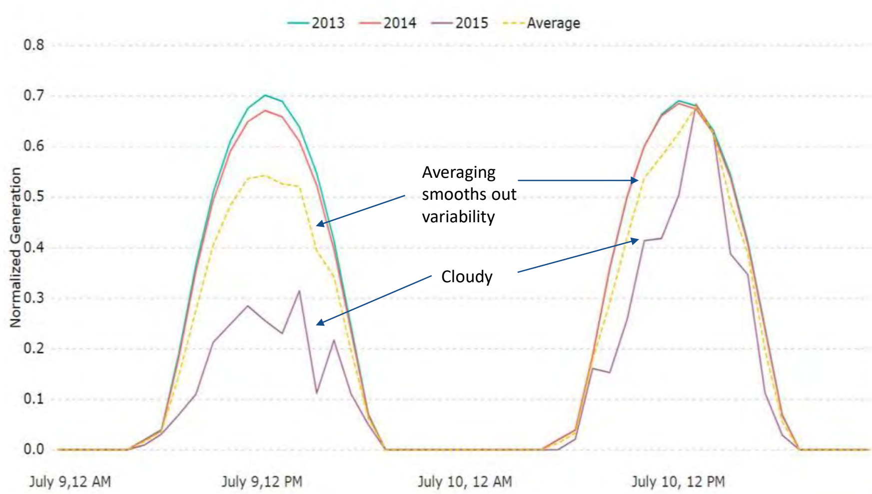
Ascend Analytics

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



Ascend Analytics

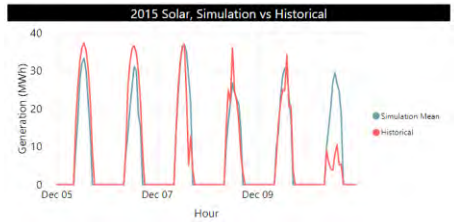
Why You Can't Just Average Renewables: Solar in July

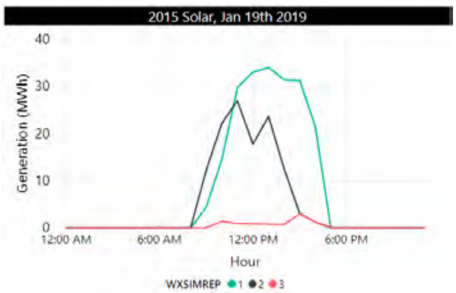


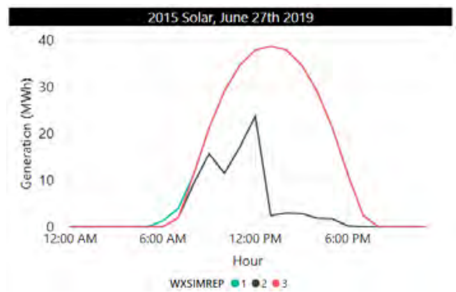
Ascend Analytics

Renewables - Solar

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







Ascend Analytics

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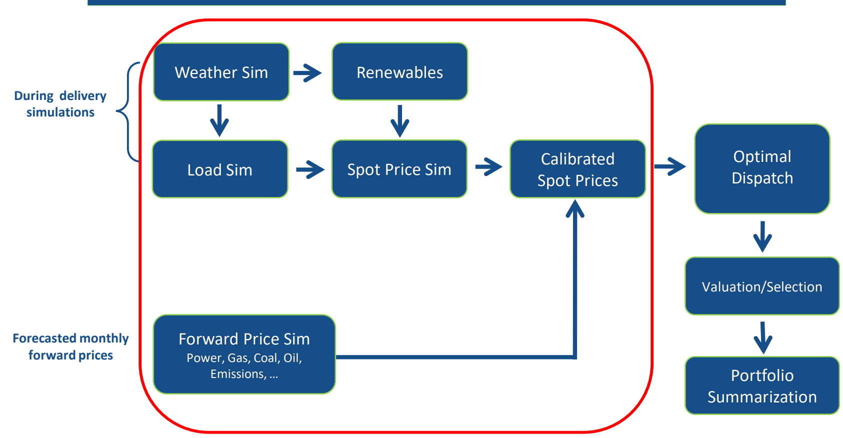
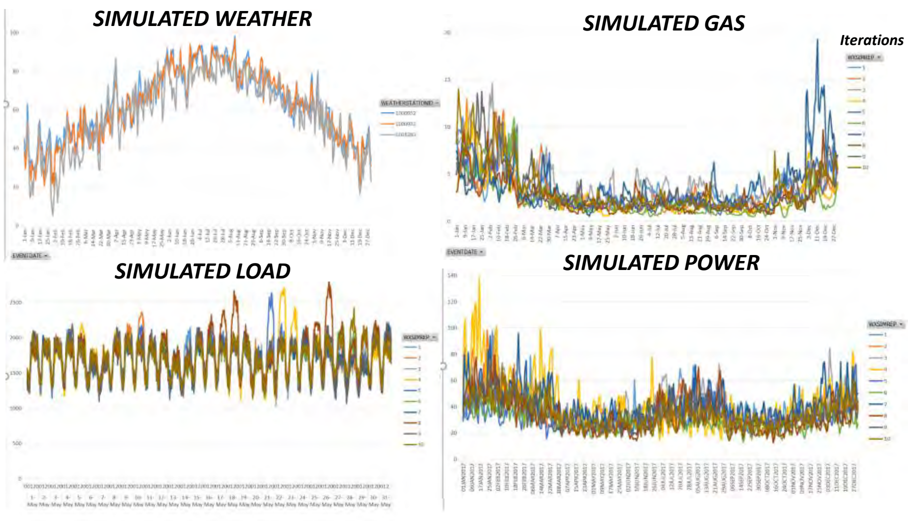


Ascend Analytics

Example: Simulated Temperature, Load, Gas and Power Prices



Ascend Analytics

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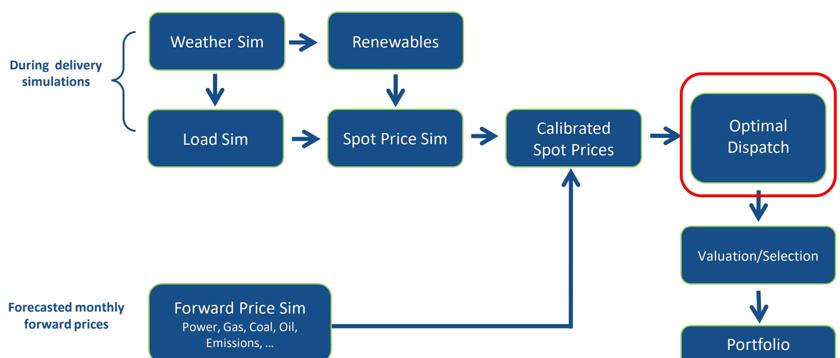
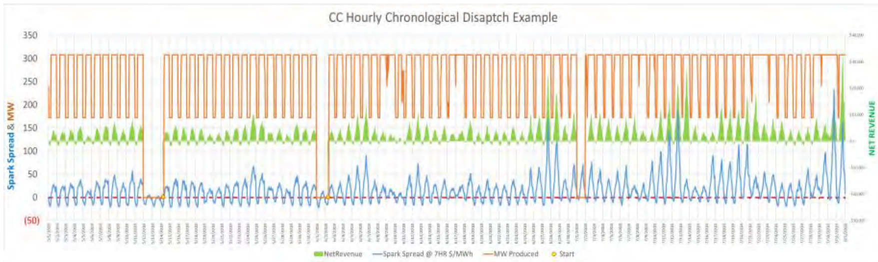
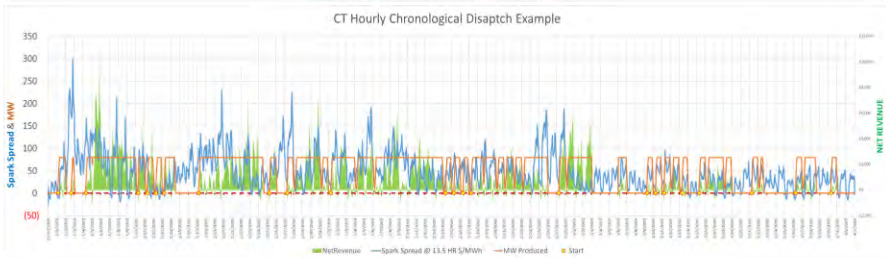


Ascend Analytics

Thermal Asset Modeling

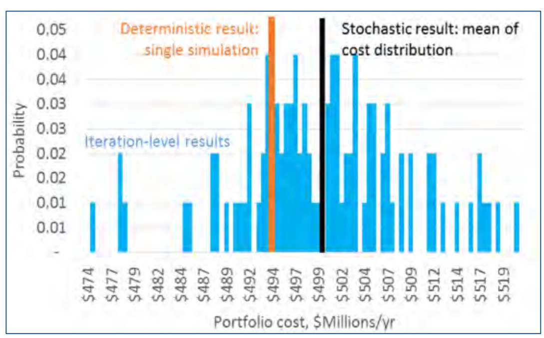




Ascend Analytics

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



Ascend Analytics

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

PowerSimm finds the best plan across hundreds of possible future conditions

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

Dave Scott

Best Triathlete

Katie Ledecky

Ryan Hall

Megan Guanier

Ascend Analytics

ipl an AES company

REPLACEMENT RESOURCES IN THE 2019 IRP

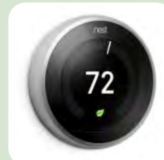
Patrick Maguire

Director of Resource Planning

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

NATURAL GAS

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

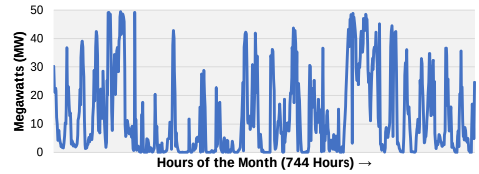
NATURAL GAS
Mature technologies with more certainty around operational parameters and capital costs

WIND

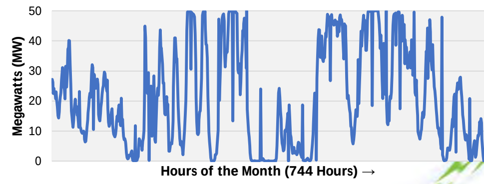
Building Profiles and Capacity Factors

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

Hypothetical 50 MW Wind Farm in Indiana
JULY Hourly Profile



Hypothetical 50 MW Wind Farm in Indiana
JANUARY Hourly Profile



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

WIND (CONT'D)

Wind Capacity Credit

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

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

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

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

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

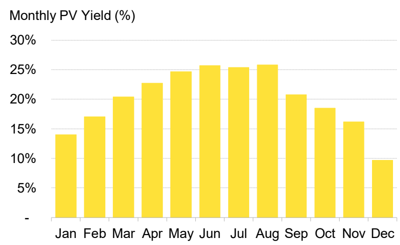
* MISO Wind & Solar Capacity Credit Report, December 2018 (PDF): https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf

SOLAR

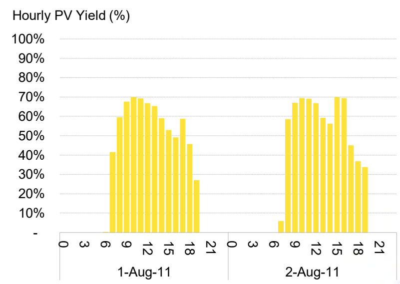
Building Profiles and Capacity Factors

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

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



Source: BloombergNEF & PVGIS.



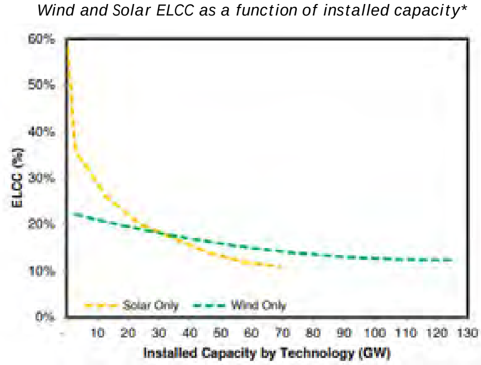
Source: BloombergNEF & PVGIS.

SOLAR (CONT'D)

Solar Capacity Credit

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

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



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

STORAGE

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

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

BREAK

DSM/EE AND LOAD FORECAST OVERVIEW

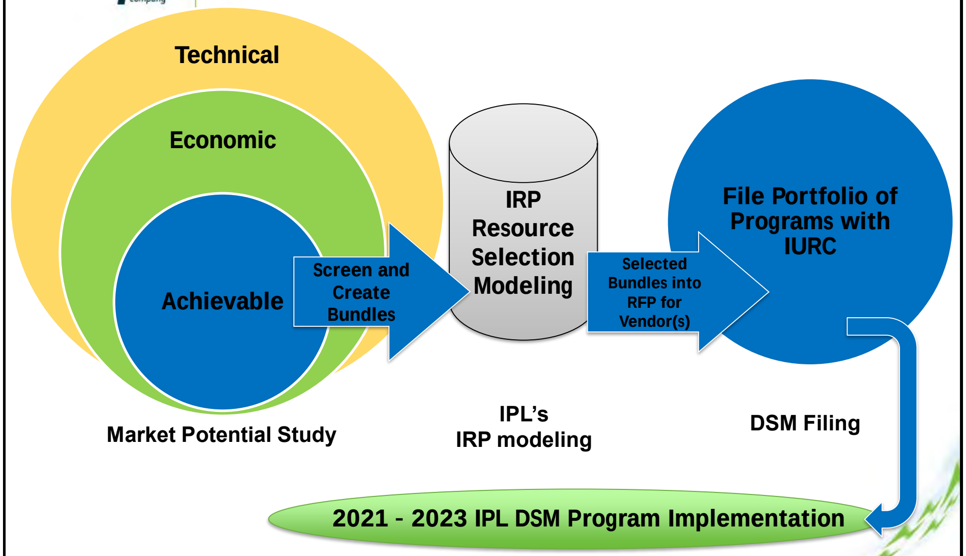
Erik Miller

Senior Research Analyst

DSM UPDATE

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

DSM PROCESS & THE IRP



DSM BUNDLES

Example of Bundles from the IPL 2016 IRP:

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

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

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

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
  - o Results of the refresh will be considered for adoption in 2020; not be modeled as a resource in the IRP

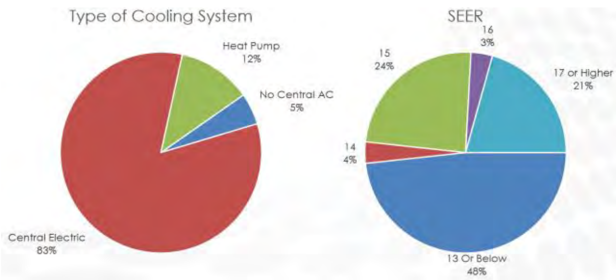
MARKET POTENTIAL STUDY PROCESS

- 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
  - o Characterizes the end uses within each sector
  - o Establishes the saturation and efficiencies of the end uses
  - o 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



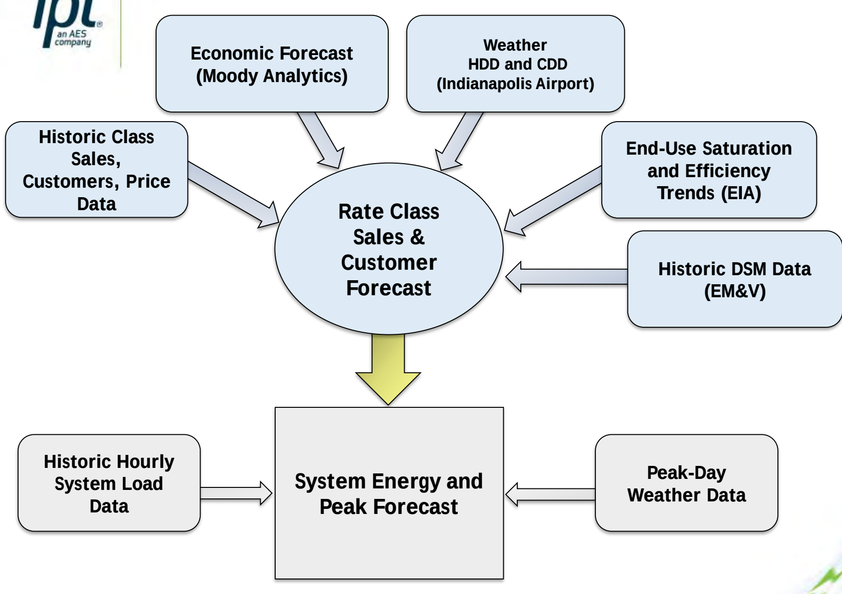
LOAD FORECASTING UPDATE

- Load Forecast
  - o Methodology & Approach
  - o 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

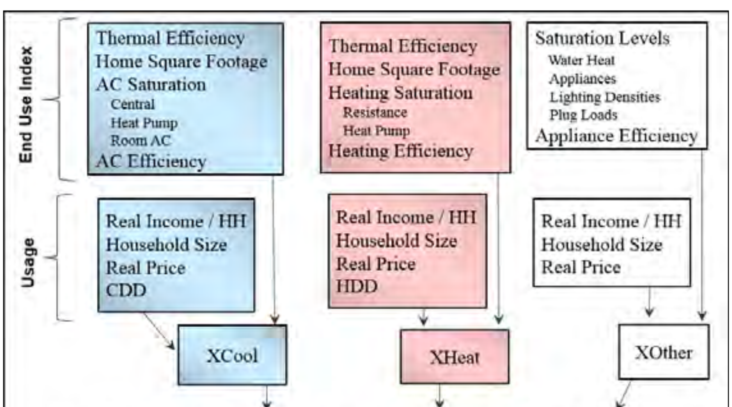
FORECAST MODELING FRAMEWORK



FORECAST MODELS

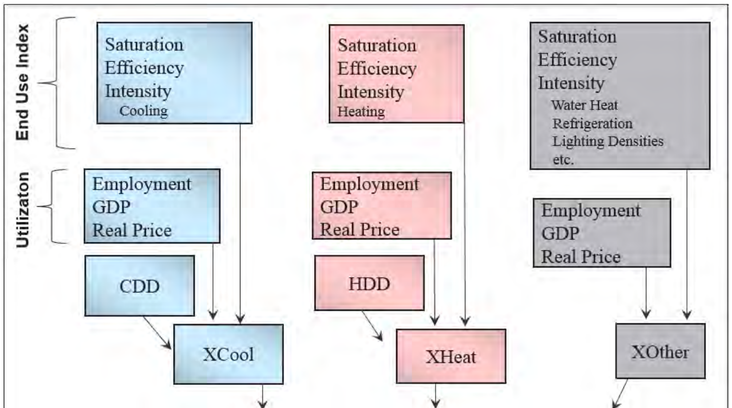
- Forecasts are based on monthly regression models using historical sales and customer data
- Sales Models
  - Residential and commercial models estimated using a blended end-use/econometric modeling framework
  - Industrial sales estimated with a generalized econometric model
  - Small rate classes 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



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

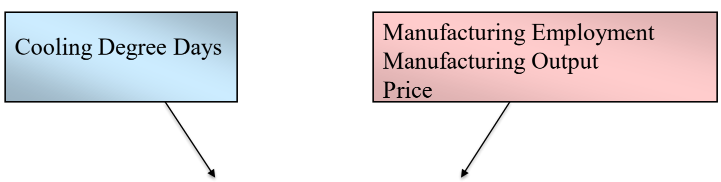
COMMERCIAL MODEL FRAMEWORK



$$\text{Sales}_m = a + b_c \times \text{XCool}_m + b_h \times \text{XHeat}_m + b_o \times \text{XOther}_m + e_m$$

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
  - MPS Results will be presented at the March 13th meeting
    - Introduction to bundles
- Load Forecast
  - 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
- 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

IPL 2019 IRP: PUBLIC ADVISORY MEETING #2

March 26, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

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

MEETING 1 RECAP

Patrick Maguire

Director of Resource Planning

2019 IRP STAKEHOLDER PROCESS

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

STAKEHOLDER PRESENTATION: SIERRA CLUB, BEYOND COAL CAMPAIGN

Matt Skuya-Boss

Lead Organizer, Sierra Club

7

DETAILED LOAD FORECAST - PEAKS & ENERGY

Erik Miller

Senior Research Analyst

8

AGENDA

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

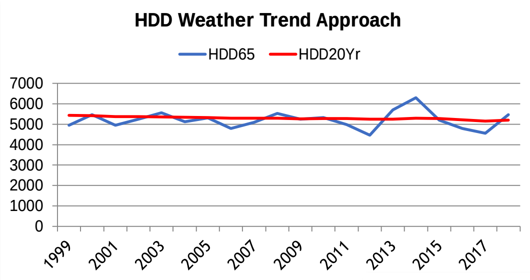
9

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

10

WEATHER 20-YR TRENDED

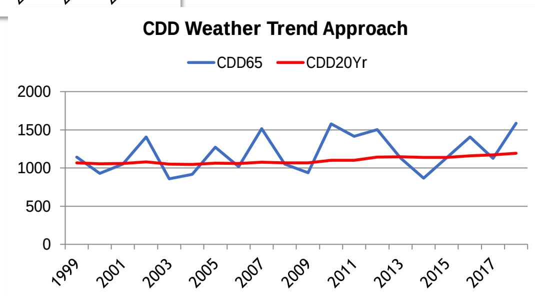


Trend line (red) developed for the 20-yr rolling average HDDs

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

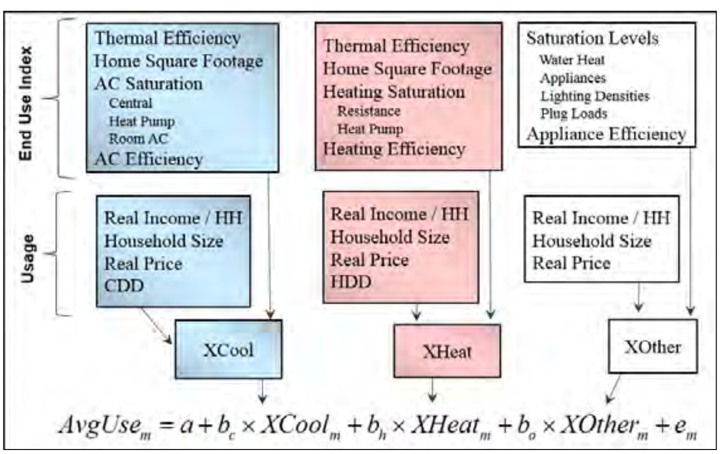
Trend line (red) developed for the 20-yr rolling average CDDs

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

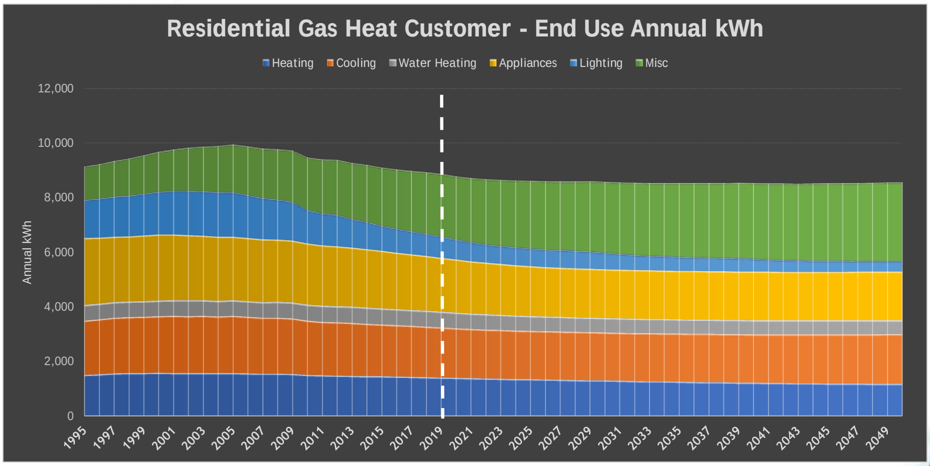


HDD = Heating Degree Day
CDD = Cooling Degree Day

RESIDENTIAL MODEL



RESIDENTIAL END USE TRENDS

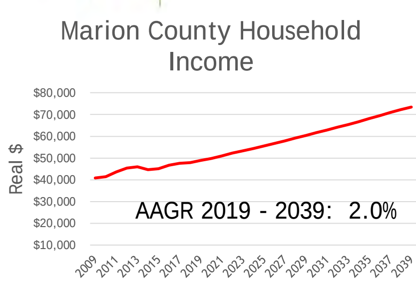


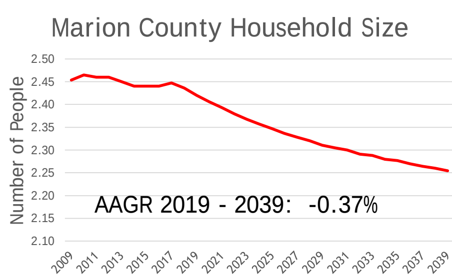
Cool AAGR 2019 - 2039: 0.13%
Heat AAGR 2019 - 2039: -0.39%

AAGR = Average Annual Growth Rate

Source: 2018 EIA Annual Energy Outlook

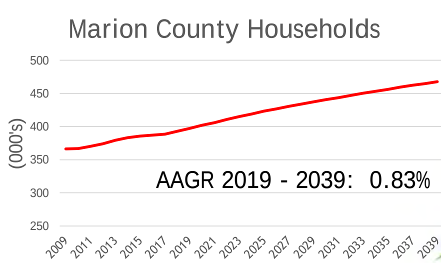
RESIDENTIAL ECONOMIC DRIVERS



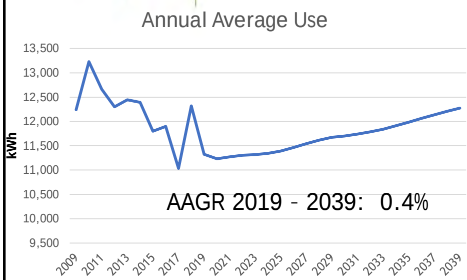


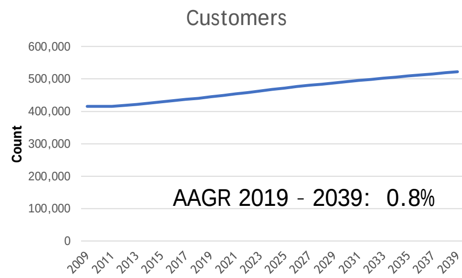
- Moody's Analytics Marion County Economic Forecast
- Multifamily Growth:
  - Increasing # of households
  - Decreasing persons / household

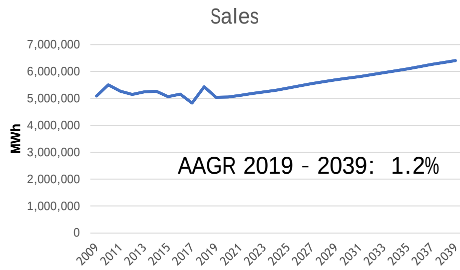
AAGR = Average Annual Growth Rate



RESIDENTIAL FORECAST

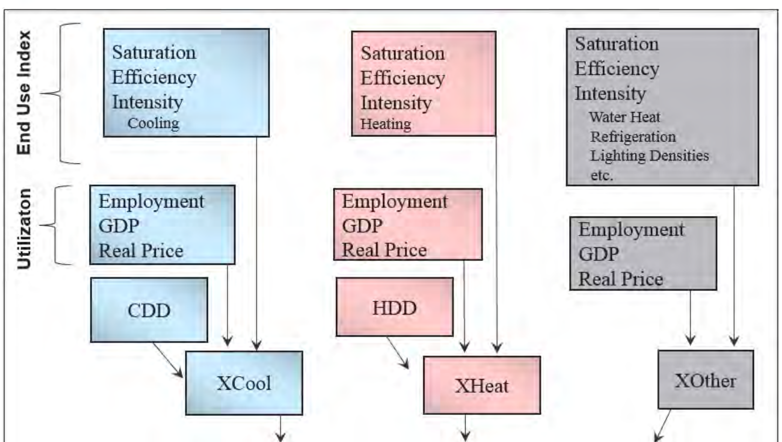






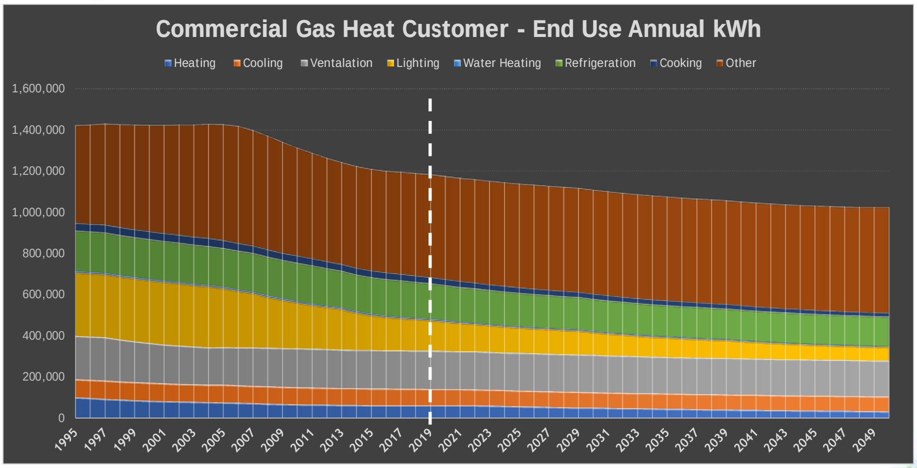
AAGR = Average Annual Growth Rate

COMMERCIAL MODEL



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

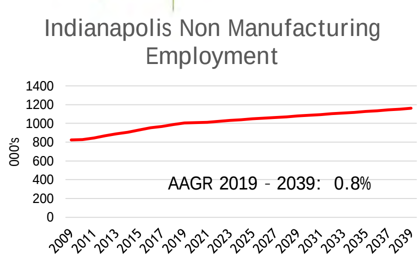
COMMERCIAL END USE TRENDS

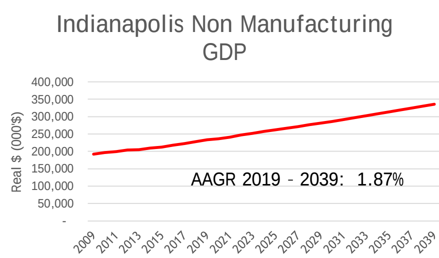


Cool AAGR 2019 - 2039: -0.45%
Heat AAGR 2019 - 2039: -1.9%
AAGR = Average Annual Growth Rate

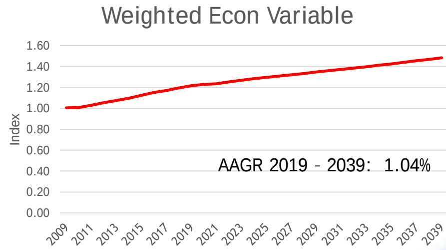
Source: 2018 EIA Annual Energy Outlook

COMMERCIAL ECONOMIC DRIVERS





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



AAGR = Average Annual Growth Rate

INDUSTRIAL MODEL

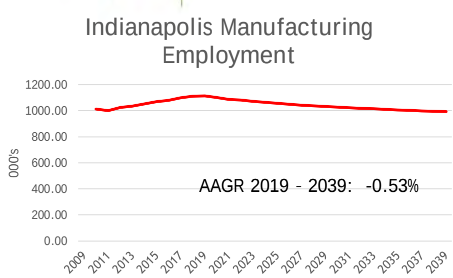
Industrial sales are estimated with a generalized econometric model

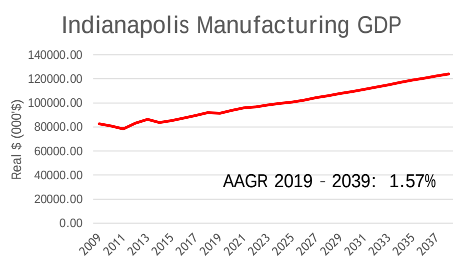
Cooling Degree Days

Manufacturing Employment
Manufacturing Output
Price

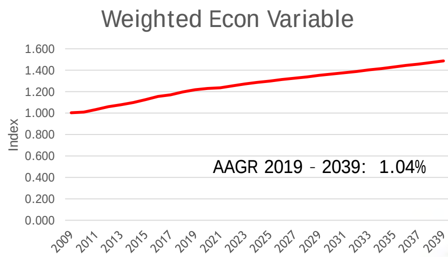
$$Sales_m = a + b_{cdd} \times CDD_m + b_{Econ} \times EconVariable_m + e_m$$

INDUSTRIAL ECONOMIC DRIVERS





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

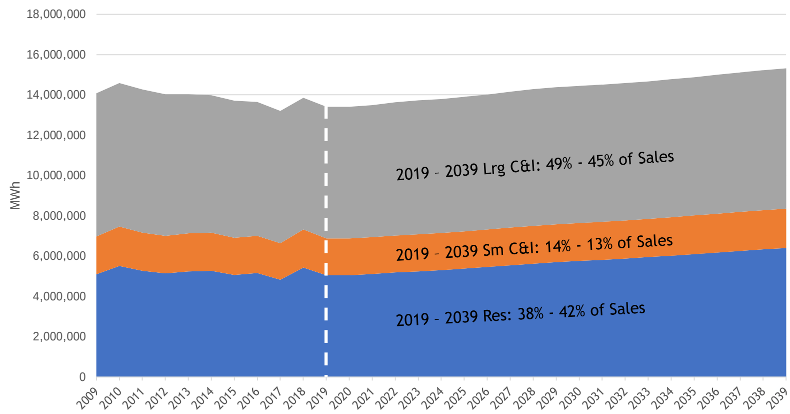


AAGR = Average Annual Growth Rate

CLASS SALES FORECAST

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

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



No Losses Included

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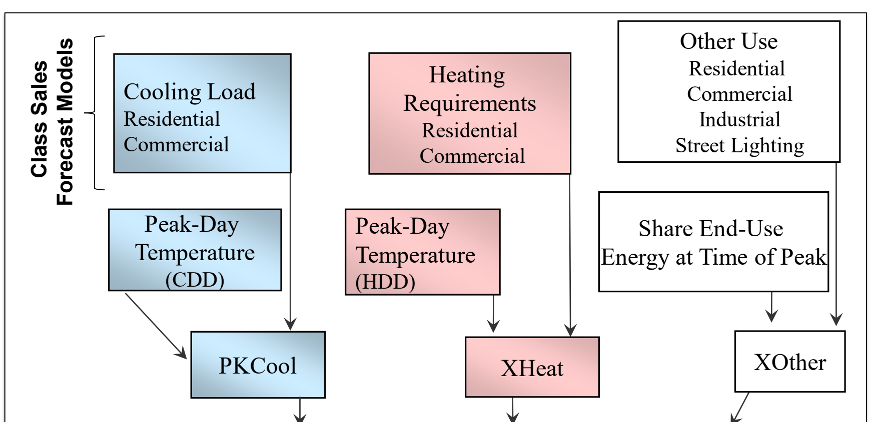
PEAK MODEL



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

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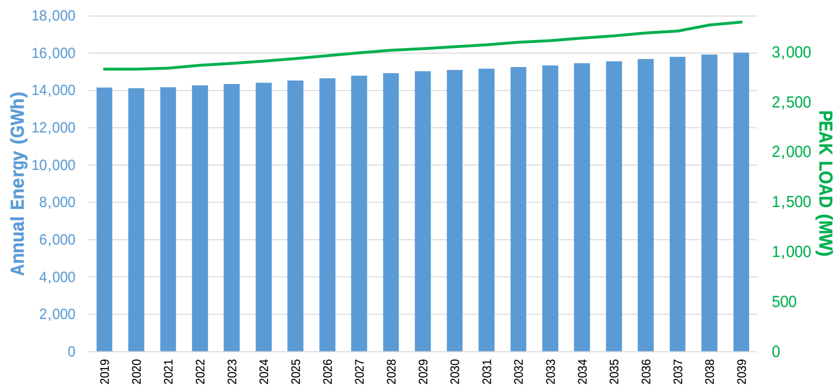
IRP ENERGY & PEAK FORECAST

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

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



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

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END USE ANALYSIS OBJECTIVES

RESEARCH TO IMPROVE UPON INPUTS TYPICALLY USED IN LOAD FORECAST

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

UNDERSTANDING ENERGY EFFICIENCY BEHAVIOR

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

*commercial building energy consumption survey

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RESEARCH DESIGN-RESIDENTIAL END USE ANALYSIS

SELF-REPORT SURVEY

Online/Mail

384 responses (95/5)

Sample stratified by average usage

Data elements

End-use saturation

Miscellaneous end-uses

Hours of use

Willingness to participate in a site visit

Demographics

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

SITE VISITS

Sub-sample of survey respondents (n=68)

Verify accurate reporting on survey

Catalogue of misc. end-uses

Evaluate willingness to participate in programs

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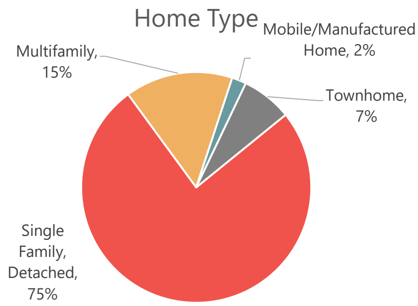
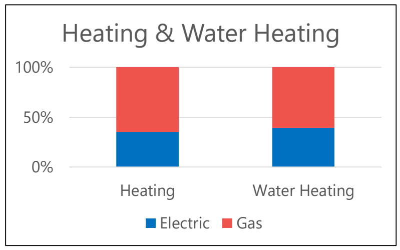
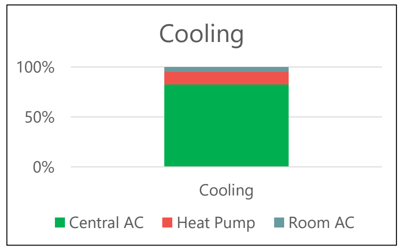
Market Segmentation







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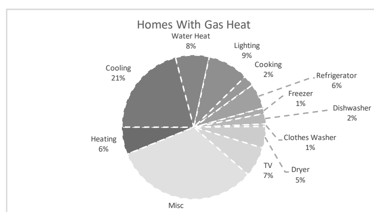
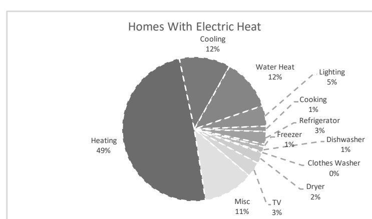
End Use Profiles

average annual kWh per home

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





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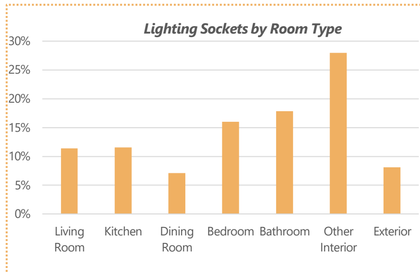
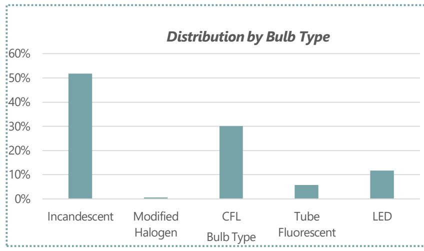
LIGHTING *averages per home*

40.5 *sockets*

5.5 *bulbs in storage*

61% *of storage are incandescent*





LIGHTING

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

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

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

RESEARCH DESIGN-SMALL C&I END USE ANALYSIS

ENERGY INTENSITY

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

END-USE SATURATION

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

BUILDING TYPES

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

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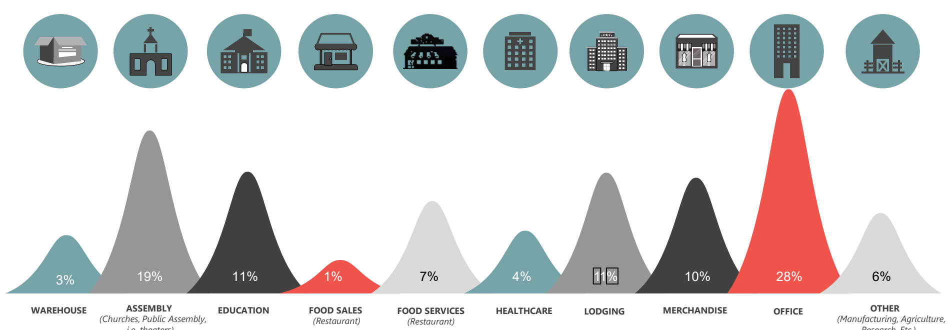
SEGMENTATION *by Electric Consumption*

Commercial Segmentation by Commercial Building Type



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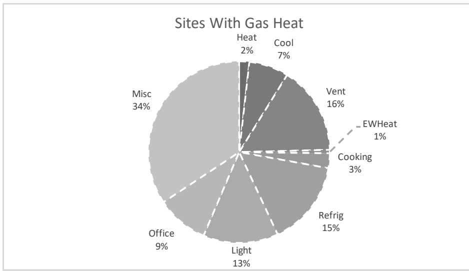
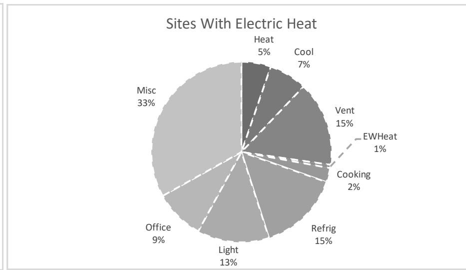
AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-2
Page 68 of 246

End Use Profiles

average annual kWh per commercial site





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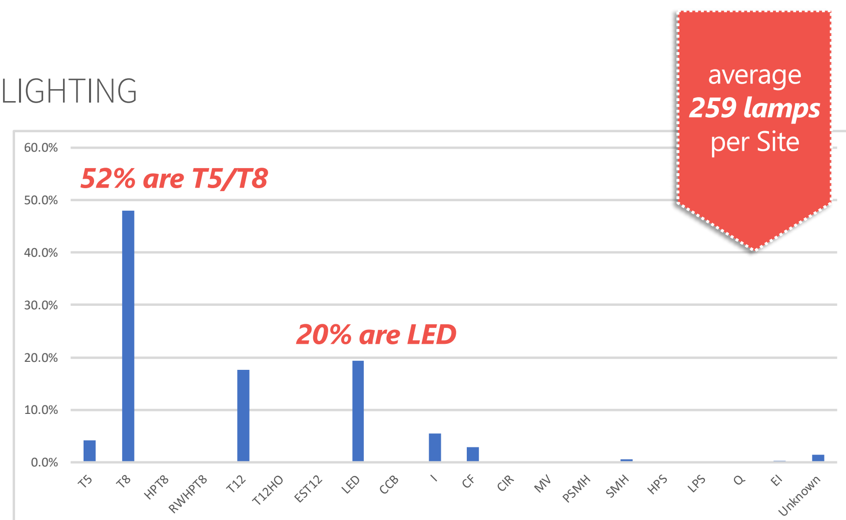
LIGHTING



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RESEARCH DESIGN LARGE C&I END-USE ANALYSIS

IDENTIFY POPULATION FRAME

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

RECRUIT PARTICIPANTS
(45 accounts)

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

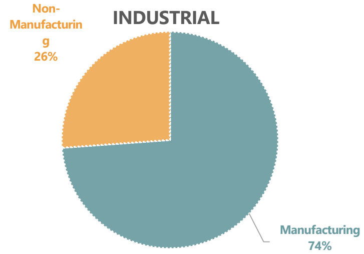
CONDUCT ON-SITE SURVEYS

Collect equipment characteristics
Willingness to participate

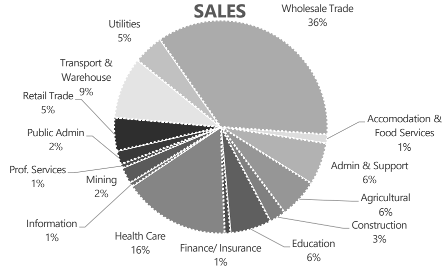
COLLECT INFORMATION ON EFFICIENCY ACTIVITY

INDUSTRY SEGMENTATION

DISTRIBUTION OF ENERGY SALES - INDUSTRIAL

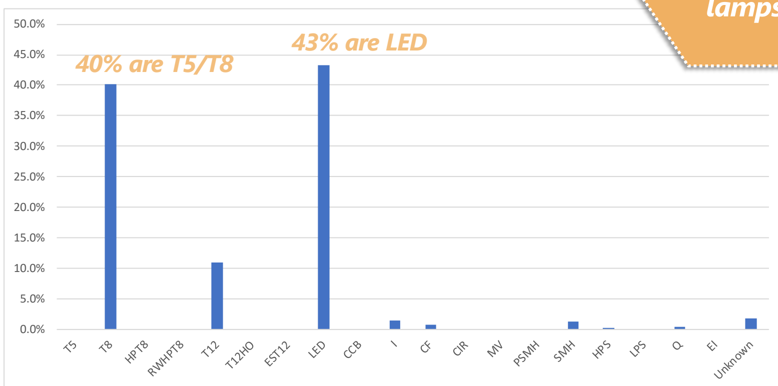


DISTRIBUTION OF NON-MANUFACTURING SALES



LIGHTING

average **347 lamps** per site



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IPL DSM MARKET POTENTIAL STUDY (MPS) PRELIMINARY RESULTS

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

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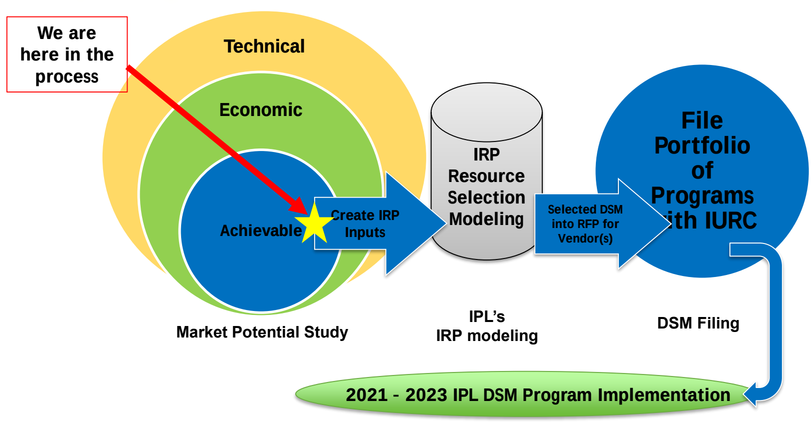
DSM PROCESS & THE IRP



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POTENTIAL STUDY METHODOLOGY

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METHODOLOGY-MEASURE CHARACTERIZATION

Draft Results

01 INCLUDES...

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

02 DATA SOURCES...

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

03 ASSUMPTIONS...

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

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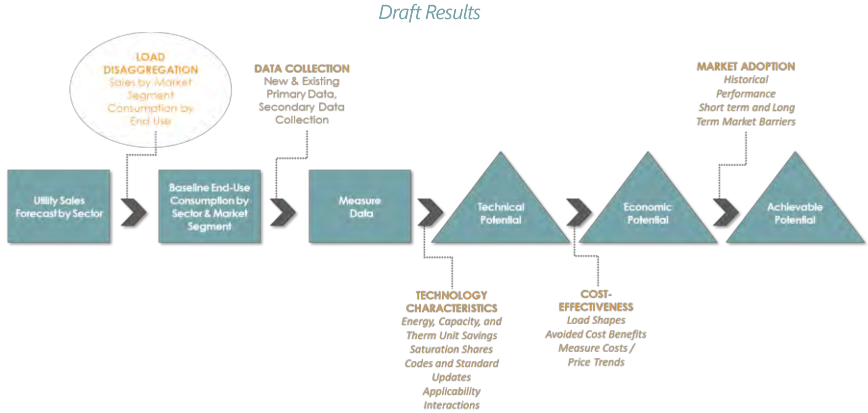
METHODOLOGY-STUDY APPROACH

Draft Results



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METHODOLOGY-TECHNICAL POTENTIAL

Draft Results

Residential Example *(electric)*

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

analysis covers a 20-year timeframe

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

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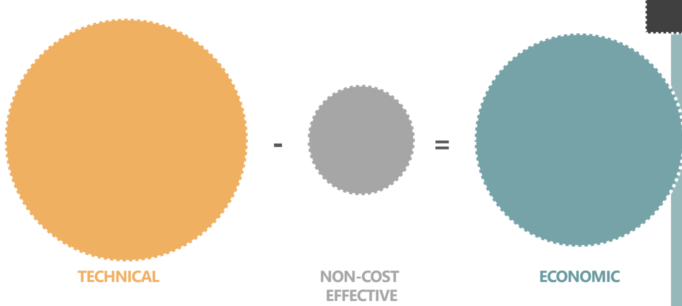
METHODOLOGY-ECONOMIC POTENTIAL

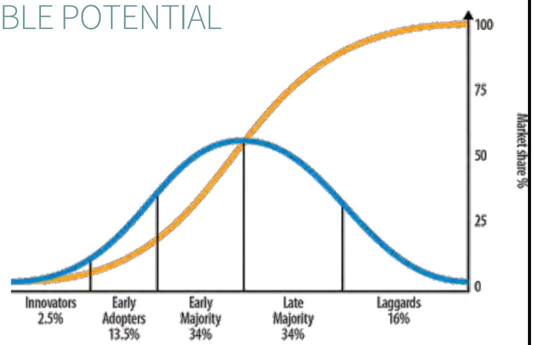
Draft Results

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



METHODOLOGY-ACHIEVABLE POTENTIAL

Draft Results



ADOPTION RATES

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

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METHODOLOGY-ACHIEVABLE POTENTIAL

Draft Results

SHORT TERM ADOPTION RATE

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

LONG TERM ADOPTION RATE

incentive and payback are two primary variables; others considered

IPL willingness to participate research

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RESIDENTIAL

RESIDENTIAL POTENTIAL RESULTS

Draft Results

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

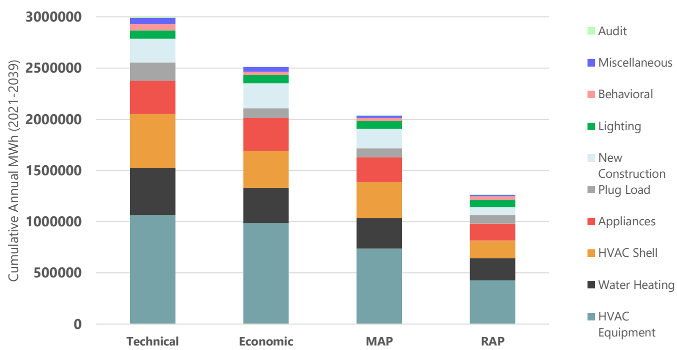
02 **Economic Potential is about 85% of Technical Potential**
- Utility Cost Test used for benefit-cost screening
- Low-income measures retained in Economic Potential, regardless of UCT ratio

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

RESIDENTIAL POTENTIAL RESULTS

Draft Results

2021-2039 Cumulative (gross MWh)



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

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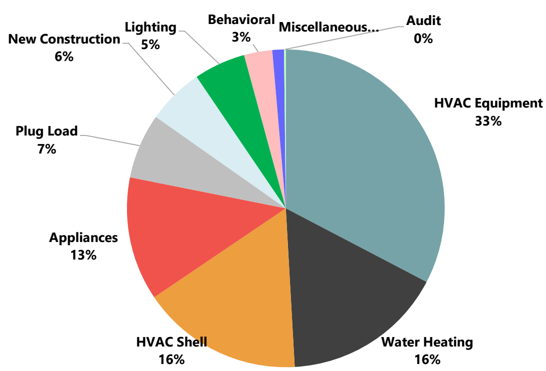
RESIDENTIAL POTENTIAL RESULTS

Draft Results

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



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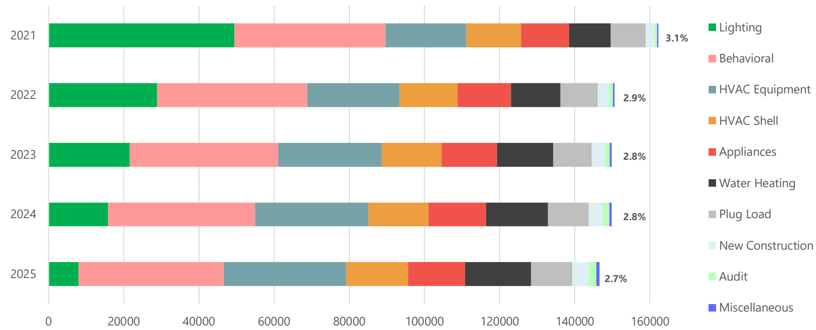
RESIDENTIAL POTENTIAL RESULTS

Draft Results

Annual Incremental RAP 2021-2025 (gross MWh)



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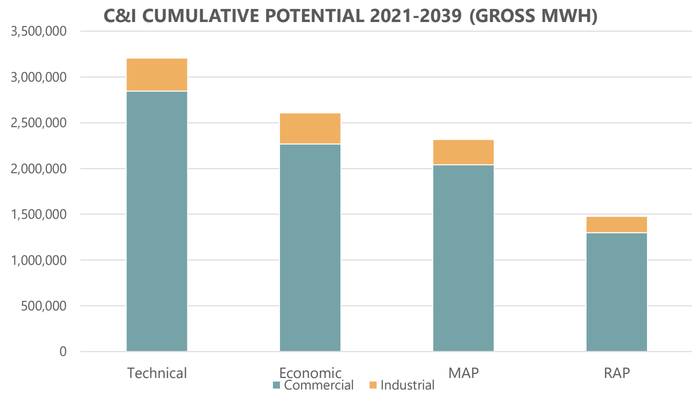
COMMERCIAL & INDUSTRIAL

ipl an AES company

C&I POTENTIAL RESULTS

Draft Results



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

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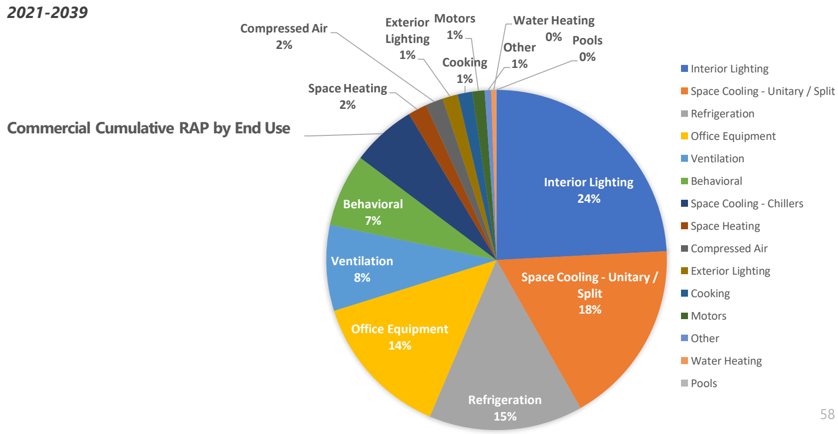
COMMERCIAL POTENTIAL RESULTS

Draft Results

2021-2039



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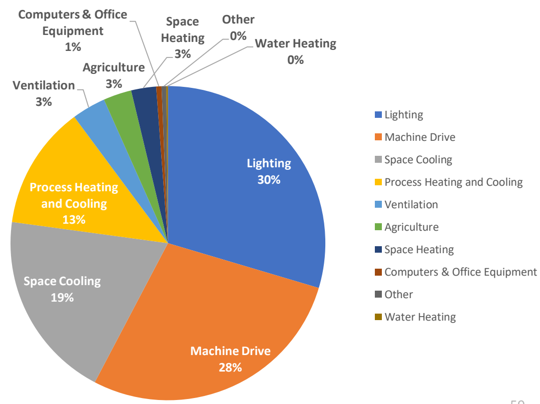
INDUSTRIAL POTENTIAL RESULTS

Draft Results

2021-2039

Industrial Cumulative RAP by End Use



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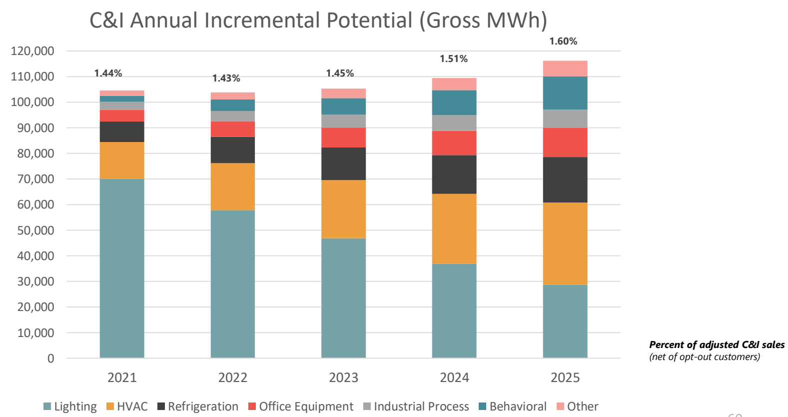
TOTAL C&I 2021-2025 POTENTIAL

Draft Results



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DEMAND RESPONSE

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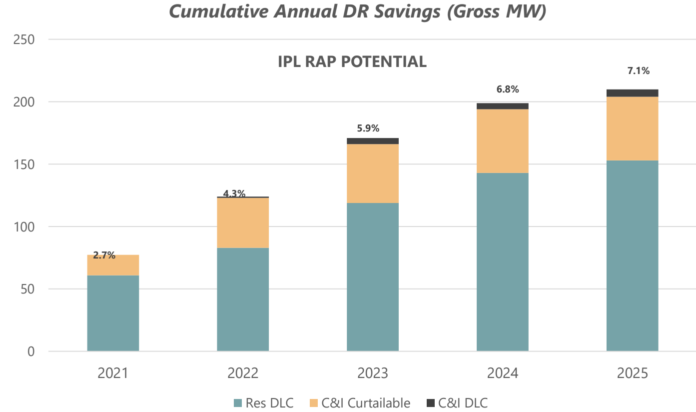
DEMAND RESPONSE

Draft Results

Cumulative Annual DR Savings (Gross MW)



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MPS PRELIMINARY RESULTS NEXT STEPS

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

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LUNCH

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COMMODITY PRICES AND MODELING

Patrick Maguire

Director of Resource Planning

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FORWARD CURVES USED IN IRP MODELING

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

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FUNDAMENTAL FORECAST VENDOR

Wood Mackenzie
POWER & RENEWABLES

- **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

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

MISO CAPACITY PRICE FORECAST

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

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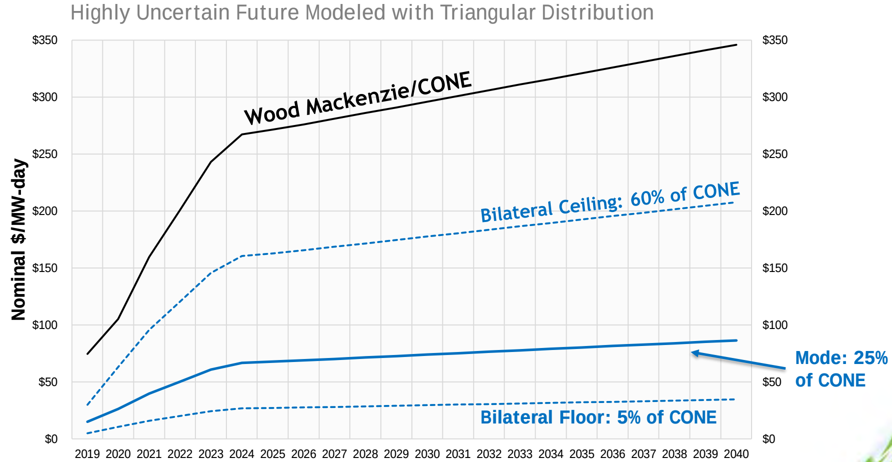
MISO CAPACITY PRICE FORECAST (CONT.)

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



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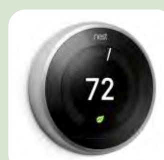
ASSUMPTIONS FOR REPLACEMENT RESOURCES

Patrick Maguire

Director of Resource Planning

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

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

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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

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RESOURCE COST DATA SOURCES

PUBLIC DATA SOURCES

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

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

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

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

RESOURCE COST DATA SOURCES (CONT.)

CONFIDENTIAL DATA SOURCES AVAILABLE WITH SIGNED NDA

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

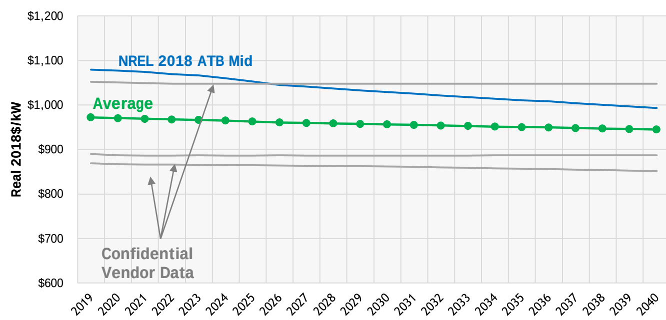
Bloomberg New Energy Finance (BNEF)
- Energy Project Asset Valuation Model (EPVAL 8.8.4)
- 2H 2018 LCOE: Data Viewer
- Subscription Required: https://www.bnef.com

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

NATURAL GAS TECHNOLOGIES

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

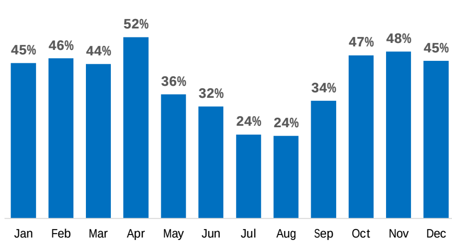
EXAMPLE: Gas Combined Cycle Capital Costs (Real 2018 $/kW)



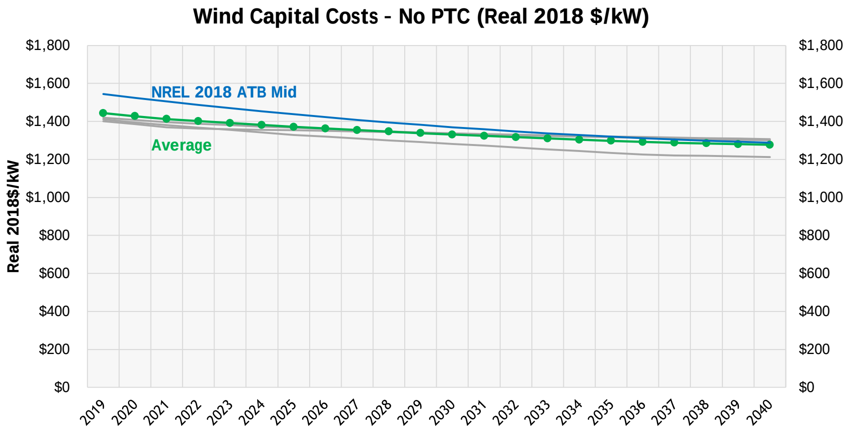
WIND: OPERATIONAL PARAMETERS

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

Generic Wind: Monthly Capacity Factors



WIND: CAPITAL COSTS



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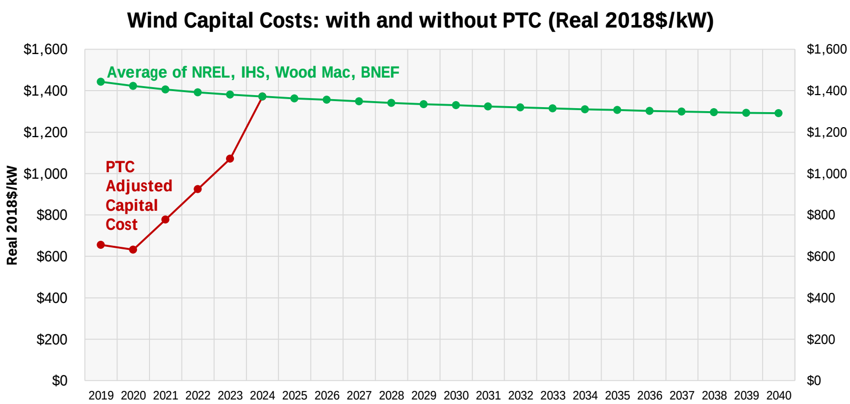
WIND: CAPITAL COSTS (CONT.)

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



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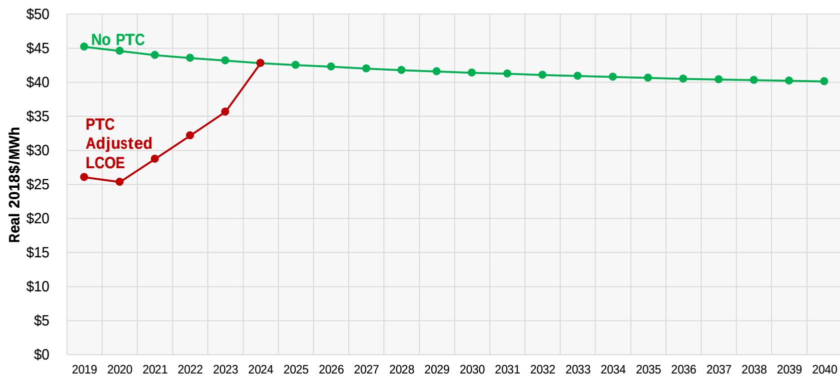
WIND LCOE

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

Wind LCOE (Real 2018$/MWh)



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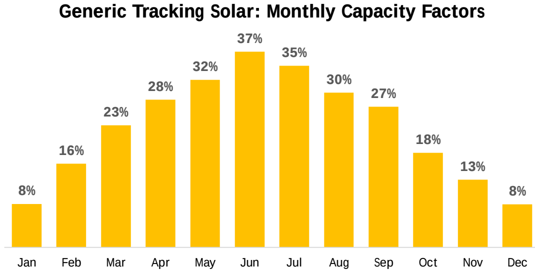
SOLAR: OPERATIONAL PARAMETERS

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

Generic Tracking Solar: Monthly Capacity Factors



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SOLAR: CAPACITY FACTORS

IPL Rate REP Solar: 2016-2018 Monthly Capacity Factors

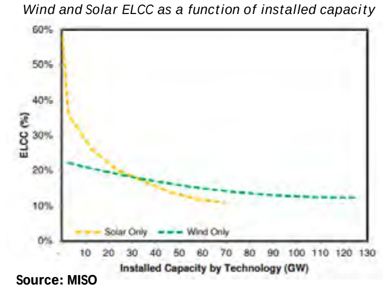
	GROUND FIXED TILT			TRACKING			COMMERCIAL ROOFTOP		
	2016	2017	2018	2016	2017	2018	2016	2017	2018
Jan	9.8%	5.8%	7.0%	9.7%	6.1%	7.1%	6.7%	4.0%	4.7%
Feb	16.5%	15.7%	9.9%	17.3%	16.4%	10.4%	13.2%	12.6%	9.4%
Mar	19.5%	18.6%	15.7%	23.0%	21.6%	19.8%	16.4%	16.7%	15.2%
Apr	19.3%	21.3%	21.8%	27.1%	24.8%	26.2%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

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

SOLAR CAPACITY CREDIT

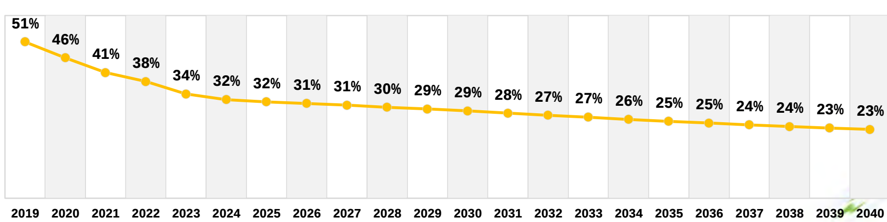
- Solar capacity credit changes as more solar is added to the MISO system
- "Duck curve" phenomenon of shifting net peak load
- Annual capacity credit calculated using forecasted annual installed GW of utility solar in MISO Central
- Installed solar forecast from Wood Mackenzie

Wind and Solar ELCC as a function of installed capacity

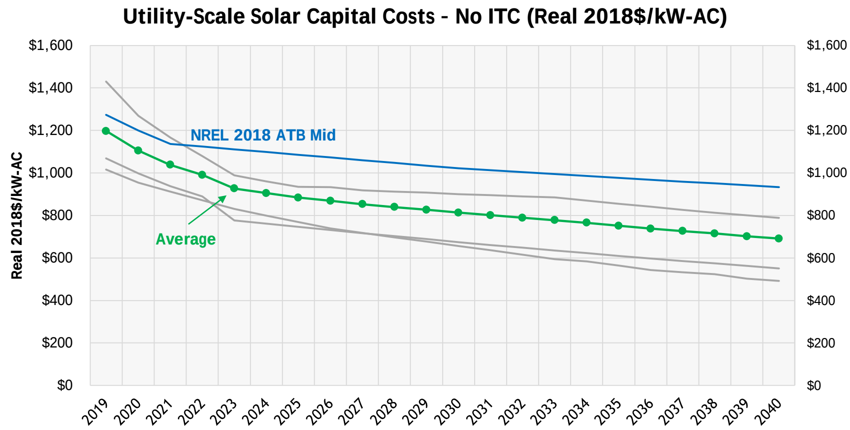


Source: MISO

Annual Solar Capacity Credit



SOLAR: CAPITAL COSTS



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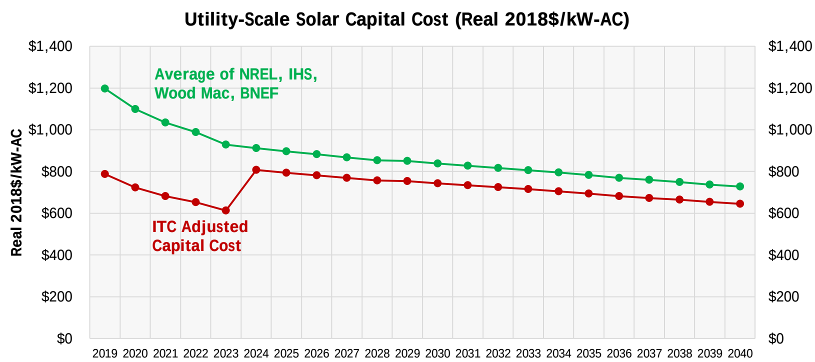
SOLAR: CAPITAL COSTS (CONT.)

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



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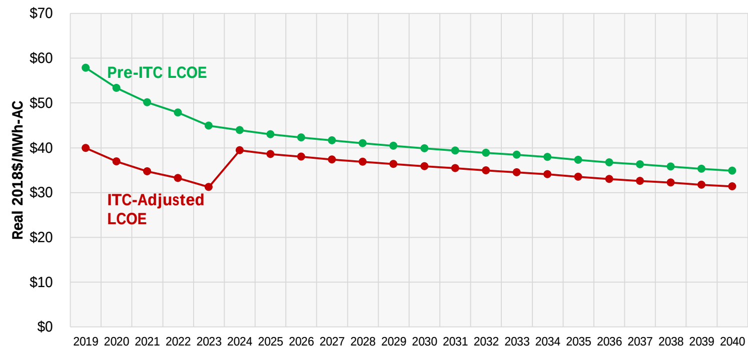
SOLAR: LCOE

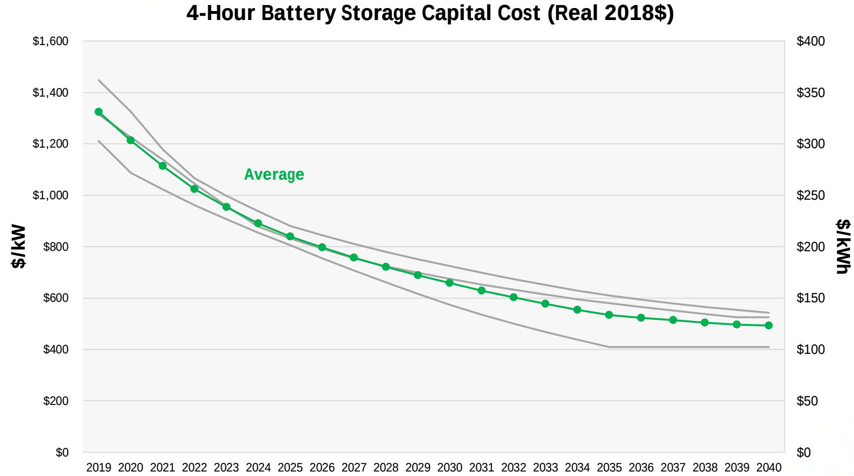
	2020	2021	2022	2023	2024+
ITC Safe Harbor	30%	30%	30%	30%	10%

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



STORAGE CAPITAL COST

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



SCENARIO ANALYSIS FRAMEWORK & PROPOSED SCENARIOS

Patrick Maguire

Director of Resource Planning

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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

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SCENARIO DRIVERS

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

PROPOSED SCENARIO FRAMEWORK

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

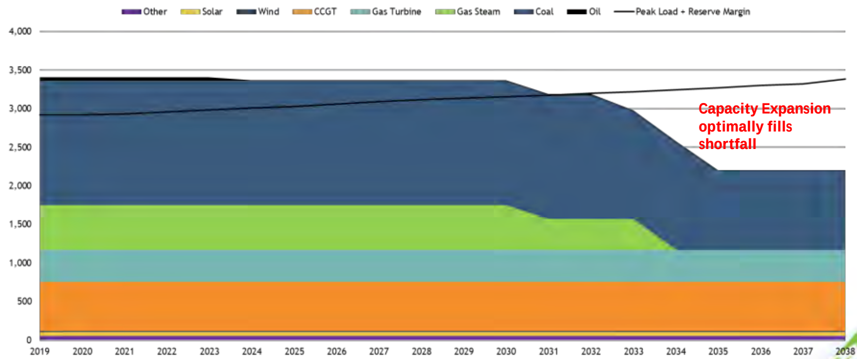
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
No Accelerated Retirements	**Portfolio 1**	1a	1b	1c	1d
Pete Unit 1 Retire **2021** Pete Units 2-4 Operational	**Portfolio 2**	2a	2b	2c	2d
Pete 1 Retire **2021**; Pete 2 Retire **2023** Pete Units 3-4 Operational	**Portfolio 3**	3a	3b	3c	3d
Pete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

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

IPL STARTING POSITION

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

BASE CASE: NO ACCELERATED RETIREMENTS



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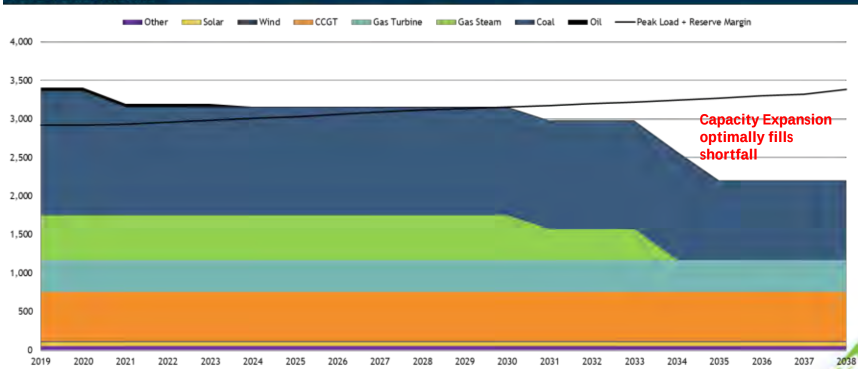
RETIREMENT PORTFOLIOS (1 OF 4)

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

PETE 1 EARLY RETIRE



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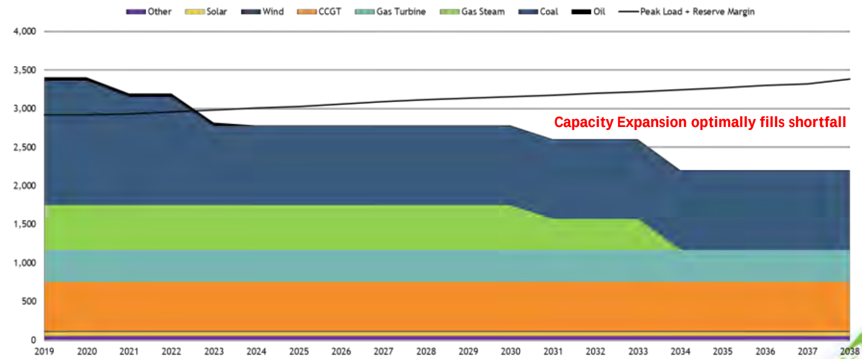
RETIREMENT PORTFOLIOS (2 OF 4)

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

PETE 1-2 EARLY RETIRE: SHORT IN 2023



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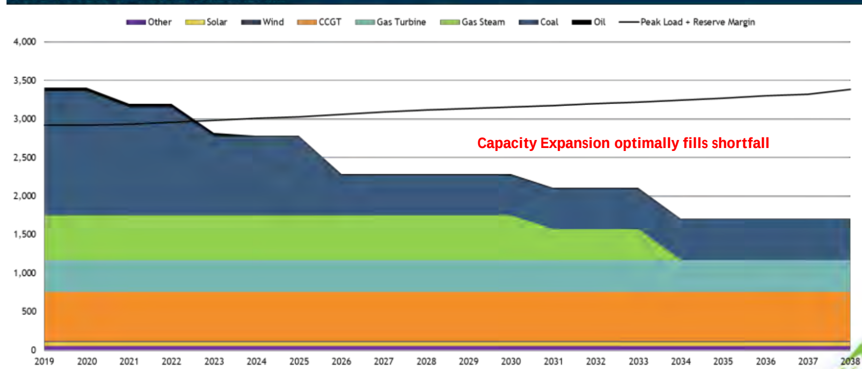
RETIREMENT PORTFOLIOS (3 OF 4)

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

PETE 1 + PETE 2 + PETE 3 EARLY RETIRE



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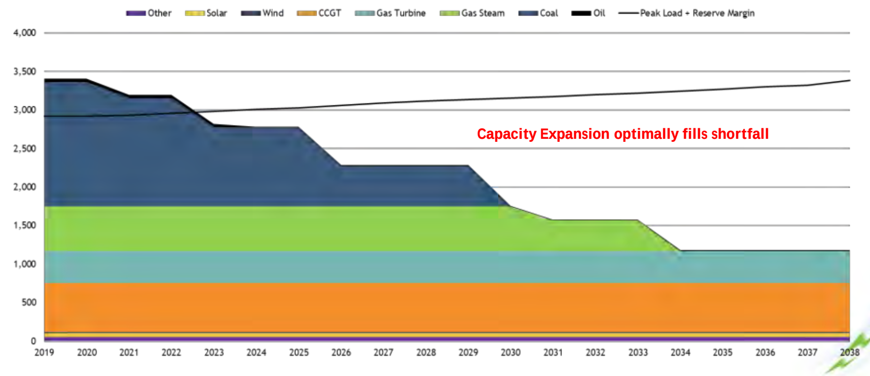
RETIREMENT PORTFOLIOS (4 OF 4)

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

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



PORTFOLIO COMPARISON

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

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

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

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

ROLE OF STOCHASTICS

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

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FINAL Q&A AND NEXT STEPS

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NEXT STEPS

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

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

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IPL 2019 IRP: PUBLIC ADVISORY MEETING #3

May 14, 2019

WELCOME & OPENING REMARKS

Lisa Krueger

President, AES US SBU

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AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-2
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MEETING OBJECTIVES & AGENDA

Stewart Ramsay

Meeting Facilitator

AGENDA

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

MEETING 2 RECAP

Patrick Maguire
Director of Resource Planning

IPL 2019 IRP

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

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

What is a preferred resource portfolio?

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

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

2019 IRP STAKEHOLDER PROCESS

Dates to follow for Meeting #4 & Meeting #5

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

IPL is committed to conducting a robust and collaborative stakeholder process. Multiple communication avenues will be provided to ensure that all stakeholders have the opportunity to be a part of the 2019 IRP process.

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STAKEHOLDER PRESENTATION

Denise Abdul-Rahman

NAACP

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STAKEHOLDER PRESENTATION

Ingrid Bjorklund

Advanced Energy Management Alliance (AEMA)

ELECTRIC VEHICLE (EV) & DISTRIBUTED SOLAR FORECAST

Ed Schmidt

MCR Performance Solutions

AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-2
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Electric Vehicle and Distributed Solar Forecasts: 2020-2040

ipl an AES company

5/14/19

MCR Performance Solutions: Management Consulting to the Utility Industry

Regulatory Services
- Strategic Analysis
- Rate Design & Cost Analysis
- Regulatory Filings
- Process Improvement

Energy Efficiency
- Strategy and Program Design
- Process and Data Management
- Program Implementation
- Program Management & Administration
- Program Tracking & Reporting

Utility Transformation
- New Technology Strategy & Product Development: Electric Vehicles and C&I
- Customer Onsite Product Development
- Enhanced Customer Experience: Strategies, Roadmaps and Product Financing Strategy

Financial Advisory
- Financial Forecasting
- Enterprise Risk Management
- Strategic Planning
- Capital Allocation
- Financial Processes & Systems

Transmission Strategy
- Formula Rate and Cost Analysis
- FERC Filings
- Strategic Analysis

Asset Management
- Zero-Base Budgeting
- Capital Project Evaluation
- Life Cycle Management Planning
- Long Range Planning
- Management Reporting
- Capitalization Policies and Procedures

Table of Acronyms

BNEF	Bloomberg New Energy Finance
BRT	IndyGo bus rapid transit routes
BYD	IndyGo-selected bus manufacturer
CAGR	Compound annual growth rate
C&I	Commercial and industrial
EEI	Edison Electric Institute
EIA	US Energy Information Administration
EV	Electric vehicle

GTM	GreenTech Media
ICE	Internal combustion engine
IHS	IHS Markit Company
IU	Indiana University
LDEV	Light duty electric vehicle
NEM	Net metered
PV	Photovoltaic, or distributed, solar
PVWatts	US National Renewable Energy Laboratory PV calculation tool

Agenda

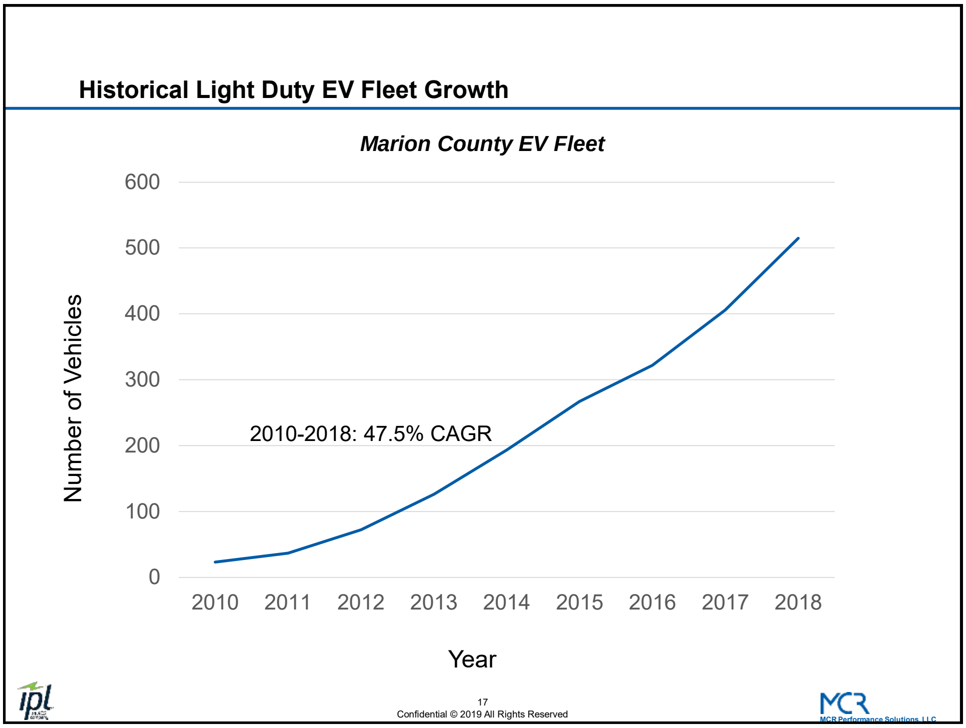
- EV Forecast
  - 2018 baseline data
  - Methodology
  - Input data
  - Forecast
- Distributed solar (PV) Forecast
  - 2018 baseline data
  - Methodology
  - Input data
  - Forecast
- Summary: EV and Distributed Solar Forecast

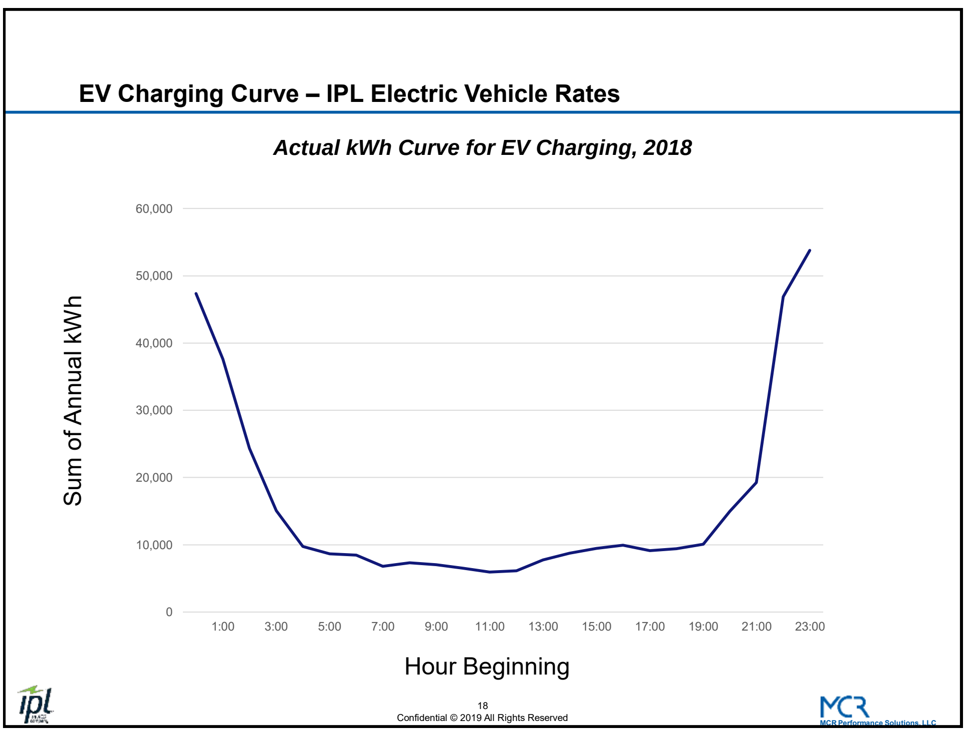
EV Forecast

Light Duty EV (LDEV)

Attribute	Value	Source
Count	515	IPL-provided IHS/Polk
kWh/100 miles	31	www.fueleconomy.gov
Annual miles	11,655	www.carinsurance.com
Annual kWh	3,613	= 31 * (11,655/100)

Notes: 1. 31 kWh/100 miles takes the weighted average for Bolt, Leaf, Tesla S, Tesla 3, Tesla X
2. Annual kWh = 11,655 miles / 100 * 31


Historical Light Duty EV Fleet Growth
Marion County EV Fleet
600
500
400
300
200
100
0
Number of Vehicles
2010-2018: 47.5% CAGR
2010
2011
2012
2013
2014
2015
2016
2017
2018
Year
17
Confidential © 2019 All Rights Reserved


EV Charging Curve – IPL Electric Vehicle Rates
Actual kWh Curve for EV Charging, 2018
60,000
50,000
40,000
30,000
20,000
10,000
0
Sum of Annual kWh
1:00
3:00
5:00
7:00
9:00
11:00
13:00
15:00
17:00
19:00
21:00
23:00
Hour Beginning
18
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IndyGO Electric Buses

Attribute	60' BYD BRT	40' Fleet
Current quantity	2	21
2032 quantity	56	144
Range	275	250
Miles/year	45,600	45,600
Charger	40 kW x 2	40 kW x 2
Battery kWh	652	489
Charge time hours	6	4.5

Notes: 1. 2032 quantities are per IndyGO capital plan
2. Ranges are current per manufacturers
3. BYD charger, battery kWh and charge time are per BYD, fleet buses are estimated

LDEV Unit Forecasting Methodology

Data Sources
- BNEF Forecast (2040)
- EEI Forecast (2030)
- US Census Population Projection and Facts
- IU Marion County Population Projection
- Polk Vehicle Registrations

National Forecasts
- Examination of both BNEF and EEI forecasts
- Review of relationship between forecasts to extend EEI from 2030 to 2040

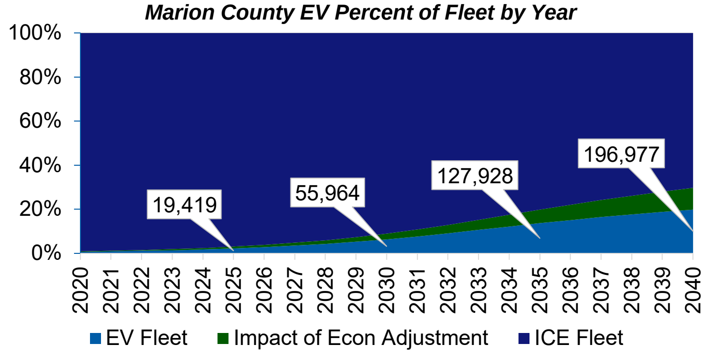
EV Fleet Estimate
- National EV % of vehicle fleet
- Project Marion County fleet size based on population growth
- % of fleet values applied to Marion County fleet

Economic Adjustment
- Ratio of Marion County to National median household income used to scale down EV fleet

LDEV Unit Forecast

Year	Total Fleet	EV Fleet	ICE Fleet	EV % Fleet
2020	833,269	5,573	827,696	0.7%
2025	850,552	19,419	831,133	2.3%
2030	865,691	55,964	809,727	6.5%
2035	879,523	127,928	751,595	14.6%
2040	893,781	196,977	696,804	22.0%

Marion County EV Percent of Fleet by Year



EV MWh Forecasting Methodology

LDEV Unit Energy → IPL Peak / Off-Peak Hours → IndyGo Buses → Energy Forecast

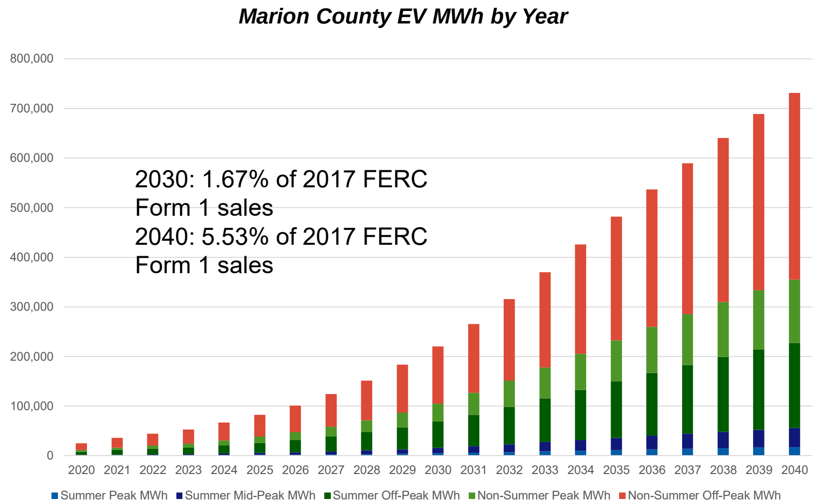
- 3,613 kWh/year used, as discussed above

- 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



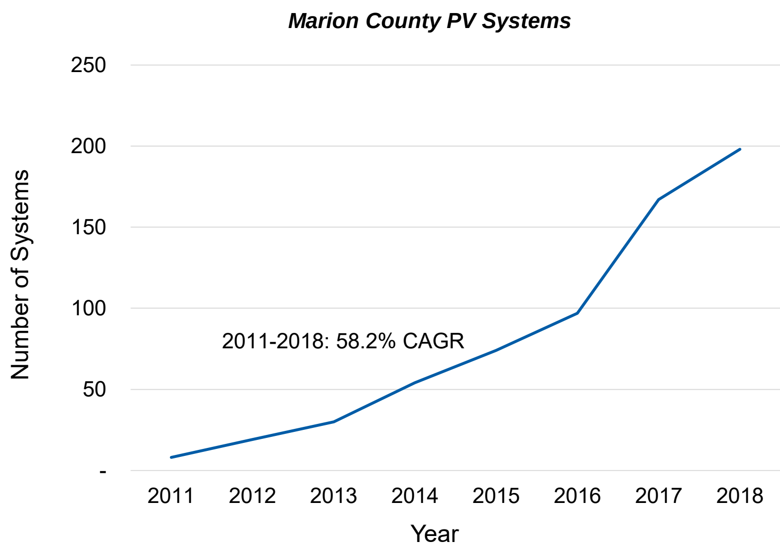
Distributed Solar Forecast

2018 Residential and Commercial Distributed Solar Baseline

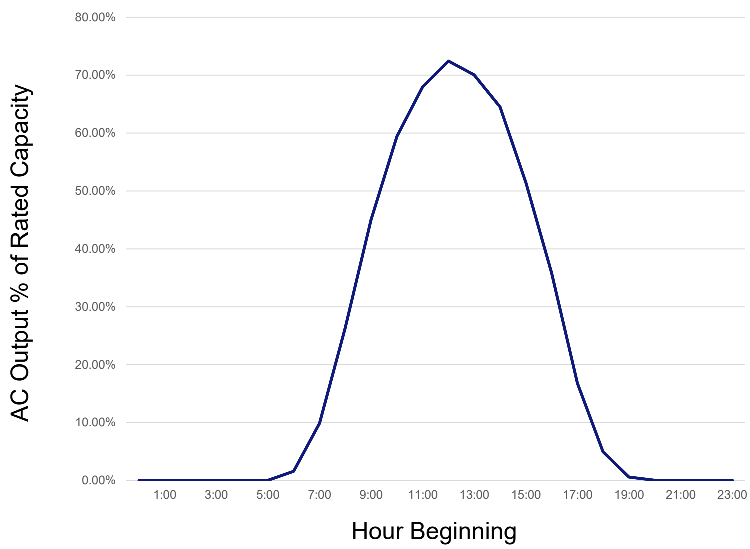
Attribute	Residential	C&I
IPL NEM count (Adjusted EIA counts from IPL 2018 NEM file)	177	21
Size (kW - DC)	8	125
Panel type	Anti-reflective crystalline silicon	Anti-reflective crystalline silicon
Array type	Fixed	Fixed
Capacity factor (AC)	15.8%	15.8%
Production basis	PVWatts – 46241	PVWatts – 46241

Notes: 1. Panel type is PVWatts "premium"
2. Zip code 46241 shows relatively high solar penetration

Historical Distributed Solar System Growth



Distributed Solar Production Curve



Distributed Solar Unit Forecasting Methodology

IPL 2018 NEM Baseline
- Cleaned input 2018 IPL NEM census dataset
- Retained all NEM records showing non-null system size and installation date

GTM 4Q18 Solar Outlook
- Compiled annual installed MWdc national actual and forecasts for 2013-2023 separately for residential and non-residential customers
- Examined impact of high-volume states, relative intensity of activity in Indiana, etc.

2019-23 GTM-based CAGR
- Computed 2019-2023 compound annual growth rates for residential and non-residential MWdc installed nationally

Apply CAGR to IPL NEM Baseline
- Applied compound annual growth rates to 2018 IPL actual number of systems for 2019 and 2020-2040
- Applied baseline IPL system size in kW-DC and annual kWh-AC separated into Rate CGS peak/off-peak splits

Input Data: GTM-based CAGR

Year	Incremental Residential MWdc	Incremental Residential Growth Rate	Incremental C&I MWdc	Incremental C&I Growth Rate
2019	2,510	10.62%	1,761	-16.70%
2020	2,827	12.63%	1,853	5.22%
2021	3,302	16.80%	1,965	6.04%
2022	3,424	3.69%	1,944	-1.07%
2023	3,775	10.25%	2,144	10.29%
CAGR		10.74%		5.04%

Distributed Solar kW and MWh Forecasting Methodology

PVWatts Output

- 8 kW-DC residential and 125 kW-DC C&I systems
- 46241 zip code
- Fixed, open rack coated crystalline silicone panels

IPL Peak/Off-Peak Hours

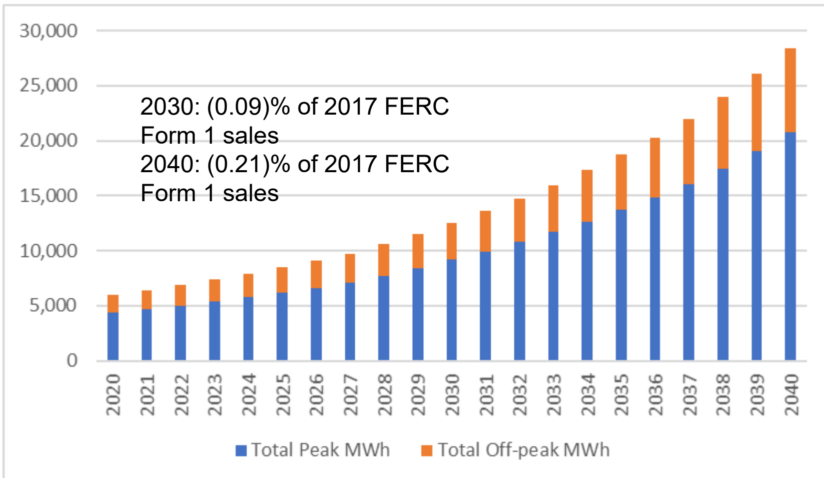
- Rate CGS hours 8-23 are peak
- Rate CGS assigns all weekends to off-peak

Derived kWh per kW

- PVWatts sum of peak kWh-AC output divided by system kW-DC
- PVWatts sum of off-peak kWh-AC divided by system kW

Distributed Solar MWh Impacts through 2040

Marion County PV MWh by Year



Summary: EV and Distributed Solar Forecast

EV and Distributed Solar Forecast Summary: MWh

Year	EV Summer Peak MWh	EV Summer Mid-Peak MWh	EV Summer Off-Peak MWh	EV Non-Summer Peak MWh	EV Non-Summer Off-Peak MWh	EV Annual MWh	PV Peak MWh	PV Off-Peak MWh	PV Annual MWh
2020	500	1,076	6,273	3,610	13,506	24,965	4,388	1,619	6,007
2021	697	1,500	9,129	5,031	19,595	35,952	4,701	1,734	6,435
2022	887	1,908	11,277	6,399	24,255	44,726	5,035	1,858	6,893
2023	1,063	2,287	13,296	7,668	28,631	52,944	5,399	1,992	7,391
2024	1,378	2,966	16,620	9,947	35,883	66,795	5,783	2,134	7,917
2025	1,743	3,751	20,399	12,578	44,140	82,611	6,197	2,286	8,483
2026	2,175	4,680	24,803	15,693	53,776	101,126	6,632	2,447	9,079
2027	2,730	5,875	30,362	19,702	65,961	124,630	7,114	2,626	9,740
2028	3,374	7,259	36,738	24,343	79,945	151,657	7,754	2,861	10,615
2029	4,138	8,903	44,241	29,856	96,417	183,555	8,432	3,111	11,543
2030	5,023	10,809	52,878	36,248	115,389	220,348	9,170	3,383	12,553

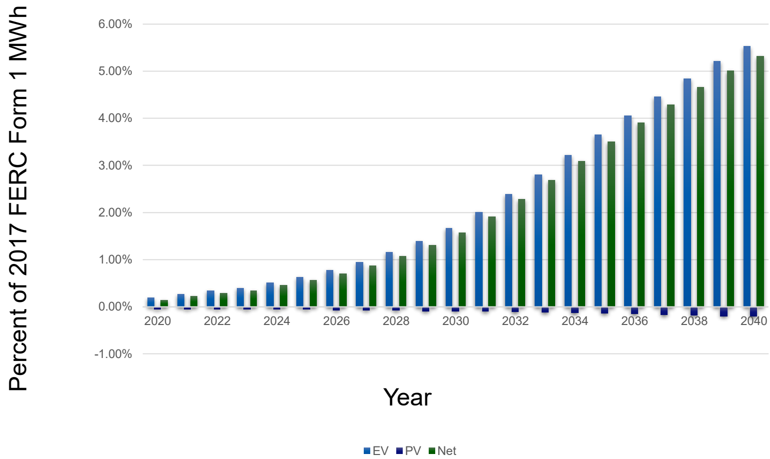
MCR Performance Solutions, LLC

EV and Distributed Solar Forecast Summary: MWh (continued)

Year	EV Summer Peak MWh	EV Summer Mid-Peak MWh	EV Summer Off-Peak MWh	EV Non-Summer Peak MWh	EV Non-Summer Off-Peak MWh	EV Annual MWh	PV Peak MWh	PV Off-Peak MWh	PV Annual MWh
2031	6,117	13,163	63,456	44,142	138,644	265,523	9,948	3,670	13,618
2032	7,358	15,833	75,151	53,094	164,413	315,848	10,777	3,976	14,753
2033	8,706	18,734	87,718	62,822	192,132	370,112	11,677	4,308	15,985
2034	10,095	21,723	100,667	72,845	220,694	426,023	12,648	4,666	17,314
2035	11,483	24,709	113,604	82,859	249,229	481,884	13,689	5,050	18,739
2036	12,843	27,636	126,285	92,675	277,200	536,639	14,811	5,464	20,275
2037	14,156	30,462	138,525	102,150	304,200	589,493	16,034	5,916	21,950
2038	15,414	33,168	150,251	111,227	330,063	640,122	17,490	6,453	23,943
2039	16,615	35,751	161,440	119,888	354,744	688,439	19,057	7,031	26,088
2040	17,681	38,045	171,380	127,583	376,669	731,358	20,756	7,658	28,414

MCR Performance Solutions, LLC

EV and Distributed Solar as a Percent of 2017 Sales



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MCR Performance Solutions, LLC

BREAK

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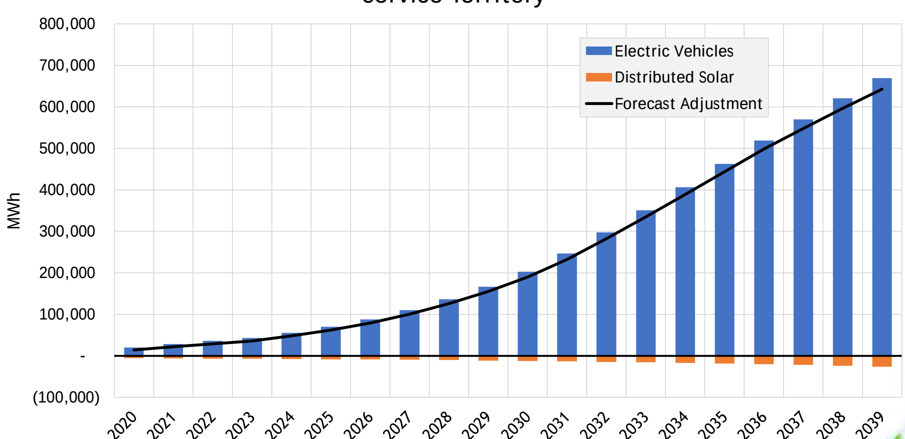
LOAD FORECAST - HIGH & LOW RECAP OF CUSTOMER CLASS BREAKOUT

Erik Miller

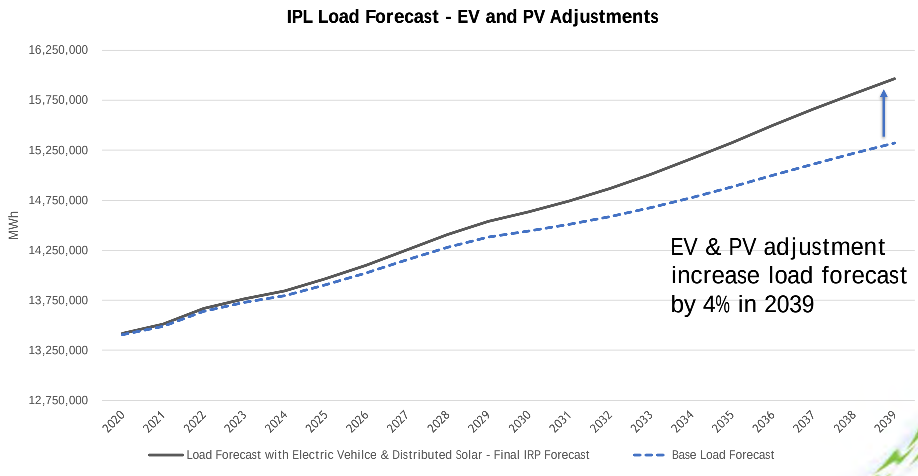
Senior Research Analyst

EV & PV ADJUSTMENT

Electric Vehicle and Distributed Solar Annual kWh for IPL Service Territory

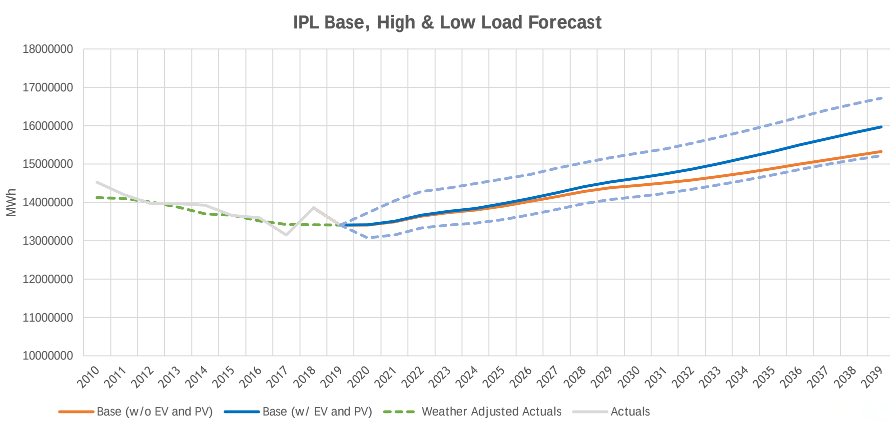


IPL LOAD FORECAST EV & PV ADJUSTMENT



IPL BASE, HIGH & LOW LOAD FORECAST

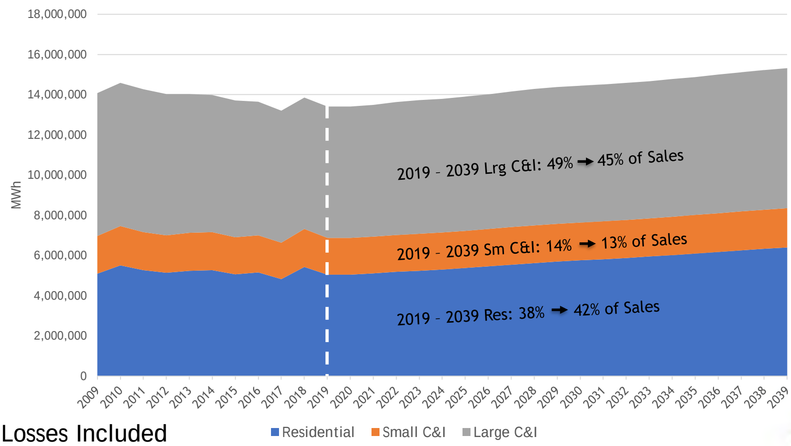
INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP



CLASS SALES FORECAST

INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP

	Residential	Small C&I	Large C&I
Average Annual Growth Rate 2020 - 2039:	1.2%	0.2%	0.3%



No Losses Included

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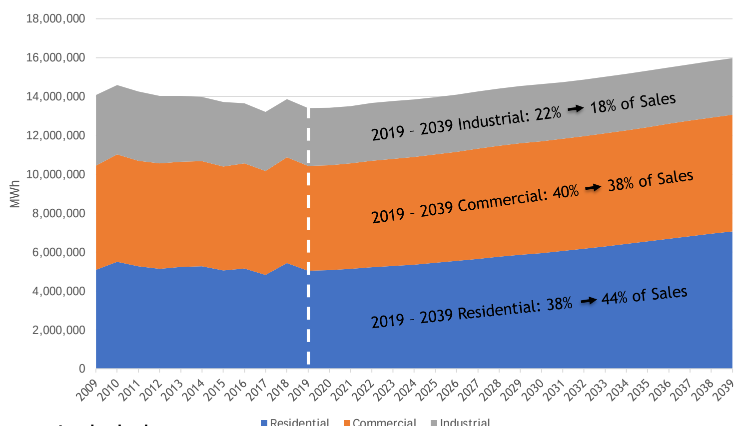
CLASS SALES FORECAST

INCLUDES PRIOR YEAR DSM IMPACTS;
FUTURE DSM WILL BE MODELED IN THE IRP;
INCLUDES EV & PV

	Residential	Commercial	Industrial
Average Annual Growth Rate 2020 - 2039:	1.7%	0.5%	-0.1%



No Losses Included

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DSM BUNDLES IN IRP MODELING

Erik Miller

Senior Research Analyst

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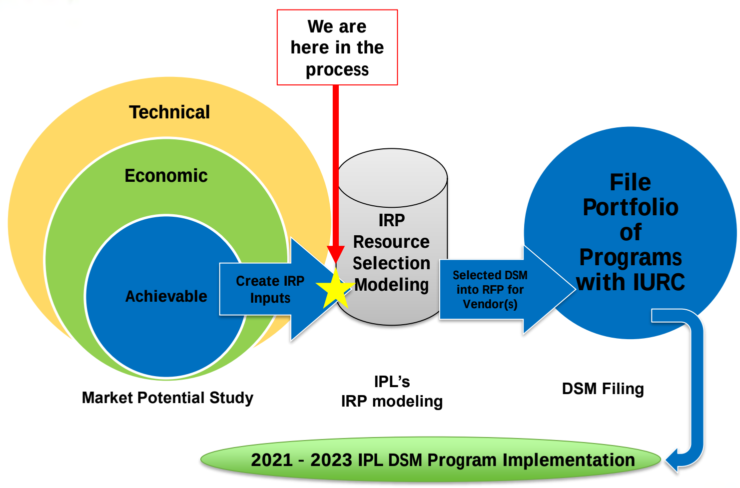
DSM PROCESS & THE IRP



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IRP DSM BUNDLING APPROACH

- DSM Bundles are 0.25% "decrements" of annual load excluding Opt Out customers
- Bundles are created from the Market Potential Study's Realistic Achievable Potential
- Each "decrement" bundle has an associated loadshape and cost/MWh that serves as inputs into the IRP model
- GDS uses loadshapes specific to measure-types to create 8760s for the IRP model
- Residential and C&I are combined in bundles
- Ten bundles will be included as selectable resources in the IRP model
  - 8 - Energy Efficiency Bundles
  - 2 - Demand Response Bundles

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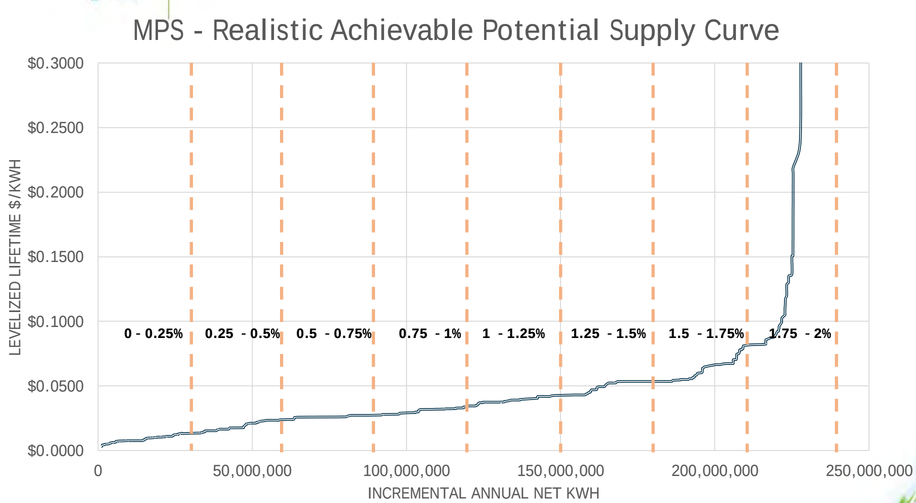
DSM DECREMENT BUNDLES



Data from IRP/MPS Planning Year: 2026

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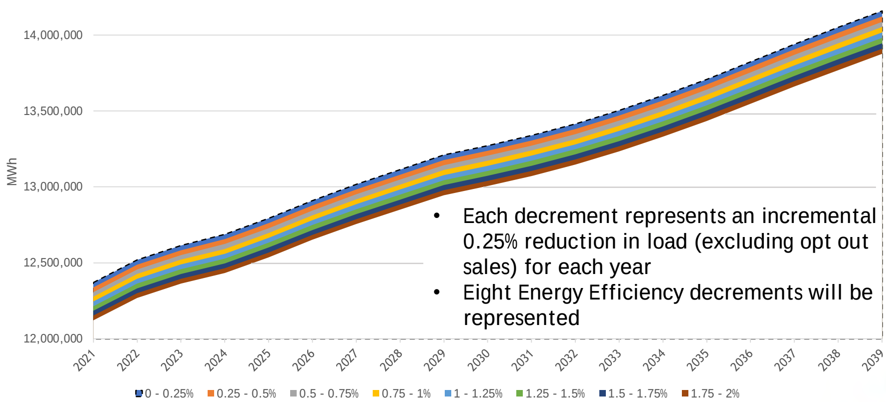
DSM DECREMENT BUNDLES - PERCENT OF OPT OUT SALES



- Each decrement represents an incremental 0.25% reduction in load (excluding opt out sales) for each year
- Eight Energy Efficiency decrements will be represented

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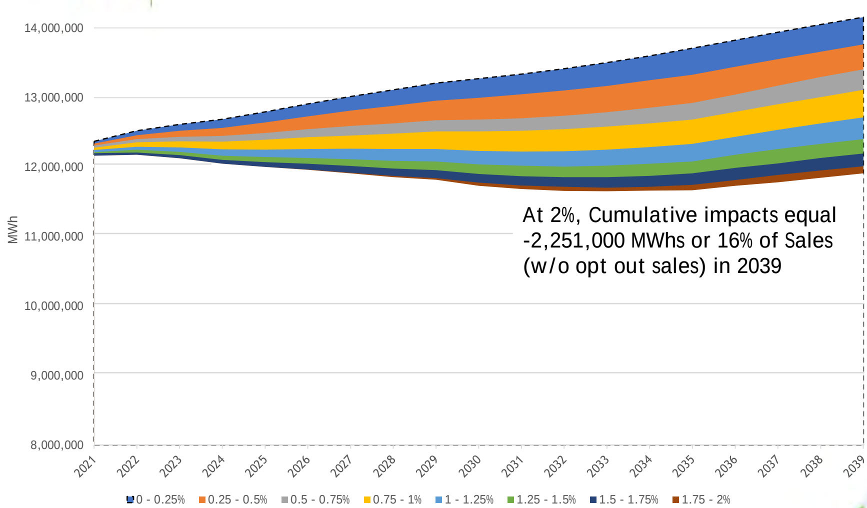
DSM DECREMENT BUNDLES - CUMULATIVE IMPACTS



At 2%, Cumulative impacts equal -2,251,000 MWhs or 16% of Sales (w/o opt out sales) in 2039

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DSM NEXT STEPS

Next Steps:

- Evaluate DSM in the IRP Model in May and June
- Present results at Public Advisory Meeting #4

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LUNCH BREAK

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MODELING AND SCENARIO RECAP

Patrick Maguire

Director of Resource Planning

RECAP: SCENARIO DRIVERS

	Reference Case	Scenario A: Carbon Tax	Scenario B: Carbon Tax + High Gas	Scenario C: Carbon Tax + Low Gas	Scenario D: No Carbon Tax + High Gas
Natural Gas Prices	Base	Base	**HIGH ↑**	**LOW ↓**	**HIGH ↑**
Carbon Tax	No Carbon Price	**Carbon Price (2028+)**	**Carbon Price (2028+)**	**Carbon Price (2028+)**	No Carbon Price
Coal Prices	Base	Base	Base	Base	Base
IPL Load	Base	Base	Base	**LOW ↓**	**HIGH ↑**
Capital Costs for Wind, Solar, and Storage	Base	Base	Base	Base	Base

FUNDAMENTAL FORECAST VENDOR

- **Wood Mackenzie H1 2018 Long Term Outlook**
- Provided Cases:
  1. Federal Carbon Case (Carbon tax starting 2028)
  2. Federal Carbon Case + High Gas Sensitivity
  3. No Carbon Case
  4. No Carbon + Low Gas Sensitivity
  5. No Carbon Case + High Gas Sensitivity
  6. Federal Carbon Case + Low Gas Sensitivity

Custom sensitivities completed for IPL - provided to NDA stakeholders

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RECAP: FORWARD CURVES

	Deterministic Modeling	Stochastic Ranges	Notes
Power	✓	✓	On/Off peak monthly power prices from Wood Mackenzie. Hourly shapes created in PowerSimm.
Natural Gas	✓	✓	Wood Mackenzie monthly gas prices with delivery adders. Daily price shapes created in PowerSimm.
Coal	✓	✓	Internally sourced IPL coal curves.
Fuel Oil	✓	✓	Wood Mackenzie
Emissions	✓	✗	NOx and SO2 curves will be sourced from forward curves. Carbon prices from Wood Mackenzie.
Capacity	✓	✓	Capacity will be valued at the estimated bilateral price for MISO Zone 6.

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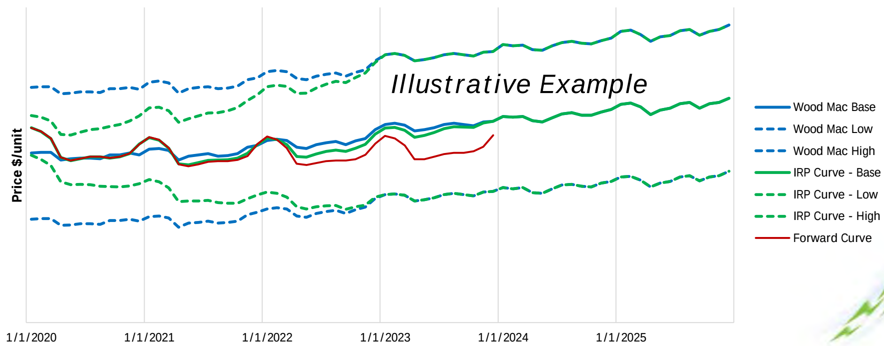
POWER AND NATURAL GAS: BLENDED CURVES FOR YEARS 1-3

- Forward curves utilized through 2023
- Blended into fundamental curves starting in 2021 for Base Case, 2020 for High and Low Gas Sensitivities



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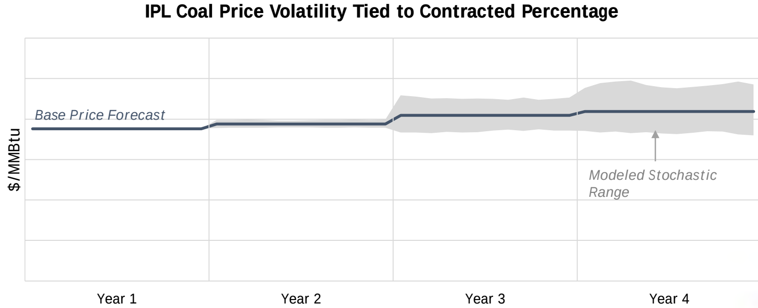
COAL PRICE MODELING

- IPL Coal Curve based on RFP prices and market intelligence on southern Indiana inland coal market
- Stochastic volatility applied only to open/unhedged portion

IPL Coal Price Volatility Tied to Contracted Percentage



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SCENARIO FRAMEWORK

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
No Accelerated Retirements	Portfolio 1	1a	1b	1c	1d
Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	Portfolio 2	2a	2b	2c	2d
Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	Portfolio 3	3a	3b	3c	3d
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	Portfolio 4	4a	4b	4c	4d
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	Portfolio 5	5a	5b	5c	5d

Wide range of scenarios and portfolios will inform resource decisions. Modeling underway and will be ongoing over the next two months.

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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

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DATA RELEASE SCHEDULE

IPL 2019 IRP Assumptions: Data Release Schedule

Dataset	Data Available
Commodity Price Forecasts [Complete]	Friday, April 12, 2019
MISO Solar Capacity Credit Calculation [Complete]	Friday, April 12, 2019
Capital Cost Assumptions for New Resources [Complete]	Friday, April 12, 2019
Updated Commodity Price Forecasts	Tuesday, May 14, 2019
IPL Load Forecast: Energy, Peak, Reserve Margin Target	Tuesday, May 14, 2019
Operating Characteristics for New Resources	Tuesday, June 11, 2019
Modeling Constraints for New Resources	Tuesday, June 11, 2019
Cost and Operating Characteristics for Existing IPL Resources	Tuesday, June 11, 2019
Stochastic Parameters and Distributions	Tuesday, June 11, 2019

Q&A, CONCLUDING REMARKS & NEXT STEPS

Stewart Ramsay
Meeting Facilitator

Patrick Maguire
Director of Resource Planning

NEXT STEPS

- **Next Meeting: TBD**
- Meeting #4 Material:
  - Scenario Descriptions and Results
  - Preliminary Model Results
  - Risk Analysis and Stochastics

Email questions, comments, or other feedback to ipl.irp@aes.com

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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

Topic	Time (Eastern)	Presenter(s)
Registration	12:30 – 1:00	-
Welcome & Opening Remarks	1:00 – 1:15	Vince Parisi, President and CEO, IPL
Meeting Objectives & Agenda	1:15 – 1:20	Stewart Ramsay, Meeting Facilitator
Modeling and Scenario Recap	1:20 – 1:40	Patrick Maguire, Director of Resource Planning
Preliminary Model Results – Optimized Portfolios	1:40 – 2:30	Patrick Maguire, Director of Resource Planning
BREAK	2:30 – 3:00	
Portfolio Metrics	3:00 – 3:45	Patrick Maguire, Director of Resource Planning
Final Q&A, Concluding Remarks & Next Steps	3:45 – 4:00	Stewart Ramsay, Meeting Facilitator Patrick Maguire, Director of Resource Planning

MODELING AND SCENARIO RECAP

Patrick Maguire

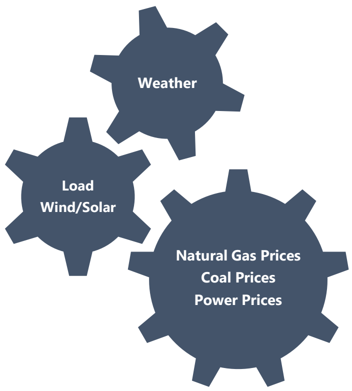
Director of Resource Planning

MODELING ASSUMPTIONS

- Solar Capacity Credit: re-calibrated capacity credit to reflect capacity contribution for tracking solar, which is higher than fixed tilt and rooftop. Capacity contribution validated by IPL tracking solar historical data
- Updated modeling constraints around new resources
- Releasing aero and recip capital costs, battery storage costs and operating characteristics
- Added 1x1 CCGT in 2034 in all portfolios: firm, dispatchable capacity on IPL's 138 kV system required with Harding Street Steam 5-7 retirements; <u>final technology solution to be determined at a later date, but CCGT simply used as placeholder for now</u>

CAPACITY EXPANSION

Stochastic Capacity Expansion



Portfolios optimized across a wide range of futures with dynamic commodity prices, load shapes, and renewable profiles through time and across iterations

KEY HIGHLIGHTS FROM CAPACITY EXPANSION RUNS

- Renewables being selected first, with storage and gas technology filling in remaining shortfall
- Small variations in capacity expansion between carbon tax and no carbon tax case because of model preference for renewables in both cases
- Results led IPL to determine fewer candidate portfolios stressed across range of scenarios better than assessment of more portfolios with slight variations

UNIT RETIREMENTS AND PORTFOLIOS

MODELED COAL RETIREMENTS

No Accelerated Retirements	**Portfolio 1**
Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	**Portfolio 2**
Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	**Portfolio 3**
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	**Portfolio 4**
Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	**Portfolio 5**

RETIREMENTS IN ALL PORTFOLIOS

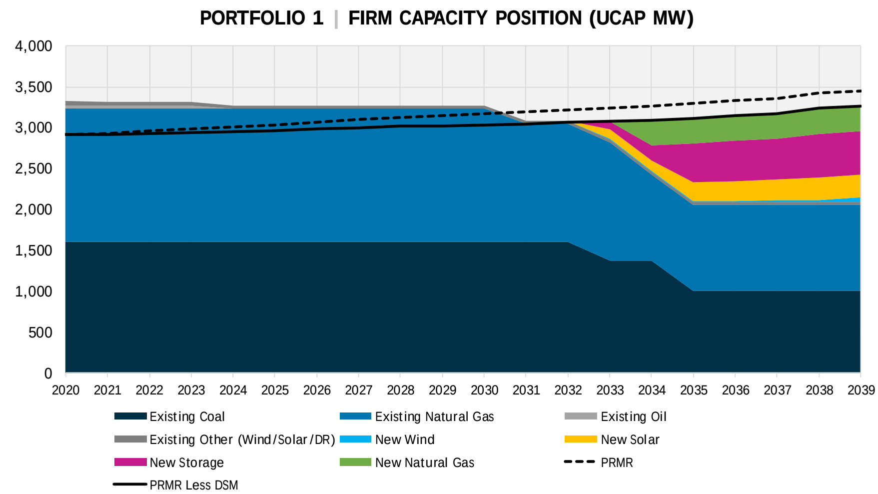
- 2024: Harding Street Oil 1-2 (37 MW)
- 2031: Harding Street ST 5-6 (189 MW)
- 2034: Harding Street ST 7 (394 MW)

PRELIMINARY MODEL RESULTS: OPTIMIZED PORTFOLIOS

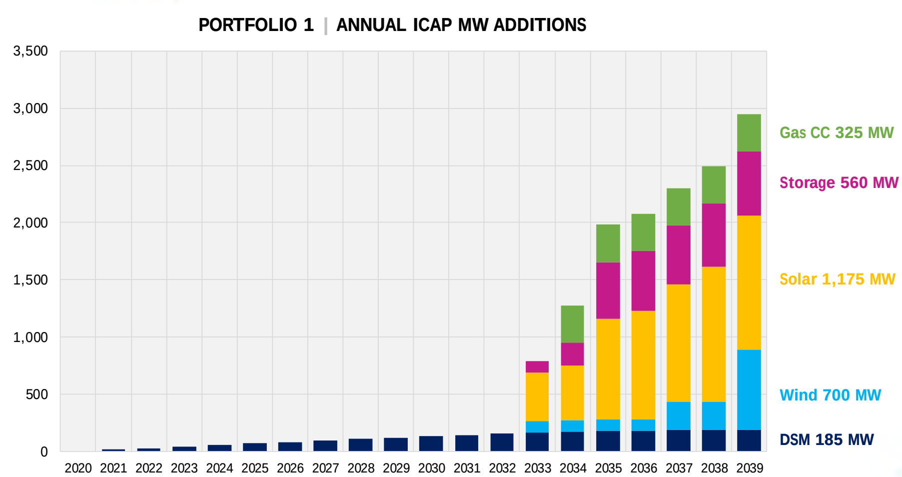
Patrick Maguire

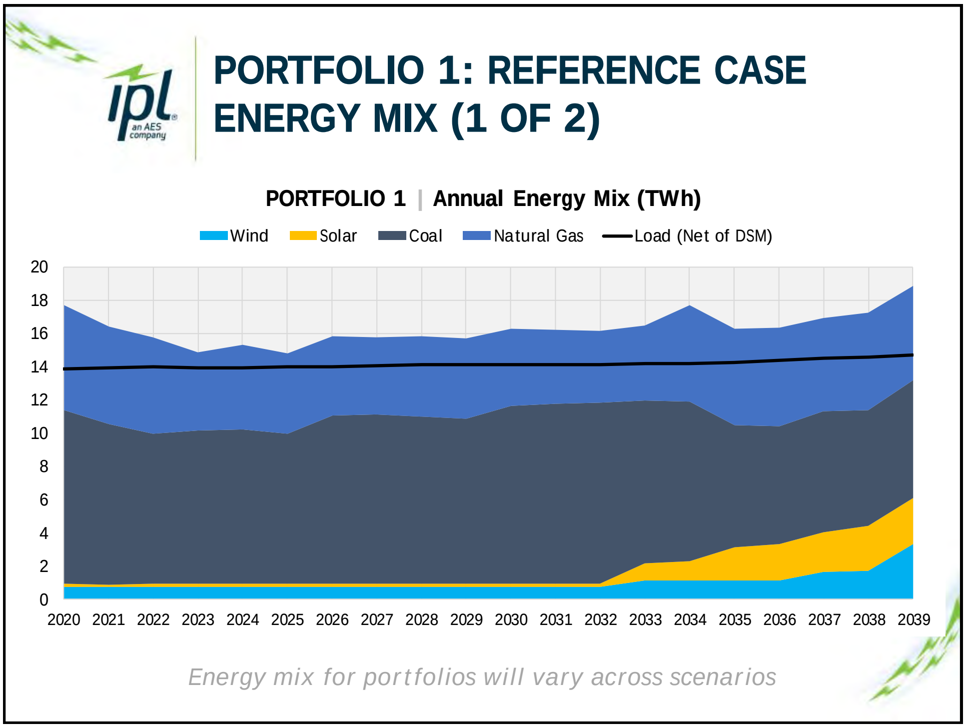
Director of Resource Planning

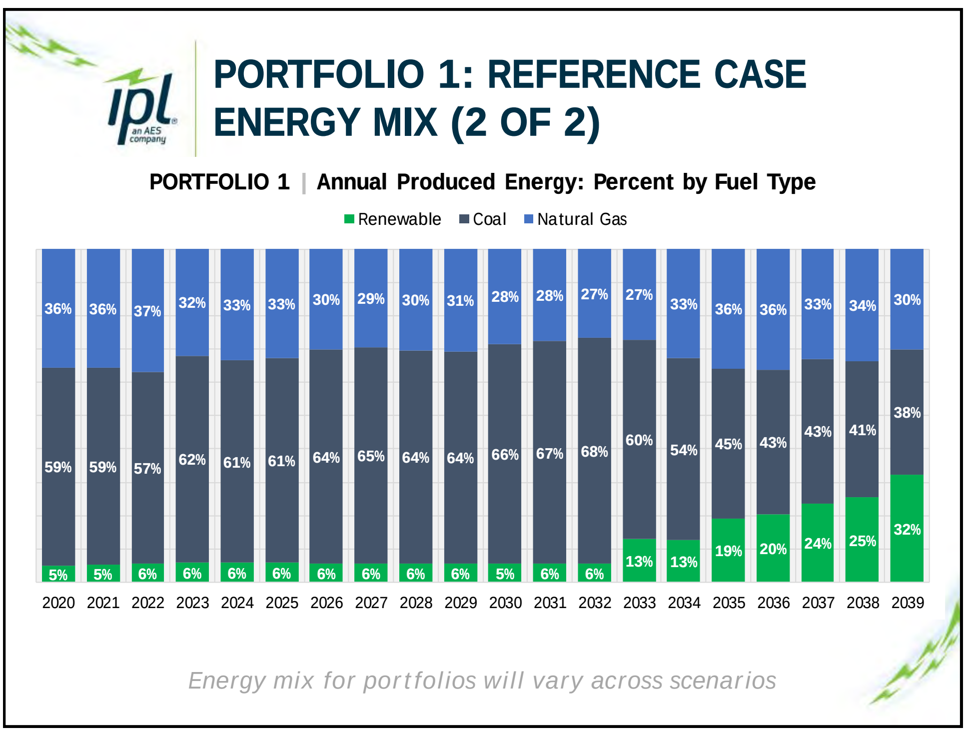
PORTFOLIO 1: FIRM UCAP POSITION



PORTFOLIO 1: ICAP MW ADDITIONS




PORTFOLIO 1: REFERENCE CASE ENERGY MIX (1 OF 2)
PORTFOLIO 1 | Annual Energy Mix (TWh)
Wind
Solar
Coal
Natural Gas
Load (Net of DSM)
0 2 4 6 8 10 12 14 16 18 20
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039
Energy mix for portfolios will vary across scenarios


PORTFOLIO 1: REFERENCE CASE ENERGY MIX (2 OF 2)
PORTFOLIO 1 | Annual Produced Energy: Percent by Fuel Type
Renewable
Coal
Natural Gas
2020: 36% 59% 5%
2021: 36% 59% 5%
2022: 37% 57% 6%
2023: 32% 62% 6%
2024: 33% 61% 6%
2025: 33% 61% 6%
2026: 30% 64% 6%
2027: 29% 65% 6%
2028: 30% 64% 6%
2029: 31% 64% 6%
2030: 28% 66% 5%
2031: 28% 67% 6%
2032: 27% 68% 6%
2033: 27% 60% 13%
2034: 33% 54% 13%
2035: 36% 45% 19%
2036: 36% 43% 20%
2037: 33% 43% 24%
2038: 34% 41% 25%
2039: 30% 38% 32%
Energy mix for portfolios will vary across scenarios

PORTFOLIO 1 RECAP

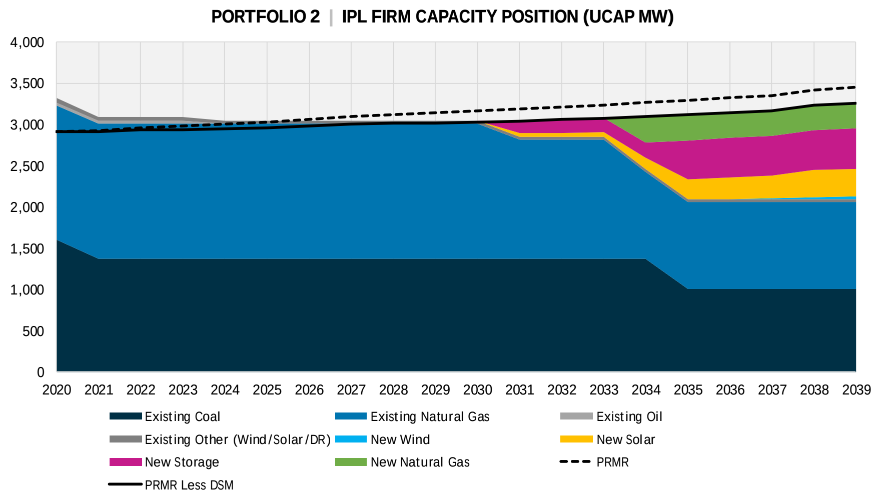
New Build by 2039

- 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

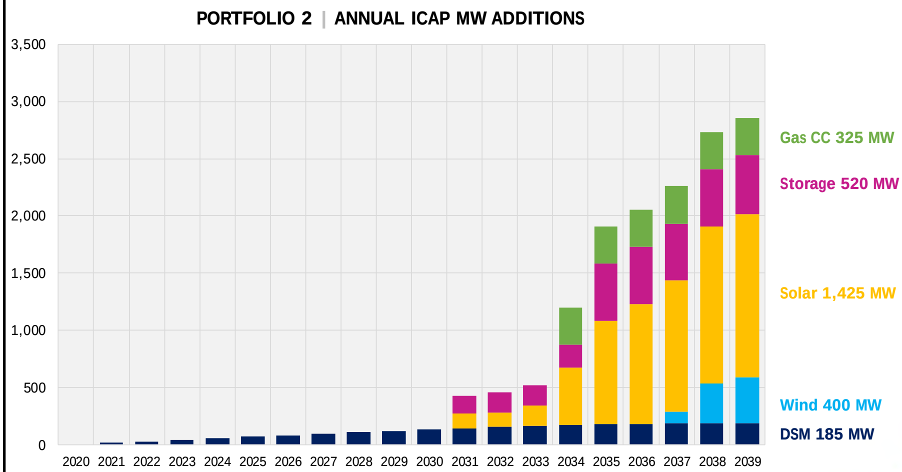
Retirements

- 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

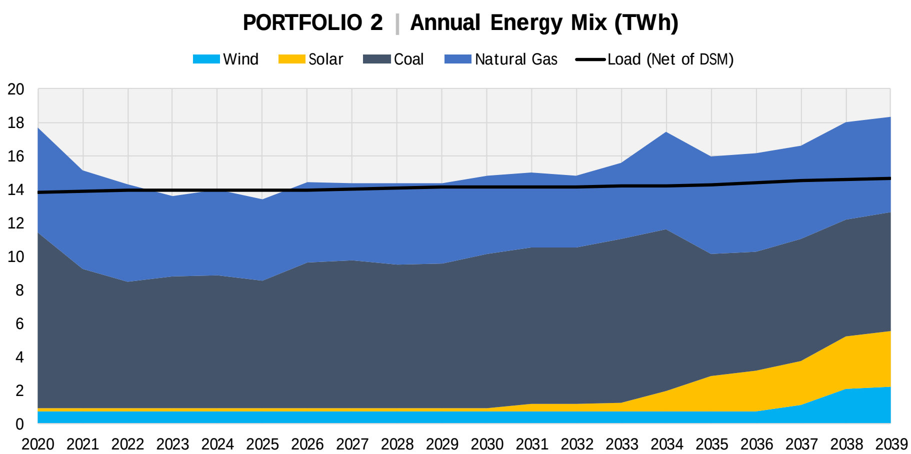
PORTFOLIO 2: FIRM UCAP CAPACITY



PORTFOLIO 2: ICAP MW ADDITIONS



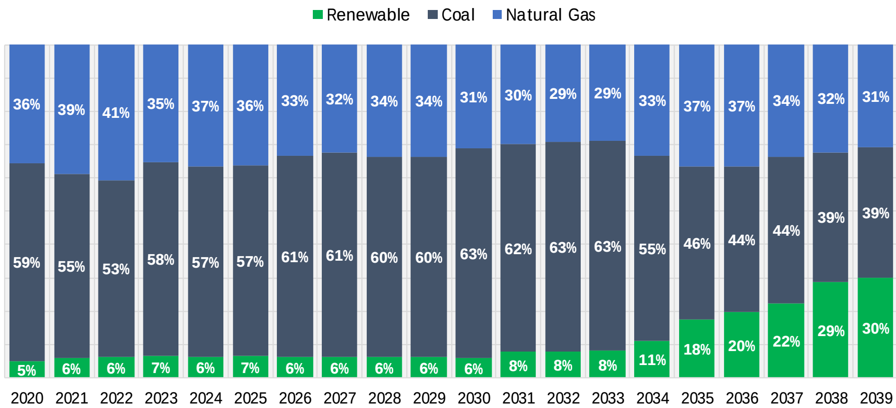
PORTFOLIO 2: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

PORTFOLIO 2: REFERENCE CASE ENERGY MIX (2 OF 2)

PORTFOLIO 2 | Annual Produced Energy: Percent by Fuel Type



Energy mix for portfolios will vary across scenarios

PORTFOLIO 2 RECAP

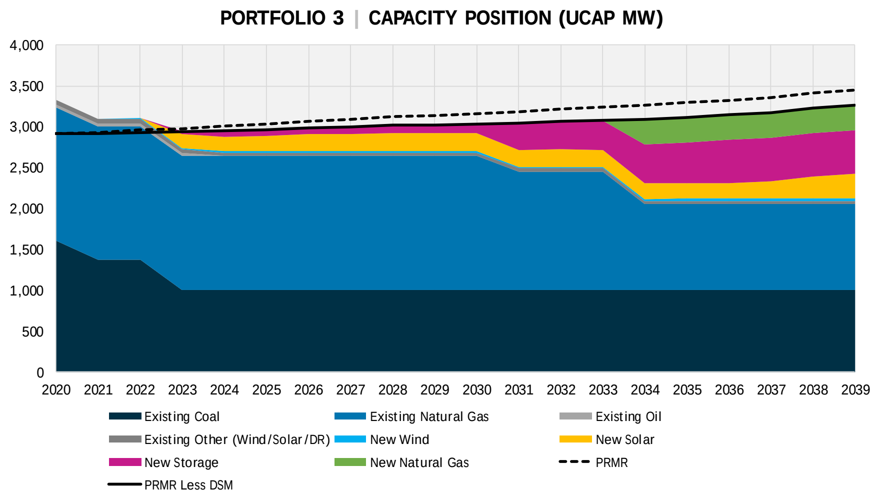
New Build by 2039

- 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

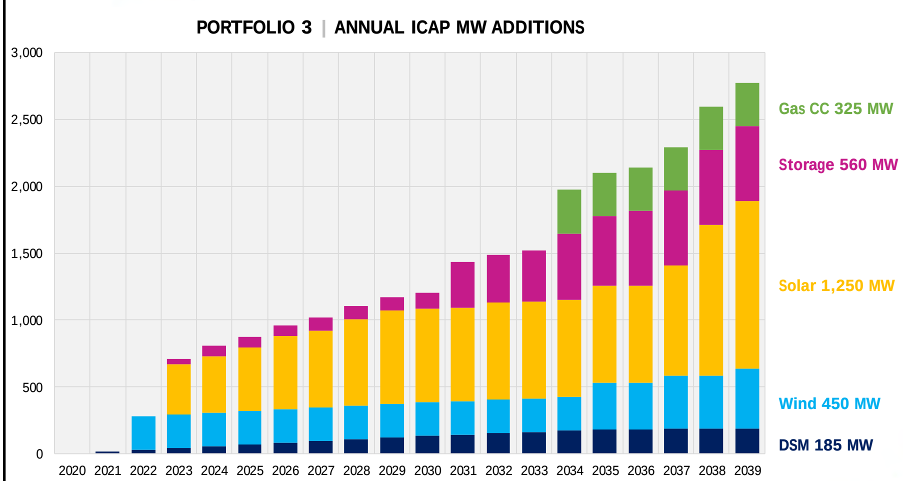
Retirements

- 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: FIRM UCAP CAPACITY

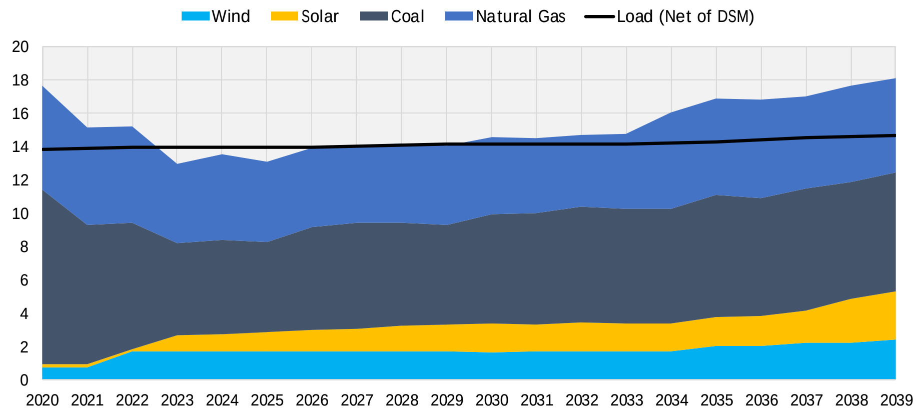


PORTFOLIO 3: ICAP MW ADDITIONS



PORTFOLIO 3: REFERENCE CASE ENERGY MIX (1 OF 2)

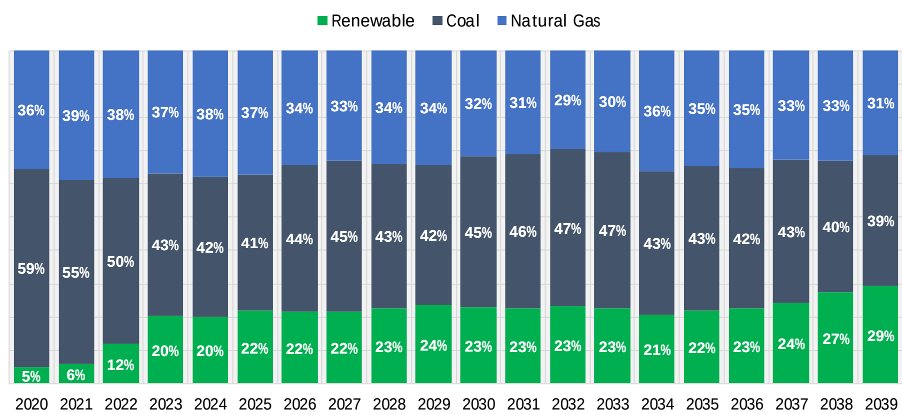
PORTFOLIO 3 | Annual Energy Mix (TWh)



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



Energy mix for portfolios will vary across scenarios

PORTFOLIO 3 RECAP

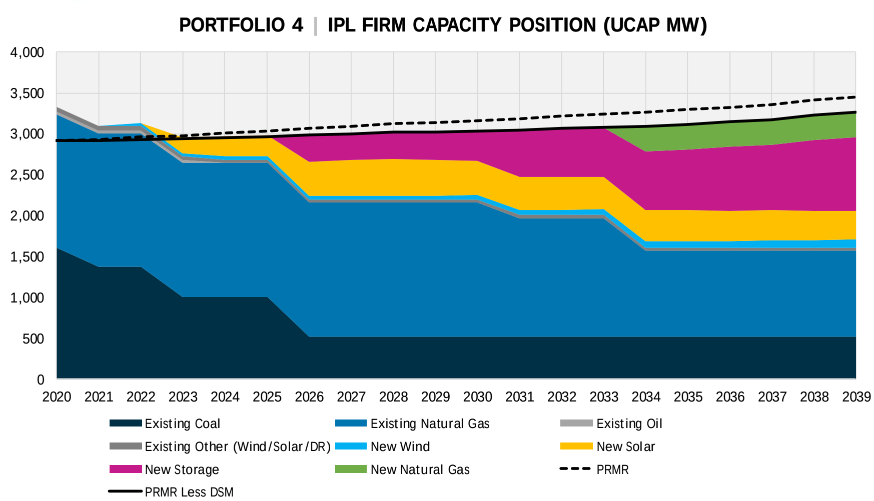
New Build by 2039

- 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

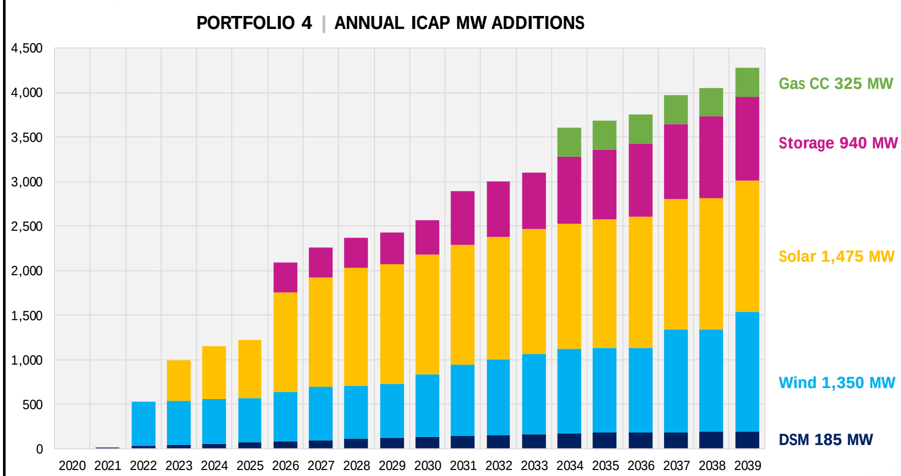
Retirements

- 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

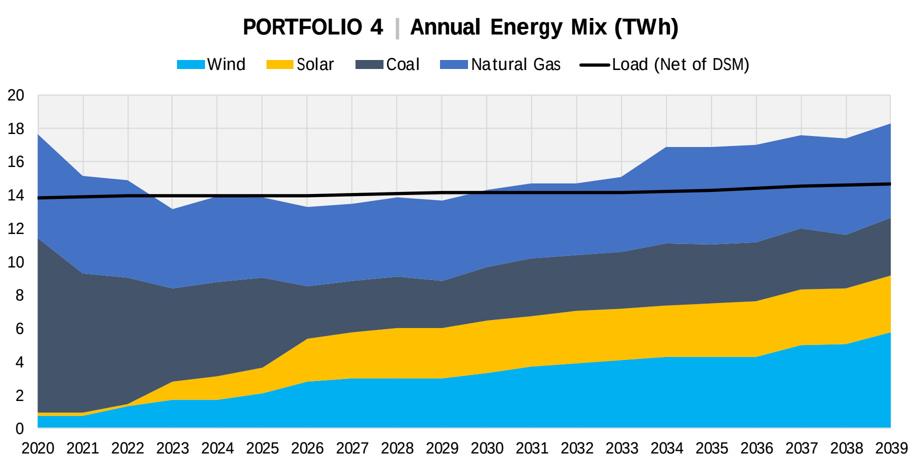
PORTFOLIO 4: FIRM UCAP CAPACITY



PORTFOLIO 4: ICAP MW ADDITIONS

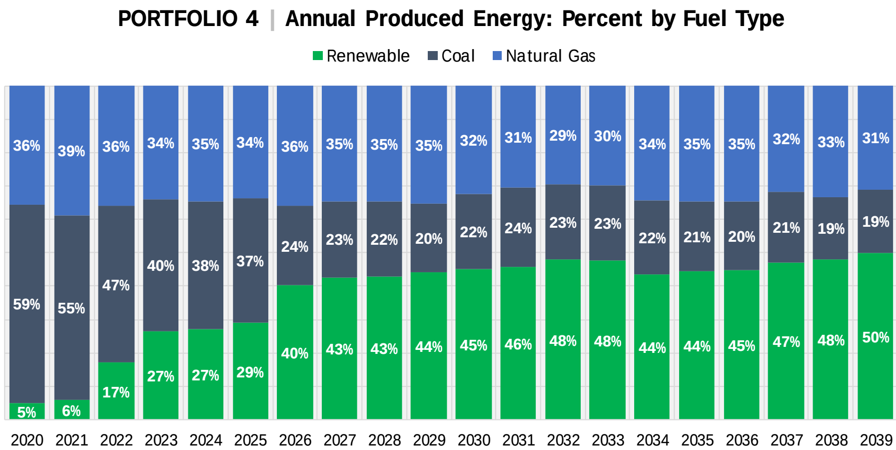


PORTFOLIO 4: REFERENCE CASE ENERGY MIX (1 OF 2)



Energy mix for portfolios will vary across scenarios

PORTFOLIO 4: REFERENCE CASE ENERGY MIX (2 OF 2)



Energy mix for portfolios will vary across scenarios

PORTFOLIO 4 RECAP

New Build by 2039

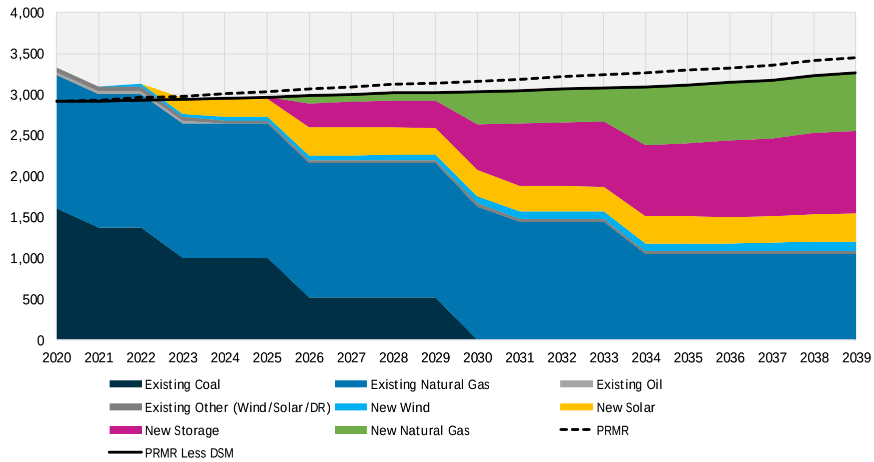
- First year short: 2023
- DSM: 185 MW
- Wind: 1,350 MW
- Solar: 1,475 MW
- Storage: 940 MW
- Gas CCGT: 325 MW

Retirements

- Petersburg
  - Pete 1: 2021
  - Pete 2: 2023
  - Pete 3: 2026
  - Total UCAP: 1,076 MW
- Harding Street:
  - HS ST5: 2031
  - HS ST6: 2031
  - HS ST7: 2034
  - Total UCAP MW: 583

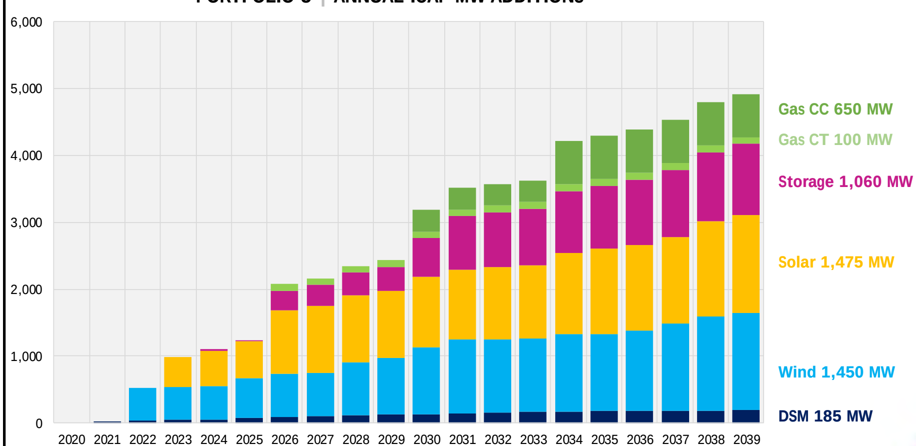
PORTFOLIO 5: FIRM UCAP CAPACITY

PORTFOLIO 5 | IPL FIRM CAPACITY POSITION (UCAP MW)



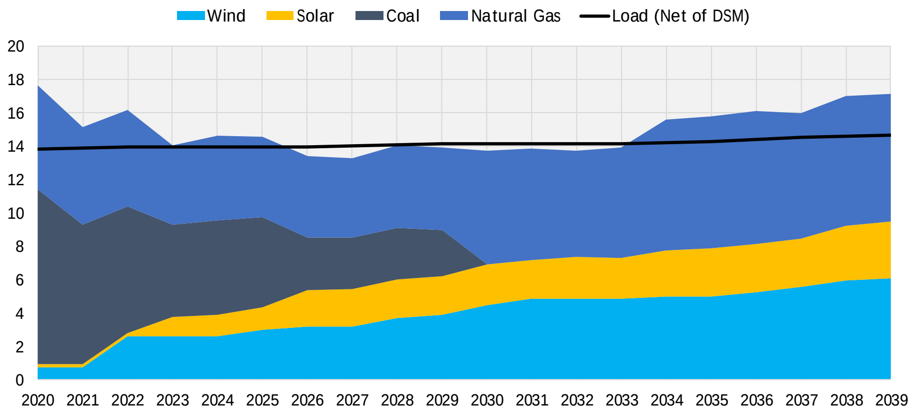
PORTFOLIO 5: ICAP MW ADDITIONS

PORTFOLIO 5 | ANNUAL ICAP MW ADDITIONS



PORTFOLIO 5: REFERENCE CASE ENERGY MIX (1 OF 2)

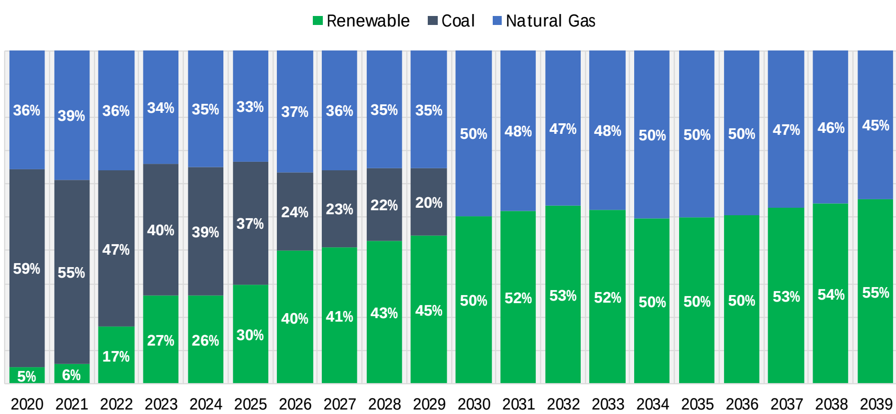
PORTFOLIO 5 | Annual Energy Mix (TWh)



Energy mix for portfolios will vary across scenarios

PORTFOLIO 5: REFERENCE CASE ENERGY MIX (2 OF 2)

PORTFOLIO 5 | Annual Produced Energy: Percent by Fuel Type



Energy mix for portfolios will vary across scenarios

PORTFOLIO 5 RECAP

New Build by 2039

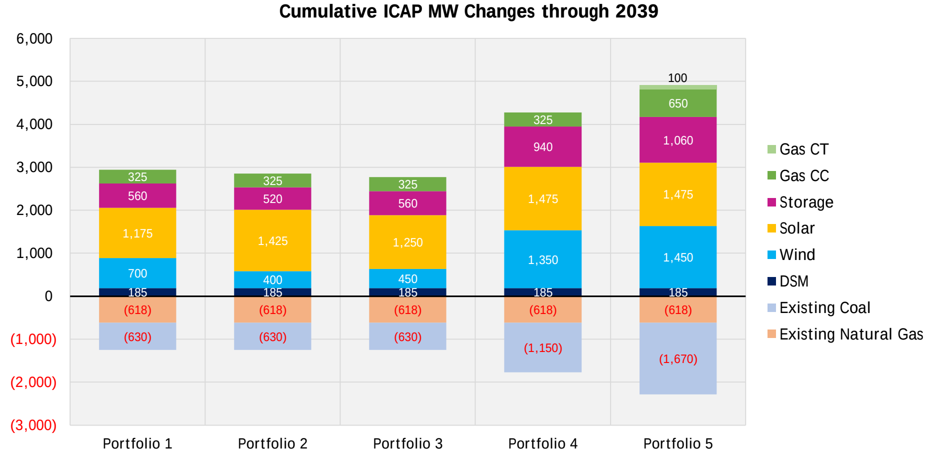
- First year short: 2023
- DSM: 185 MW
- Wind: 1,450 MW
- Solar: 1,475 MW
- Storage: 1,060 MW
- Gas CCGT: 650 MW
- Gas CT: 100 MW

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

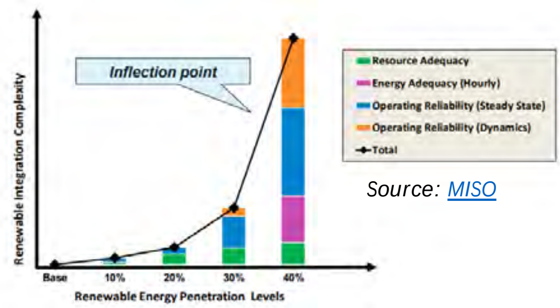
PORTFOLIO SUMMARIES

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

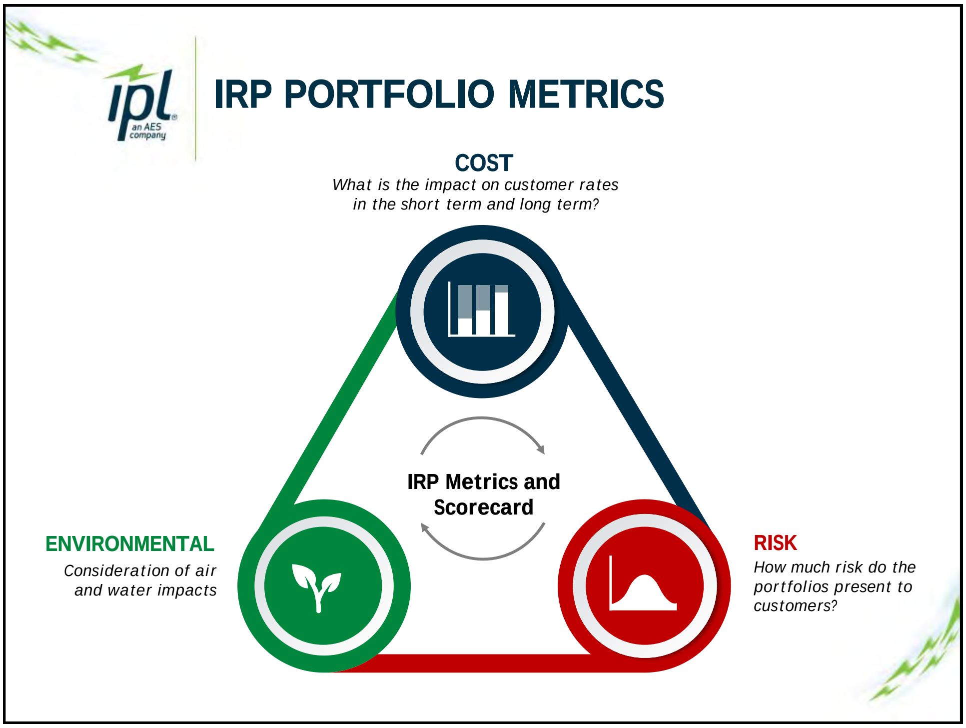


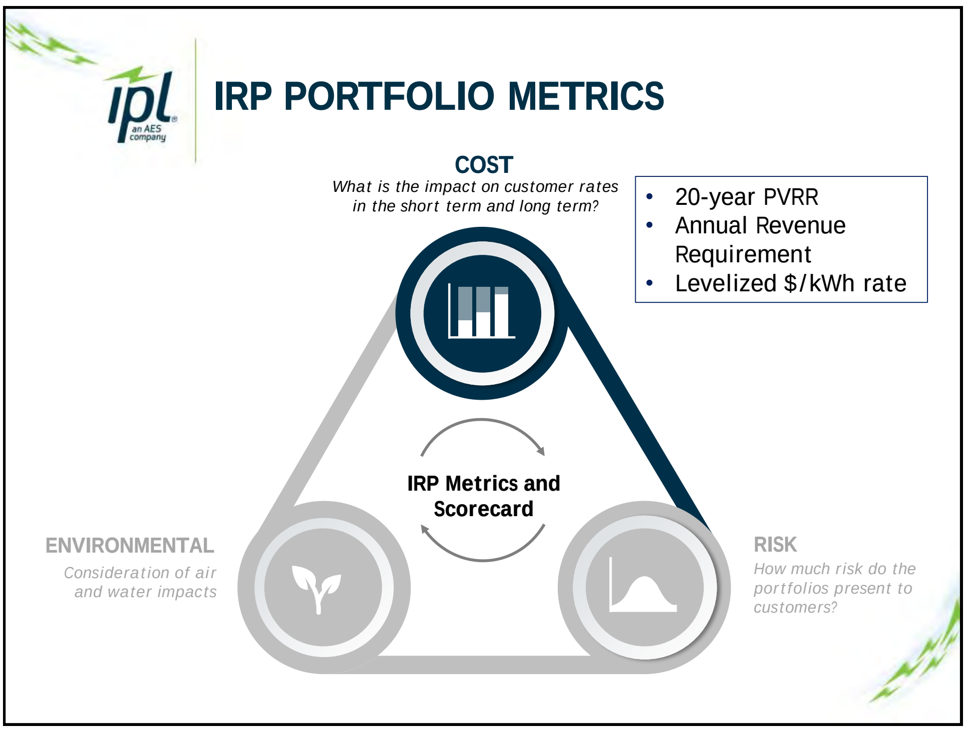
Source: MISO

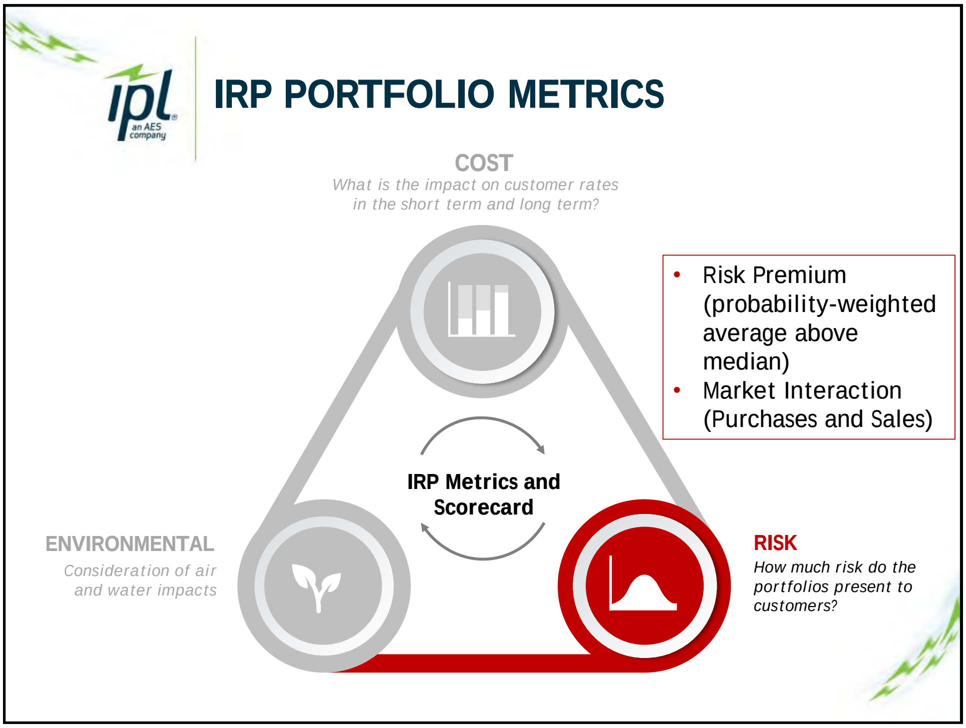
PORTFOLIO METRICS

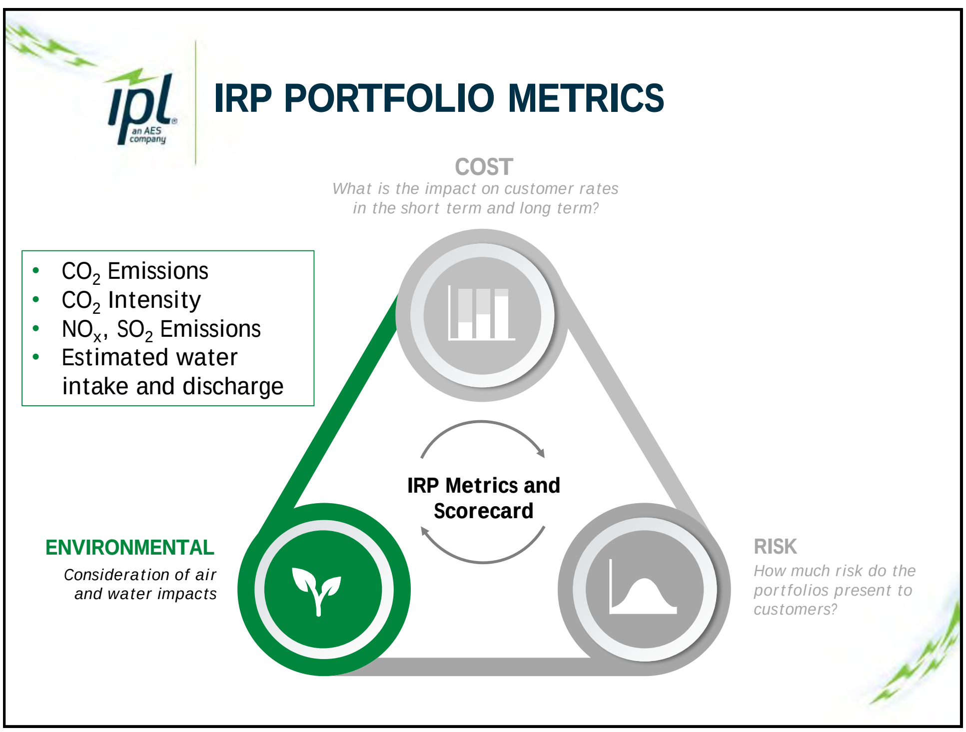
Patrick Maguire

Director of Resource Planning


IRP PORTFOLIO METRICS
COST
What is the impact on customer rates in the short term and long term?
IRP Metrics and Scorecard
ENVIRONMENTAL
Consideration of air and water impacts
RISK
How much risk do the portfolios present to customers?


IRP PORTFOLIO METRICS
COST
What is the impact on customer rates in the short term and long term?
• 20-year PVRR
• Annual Revenue Requirement
• Levelized $/kWh rate
IRP Metrics and Scorecard
ENVIRONMENTAL
Consideration of air and water impacts
RISK
How much risk do the portfolios present to customers?


IRP PORTFOLIO METRICS
COST
What is the impact on customer rates
in the short term and long term?
Risk Premium (probability-weighted average above median)
Market Interaction (Purchases and Sales)
IRP Metrics and Scorecard
ENVIRONMENTAL
Consideration of air and water impacts
RISK
How much risk do the portfolios present to customers?


IRP PORTFOLIO METRICS
COST
What is the impact on customer rates
in the short term and long term?
CO_2 Emissions
CO_2 Intensity
NO_x, SO_2 Emissions
Estimated water intake and discharge
IRP Metrics and Scorecard
ENVIRONMENTAL
Consideration of air and water impacts
RISK
How much risk do the portfolios present to customers?

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

APPENDIX

ACRONYM LIST

Acronym	Name
CCGT/CC	Combined Cycle
ST	Steam Turbine
CT	Combustion Turbine
UCAP	Unforced Capacity
ICAP	Installed Capacity
PRMR	Planning Reserve Margin Requirement
DR	Demand Response
DSM	Demand Side Management
MISO	Midcontinent Independent System Operator
RIIA	Renewable Integration Impact Assessment
PVRR	Present Value Revenue Requirement

INDIANAPOLIS POWER & LIGHT COMPANY

IPL 2019 IRP: PUBLIC ADVISORY MEETING #5

DECEMBER 9, 2019

INTRODUCTIONS & SAFETY MESSAGE

Shelby Houston

Regulatory Analyst, IPL

MEETING OBJECTIVES & AGENDA

Stewart Ramsey

Meeting Facilitator, Vanry & Associates

AGENDA

Topic	Time (Eastern)	Presenter(s)
Registration & Breakfast	9:00 – 9:30	-
Introductions & Safety Message	9:30 – 9:40	Shelby Houston, Regulatory Analyst, IPL
Meeting Objectives & Agenda	9:40 – 9:50	Stewart Ramsay, Meeting Facilitator, Vanry & Associates
Executive Summary of Preferred Resource Plan	9:50 – 10:20	Vince Parisi, President and CEO, IPL
2019 IRP: Modeling Insights	10:20 – 10:50	Patrick Maguire, Director of Resource Planning, IPL
BREAK	10:50 – 11:00	
Analysis of Alternatives: 2019 IRP Modeling	11:00 – 12:00	Patrick Maguire, Director of Resource Planning, IPL
LUNCH	12:00 – 12:45	
Sensitivity Analysis	12:45 – 1:15	Patrick Maguire, Director of Resource Planning, IPL
Preferred Resource Portfolio & Short Term Action Plan	1:15 – 1:30	Patrick Maguire, Director of Resource Planning, IPL
Concluding Remarks	1:30 – 2:00	Vince Parisi, President and CEO, IPL Stewart Ramsay, Meeting Facilitator, Vanry & Associates

EXECUTIVE SUMMARY OF SHORT TERM ACTION PLAN

Vince Parisi,

President and CEO, IPL

IPL 2019 IRP

INTEGRATED RESOURCE PLAN (IRP):
IPL's plan to provide safe, reliable, and sustainable energy solutions for the communities we serve

- IRP submitted every three years
- Plan created with stakeholder input
- 20-year look at how IPL will serve load
- Modeling and analysis culminates in a preferred resource portfolio

What is a preferred resource portfolio?

" 'Preferred resource portfolio' means the utility's selected long term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, taking cost, risk, and uncertainty into consideration."

170 IAC 4-7-1(cc)

2019 IRP STAKEHOLDER PROCESS

January 29th	March 13th	May 14th	September 30th	December 9th
• 2016 IRP Recap • 2019 IRP Timeline, Objectives, Stakeholder Process • Capacity Discussion • IPL Existing Resources and Preliminary Load Forecast • Introduction to Ascend Analytics • Supply-Side Resource Types • DSM/Load Forecast Schedule	• Stakeholder Presentations • Commodity Assumptions • Capital Cost Assumptions • IPL-Proposed Scenario Framework • Scenario Workshop • MPS Update and Plan	• Summary of Stakeholder Feedback • Present Final Scenarios • Modeling Update • Assumptions Review and Updates	• Summary of Stakeholder Feedback • Preliminary Model Results • Scenario Descriptions and Results • Portfolio metrics and scoring	• Final Model Results • Full set of portfolio metrics and scoring criteria • Preferred Plan • Short Term Action Plan

IPL set out to conduct a robust and collaborative stakeholder process. Multiple communication avenues were provided to ensure that all viewpoints and suggestions were heard from stakeholders wanting to participate in the 2019 IRP process.

IPL PORTFOLIO DIVERSIFICATION: 2009 - 2018

2009
Signed 100 MW PPA at Hoosier Wind Park in NW Indiana

2011
Signed 200 MW PPA at Lakefield Wind Farm in Minnesota

2013-2015
Signed 96 MW PPA for solar in Indianapolis through Rate REP

2016
Retired 260 MW of coal at Eagle Valley

2016
Finalized conversion of 630 MW of coal-fired generation at Harding Street to natural gas

2018
Eagle Valley 671 MW Gas-Fired Combined Cycle Plant Completed

IPL PREFERRED PORTFOLIO & SHORT-TERM ACTION PLAN

RETIRE	REPLACE	SAVE	MONITOR
Retire **630 MW** of coal generation by 2023: • Pete 1: 2021 • Pete 2: 2023	Competitively bid for approximately **200 MW** of firm capacity with all-source RFP	Target ~130,000 MWh per year of new DSM as part of the 2021-2023 DSM Plan	Maintain cost-effective units to retain flexibility and continue to monitor market conditions leading to our 2022 IRP

BENEFITS OF PREFERRED RESOURCE PORTFOLIO

IPL Preferred Portfolio: Areas of Focus

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Measured approach maintaining optionality

Greener Energy Future
Moves the company to more renewables

CUSTOMER CENTRICITY

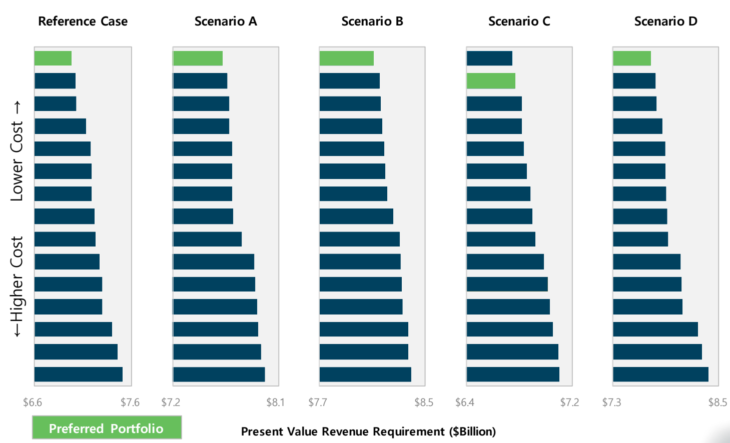
Focus on customer needs and wants

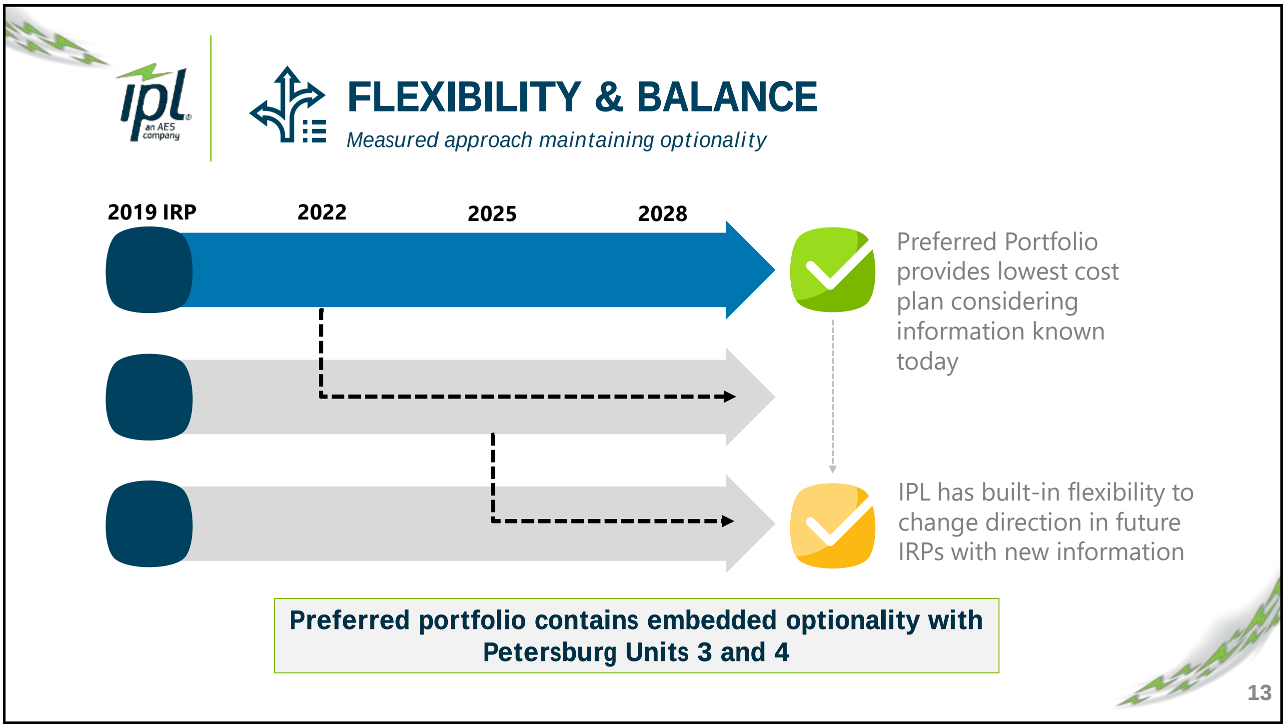
- IPL' s Preferred Resource Portfolio delivers safe, reliable, and economic electricity to customers at just and reasonable rates
- The preferred resource portfolio best serves IPL customers today and into the future, contemplates customers' evolving energy needs, and relies on data-driven models

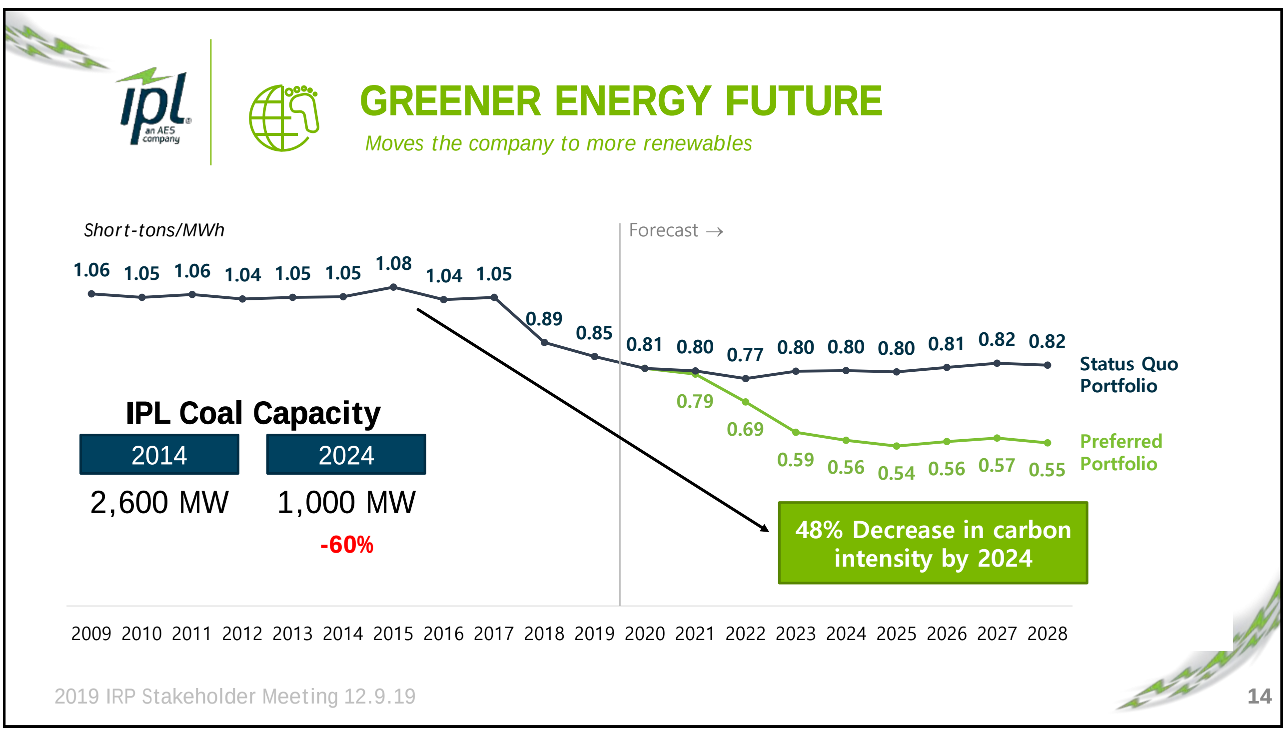
LEAST COST

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




ipl an AES company
FLEXIBILITY & BALANCE
Measured approach maintaining optionality
2019 IRP
2022
2025
2028
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
13


ipl an AES company
GREENER ENERGY FUTURE
Moves the company to more renewables
Short-tons/MWh
Forecast →
1.06 1.05 1.06 1.04 1.05 1.05 1.08 1.04 1.05 0.89 0.85 0.81 0.80 0.77 0.80 0.80 0.80 0.81 0.82 0.82
Status Quo Portfolio
0.79 0.69 0.59 0.56 0.54 0.56 0.57 0.55
Preferred Portfolio
IPL Coal Capacity
2014
2024
2,600 MW
1,000 MW
-60%
48% Decrease in carbon intensity by 2024
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028
2019 IRP Stakeholder Meeting 12.9.19
14

BENEFITS OF PREFERRED RESOURCE PORTFOLIO

IPL Preferred Portfolio: Areas of Focus

Customer Centricity
Focus on customer needs and wants

Least Cost
Considers current and forecasted market economics

Flexibility & Balance
Measured approach maintaining optionality

Greener Energy Future
Moves the company to more renewables

2019 IRP: MODELING INSIGHTS

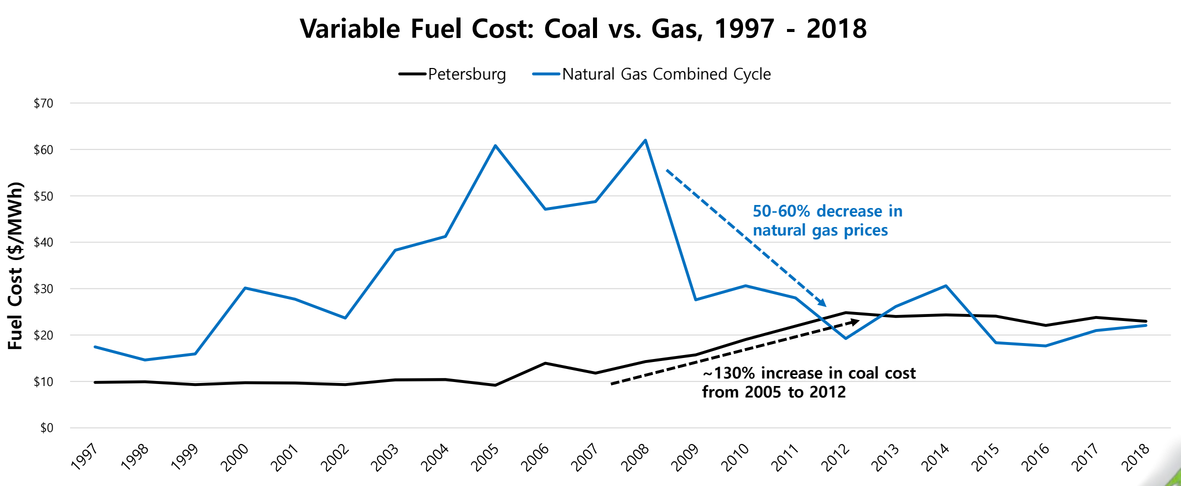
Patrick Maguire

Director of Resource Planning, IPL

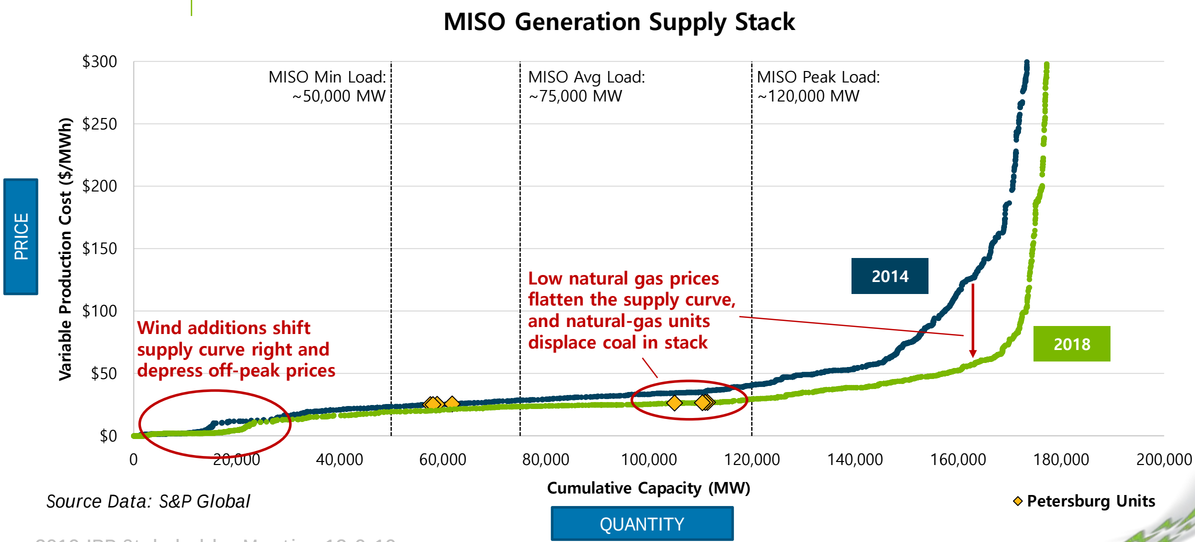
HIGH IMPACT MARKET FORCES

- Significant market changes over the past 10 years have impacted IPL's existing resources
- Opportunities and risk associated with alternative resources
- Present Value Revenue Requirement (PVRR) is key cost metric that is impacted by relative economics of resource technologies
  - Look at underlying fundamentals key to understanding high impact variables on all of the candidate portfolios

COAL ECONOMICS (1 OF 3)



COAL ECONOMICS (2 OF 3)

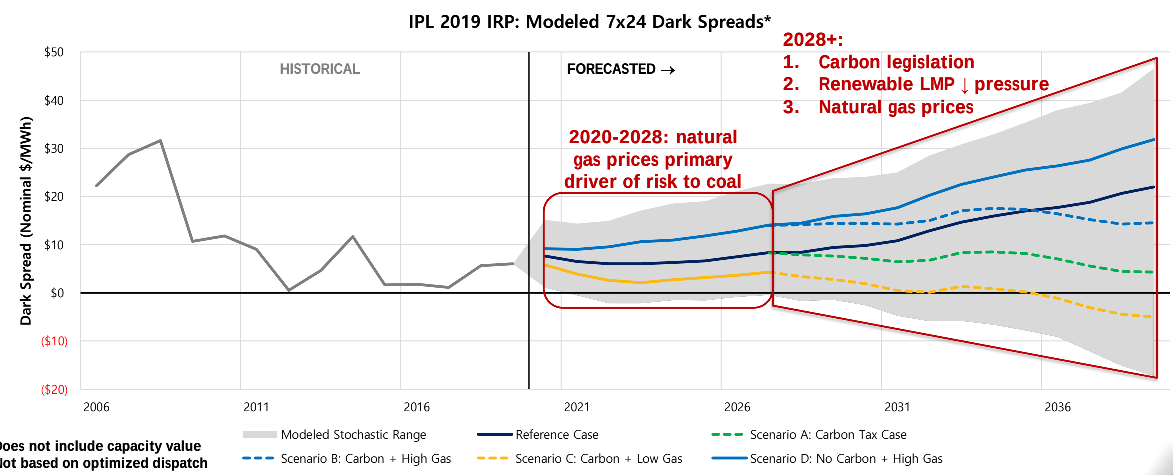


Source Data: S&P Global

COAL ECONOMICS (3 OF 3)

Dark spread = LMP – <u>variable</u> production cost (fuel, VOM, emissions)

Dark spread market indicator of variable margins to offset fixed costs. Does not include capacity value.



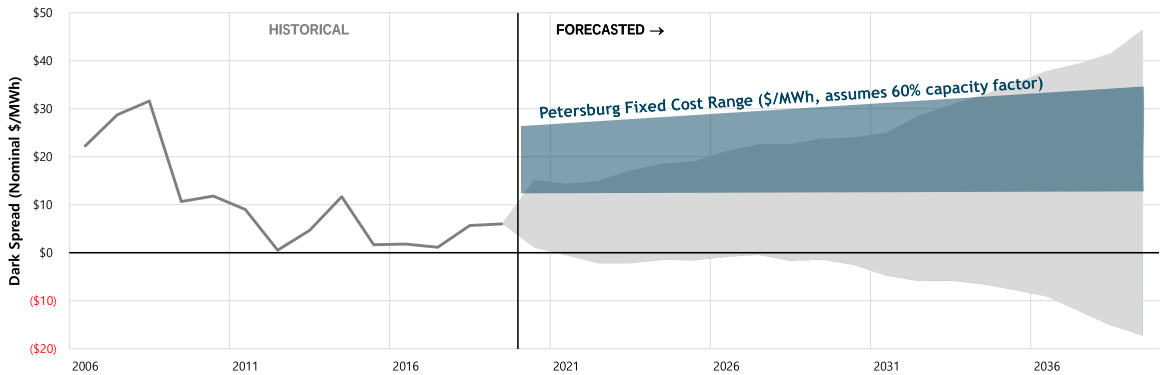
*** Does not include capacity value**
*** Not based on optimized dispatch**

COAL ECONOMICS (3 OF 3)

Dark spread = LMP – variable production cost (fuel, VOM, emissions)

Dark spread market indicator of variable margins to offset fixed costs. Does not include capacity value.

IPL 2019 IRP: Modeled 7x24 Dark Spreads*

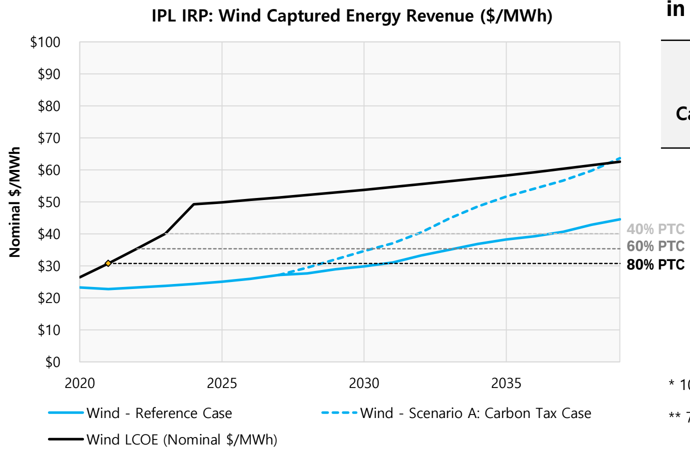


*** Does not include capacity value**
*** Not based on optimized dispatch**

This is illustrative to show macro-level trends and forecasts in coal unit economics and is not inclusive of all factors needed to make a decision. The full IRP modeling used detailed hourly economic dispatch models and full cost accounting for coal and new capacity in the total portfolio cost calculation.

WIND ECONOMICS: HEADWINDS AND UPSIDE POTENTIAL

IPL IRP: Wind Captured Energy Revenue ($/MWh)



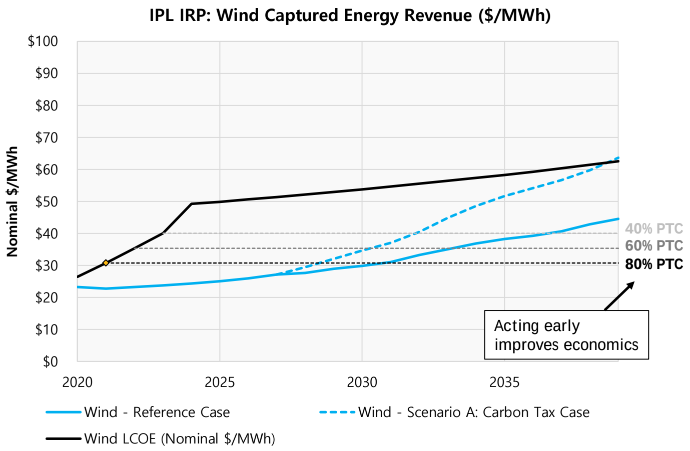
Carbon tax increases wholesale prices via increase in variable cost of fossil units on the margin

Carbon Price ($/ton)	Increase in Variable Cost ($/MWh) Coal Plant*	Natural Gas Combined Cycle**
$2	$2	$1
$5	$5	$2
$10	$11	$4
$20	$22	$8
$40	$43	$17

* 10.5 MMBtu/MWh heat rate, 206 lb/MMBtu CO2 emission rate

** 7.0 MMBtu/MWh heat rate, 119 lb/MMBtu CO2 emission rate

WIND ECONOMICS: HEADWINDS AND UPSIDE POTENTIAL



Challenging wind economics with PTC phaseout

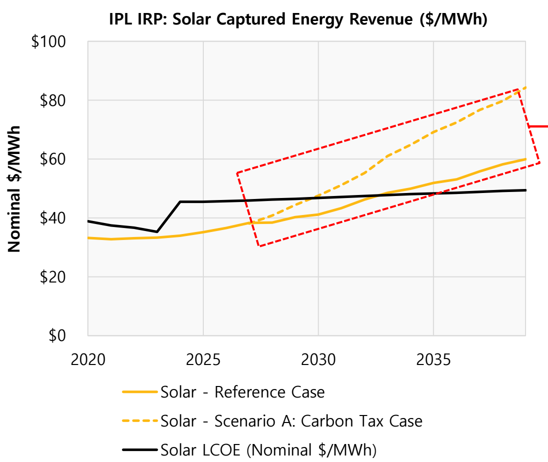
Headwinds:

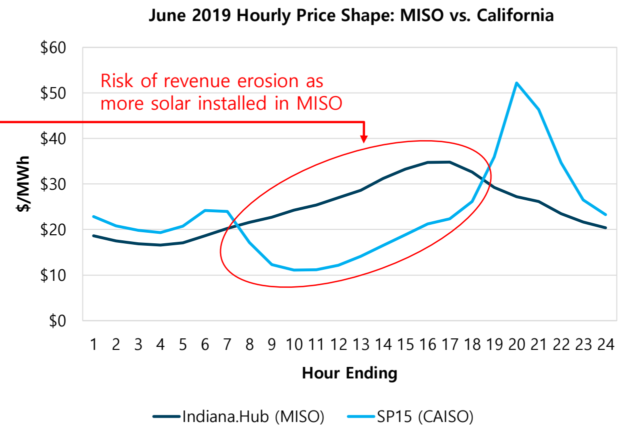
- Each 20% reduction in PTC increases LCOE by $3-$5/MWh
- Captured revenue remains hampered by production shapes, congestion

Upside potential:

- New bulk transmission
- Co-located storage
- New load near site
- Carbon Tax
- PTC Extension

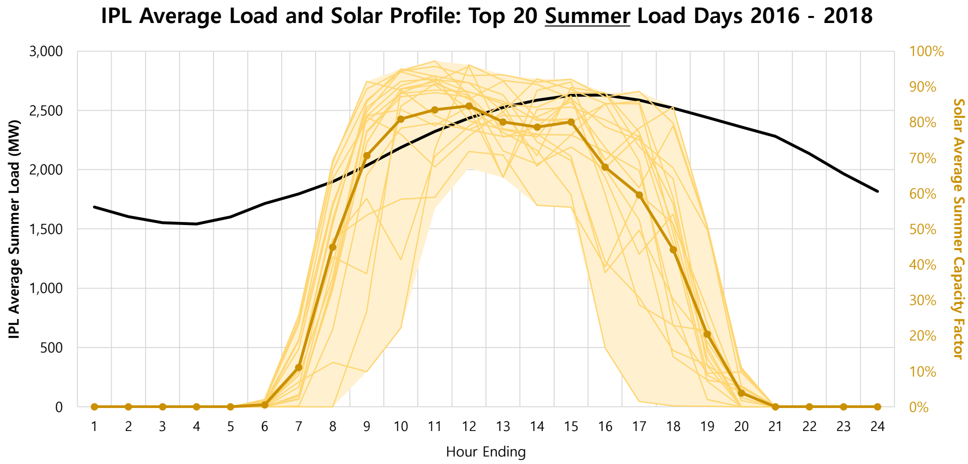
SOLAR ECONOMICS: FAVORABLE IN SHORT TERM, LONG TERM RISKS





SOLAR CAPACITY CREDIT: SUMMER

Summer capacity credit for single-axis tracking solar is 60-70% at low penetration levels



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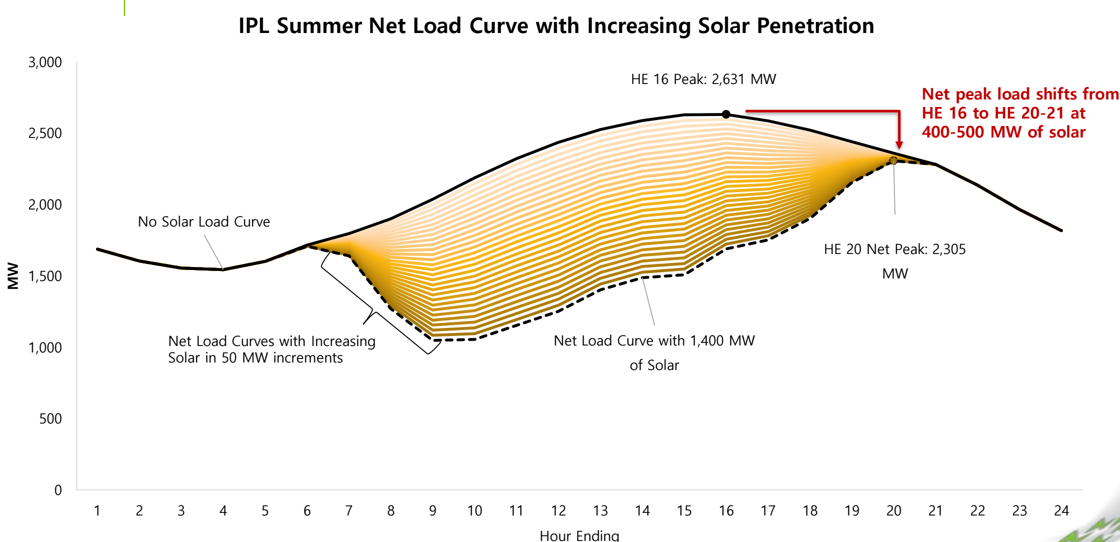
SUMMER NET LOAD CURVE



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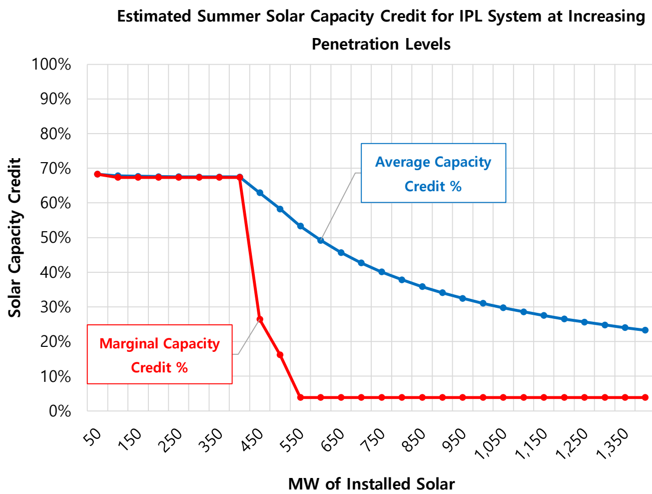
SOLAR CAPACITY CREDIT



Marginal capacity credit for solar erodes quickly past 400-500 MW without intervention

Mitigation measures to improve solar capacity value: storage, demand response, geographically diverse locations, load shifting DSM/EE measures

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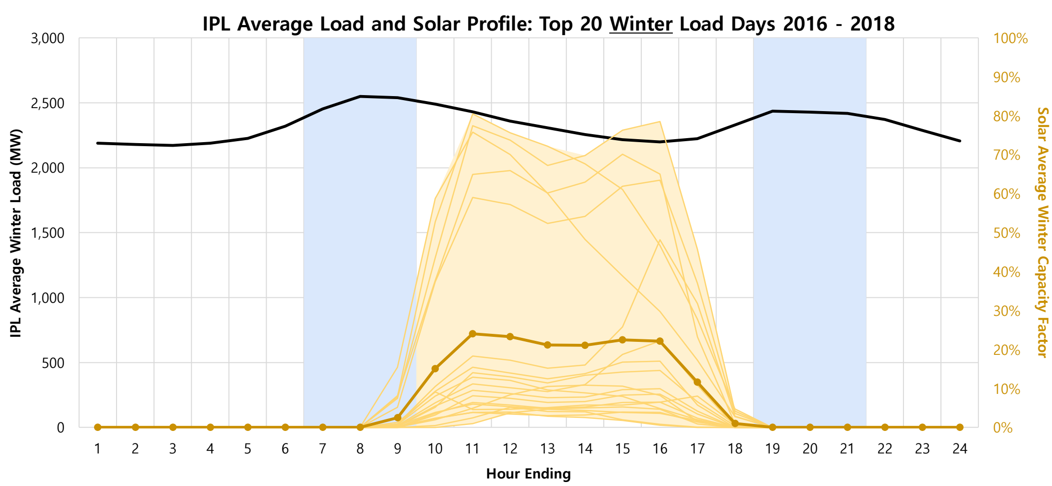
SOLAR CAPACITY CREDIT: WINTER

Limited capacity value in the winter for solar as a standalone resource



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BREAK

ANALYSIS OF ALTERNATIVES: 2019 IRP MODELING

Patrick Maguire

Director of Resource Planning, IPL

2019 IRP MODELING FRAMEWORK

SCENARIOS

	PORTFOLIOS	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas	Scenario D: No Carbon + High Gas
Portfolio 1	No Early Retirements					
Portfolio 2	Pete Unit 1 Retire 2021 Pete Units 2-4 Operational					
Portfolio 3	Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational					
Portfolio 4	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational					
Portfolio 5	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030					

IRP Modeling Framework:
- Systematic evaluation of coal retirements based on age, size, and reasonable transition pathways to allow for construction or acquisition of replacement capacity
- Stochastic capacity expansion with hourly chronological dispatch
- Candidate portfolios stressed against a wide range of uncertainty with stochastic scenario analysis

TESTING FOR COST EFFECTIVENESS OF INCREMENTAL DSM

Presented at Sep. 30th Meeting ↓ New portfolios

	Description	DSM Decrements 1-3	DSM Decrements 1-4	DSM Decrements 1-5
Portfolio 1	No Early Retirements	1a	1b	1c
Portfolio 2	Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	2a	2b	2c
Portfolio 3	Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	3a	3b	3c
Portfolio 4	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	4a	4b	4c
Portfolio 5	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	5a	5b	5c

IPL ran 10 additional capacity expansion runs with DSM decrements/bundles forced in to ensure optimal level of DSM targeted in 2021-2023 plan

MODELING SUMMARY

- **Final modeling framework:**
  - 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

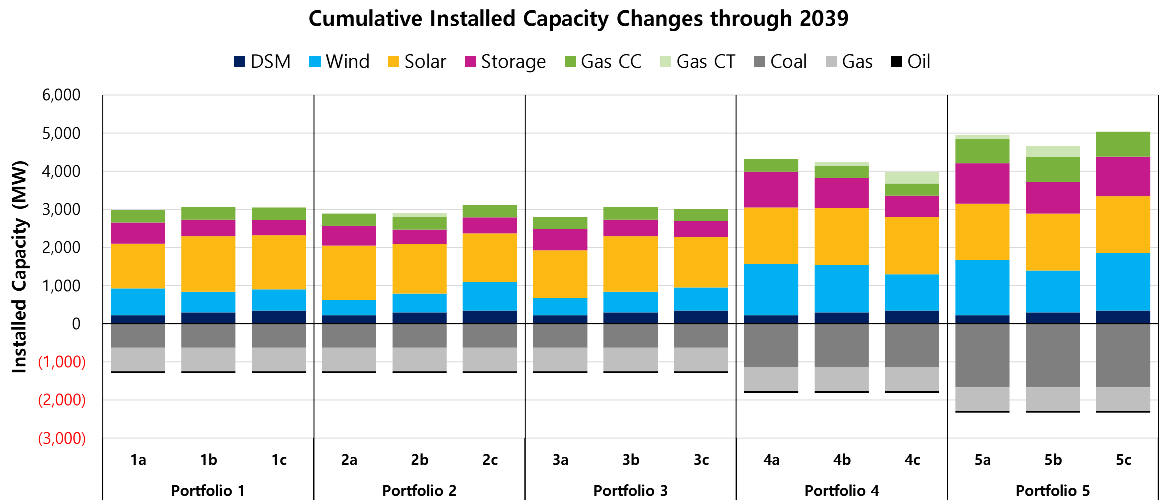
Modeling Tools and Analysis

- 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

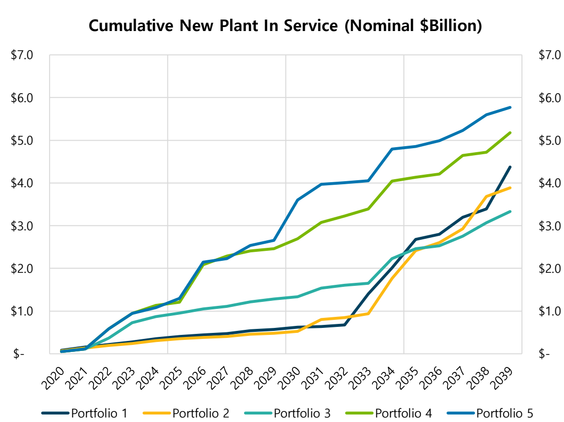
Renewable Modeling

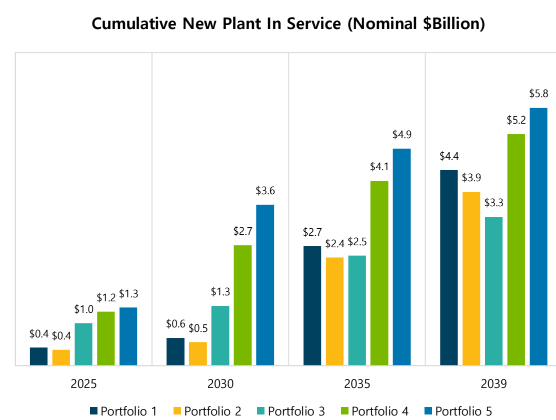
- Robust development of wind and solar profiles
- Solar ELCC and net price shape analysis
- Capital costs: transparent, multi-source cost estimates benchmarked to market bids
- Improved storage modeling

CANDIDATE RESOURCE PORTFOLIOS

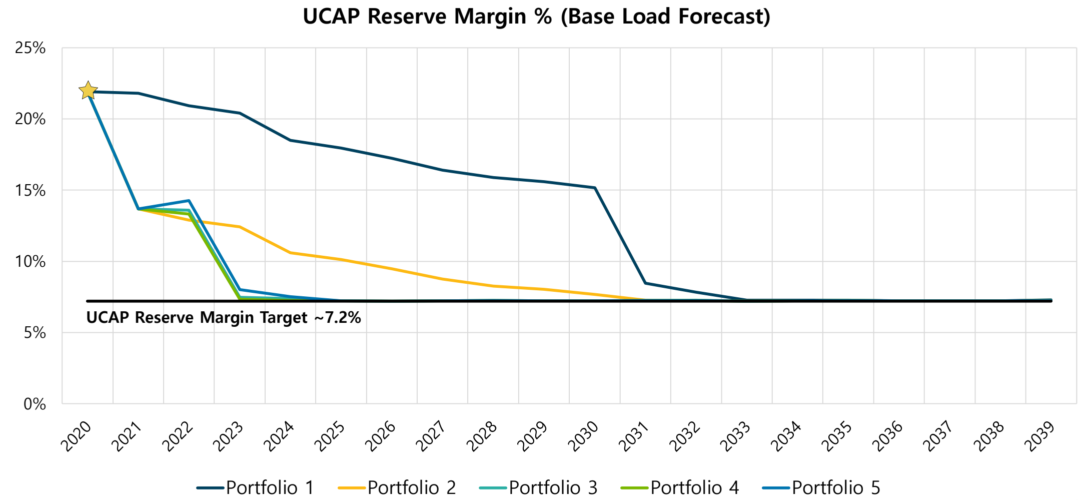


CAPEX REQUIREMENTS BY PORTFOLIO

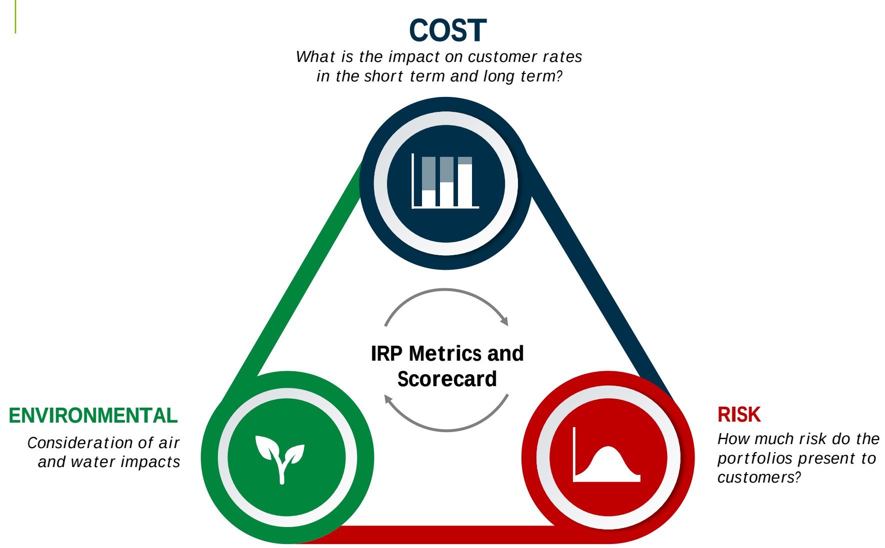




RESERVE MARGIN



PORTFOLIO METRICS

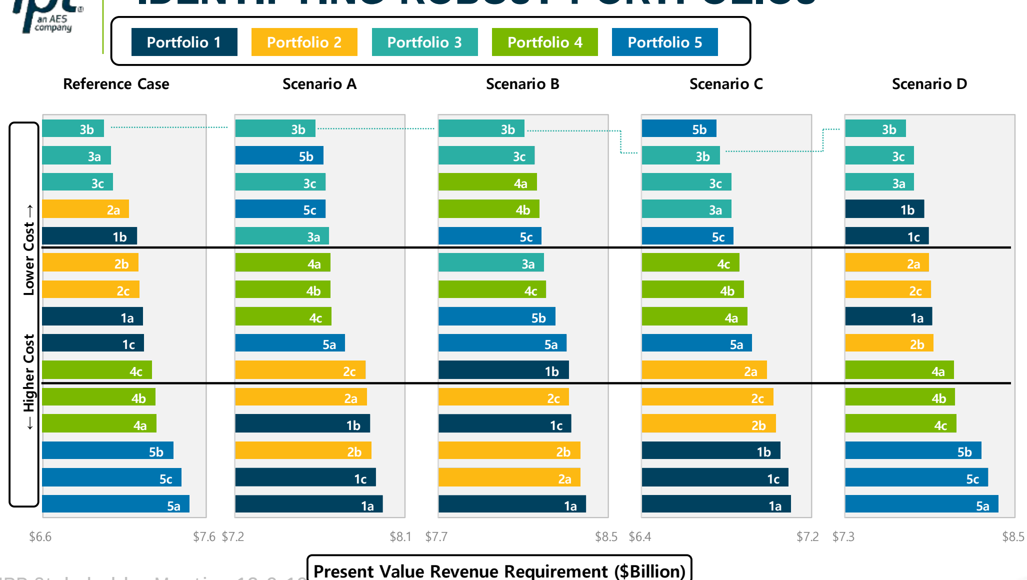


PVRR SUMMARY TABLE BY SCENARIO

20-Year PVRR ($MM)

	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas	Scenario D: No Carbon + High Gas
Portfolio 1a	$7,215	$8,018	$8,427	$7,137	$7,923
Portfolio 2a	$7,132	$7,932	$8,399	$7,017	$7,900
Portfolio 3a	2 $7,016	$7,737	$8,211	3 $6,843	3 $7,798
Portfolio 4a	$7,295	$7,740	3 $8,174	$6,922	$8,070
Portfolio 5a	$7,500	$7,819	$8,329	$6,948	$8,376
Portfolio 1b	$7,176	$7,950	$8,338	$7,087	$7,864
Portfolio 2b	$7,188	$7,956	$8,398	$7,062	$7,932
Portfolio 3b	1 $6,976	1 $7,661	1 $8,114	2 $6,786	1 $7,739
Portfolio 4b	$7,293	$7,742	$8,191	$6,907	$8,082
Portfolio 5b	$7,400	$7,703	$8,272	1 $6,769	$8,259
Portfolio 1c	$7,223	$7,980	$8,355	$7,128	$7,899
Portfolio 2c	$7,191	$7,923	$8,341	$7,051	$7,912
Portfolio 3c	3 $7,034	2 $7,716	2 $8,165	$6,842	2 $7,794
Portfolio 4c	$7,269	$7,747	$8,225	$6,883	$8,086
Portfolio 5c	$7,452	3 $7,716	$8,202	$6,857	$8,306

IDENTIFYING ROBUST PORTFOLIOS



AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-2
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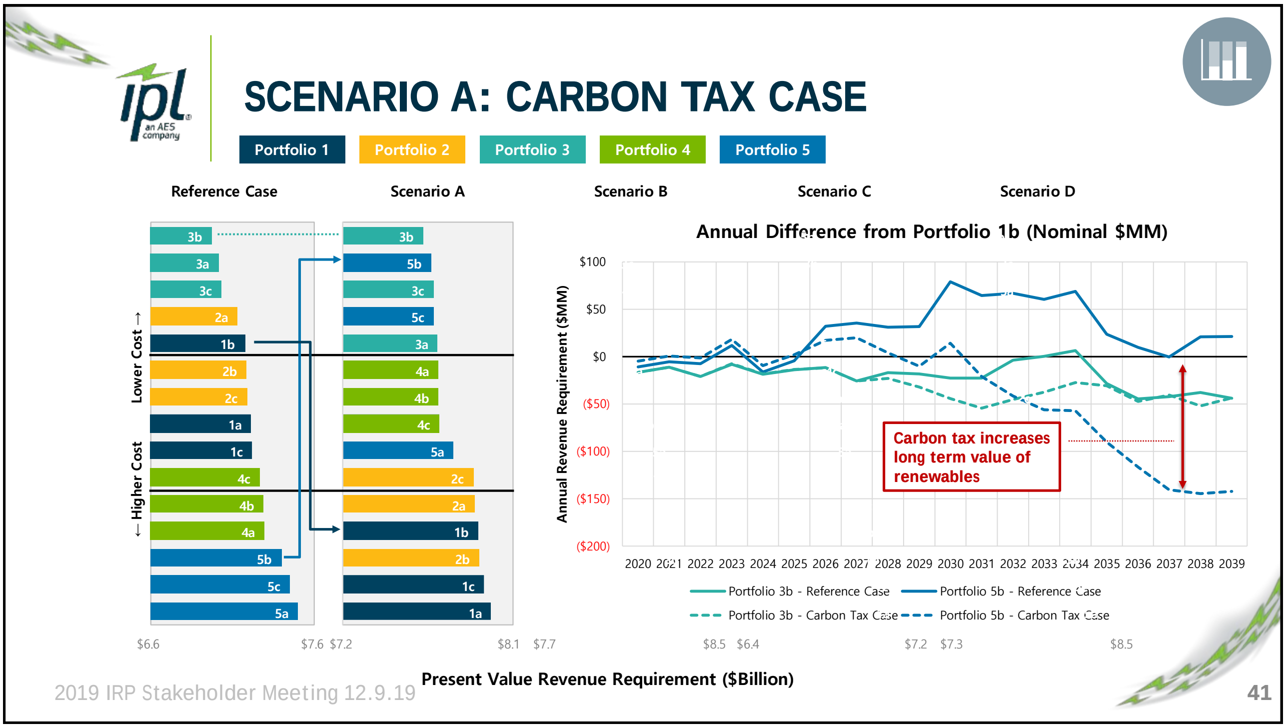
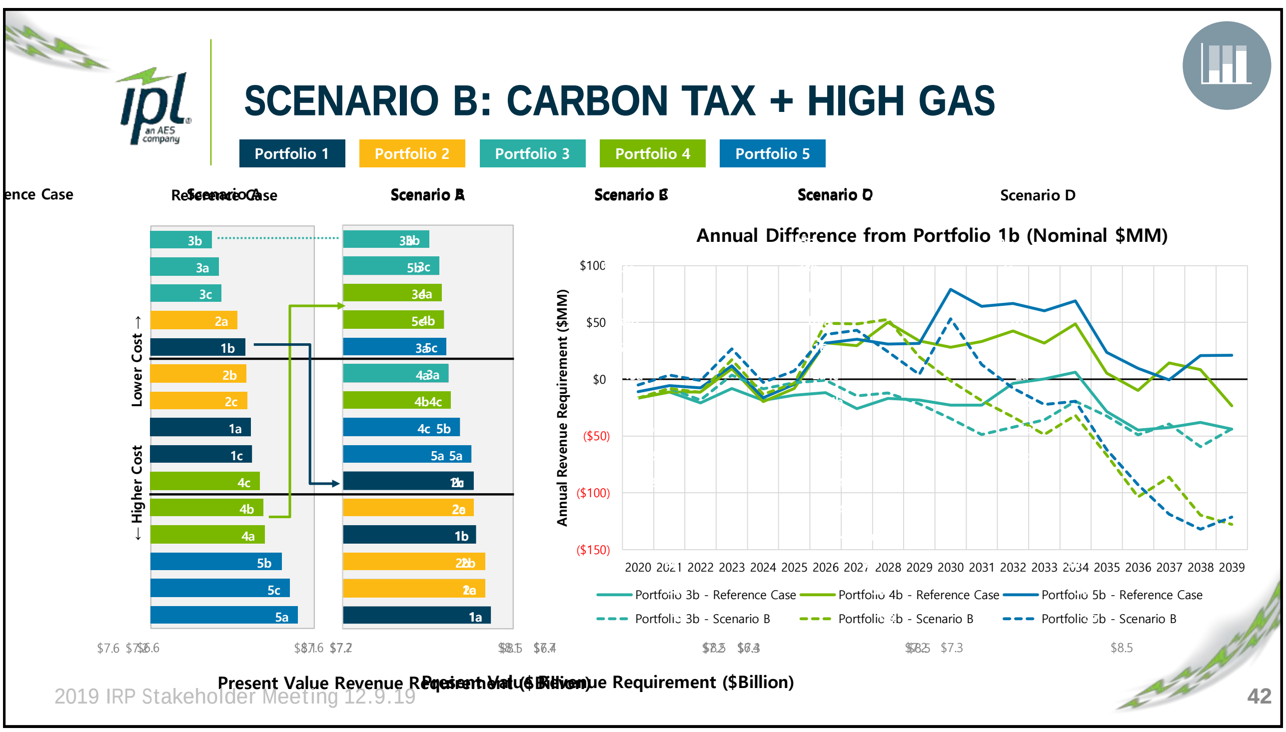
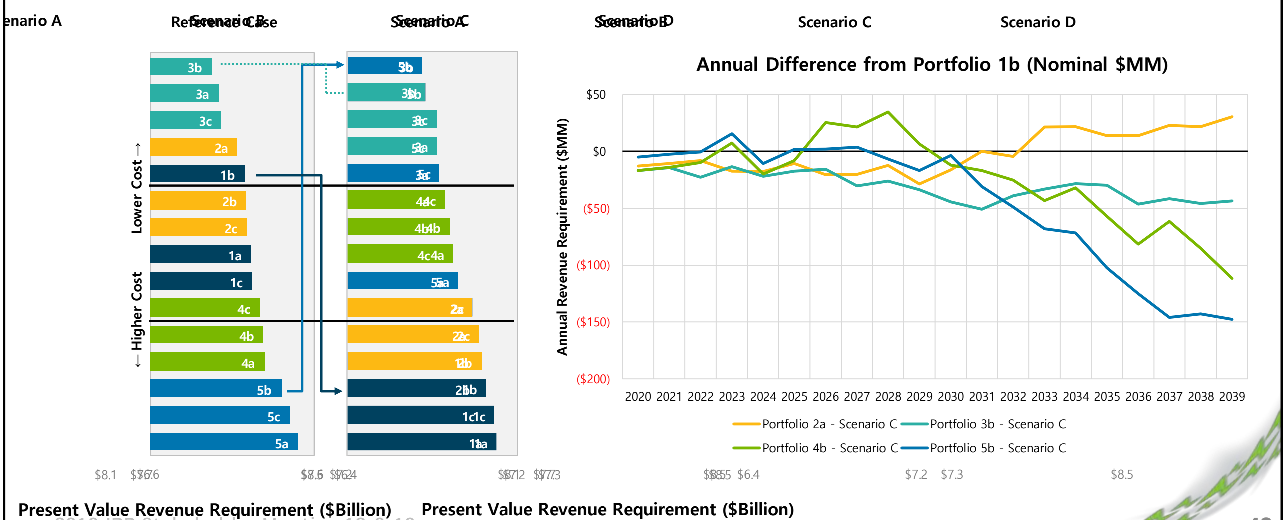




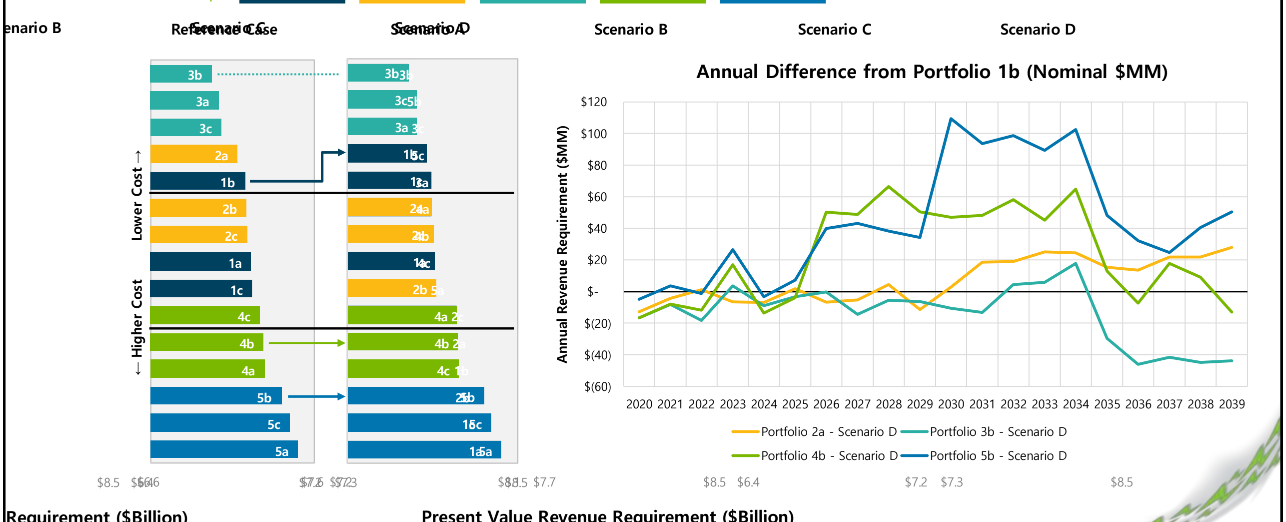
SCENARIO C: CARBON TAX + LOW GAS + LOW LOAD

Portfolio 1 | Portfolio 2 | Portfolio 3 | Portfolio 4 | Portfolio 5



SCENARIO D: NO CARBON TAX + HIGH GAS + HIGH LOAD

Portfolio 1 | Portfolio 2 | Portfolio 3 | Portfolio 4 | Portfolio 5



PVRR TAKEAWAYS

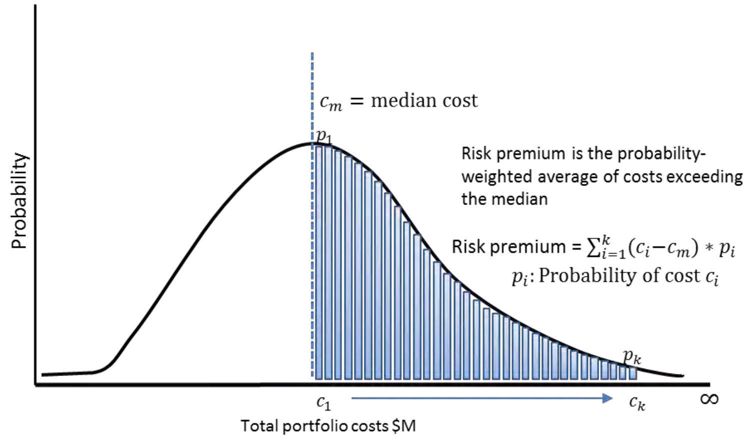
- **Carbon tax single largest driver of changes in PVRR**
  - Coal margins 40-50% lower with carbon tax
  - Renewable captured revenue 30-40% higher because of higher wholesale power prices
  - Reducing exposure to future carbon legislation important
- Natural gas will continue to be a high impact variable as coal and combined cycle units compete for positions in the dispatch stack
- Benefits of portfolio diversity on display:
  - Portfolio 3, which moves toward a 30/40/30 mix of coal, natural gas, and renewables, is the lowest cost across a range of futures

RATE IMPACTS

Levelized Rate $/kWh

	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas	Scenario D: No Carbon + High Gas
Portfolio 1a	$0.046	$0.051	$0.053	$0.047	$0.048
Portfolio 2a	$0.045	$0.050	$0.053	$0.046	$0.048
Portfolio 3a	$0.044	$0.049	$0.052	$0.045	$0.047
Portfolio 4a	$0.046	$0.049	$0.052	$0.045	$0.049
Portfolio 5a	$0.047	$0.049	$0.053	$0.045	$0.051
Portfolio 1b	$0.046	$0.051	$0.053	$0.047	$0.048
Portfolio 2b	$0.046	$0.051	$0.054	$0.047	$0.049
Portfolio 3b	$0.045	$0.049	$0.052	$0.045	$0.047
Portfolio 4b	$0.047	$0.049	$0.052	$0.046	$0.049
Portfolio 5b	$0.047	$0.049	$0.053	$0.045	$0.051
Portfolio 1c	$0.047	$0.052	$0.054	$0.048	$0.049
Portfolio 2c	$0.046	$0.051	$0.054	$0.047	$0.049
Portfolio 3c	$0.045	$0.050	$0.053	$0.046	$0.048
Portfolio 4c	$0.047	$0.050	$0.053	$0.046	$0.050
Portfolio 5c	$0.048	$0.050	$0.053	$0.046	$0.051

RISK PREMIUM METRIC



The risk premium metric assesses the risk of high cost outcomes based on the stochastic results for each portfolio

Taking the average of the outcomes above the mean captures tail risk better than P75 or P95

RISK PREMIUM ($MM)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1a	$329	$383	$406	$353	$400
Portfolio 2a	$370	$425	$465	$384	$452
Portfolio 3a	$367	$419	$464	$370	$448
Portfolio 4a	$466	$537	$611	$466	$554
Portfolio 5a	$441	$498	$574	$431	$539
Portfolio 1b	$358	$420	$447	$385	$430
Portfolio 2b	$354	$407	$442	$363	$431
Portfolio 3b	$408	$468	$532	$415	$495
Portfolio 4b	$461	$534	$609	$467	$554
Portfolio 5b	$493	$565	$649	$481	$595
Portfolio 1c	$348	$406	$430	$374	$416
Portfolio 2c	$360	$412	$449	$368	$438
Portfolio 3c	$372	$424	$476	$378	$448
Portfolio 4c	$457	$534	$612	$464	$554
Portfolio 5c	$442	$507	$584	$448	$543

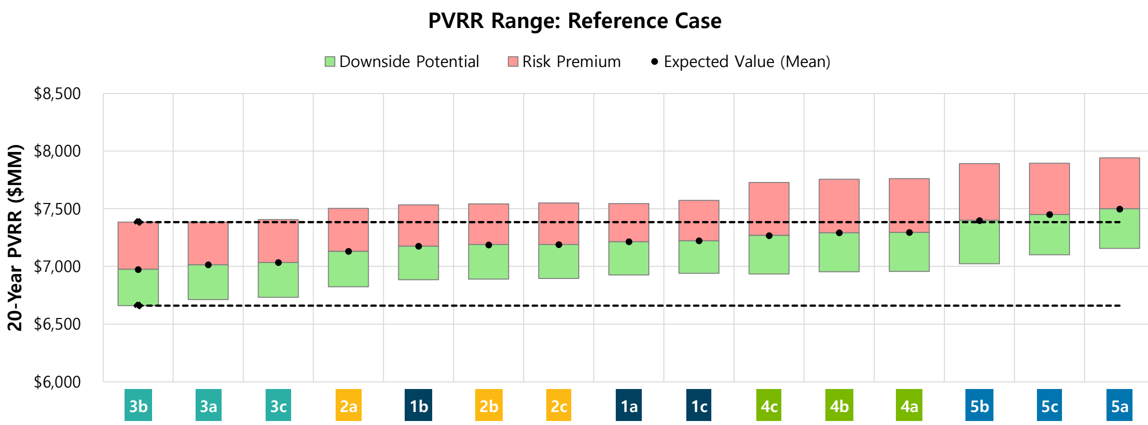
- Risk premiums are 4-7% of total cost
- Risk premium lowest for Portfolios 1 and 2
- Coal prices relatively stable, dispatchability improves economics
- High renewable portfolios can create mismatch between load and generation

RISK-ADJUSTED PVRR ($MM)

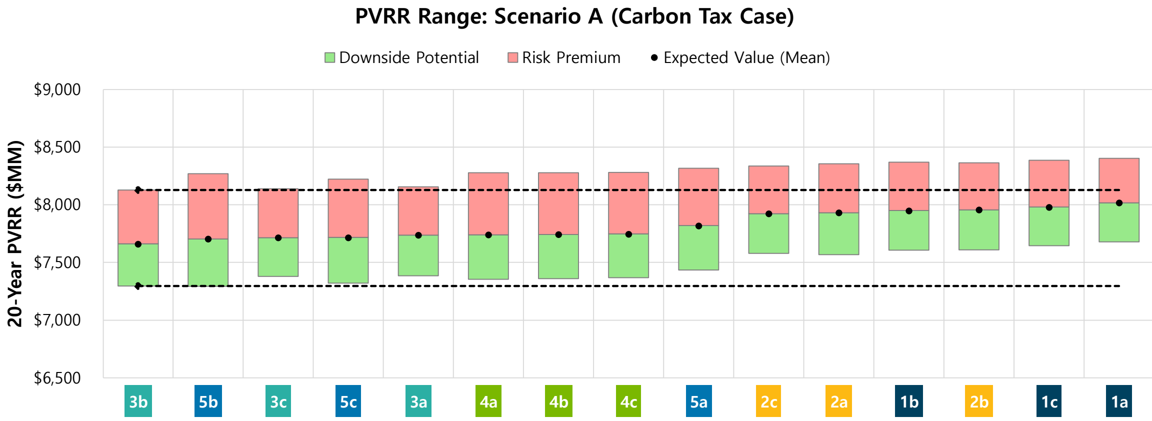
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1a	$7,544	$8,401	$8,833	$7,489	$8,324
Portfolio 2a	$7,502	$8,356	$8,865	$7,401	$8,351
Portfolio 3a	$7,383	$8,156	$8,676	$7,213	$8,246
Portfolio 4a	$7,761	$8,278	$8,784	$7,388	$8,623
Portfolio 5a	$7,941	$8,317	$8,904	$7,379	$8,915
Portfolio 1b	$7,533	$8,370	$8,785	$7,472	$8,294
Portfolio 2b	$7,542	$8,363	$8,840	$7,425	$8,363
Portfolio 3b	$7,384	$8,129	$8,646	$7,201	$8,234
Portfolio 4b	$7,754	$8,277	$8,800	$7,374	$8,636
Portfolio 5b	$7,892	$8,268	$8,921	$7,250	$8,854
Portfolio 1c	$7,571	$8,387	$8,785	$7,502	$8,315
Portfolio 2c	$7,551	$8,335	$8,791	$7,418	$8,350
Portfolio 3c	$7,407	$8,139	$8,642	$7,221	$8,242
Portfolio 4c	$7,726	$8,281	$8,837	$7,347	$8,640
Portfolio 5c	$7,893	$8,223	$8,786	$7,305	$8,849

- Adding risk premium to expected value PVRR puts all portfolios on level playing field
- **Portfolio 3 is lowest cost on a risk-adjusted basis in all scenarios**

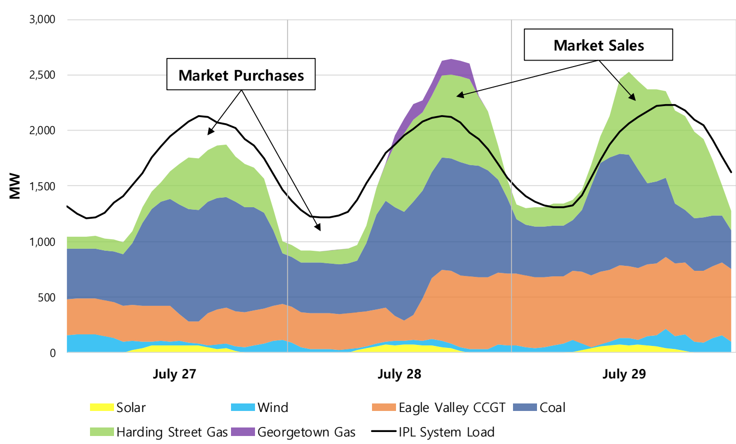
PVRR WITH RISK DISTRIBUTIONS: REFERENCE CASE



PVRR WITH RISK DISTRIBUTIONS: SCENARIO A (CARBON TAX CASE)



RISK METRIC: MARKET INTERACTION

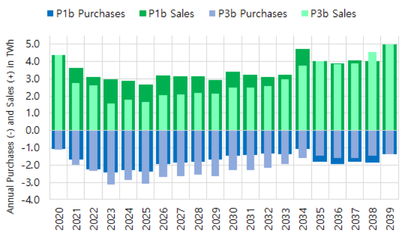


- Looking only at annual energy misses the actual market interaction that will occur hourly
- Market purchases and sales occur in all portfolios
- Relying too heavily on market purchases introduces risk
- Relying on value from market sales is equally risky

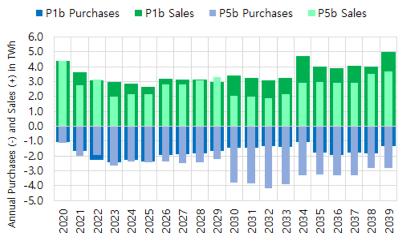
RELIANCE ON THE MARKET: BALANCED APPROACH

Reference Case

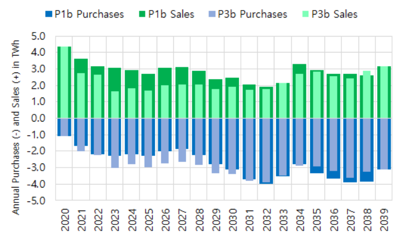
Portfolio 1 vs. Portfolio 3

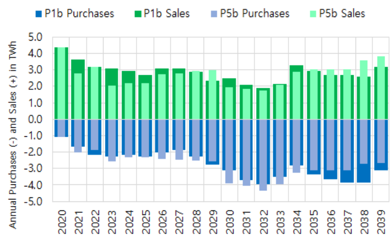


Portfolio 1 vs. Portfolio 5



Scenario A: Carbon Case





Market Interaction

(in Millions of MWh)

|Purchases| + |Sales|

Reference Case	
Portfolio	
1b	5.2
3b	5.0
5b	5.6

Scenario A: Carbon Case	
Portfolio	
1b	5.7
3b	5.4
5b	5.6

ENVIRONMENTAL: AIR EMISSIONS

Reference Case

	CO_2 (million short-tons)	CO_2 Intensity (short-tons/MWh)	NO_x (short-tons)	SO_2 (short-tons)
2010 - 2012 Baseline (3-year average)	16.1	1.05	14,255	53,107
	20-Year Average (2020 - 2039)			
Portfolio 1a	11.9	0.75	8,028	10,972
Portfolio 2a	11.0	0.73	7,120	10,477
Portfolio 3a	9.5	0.64	6,371	9,577
Portfolio 4a	7.0	0.46	5,152	6,038
Portfolio 5a	5.6	0.38	2,991	3,582
Portfolio 1b	11.9	0.74	8,028	10,972
Portfolio 2b	11.1	0.72	7,124	10,477
Portfolio 3b	9.5	0.63	6,371	9,577
Portfolio 4b	7.0	0.47	5,164	6,039
Portfolio 5b	5.8	0.41	3,014	3,583
Portfolio 1c	11.9	0.74	8,028	10,972
Portfolio 2c	11.0	0.71	7,120	10,477
Portfolio 3c	9.5	0.64	6,371	9,577
Portfolio 4c	7.1	0.49	5,182	6,039
Portfolio 5c	5.7	0.38	2,988	3,583

Scenario A: Carbon Tax Case

	CO_2 (million short-tons)	CO_2 Intensity (short-tons/MWh)	NO_x (short-tons)	SO_2 (short-tons)
2010 - 2012 Baseline (3-year average)	16.1	1.05	14,255	53,107
Portfolio 1a	10.0	0.71	6,547	8,653
Portfolio 2a	9.3	0.69	5,722	8,203
Portfolio 3a	8.0	0.59	5,085	7,438
Portfolio 4a	6.3	0.43	4,265	5,059
Portfolio 5a	5.6	0.38	2,952	3,552
Portfolio 1b	10.0	0.70	6,547	8,653
Portfolio 2b	9.3	0.68	5,726	8,203
Portfolio 3b	8.0	0.58	5,085	7,438
Portfolio 4b	6.3	0.44	4,277	5,059
Portfolio 5b	5.8	0.41	2,974	3,553
Portfolio 1c	10.0	0.70	6,547	8,653
Portfolio 2c	9.3	0.67	5,722	8,203
Portfolio 3c	8.0	0.59	5,085	7,438
Portfolio 4c	6.4	0.46	4,294	5,060
Portfolio 5c	5.7	0.38	2,950	3,552

ENVIRONMENTAL: NON-AIR IMPACTS

- Impact of coal retirements on water:
  - Retire Units 1 and 2: significant reduction in actual intake flow (estimate: greater than 67%);
  - Retire Units 1-4 (assume no water withdrawal): result in the elimination of 354 million gallons per day (MGD) (100% reduction) of water withdraw from the river

PORTFOLIO METRICS SUMMARY

Cost	Risk	Environmental

• Portfolio 3b is the lowest cost portfolio across wide range scenarios
• O&M and Capex savings from retirements mitigates rate impacts of cost of new capacity
	• Portfolio 3b lowest cost on risk-adjusted basis
	• Portfolio 3b resource mix provides balanced energy and load profile and reduction total market interaction
		• Portfolio 3b benefits:
		  • Near term reductions in CO2, NOx, SO2
		  • 60-70% reduction in water intake flow at the plant

LUNCH BREAK

SENSITIVITY ANALYSIS

Patrick Maguire

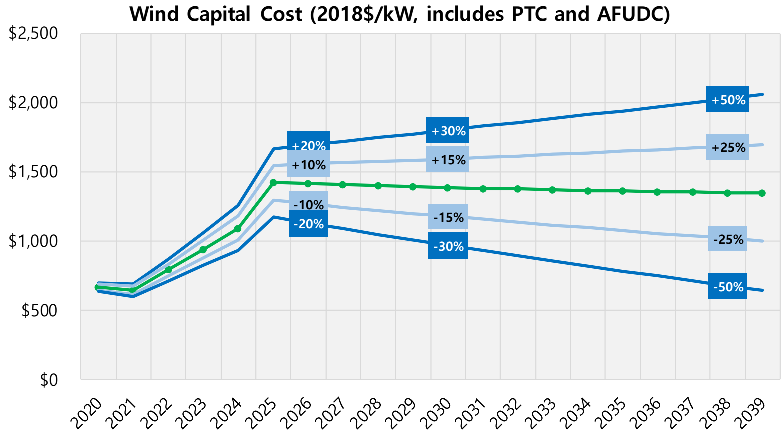
Director of Resource Planning, IPL

SENSITIVITY ANALYSIS

- **Sensitivity: change of a single variable to isolate the impact of future uncertainty**
- Four deterministic analyses conducted:
  1. Capital Costs for wind, solar, and storage
  2. MISO Capacity Prices
  3. Wind Capacity Factor
  4. Wind LMP Basis

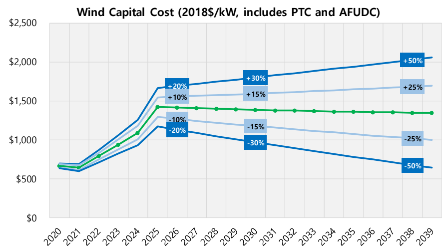
CAPITAL COST SENSITIVITY (1 OF 4)

Wind Capital Cost (2018$/kW, includes PTC and AFUDC)

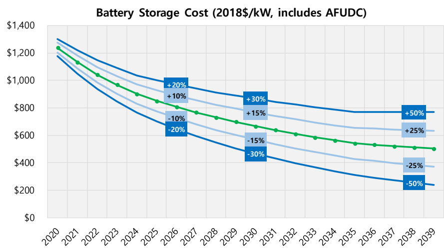


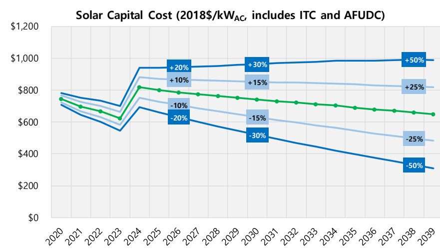
High and low capital cost ranges established for wind, solar, and storage

CAPITAL COST SENSITIVITY (2 OF 4)



- Wind, solar, and storage cost sensitivities applied to fixed portfolios
- All three costs moved together





CAPITAL COST SENSITIVITY (3 OF 4)

Reference Case PVRR ($MM)

	Percent Change by 2030		PVRR w/ Base	Percent Change by 2030	
	-30%	-15%	Capital Costs ↓	+15%	+30%
Portfolio 3b	$6,775	$6,874	$6,976	$7,077	$7,177
Portfolio 3a	$6,841	$6,927	$7,016	$7,105	$7,191
Portfolio 3c	$6,843	$6,938	$7,034	$7,131	$7,225
Portfolio 2a	$6,965	$7,049	$7,132	$7,214	$7,298
Portfolio 1b	$7,004	$7,091	$7,176	$7,261	$7,348
Portfolio 2b	$7,010	$7,100	$7,188	$7,276	$7,366
Portfolio 2c	$6,986	$7,089	$7,191	$7,292	$7,396
Portfolio 1a	$7,043	$7,130	$7,215	$7,300	$7,387
Portfolio 1c	$7,043	$7,134	$7,223	$7,312	$7,403
Portfolio 4c	$6,978	$7,121	$7,269	$7,417	$7,560
Portfolio 4b	$6,928	$7,107	$7,293	$7,478	$7,658
Portfolio 4a	$6,912	$7,100	$7,295	$7,490	$7,678
Portfolio 5b	$7,073	$7,234	$7,400	$7,565	$7,726
Portfolio 5c	$7,001	$7,224	$7,452	$7,679	$7,902
Portfolio 5a	$7,100	$7,309	$7,500	$7,741	$7,950

Takeaways:

1. Portfolio 3b lowest cost with a 30% reduction from base cost forecasts for wind, solar, and storage
2. Portfolio 3b lowest cost with a significant increase in capital costs for wind, solar, and storage

CAPITAL COST SENSITIVITY (4 OF 4)

Scenario A (Carbon Tax Case) PVRR ($MM)

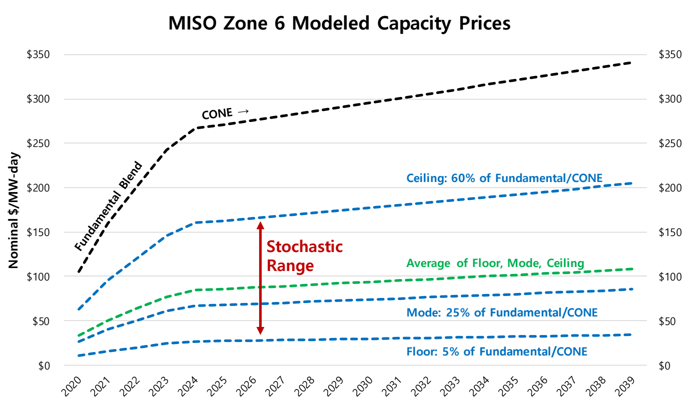
	Percent Change by 2030		PVRR w/ Base Capital Costs ↓	Percent Change by 2030	
	-30%	-15%		+15%	+30%
Portfolio 3b	$7,460	$7,560	$7,661	$7,763	$7,862
Portfolio 5b	$7,377	$7,538	$7,703	$7,869	$8,030
Portfolio 3c	$7,524	$7,619	$7,716	$7,812	$7,907
Portfolio 5c	$7,266	$7,489	$7,716	$7,944	$8,166
Portfolio 3a	$7,562	$7,648	$7,737	$7,826	$7,912
Portfolio 4a	$7,357	$7,546	$7,740	$7,935	$8,123
Portfolio 4b	$7,377	$7,538	$7,742	$7,928	$8,107
Portfolio 4c	$7,456	$7,599	$7,747	$7,896	$8,039
Portfolio 5a	$7,394	$7,603	$7,819	$8,035	$8,244
Portfolio 2c	$7,719	$7,822	$7,923	$8,025	$8,128
Portfolio 2a	$7,765	$7,849	$7,932	$8,014	$8,098
Portfolio 1b	$7,778	$7,865	$7,950	$8,035	$8,122
Portfolio 2b	$7,778	$7,868	$7,956	$8,044	$8,134
Portfolio 1c	$7,800	$7,891	$7,980	$8,069	$8,160
Portfolio 1a	$7,846	$7,933	$8,018	$8,103	$8,190

Carbon Tax Case Results:

1. Portfolio 5 becomes lowest cost with (a) federal price on carbon and (b) cost declines (from base forecast) in wind, solar, and storage

2. Portfolio 3b lowest cost with a significant increase in capital costs for wind, solar, and storage

MISO CAPACITY PRICE SENSITIVITY (1 OF 3)



- MISO capacity prices applied to portfolio position imbalances (long/short)
- Greatest impact on Portfolios 1 and 2 because IPL is in a net long capacity position today
- Capacity prices modeled stochastically to capture range of uncertainty
- Deterministic sensitivities conducted to measure impact of capacity prices on PVRR results

MISO CAPACITY PRICE SENSITIVITY (2 OF 2)

Reference Case PVRR ($MM)

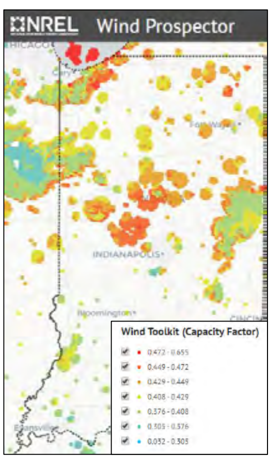
	Bilateral Floor	Bilateral Most Likely	[Base] Stochastic Mean ↓	Bilateral Ceiling	CONE
Portfolio 3b	$6,983	$6,978	$6,976	$6,966	$6,953
Portfolio 3a	$7,024	$7,018	$7,016	$7,006	$6,993
Portfolio 3c	$7,034	$7,034	$7,034	$7,034	$7,034
Portfolio 2a	$7,146	$7,136	$7,132	$7,113	$7,087
Portfolio 1b	$7,221	$7,190	$7,176	$7,116	$7,035
Portfolio 2b	$7,203	$7,193	$7,188	$7,169	$7,144
Portfolio 2c	$7,191	$7,191	$7,191	$7,191	$7,191
Portfolio 1a	$7,260	$7,229	$7,215	$7,156	$7,074
Portfolio 1c	$7,223	$7,223	$7,223	$7,223	$7,223
Portfolio 4c	$7,269	$7,269	$7,269	$7,269	$7,269
Portfolio 4b	$7,301	$7,295	$7,293	$7,281	$7,267
Portfolio 4a	$7,304	$7,298	$7,295	$7,284	$7,269
Portfolio 5b	$7,408	$7,402	$7,400	$7,389	$7,375
Portfolio 5c	$7,452	$7,452	$7,452	$7,452	$7,452
Portfolio 5a	$7,508	$7,503	$7,500	$7,489	$7,475

Reference Case Results:

1. Portfolio 3b lowest cost even with applying CONE capacity price to capacity length in Portfolios 1 and 2

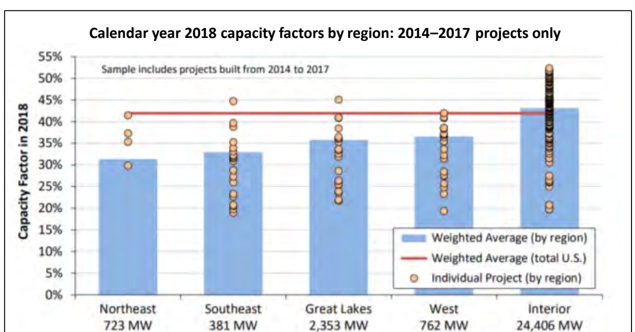
2. Sustained low capacity prices increases value of Portfolio 3 relative to Portfolios 1 and 2

WIND CAPACITY FACTOR (1 OF 3)



Source: NREL

- IPL utilized the NREL Wind Toolkit to source generic hourly wind profiles
- Capacity factor sensitivity evaluates PVRR impact of lower actual wind production compared to modeled
- Captured revenue “locked” from base, MWh adjusted



DOE 2018 Wind Technologies Market Report (PDF)

WIND CAPACITY FACTOR (2 OF 3)

Wind annual capacity factor →

Reference Case PVRR ($MM)

	46%	44%	Base (42%) ↓	40%	38%	36%	34%	32%	30%
Portfolio 3b	$6,959	$6,968	$6,976	$6,987	$6,996	$7,005	$7,014	$7,024	$7,033
Portfolio 3a	$6,991	$7,004	$7,016	$7,032	$7,046	$7,059	$7,073	$7,087	$7,101
Portfolio 3c	$7,012	$7,024	$7,034	$7,049	$7,061	$7,073	$7,086	$7,098	$7,110
Portfolio 2a	$7,128	$7,130	$7,132	$7,134	$7,136	$7,138	$7,140	$7,142	$7,144
Portfolio 1b	$7,172	$7,174	$7,176	$7,178	$7,180	$7,182	$7,184	$7,186	$7,187
Portfolio 2b	$7,179	$7,184	$7,188	$7,194	$7,199	$7,203	$7,208	$7,213	$7,218
Portfolio 2c	$7,180	$7,186	$7,191	$7,198	$7,204	$7,210	$7,215	$7,221	$7,227
Portfolio 1a	$7,208	$7,212	$7,215	$7,219	$7,223	$7,227	$7,230	$7,234	$7,238
Portfolio 1c	$7,217	$7,221	$7,223	$7,227	$7,230	$7,233	$7,237	$7,240	$7,243
Portfolio 4c	$7,222	$7,248	$7,269	$7,299	$7,325	$7,350	$7,376	$7,401	$7,427
Portfolio 4b	$7,234	$7,266	$7,293	$7,330	$7,362	$7,394	$7,426	$7,458	$7,489
Portfolio 4a	$7,228	$7,265	$7,295	$7,338	$7,375	$7,411	$7,448	$7,484	$7,521
Portfolio 5b	$7,355	$7,379	$7,400	$7,428	$7,453	$7,477	$7,502	$7,526	$7,551
Portfolio 5c	$7,372	$7,416	$7,452	$7,503	$7,546	$7,589	$7,633	$7,676	$7,720
Portfolio 5a	$7,417	$7,461	$7,500	$7,549	$7,593	$7,638	$7,682	$7,726	$7,770

Reference Case Results:

1 Very low capacity factor for wind does not change lowest cost portfolio in Reference Case

2 Every 2% decrease in annual net capacity factor for wind increases Portfolio 5 PVRR by ~$43M, or 1%

WIND CAPACITY FACTOR (3 OF 3)

Wind annual capacity factor →

Scenario A (Carbon Tax Case) PVRR ($MM)

	46%	44%	Base (42%) ↓	40%	38%	36%	34%	32%	30%
Portfolio 3b	$7,640	$7,652	$7,661	$7,675	$7,686	$7,698	$7,709	$7,721	$7,733
Portfolio 5b	$7,649	$7,679	$7,703	$7,739	$7,769	$7,798	$7,828	$7,858	$7,888
Portfolio 3c	$7,688	$7,703	$7,716	$7,733	$7,748	$7,764	$7,779	$7,794	$7,809
Portfolio 5c	$7,619	$7,672	$7,716	$7,779	$7,832	$7,886	$7,939	$7,993	$8,046
Portfolio 3a	$7,707	$7,723	$7,737	$7,756	$7,772	$7,789	$7,805	$7,822	$7,838
Portfolio 4a	$7,659	$7,704	$7,740	$7,793	$7,837	$7,881	$7,926	$7,970	$8,015
Portfolio 4b	$7,671	$7,710	$7,742	$7,788	$7,827	$7,867	$7,906	$7,945	$7,984
Portfolio 4c	$7,691	$7,722	$7,747	$7,784	$7,815	$7,845	$7,876	$7,907	$7,938
Portfolio 5a	$7,718	$7,772	$7,819	$7,879	$7,933	$7,986	$8,040	$8,094	$8,148
Portfolio 2c	$7,909	$7,917	$7,923	$7,933	$7,941	$7,949	$7,958	$7,966	$7,974
Portfolio 2a	$7,927	$7,929	$7,932	$7,935	$7,937	$7,940	$7,943	$7,946	$7,948
Portfolio 1b	$7,945	$7,948	$7,950	$7,953	$7,956	$7,959	$7,961	$7,964	$7,967
Portfolio 2b	$7,944	$7,950	$7,956	$7,964	$7,970	$7,977	$7,983	$7,990	$7,996
Portfolio 1c	$7,972	$7,977	$7,980	$7,985	$7,990	$7,994	$7,999	$8,003	$8,008
Portfolio 1a	$8,009	$8,014	$8,018	$8,024	$8,029	$8,034	$8,039	$8,044	$8,050

Carbon Tax Case Results:

1 Portfolio 3b still lowest cost in Carbon Tax case.

2 Lower realized capacity factor for wind moves Portfolio 4 ahead of 5; Portfolio 3 still lowest cost

WIND LMP BASIS/CAPTURED REVENUE (1 OF 3)

- Congestion, due to transmission constraints, outages, and other factors, results in price separation from generator to IPL load
- LMP basis to MISO Indiana Hub applied to existing and new resources to account for congestion impacts on nodal LMPs
- Sensitivity analysis designed to evaluate the impact of removing that LMP discount for wind
- Wind production (MWh) locked and fixed across portfolios
- Captured revenue increased in 5% increments to remove LMP discount

WIND LMP BASIS/CAPTURED REVENUE (2 OF 3)

Reference Case PVRR ($MM)

	Base	Revenue +5%	Revenue +10%	Revenue +15%	Revenue +20%
Portfolio 3b	$6,976	$6,966	$6,956	$6,946	$6,937
Portfolio 3a	$7,016	$7,001	$6,987	$6,972	$6,958
Portfolio 3c	$7,034	$7,021	$7,008	$6,995	$6,982
Portfolio 2a	$7,132	$7,130	$7,128	$7,126	$7,124
Portfolio 1b	$7,176	$7,174	$7,172	$7,170	$7,168
Portfolio 2b	$7,188	$7,183	$7,178	$7,173	$7,168
Portfolio 2c	$7,191	$7,185	$7,178	$7,172	$7,166
Portfolio 1a	$7,215	$7,211	$7,207	$7,203	$7,199
Portfolio 1c	$7,223	$7,220	$7,216	$7,213	$7,210
Portfolio 4c	$7,269	$7,242	$7,215	$7,188	$7,161
Portfolio 4b	$7,293	$7,259	$7,225	$7,191	$7,158
Portfolio 4a	$7,295	$7,256	$7,218	$7,179	$7,140
Portfolio 5b	$7,400	$7,374	$7,348	$7,322	$7,296
Portfolio 5c	$7,452	$7,406	$7,360	$7,314	$7,268
Portfolio 5a	$7,500	$7,453	$7,407	$7,360	$7,314

Reference Case Results:

1 Removing the LMP basis on wind closes the gap between Portfolio 5 and Portfolio 3 by ~$124M; Portfolio 3 still lowest cost

WIND LMP BASIS/CAPTURED REVENUE (3 OF 3)

Scenario A (Carbon Tax Case) PVRR ($MM)

	Base	Revenue +5%	Revenue +10%	Revenue +15%	Revenue +20%
Portfolio 3b	$7,661	$7,649	$7,637	$7,625	$7,612
Portfolio 5b	$7,703	$7,672	$7,640	$7,608	$7,576
Portfolio 3c	$7,716	$7,699	$7,683	$7,667	$7,651
Portfolio 5c	$7,716	$7,660	$7,603	$7,547	$7,490
Portfolio 3a	$7,737	$7,720	$7,702	$7,685	$7,668
Portfolio 4a	$7,740	$7,693	$7,646	$7,599	$7,552
Portfolio 4b	$7,742	$7,701	$7,659	$7,618	$7,576
Portfolio 4c	$7,747	$7,715	$7,682	$7,649	$7,616
Portfolio 5a	$7,819	$7,763	$7,706	$7,649	$7,593
Portfolio 2c	$7,923	$7,915	$7,906	$7,898	$7,889
Portfolio 2a	$7,932	$7,929	$7,926	$7,923	$7,920
Portfolio 1b	$7,950	$7,947	$7,944	$7,941	$7,939
Portfolio 2b	$7,956	$7,949	$7,942	$7,935	$7,928
Portfolio 1c	$7,980	$7,976	$7,971	$7,966	$7,961
Portfolio 1a	$8,018	$8,013	$8,007	$8,002	$7,996

Carbon Tax Case Results:

1. Improved congestion, and therefore revenue, for wind increases value of Portfolio 5 compared to Portfolio 3 with a federal price on carbon

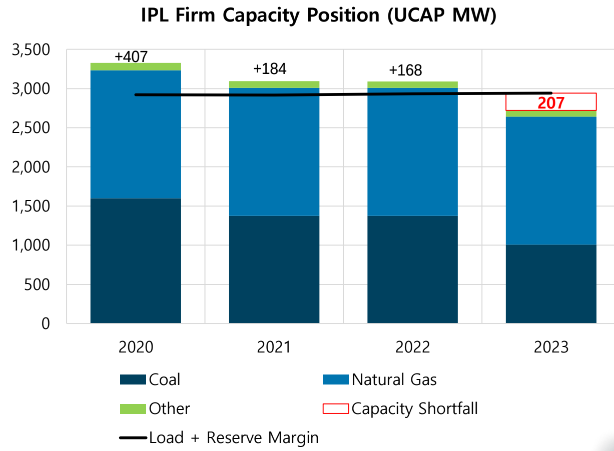
PREFERRED RESOURCE PORTFOLIO & SHORT TERM ACTION PLAN

Patrick Maguire

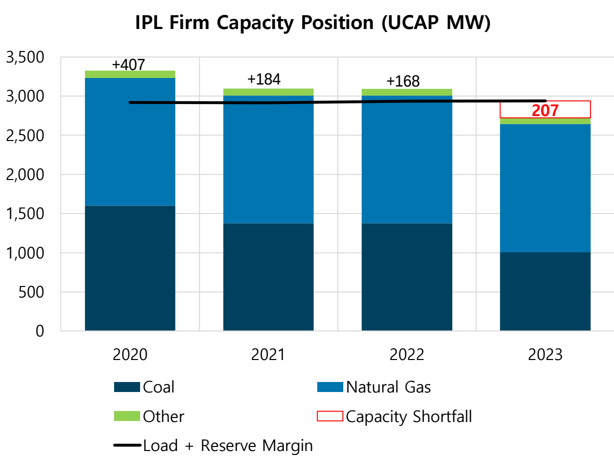
Director of Resource Planning, IPL

PREFERRED PORTFOLIO

- Portfolio 3b:
  - Least cost portfolio on a risk-adjusted basis across a wide range of futures
  - Retirement of Pete 1 and 2 lowest cost when stressing capacity value, cost of replacement capacity, and value of replacement capacity
  - Preserve flexibility and optionality in the face of uncertainty over the next 3-5 years



PREFERRED PORTFOLIO



Model indicating that lowest cost portfolio fills capacity shortfall with a combination of wind, solar, storage, and DSM

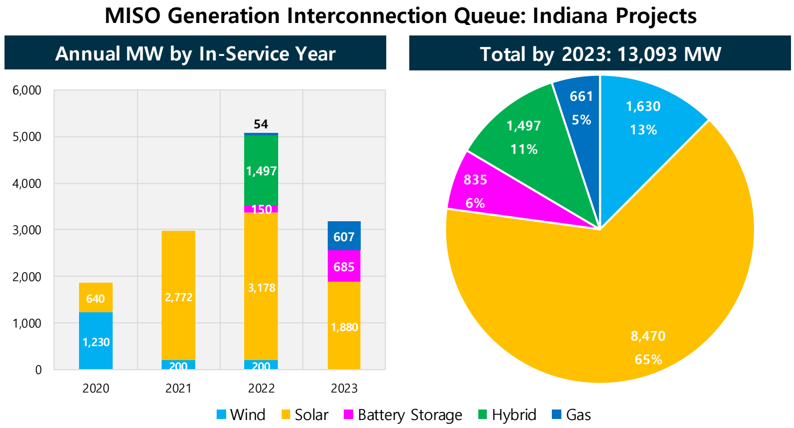
~200 MW of firm capacity =

	Portfolio 3a	Portfolio 3b	Portfolio 3c
Wind	250	100	150
Solar	375	450	400
Storage	40	0	20
Total ICAP MW	**665**	**550**	**570**

Actual mix will be influenced by bids received in all-source RFP

ALL-SOURCE RFP

- Sargent & Lundy contracted to run competitively bid, all-source RFP
- More detail will be released in the upcoming weeks
- All information will be hosted at iplpower.com/RFP



Source Data: MISO Generation Inteconnection Queue as of 11/10/2019

DSM ACTION PLAN 2021 - 2023

	2021	2022	2023
Decrements 1 - 3 (Gross MWh)	116,376	112,403	113,197
Decrements 1 - 4 (Gross MWh) *	144,890	146,158	146,490
DSM Action Plan Target (Gross MWh)	116,376 - 144,890	112,403 - 146,158	113,197 - 146,490
***DSM level in Reference Case**			

- IPL will target the level of DSM included in Decrement 4 (Ref Case)
  - Decrement 4 is equivalent to roughly 1% of sales
- Residential general service LEDs will no longer be offered in 2021 – 2023 due to lighting baseline change
  - Currently lighting makes up 40% of Residential savings
  - Change possibly eliminates some Residential programs
  - General service LEDs will still be available to income qualified customers

FUTURE MODELING ENHANCEMENTS

Renewables and storage introduce complexity in the market and fundamentally change the type of modeling required for long-term resource planning

Previous IPL IRPs	2019 IPL IRP	Considerations for Future IRPs
• Annual Reserve Margin Target based on Summer Peak • "Typical week" capacity expansion • Deterministic view with a single normalized set of load, price, and renewable shapes • Fixed capacity values for renewables • Cursory look at electric vehicle and distributed solar	• Annual Reserve Margin Target based on Summer Peak • Hourly chronological capacity expansion with stochastic weather, load, and commodity prices • Solar ELCC considerations through time • Hourly stochastic variations in weather with an integrated weather-load-price-renewable model • Top down annual electric vehicle and distributed solar forecasts at the system level	• Seasonal capacity assessment • Hourly and sub-hourly modeling • DSM, EE, and DR shapes modeled hourly and sub-hourly to assess peak reduction, load shifting value • Dynamic wind, solar, and storage ELCC • Bottom up electric vehicle and distributed solar forecast integrated with generation, transmission, and distribution planning • Scenario planning centered around decarbonization pathways that prioritize least cost, reliability, and effectiveness

CONCLUDING REMARKS

Vince Parisi

President and CEO, IPL

APPENDIX

ACRONYM LIST

Acronym	Name
CCGT/CC	Combined Cycle
ST	Steam Turbine
CT	Combustion Turbine
UCAP	Unforced Capacity
ICAP	Installed Capacity
PRMR	Planning Reserve Margin Requirement
ELCC	Effective Load Carrying Capability
DR	Demand Response
DSM	Demand Side Management
MISO	Midcontinent Independent System Operator

Acronym	Name
RFP	Request for Proposals
LCOE	Levelized Cost of Energy
LMP	Locational Marginal Price
PPA	Power Purchase Agreement
PTC	Production Tax Credit
ITC	Investment Tax Credit
CONE	Cost of New Entry
NREL	National Renewable Energy Laboratory
RIIA	Renewable Integration Impact Assessment
PVRR	Present Value Revenue Requirement

PORTFOLIO 1 ICAP CHANGES

Portfolio 1a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	250	250	700
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	425	475	875	950	1,025	1,175	1,175
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200	500	520	520	560	560
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 1b: Includes Decrements 1-4

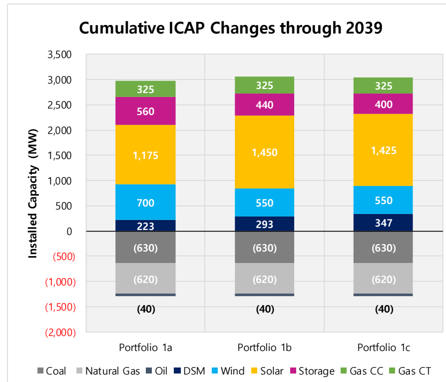
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	550
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	500	900	1,375	1,375	1,450	1,450	1,450
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	40	40	320	360	360	440	440
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 1c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	250	400	550
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	500	825	1,250	1,325	1,325	1,425	1,425
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	300	320	340	380	400
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 1 Runs

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	-220	-220	-630	-630	-630	-630	-630
Gas	0	0	0	0	0	0	0	0	0	0	-200	-200	-200	-200	-620	-620	-620	-620	-620	-620
Oil	0	0	0	0	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40



PORTFOLIO 2 ICAP CHANGES

Portfolio 2a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	350	400
New Solar	0	0	0	0	0	0	0	0	0	0	0	125	125	175	500	900	1,050	1,150	1,375	1,425
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	160	180	180	200	500	500	500	500	520
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 2b: Includes Decrements 1-4

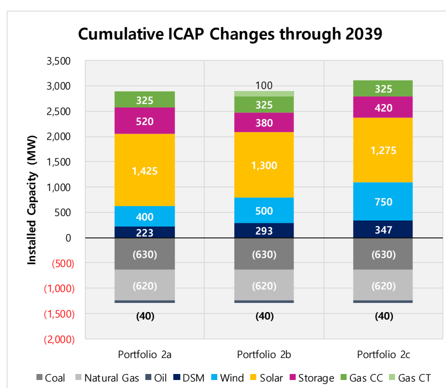
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	450	500	500
New Solar	0	0	0	0	0	0	0	0	0	0	0	350	350	400	800	900	900	900	1,175	1,300
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	40	60	60	60	340	380	380	380	380
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100

Portfolio 2c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
New Wind	0	0	0	0	0	0	0	0	0	0	0	50	50	100	100	200	200	500	600	750
New Solar	0	0	0	0	0	0	0	0	0	0	0	400	450	475	800	1,150	1,150	1,175	1,200	1,275
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	320	360	360	420	420
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 1 Runs

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-220	-630	-630	-630	-630	-630
Gas	0	0	0	0	0	0	0	0	0	0	-200	-200	-200	-200	-620	-620	-620	-620	-620	-620
Oil	0	0	0	0	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40



PORTFOLIO 3 ICAP CHANGES

Portfolio 3a: Includes DSM Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	250	250	250	250	250	250	250	250	250	250	250	250	250	350	350	400	400	450
Solar	0	0	0	375	425	475	550	575	650	700	700	700	725	725	725	725	725	825	1,125	1,250
Battery Storage	0	0	0	40	80	80	80	100	100	100	120	340	360	380	500	520	560	560	560	560
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 3b: Includes DSM Decrements 1-4

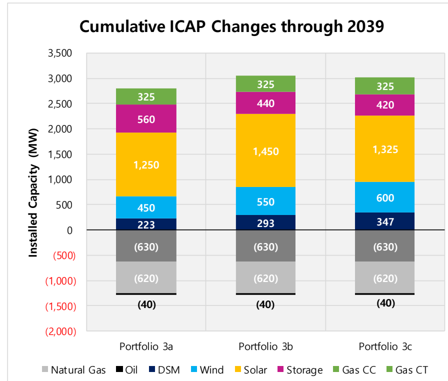
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	100	100	100	100	100	100	150	150	150	150	150	250	250	250	250	300	450	550
Solar	0	0	0	450	600	650	725	750	750	800	850	925	1,000	1,050	1,050	1,075	1,075	1,175	1,350	1,450
Battery Storage	0	0	0	0	0	0	0	20	40	40	40	240	240	240	360	380	420	420	440	440
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 3c: Includes DSM Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	150	150	150	150	150	150	150	200	250	250	300	300	300	350	350	400	450	600
Solar	0	0	0	400	525	575	575	575	625	650	675	725	725	775	825	825	875	975	1,250	1,325
Battery Storage	0	0	0	20	20	20	40	60	60	60	60	260	280	280	380	400	420	420	420	420
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 3 Runs:

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	(220)	(220)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)	(630)
Natural Gas	0	0	0	0	0	0	0	0	0	0	(200)	(200)	(200)	(200)	(620)	(620)	(620)	(620)	(620)	(620)
Oil	0	0	0	0	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)



PORTFOLIO 4 ICAP CHANGES

Portfolio 4a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	500	500	500	500	550	600	600	600	700	800	850	900	950	950	950	1,150	1,150	1,350
Solar	0	0	0	450	600	650	1,125	1,225	1,325	1,350	1,350	1,350	1,375	1,400	1,400	1,450	1,475	1,475	1,475	1,475
Battery Storage	0	0	0	0	0	0	340	340	340	360	380	600	620	640	760	780	820	840	920	940
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 4b: Includes Decrements 1-4

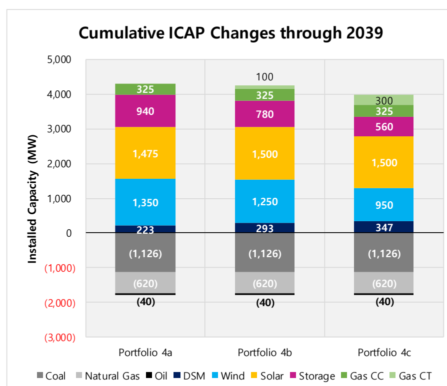
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	400	400	400	400	400	400	550	550	600	600	700	800	800	850	950	1,100	1,250	1,250
Solar	0	0	0	425	550	600	1,100	1,200	1,250	1,325	1,325	1,350	1,350	1,350	1,350	1,375	1,425	1,425	1,450	1,500
Battery Storage	0	0	0	0	0	0	240	240	240	240	260	480	500	520	640	660	680	700	760	780
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Portfolio 4c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	400	400	400	400	400	400	450	450	450	450	550	600	600	650	650	800	800	950
Solar	0	0	0	400	400	400	900	925	925	975	1,025	1,475	1,475	1,475	1,475	1,500	1,500	1,500	1,500	1,500
Battery Storage	0	0	0	20	80	80	200	220	240	240	240	320	340	360	380	400	440	460	540	560
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	200	200	200	200	200	200	200	200	300	300	300	300	300	300

Retirements in All Portfolio 3 Runs:

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	(220)	(220)	(630)	(630)	(630)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)	(1,126)
Natural Gas	0	0	0	0	0	0	0	0	0	0	(200)	(200)	(200)	(200)	(620)	(620)	(620)	(620)	(620)	(620)
Oil	0	0	0	0	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)



PORTFOLIO 5 ICAP CHANGES

Portfolio 5a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	500	500	500	500	550	600	600	600	700	800	850	900	950	950	950	1,150	1,150	1,350
Solar	0	0	0	450	600	650	1,125	1,225	1,325	1,350	1,350	1,350	1,375	1,400	1,400	1,450	1,475	1,475	1,475	1,475
Battery Storage	0	0	0	0	0	0	340	340	340	360	380	600	620	640	760	780	820	840	920	940
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 5b: Includes Decrements 1-4

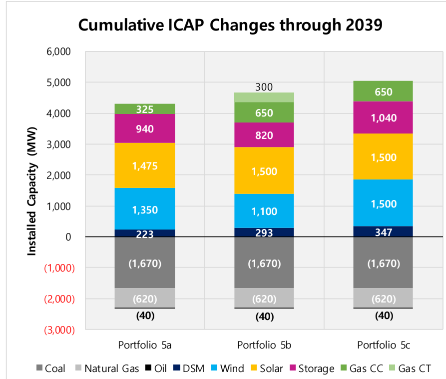
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	350	350	350	350	350	350	400	450	450	450	450	550	550	600	600	800	1,000	1,100
Solar	0	0	0	425	550	600	1,100	1,200	1,275	1,275	1,325	1,350	1,375	1,375	1,450	1,475	1,475	1,475	1,475	1,500
Battery Storage	0	0	0	0	0	0	20	20	20	40	300	520	540	560	660	680	720	740	800	820
Gas CC	0	0	0	0	0	0	325	325	325	325	325	325	325	325	650	650	650	650	650	650
Gas CT	0	0	0	0	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300

Portfolio 5c: Includes Decrements 1-5

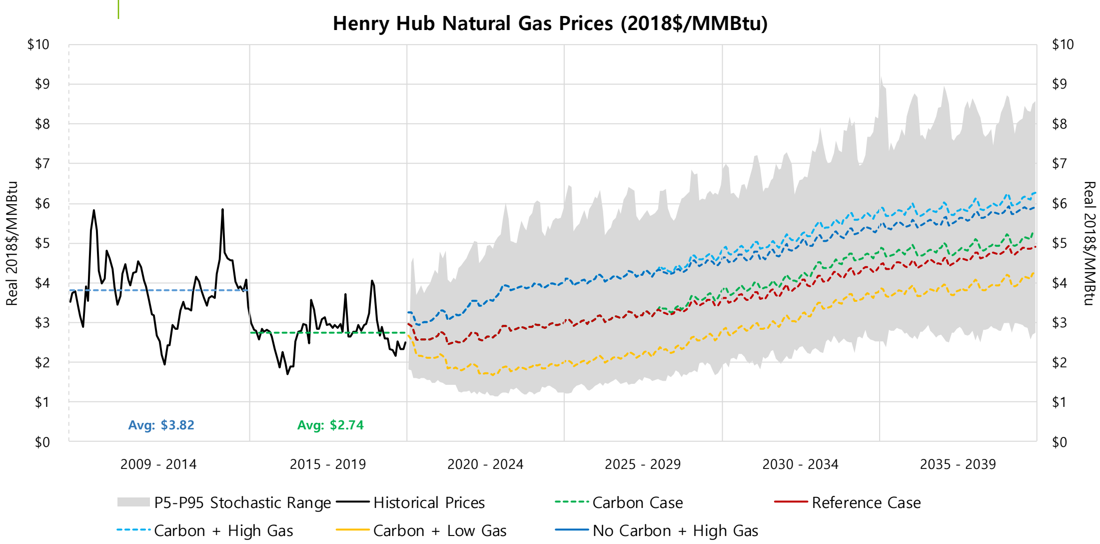
Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	500	500	500	500	500	550	550	750	950	1,150	1,150	1,200	1,200	1,300	1,300	1,300	1,500	1,500
Solar	0	0	0	425	500	525	725	775	775	775	1,225	1,375	1,400	1,400	1,400	1,400	1,400	1,450	1,450	1,500
Battery Storage	0	0	0	0	20	20	140	140	160	160	560	720	740	760	880	900	940	960	1,020	1,040
Gas CC	0	0	0	0	0	0	325	325	325	325	325	325	325	325	650	650	650	650	650	650
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Retirements in All Portfolio 3 Runs:

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal	0	(220)	(220)	(630)	(630)	(630)	(1,126)	(1,126)	(1,126)	(1,126)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)	(1,670)
Natural Gas	0	0	0	0	0	0	0	0	0	0	(200)	(200)	(200)	(200)	(620)	(620)	(620)	(620)	(620)	(620)
Oil	0	0	0	0	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)



NATURAL GAS PRICES



AES Indiana
Petersburg Energy Center
AES Indiana Attachment EKM-2
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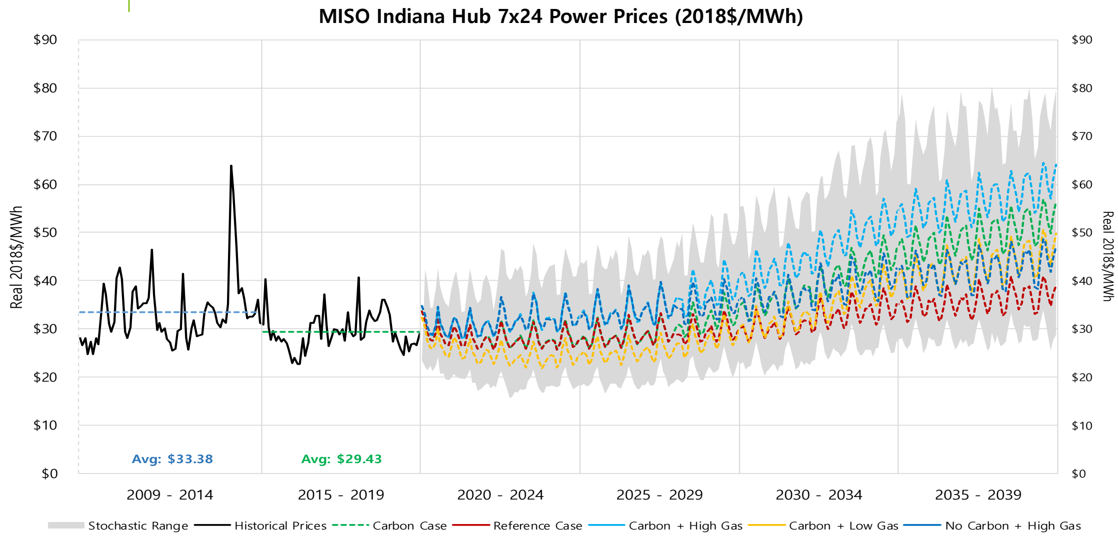
POWER PRICES



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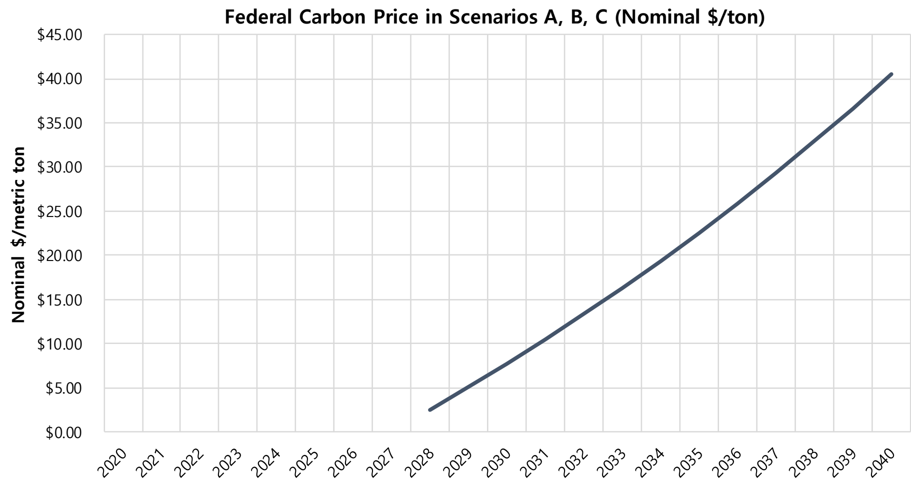
CARBON PRICE



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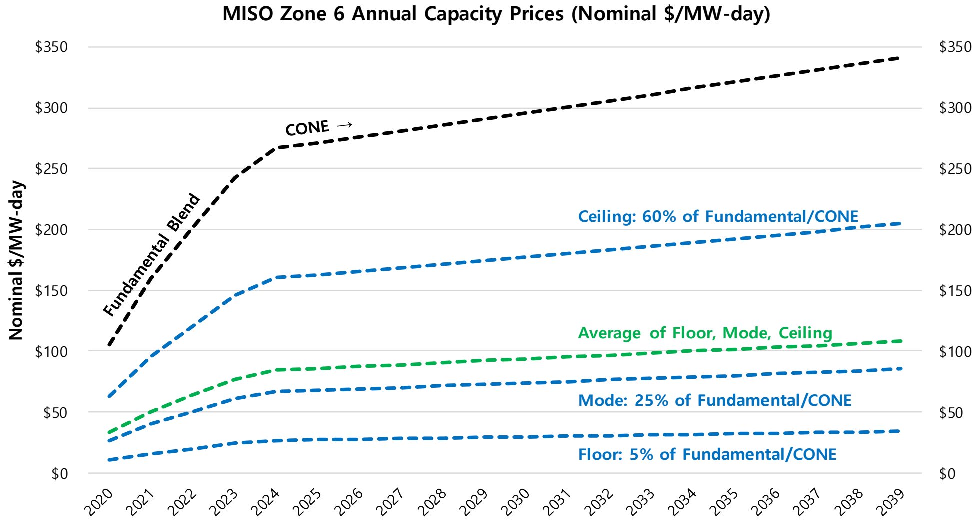
CAPACITY PRICES



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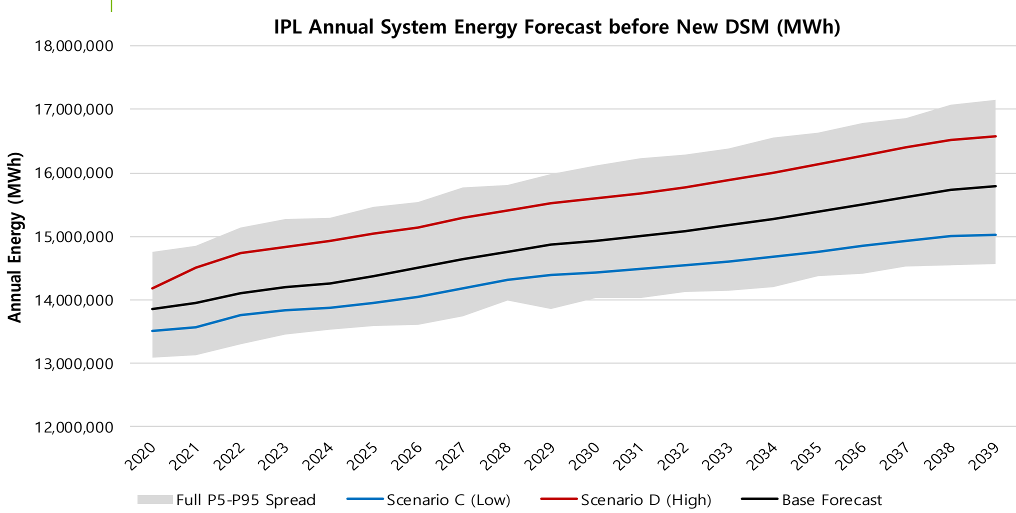
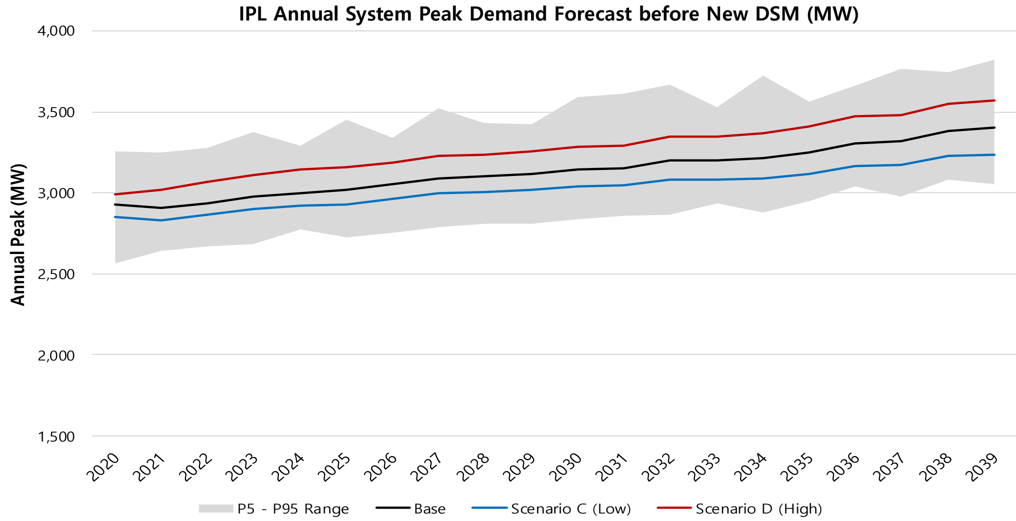
LOAD FORECAST (ENERGY)



90

LOAD FORECAST (PEAK)



STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED
December 21, 2017
INDIANA UTILITY
REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY, AN INDIANA CORPORATION, FOR APPROVAL OF ALTERNATIVE REGULATION PLAN FOR EXTENSION OF DISTRIBUTION AND SERVICE LINES, INSTALLATION OF FACILITIES AND ACCOUNTING AND RATEMAKING OF COSTS THEREOF FOR PURPOSES OF THE CITY OF INDIANAPOLIS' AND BLUEINDY'S ELECTRIC VEHICLE SHARING PROGRAM PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.*	)	**CAUSE NO. 44478**

<u>SUBMISSION OF COMPLIANCE FILING</u>

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)
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Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 21st day of December 2017, via electronic mail, on the following:

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Jeffrey M. Peabody

DMS 4569304v1

THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM ANNUAL REPORT

INDIANAPOLIS
MAYOR JOE HOGSETT

ipl an AES company

DECEMBER 31, 2017

GENERAL UPDATE

As of November 30, 2017, BlueIndy has deployed 90 electric car sharing charging stations, which includes approximately 450 electric vehicle chargers and 281 vehicles. Since its launch, BlueIndy has sold over 6,295 memberships and currently has over 2,142 yearly members. Members have logged over 82,624 rides. There is currently one site under construction with additional locations being considered throughout the IPL service territory.

The line extension costs incurred as of the most recent reporting cycle (November 30, 2017) approximates $1,130,000 and is below the IURC approved amount.

The BlueIndy Advisory Board, which is led by the City of Indianapolis and includes IPL, BlueIndy, and the Office of Utility Consumer Counselor, has continued to meet annually to discuss overall program performance, project details, and implementation progress.

The original Extension Services Agreement between IPL and the City of Indianapolis was restated and amended to reflect changes made in the IURC Order. The Agreement term has been extended through April 1, 2018 to allow for additional site deployment.

PROFIT SHARE RECEIVED

Indianapolis Power & Light Company ("IPL") has not received profit share at the time of this filing.

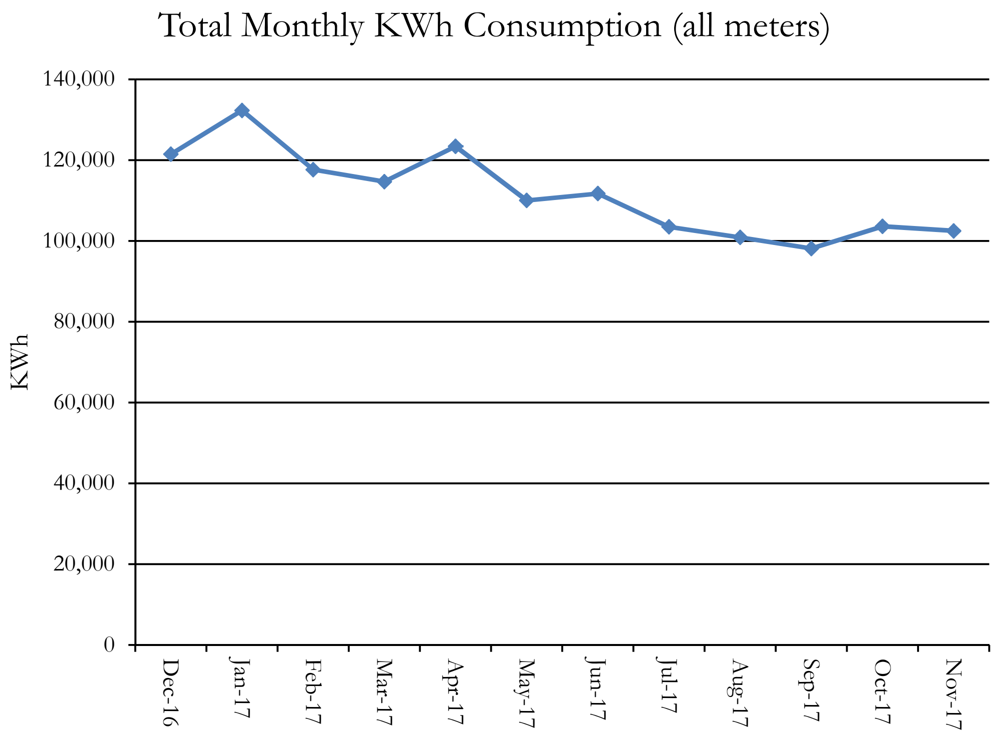
DATA GATHERED

Each BlueIndy Station generally consists of five (5) parking spots (each spot with a Charging Point Station Kiosk for powering Bluecars or members' personal Electric Vehicles), a Reservation Kiosk and a Meter Pedestal. Approximately, every 10th Station also has a covered Enrollment Kiosk. BlueIndy memberships can be secured online, in person with a BlueIndy Ambassador's iPad, via smartphones or via an Enrollment Kiosk. BlueIndy has steadily added Bluecars and Stations to the service since 2015. In 2018, they will likely not add more BlueCars but will continue to evaluate the need for more Stations.

Continuous strategic load balancing is performed by BlueIndy Ambassadors to try to make sure no Station has no more than four (4) and no fewer than one (1) Bluecar charging at any point in time to provide maximum Bluecar and parking availability, which is especially important before the two (2) daily weekday rush hours.

BlueIndy has 189 "Electric Vehicle Charging Members" who use the Stations to charge their personal EVs. These EV Charging Members connected their personal vehicles to the BlueIndy charging network for approximately 4,236 hours since opening.

IPL's analysis as of November 2017 depicted that the meters in service during the most recent 12 month period revealed an average meter consumption of ~1,400 KWh/month. Please see the graphical representation of aggregate BlueIndy energy consumption below.



The impacts to the IPL system have been minimal and represent a modest load growth.

Photos of BlueIndy Local Use

BlueIndy Station downtown Indianapolis showing Bluecars, Reservation Kiosk and Meter Pedestal.

BlueIndy Enrollment Kiosk downtown Indianapolis.
(Typically 1 per location, at select locations only)

FILED
December 21, 2018
INDIANA UTILITY
REGULATORY COMMISSION

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**

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Respectfully submitted,

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Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY

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DMS 13718691v1

THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM FINAL REPORT

DECEMBER 31, 2018

GENERAL UPDATE

As of November 30, 2018, BlueIndy has deployed 92 electric car sharing charging stations, which includes approximately 455 electric vehicle chargers and 196 vehicles. Since its launch, BlueIndy has sold over 8,525 memberships and currently has 3279 active members. Members have logged over 133,763 rides. There are currently no sites under construction. However, BlueIndy continues to evaluate additional locations throughout the IPL service territory. The most recent station opening was on the campus of IUPUI in Fall 2018.

The line extension costs incurred as of the most recent reporting cycle (November 30, 2018) approximates $1,135,000 and is below the IURC approved amount. As of the December 5th effective date of IPL's new basic rates and charges, no further carrying charges will be accrued, and amortization of the regulatory asset will begin.

The BlueIndy Advisory Board, which is led by the City of Indianapolis and includes IPL, BlueIndy, and the Office of Utility Consumer Counselor, has continued to meet annually to discuss overall program performance, project details, and implementation progress. The Commission Order in Cause No. 44478 dated February 11, 2015 directed the City and IPL to file two reports – one on or before December 31, 2015 and a second within one year of the public opening. These reporting requirements have been satisfied.

As of December 2018, the BlueIndy Advisory Board believes that all the reporting requirements have been satisfied. Therefore, given that there will be no additional service extensions funded by IPL for BlueIndy charging stations, IPL and the other members of the BlueIndy Advisory Board view this as the final report

PROFIT SHARE RECEIVED

Indianapolis Power & Light Company ("IPL") has not received profit share at the time of this filing.

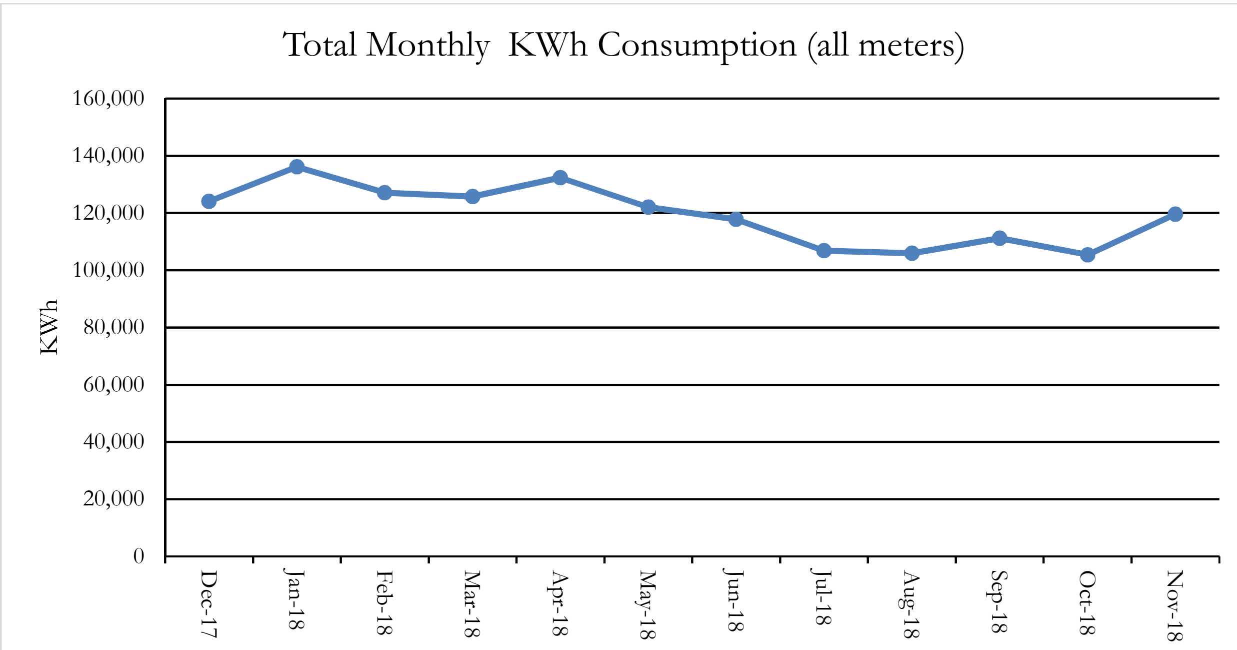
DATA GATHERED

Each BlueIndy Station generally consists of five (5) parking spots (each spot with a Charging Point Station Kiosk for powering Bluecars or members' personal Electric Vehicles), a Reservation Kiosk and a Meter Pedestal. Approximately, every 10th Station also has a covered Enrollment Kiosk. BlueIndy memberships can be secured online, in person with a BlueIndy Ambassador's iPad, via smartphones or via an Enrollment Kiosk. BlueIndy has steadily added Bluecars and Stations to the service since 2015. In 2018, they will likely not add more BlueCars but will continue to evaluate the need for more Stations.

Continuous strategic load balancing is performed by BlueIndy Ambassadors to try to make sure no Station has no more than four (4) and no fewer than one (1) Bluecar charging at any point in time to provide maximum Bluecar and parking availability, which is especially important before the two (2) daily weekday rush hours.

BlueIndy has 294 "Electric Vehicle Charging Members" who use the Stations to charge their personal EVs. These EV Charging Members connected their personal vehicles to the BlueIndy charging network for approximately 7927 hours since opening.

IPL's analysis as of November 2018 depicted that the meters in service during the most recent 12-month period revealed an average meter consumption of ~1,400 KWh/month. Please see the graphical representation of aggregate BlueIndy energy consumption below.

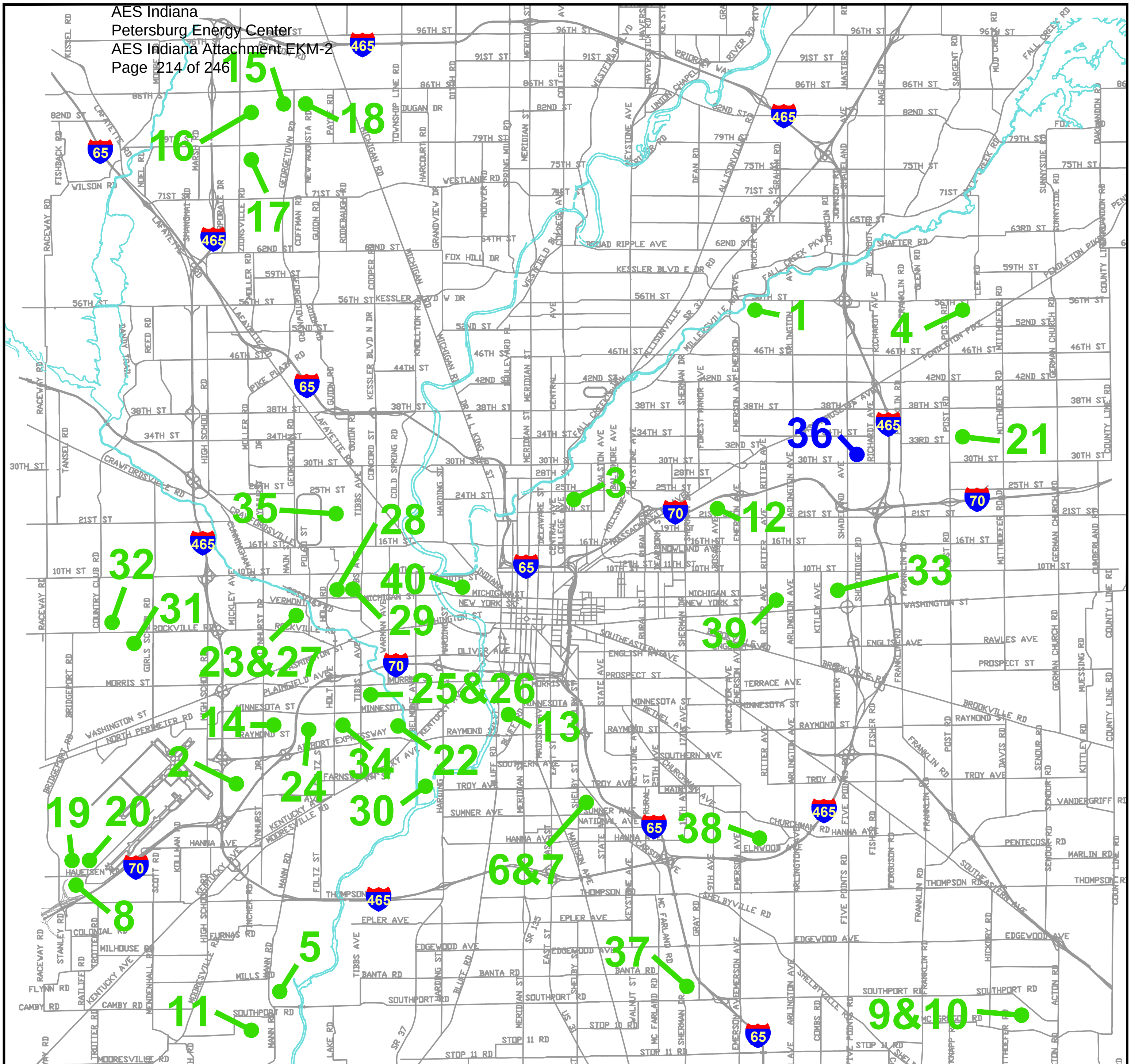


The impacts to the IPL system have been minimal and represent a modest load growth.

Photos of BlueIndy Local Use

BlueIndy Station downtown Indianapolis showing Bluecars, Reservation Kiosk and Meter Pedestal.

BlueIndy Enrollment Kiosk downtown Indianapolis.
(Typically 1 per location, at select locations only)



1. CATHEDRAL HIGH SCHOOL
2. ES by JMS
3. INDIANA VENEERS
4. GSA BEAN FINANCE CENTER
5. MELLOH ENTERPRISES
6. L&R #1 (LAURELWOOD APTS.)
7. L&R #2 (LAURELWOOD APTS.)
8. AIRPORT I
9. INDY SOLAR I
10. INDY SOLAR II
11. INDY SOLAR III
12. INDY DPW
13. INDY DPW
14. SCHAEFER TECHNOLOGIES
15. CITIZENS ENERGY (LNG NORTH)
16. DUKE REALTY #98
17. DUKE REALTY #87
18. DUKE REALTY #129
19. AIRPORT PHASE IIA
20. AIRPORT PHASE IIB
21. CELADON TRUCKING SERVICES
22. VERTELLUS
23. MERRELL BROTHERS
24. GROCERS' SUPPLY CO.
25. A-PALLET CO.
26. A-PALLET CO.
27. TOWN OF SPEEDWAY, IN
28. GenNx PROPERTIES VI, LLC. (MAPLE CREEK APTS.)
29. GenNx PROPERTIES VI, LLC. (MAPLE CREEK APTS.)
30. CITIZENS ENERGY/CWA AUTHORITY
31. REXNORD INDUSTRIES
32. EQUITY INDUSTRIAL A-ROCKVILLE LLC.
33. LIFELINE DATA CENTERS
34. OMNISOURCE
35. INDIANAPOLIS MOTOR SPEEDWAY
36. DEEM
37. INDY SOUTHSIDE SPORTS ACADEMY
38. MARINE CENTER OF INDIANA
39. 5855 LP
40. IUPUI

LEGEND

\# - OPERATING
\# - UNDER CONSTRUCTION
\# - IN DEVELOPMENT

ipl an AES company

INDIANAPOLIS POWER & LIGHT CO.

SOLAR FACILITIES

DRAWN BY: RLW
5-18-15

solar-REP-GIS-map

REV. 11-1-19 WJK

IPL 2019 IRP

Attachment 4.1 (Test Year July 2016 through June 2017 Hourly Loads MW Rate Case) is provided electronically

IPL 2019 IRP

Attachment 4.2a (IPL_LCIIndices_RS18) is provided electronically

IPL 2019 IRP

Attachment 4.2b (IPL_LCIIndices_RC18) is provided electronically

IPL 2019 IRP

Attachment 4.2c (IPL_LCIIndices_RH18) is provided electronically

IPL 2019 IRP

Attachment 4.2d (IPL_LCIIndices_SS18) is provided electronically

IPL 2019 IRP

Attachment 4.2e (IPL_LCIIndices_SH18) is provided electronically

IPL 2019 IRP

Attachment 4.2f (IPL_LCIIndices_SL18) is provided electronically

IPL 2019 IRP

Attachment 4.2g (IPL_LCIIndices_PL18) is provided electronically

Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \quad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2005 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2005 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2005 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	505
Electric Space Heating Heat Pump	190

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a ten year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \middle/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectric\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\Pr ice_{y,m}\right)^{\gamma} \tag{8}$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05,7}}\right)^{\kappa} \qquad (9)$$

Where:

- *BDays* is the number of billing days in year (*y*) and month (*m*), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2005
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \tag{11}$$

Data values in 2005 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times CoolShare_{05}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2005 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,661
Space Cooling Heat Pump	369
Room Air Conditioning	315

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \times \tag{13}$$
$$\left(TenYearMovingAverageElectric\,\mathrm{Pr}\,ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\,\mathrm{Pr}\,ice_{y,m}\right)^{\gamma}$$

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:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{05}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{05}}\right)^{\kappa} \quad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2005.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \quad (15)$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{05}^{Type} \Big/ \frac{1}{UEC_{05}^{Type}} \right)} \times MoMult_m^{Type} \times$$
$$(TenYearMovingAverageElectricPrice)^{\lambda} \times (TenYearMovingAverageGasPrice)^{\kappa} \quad (16)$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{HHSize_y}{HHSize_{05}} \right)^{0.46} \times \left(\frac{Income_y}{Income_{05}} \right)^{0.10} \times$$
$$\left(\frac{ElecPrice_{y,m}}{ElecPrice_{05}} \right)^{\phi} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{05}} \right)^{\lambda} \quad (17)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_{k} ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \qquad (18)$$

Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2013 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.2 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating equipment saturation levels,
- Heating equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

where, $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m),
$HeatIndex_y$ is the annual index of heating equipment, and
$HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating equipment saturation levels normalized by operating efficiency levels. The index will change over time with changes in heating equipment saturations (*HeatShare*) and operating efficiencies (*Eff*). Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{04} \times \frac{\left(HeatShare_y / Eff_y \right)}{\left(HeatShare_{04} / Eff_{04} \right)} \quad (4)$$

In this expression, 2004 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Base year space heating sales are defined as follows.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh/Sqft_e}\right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2004 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, prices and billing days. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{04}}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \tag{6}$$

where, *BDays* is the number of billing days in year (y) and month (m), these values are normalized by 30.5 which is the average number of billing days

WgtHDD is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.

HDD is the annual heating degree days for 2004,

Output is a real commercial output driver in year (y),

Price is the average real price of electricity in month (m) and year (y),

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling equipment saturation levels,
- Cooling equipment operating efficiencies,
- Average number of days in the billing cycle for each month, and
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$\mathrm{XCool}_{\mathrm{y,m}} = \mathrm{CoolIndex}_{\mathrm{y}} \times \mathrm{CoolUse}_{\mathrm{y,m}} \qquad (7)$$

where, $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m),
$CoolIndex_y$ is an index of cooling equipment, and
$CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{04} \times \frac{\left(CoolShare_y \big/ Eff_y \right)}{\left(CoolShare_{04} \big/ Eff_{04} \right)} \qquad (8)$$

Data values in 2004 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2004. In other years, it will be greater than one if equipment saturation levels are above their 2004 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh / Sqft_e}\right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2004 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_y}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.18} \tag{10}$$

where, *WgtCDD* is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
CDD is the annual cooling degree days for 2004.

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year (2004). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to one in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment saturation levels,
- Equipment efficiency levels,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{04}^{Type} \times \left(\frac{Share_y^{Type} \Big/ Eff_y^{Type}}{Share_{04}^{Type} \Big/ Eff_{04}^{Type}} \right) \tag{12}$$

where, *Weight* is the weight for each equipment type,
Share represents the fraction of floor stock with an equipment type, and
Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{04}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{04}}{\sum_e kWh \Big/ Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5} \right) \times \left(\frac{Output_y}{Output_{04}} \right)^{0.20} \times \left(\frac{Price_{y.m}}{Price_{04}} \right)^{-0.18} \tag{14}$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

IPL 2019 IRP

Confidential Attachments 4.4 a-c (Moodys Q4 2018 Base, Exceptionally Strong, and Lower Trend)
are provided electronically
as part of the Confidential version of the IRP

IPL 2019 IRP

Attachment 4.5 (10yr base by rate code) is provided electronically

IPL 2019 IRP

Attachment 4.6 (20yr base, high, low forecast) is provided electronically

IPL 2019 IRP

Attachment 4.7a (Energy Input Data - Residential) is provided electronically

IPL 2019 IRP

Attachment 4.7b (Energy Input Data - Small CI) is provided electronically

IPL 2019 IRP

Attachment 4.7c (Energy Input Data - Large CI) is provided electronically

IPL 2019 IRP

Attachment 4.8 (Peak-Forecast Drivers and Input Data) is provided electronically

IPL 2019 IRP

Attachment 4.9 (Forecast Analysis) is provided electronically

FILED
July 30, 2021
INDIANA UTILITY
REGULATORY COMMISSION

Cause No. 45591

INDIANAPOLIS POWER & LIGHT COMPANY

2019 Integrated Resource Plan

Volume 3 of 3

December 16, 2019

Attachment 5.1

prepared for

INDIANAPOLIS POWER & LIGHT COMPANY

2018 Demand Side Management Market Potential Study

August 13, 2019

FINAL REPORT

prepared by

GDS ASSOCIATES INC
DEMAND SIDE ANALYTICS
THORPE ENERGY SERVICES

EXECUTIVE SUMMARY

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VOLUME II *Appendices*

EXECUTIVE SUMMARY

2018 IPL DEMAND SIDE MANAGEMENT Market Potential Study

prepared for

AUGUST 2019

1 Executive Summary

1.1 OBJECTIVES & SCOPE

This project included a demand-side management (DSM) Market Potential Study and End Use Analysis for Indianapolis Power & Light Company (IPL). The study included assessments of electric energy efficiency and demand response potential. This report provides the results of the electric energy efficiency and demand response potential analysis for the 2021-2039 (19-year) timeframe.[1]

The energy efficiency potential study assessed potential by customer segment (residential, commercial, and industrial – with and without opt-out customers[2]). The effort included several preliminary tasks to assess the IPL market and develop foundational assumptions about the customer base, sales forecasts, and savings opportunities to order to then assess the overall energy efficiency potential in the IPL services territories.

1.2 APPROACH SUMMARY

The GDS team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial (C&I) sectors, GDS utilized the bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load. The demand response potential assessment was conducted in a similar manner as the energy efficiency potential assessment. Below is the summary of the Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP). More detail can be found in Section 1 of Volume I, Market Potential Study.

- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate (WTP) in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***MAP*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***RAP*** estimates achievable potential with IPL paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

The 2019 Market Potential Study included a detailed End Use Analysis that utilized primary market research at residential dwellings, as well as commercial and industrial facilities, to better understand the mix of customers, building characteristics, and efficiency trends for each customer segment. Historically, IPL's Market Potential Studies and load forecasts have been driven by the Energy Information Administration's regional end use saturation and intensity baselines and forecasts. The End Use Analysis served to create more IPL-specific saturation and efficiency profiles for both the 2019 Market Potential Study, but for future load forecasting efforts as well.

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[1] The study period is for 2021-2039 to align with the 2019 Integrated Resource Plan (IRP) timeline. In addition, the GDS Team assessed the electric energy efficiency potential in 2020 as part of an analysis to determine whether current planned DSM levels in 2020 addressed the identified potential. Results of this analysis are included as an appendix to this report.

[2] In Indiana, a combined energy efficiency resource standard repeal and opt-out bill became law in 2014. The opt-out placed eligibility at 1 MegaWatt (MW) – any customer that has a peak demand of at least 1MW can opt-out of paying the charge levied to support the utility-run energy efficiency program.

1.3 RESULTS

Table ES-1 summarizes the electric energy-efficiency savings for all measures at the different levels of potential relative to the baseline forecast. This provides cumulative annual technical, economic, MAP and RAP potential energy savings, in total MWh and as a percentage of the sector-level sales forecast for the first three years of the analysis, as well as in the 10th and 19th year of the analysis. The cumulative RAP increases to 4.8% cumulative annual savings over the next three years. The RAP savings estimates have a large residential sector low-income component.[3] Approximately 58% of the residential sector budget addresses the low-income market segment, with about 25% of the RAP savings are attributable to this segment. Forecasted sales are total sales including commercial and industrial opt-out customers.

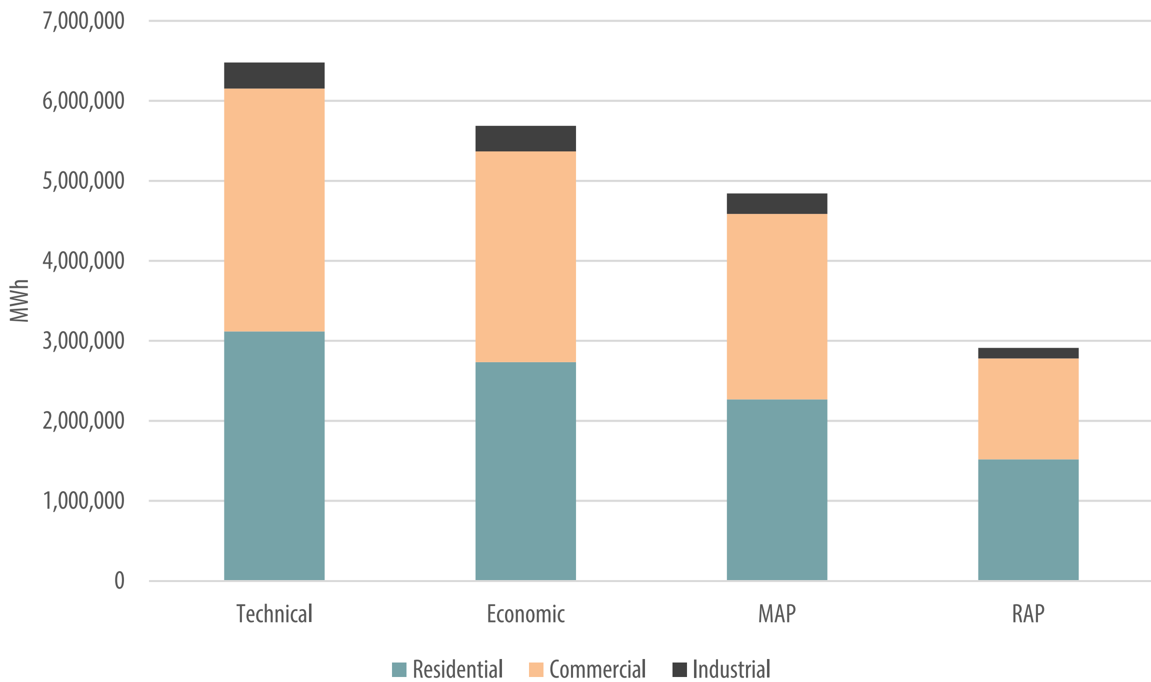
TABLE ES-1 CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY (NET OF LARGE CUSTOMER OPT-OUT LOAD)

	2021	2022	2023	2030	2039
MWh					
Technical	777,115	1,495,812	2,222,444	5,480,409	6,479,384
Economic	699,639	1,316,546	1,938,817	4,773,845	5,687,312
MAP	463,542	879,184	1,325,103	3,712,615	4,841,953
RAP	273,942	462,015	656,209	2,006,568	2,911,537
Forecasted Sales	13,543,498	13,708,234	13,809,273	14,490,281	15,411,542
Energy Savings (as % of Forecast)					
Technical	5.7%	10.9%	16.1%	37.8%	42.0%
Economic	5.2%	9.6%	14.0%	32.9%	36.9%
MAP	3.4%	6.4%	9.6%	25.6%	31.4%
RAP	2.0%	3.4%	4.8%	13.8%	18.9%

Figure ES-1 provides the electric technical, economic, and achievable potential, by sector, by the end of the 19-year timeframe for the study (2021-2039). The residential sector contributes about half of the overall RAP.

[3] Low income households were characterized as homes that have household incomes at or below 200% of federal poverty guidelines. Based on data from the American Community 5-Year Public Use Microdata Set (PUMS), GDS used household income and number of people per household to identify the percent of the population at or below 200% of federal poverty guidelines for the IPL service area. 30.6% of single-family households and 52.7% of multifamily households were identified to meet the criteria.

FIGURE ES-1 NINETEEN (19)-YEAR CUMULATIVE ANNUAL ELECTRIC ENERGY EFFICIENCY POTENTIAL – ALL SECTORS COMBINED (NET OF LARGE CUSTOMER OPT-OUT LOAD)



1.3.1 Measure-Level Realistic Achievable Potential (Net of Opt-Outs)

Table ES-2 provides the incremental RAP for each year by sector. The incremental annual savings potential ranges from 274 GWh to nearly 350 GWh. These results exclude savings attributed to large customers that have opted out of energy efficiency programs.

TABLE ES-2 INCREMENTAL ELECTRIC MEASURE LEVEL RAP – BY SECTOR (2021-2023, 2030, AND 2039)

Incremental Annual MWh	2021	2022	2023	2030	2039
Sector					
Residential	175,436	164,092	164,881	171,594	164,489
Commercial	87,433	87,790	88,538	128,764	163,720
Industrial	11,073	12,149	13,001	15,566	21,577
Total	273,942	264,031	266,420	315,924	349,786
Forecasted Sales	13,543,498	13,708,234	13,809,273	14,490,281	15,411,542
Incremental Annual Savings %					
Sector					
Residential	1.3%	1.2%	1.2%	1.2%	1.1%
Commercial	0.6%	0.6%	0.6%	0.9%	1.1%
Industrial	0.1%	0.1%	0.1%	0.1%	0.1%
% of Forecasted Sales	2.0%	1.9%	1.9%	2.2%	2.3%

Table ES-3 provides the cumulative RAP for each year across the 2021-2023 timeframe, as well as for 2030 and 2039.[4] The cumulative annual savings potential ranges from 274 GWh to nearly 2,912 GWh. These results assume that opt-out C&I customers do not provide any savings potential.

TABLE ES-3 CUMULATIVE ELECTRIC MEASURE LEVEL RAP – BY SECTOR (2021-2023, 2030, AND 2039)

Cumulative Annual MWh	2021	2022	2023	2030	2039
Sector					
Residential	175,436	266,884	365,671	1,079,971	1,518,517
Commercial	87,433	172,729	256,487	824,507	1,259,861
Industrial	11,073	22,402	34,051	102,090	133,159
Total	273,942	462,015	656,209	2,006,568	2,911,537
Forecasted Sales	13,543,498	13,708,234	13,809,273	14,490,281	15,411,542
Cumulative Annual Savings %					
Sector					
Residential	1.3%	1.9%	2.6%	7.5%	9.9%
Commercial	0.6%	1.3%	1.9%	5.7%	8.2%
Industrial	0.1%	0.2%	0.2%	0.7%	0.9%
% of Forecasted Sales	2.0%	3.4%	4.8%	13.8%	18.9%

Table ES-4 provides the annual budgets in the RAP scenario. The total RAP budgets across all sectors ranges from $91 million to $121 million during the 2020-2023 timeframe.

TABLE ES-4 ANNUAL BUDGETS (2021-2023, 2030, AND 2039) IN THE RAP SCENARIO ($ IN MILLIONS)

RAP Budgets	2021	2022	2023	2030	2039
Energy Efficiency					
Incentives	$60.5	$68.9	$75.3	$77.7	$59.6
Admin	$24.8	$27.9	$30.7	$41.6	$51.0
Energy Efficiency Sub-Total	$85.3	$96.8	$106.0	$119.4	$110.6
Demand Response					
Incentives	$2.0	$3.4	$4.9	$7.3	$8.9
Admin	$4.2	$6.9	$10.0	$3.8	$4.9
Demand Response Sub-Total	$6.1	$10.3	$14.9	$11.1	$13.8
Total					
Total Costs	$91.4	$107.1	$120.9	$130.5	$124.4

1.4 DEMAND SAVINGS

The study also included an assessment of peak demand savings potential. Table ES-5 below provides the overall peak demand savings from energy efficiency and demand response potential. The demand response potential assumes the energy efficiency peak demand reductions take precedent, and thereby reduce the baseline peak demand which can be further reduced by demand response.

[4] Cumulative annual savings refers to the overall savings occurring in a given year from both new participants and savings continuing to result from past participation with measures that are still in place. Cumulative annual does not always equal to the sum of all prior year incremental values as some measures have relatively short measure lives, and a result, their savings drop off over time.

TABLE ES-5 CUMULATIVE PEAK DEMAND SAVINGS POTENTIAL – MAP AND RAP (2021-2023, 2030, AND 2039)

MW	2021	2022	2023	2030	2039
MAP					
Energy Efficiency	79	156	239	684	896
Demand Response	91	161	228	331	397
Total	171	317	467	1,015	1,293
RAP					
Energy Efficiency	48	86	124	385	546
Demand Response	73	114	155	218	253
Total	121	200	279	603	799

VOLUME I

2018 IPL Demand Side Management Market Potential Study

prepared for

JUNE 2019

1 Introduction

1.1 BACKGROUND & STUDY SCOPE

This Market Potential Study was conducted to support the Integrated Resource Plan (IRP) and DSM planning for IPL. The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities to develop estimates of technical, economic, and achievable potential. Separate estimates of electric energy efficiency and demand response potential were developed. The effort was highly collaborative, as the GDS Team worked closely alongside IPL, as well as the IPL Oversight Board, to produce reliable estimates of future saving potential, using the best available information and best practices for developing market potential saving estimates.

The 2019 Market Potential Study included a detailed End Use Analysis that utilized primary market research at residential dwellings, as well as commercial and industrial facilities, to better understand the mix of customers, building characteristics, and efficiency trends for each customer segment. Historically, IPL's Market Potential Studies and load forecasts have been driven by the Energy Information Administration's regional end use saturation and intensity baselines and forecasts. The End Use Analysis served to create more IPL-specific saturation and efficiency profiles for both the 2019 Market Potential Study, but for future load forecasting efforts as well.

1.2 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- ***Technical Potential*** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures.
- ***Economic Potential*** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. This study uses the Utility Cost Test (UCT) to assess cost-effectiveness.
- ***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and WTP in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:
- ***MAP*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***RAP*** estimates achievable potential with IPL paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

1.3 STUDY LIMITATIONS

As with any assessment of energy efficiency potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs
- Projected penetration rates for energy efficiency measures

- Projections of electric avoided costs
- Future known changes to codes and standards
- IPL load forecasts and assumptions on their disaggregation by sector, segment, and end use
- End-use saturations and fuel shares

While the GDS team has sought to use the best and most current available data, there are often reasonable alternative assumptions which would yield slightly different results.

1.4 ORGANIZATION OF REPORT

The remainder of this report is organized in seven sections as follows:

Section 2 MPS End-Use Analysis details the primary market research studies completed in conjunction with the market potential analysis, and a summary of the end-use analysis results by sector.

Section 3 MPS Methodology details the methodology used to develop the estimates of technical, economic, and achievable energy efficiency and demand response potential savings.

Section 4 MPS Market Characterization provides an overview of the IPL service areas and a brief discussion of the forecasted energy sales by sector.

Section 5 Residential Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the residential sector.

Section 6 Commercial Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the commercial sector.

Section 7 Industrial Energy Efficiency Potential provides a breakdown of the technical, economic, and achievable potential in the industrial sector.

Section 8 Demand Response Potential provides a breakdown of the technical, economic, and achievable potential demand response by program type.

Appendices for the DSM Market Potential are included in Volume II of this report. MPS appendices include a discussion of sources used for the analysis, detailed measure level assumptions by customer segment, nonresidential sector potential savings (including opt-out customers), and detailed demand response results. A discussion of the 2020 Refresh analysis is also included as an appendix.

2 Market Potential Study End Use Analysis

In 2018 and 2019, IPL and the GDS team performed multiple market research studies targeting the residential, commercial, and industrial sectors. The goal of the research was to collect primary data from IPL customers to inform the market potential study and to improve upon assumptions built into IPL's load forecasting system. This chapter will describe the methods employed by the GDS team to collect primary research data for the end-use analysis and provide summary results.

2.1 RESIDENTIAL SECTOR

There were three objectives of the end use analysis specific to the residential sector:

- Collect market share information of electric end uses specific to IPL's residential class of customers,
- Perform a demographic survey to collect key demographic information,
- Update Unit Energy Consumption assumptions, representing the amount of electricity used by typical major appliances in homes.

To meet these objectives, the GDS team performed research activities through four tasks in 2018 and 2019. A self-report study conducted via internet and the mail was conducted to collect initial market saturation and demographic data. From the pool of respondents, participants were recruited to participate in on-site visits conducted by trained technicians to collect detailed home and end-use characteristic data. Independent of that process, an online survey of a separate population frame of residences was conducted to understand WTP in energy efficiency programs. Finally, GDS developed building energy simulation models.

2.1.1 Self-Report Survey

The self-report study was conducted via a mailed questionnaire to selected representative homes in the IPL service territory. The recruitment population frame was drawn using a structured stratified sampling approach using annual energy consumption to stratify the population. Homeowners were asked to complete the questionnaire either by filling out a form mailed to them or by visiting a web-based survey instrument online. A total of 30 questions were included in the survey, seeking to collect information about ownership of electric appliances; the type, fuel, and age of heating, ventilation, and air conditioning (HVAC) and water heating equipment in the home; the types of energy improvements that may have been made to the home; demographic information; and if the homeowner had interest in participating in the onsite survey.

The research objective was to collect at least 384 survey responses, representing a design with 95% confidence and +/- 5% precision. The survey was initially mailed to 1,400 residences drawn from IPL's billing database. After the first mailing, only 94 responses were collected by mail and 32 by internet, representing only 126 responses. A reminder email was sent to those customers in the original recruitment frame for whom IPL had a valid email address and who had not yet responded to the survey, which generated an additional 27 responses. Finally, a second recruitment frame of 1,375 new residences was developed. For the new frame, an email campaign was launched asking customers to respond online. The second wave garnered an additional 72 responses. In total, the self-report study solicited 231 responses, representing 95% confidence with +/- 6.45% precision.[5]

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[5] Although the goal was to achieve 5% precision, this result is acceptable, especially given the additional site-specific research conducted for the residential sector. It was concluded by GDS and IPL that the costs of additional efforts to improve precision outweighed the value achieving such additional precision would provide.

FIGURE 2-1 SELF-REPORT SURVEY RETURNS BY MEDIUM

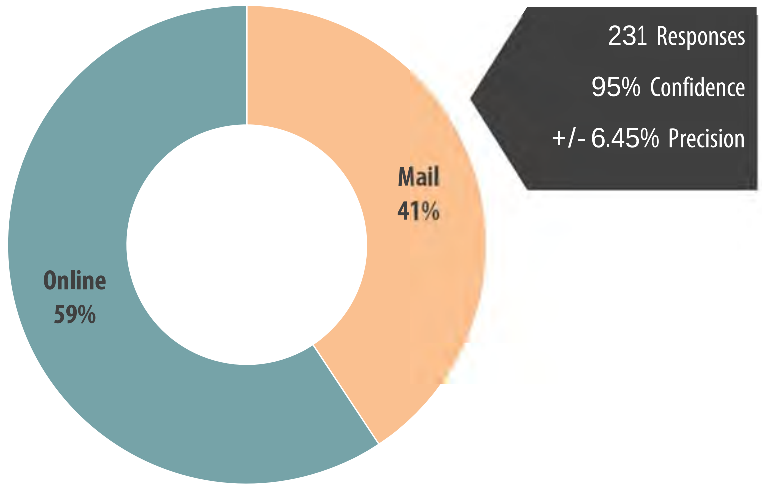
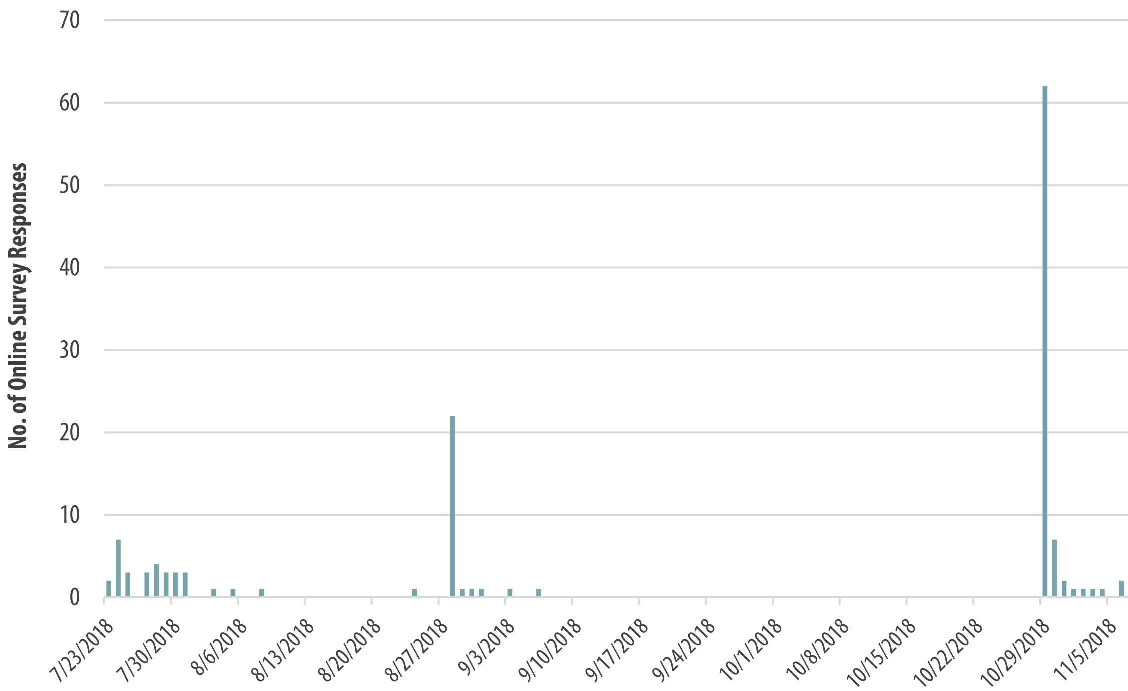


FIGURE 2-2 SELF-REPORT SURVEY, TIMING OF ONLINE RESPONSES



2.1.2 On-Site Survey

Following the self-report survey, the GDS team conducted a series of residential on-site visits. The purpose of the site-visits was to collect more detailed end-use and housing characteristics that are difficult to collect in a self-report survey. The goal was to recruit 68 homes to participate in site visits, using the self-report survey as the first recruitment tool. Interest in participating in a site visit was high from survey respondents, with 67% (156) respondents indicating interest in finding out more about the visits. To ensure a representative sample of homes in the study, GDS developed 68 recruitment bins sorted by average usage. Nearly 40 of the recruitment bins were successfully filled from the 156 homes that indicated initial interest in the study, with attrition associated with fulfilling recruitment bins from other homes and loss of interest once homeowners understood in more detail the nature of the site visits. Therefore, the GDS team supplemented the study by recruiting additional homes to agree to participate in site visits by contacting homes from the initial recruitment frames of the self-report survey group.

2.1.3 Willingness to Participate

IPL and the GDS team worked together to develop a series of questions designed to understand residential WTP in various energy efficiency programs given varying incentive levels. Such research was valuable to helping identify participation levels that can be assumed in various scenarios within the market potential study. The original goal was to collect WTP information during the residential site visits. However, the WTP questionnaire was still being developed by the GDS team while technicians were conducting site visits. The site visits therefore did not collect a statistically significant number of WTP survey responses. Therefore, GDS created a supplemental online WTP survey. Fifteen thousand (15,000) residential accounts were selected to receive an email asking for participation in the online WTP survey. These accounts had not yet been contacted by IPL and GDS for any aspect of survey work prior to this email. GDS collected 875 WTP survey responses.

2.1.4 Building Energy Simulation Modeling

The final phase of end use analysis for the residential sector consisted of constructing building energy simulation models using BEopt^{TM} (Building Energy Optimization)[6] software. The building simulations involve developing end-use energy profiles based on assigned housing characteristics. The housing characteristics (e.g., size of home, type of end use equipment, etc.) were developed from the primary market research conducted by the GDS team.

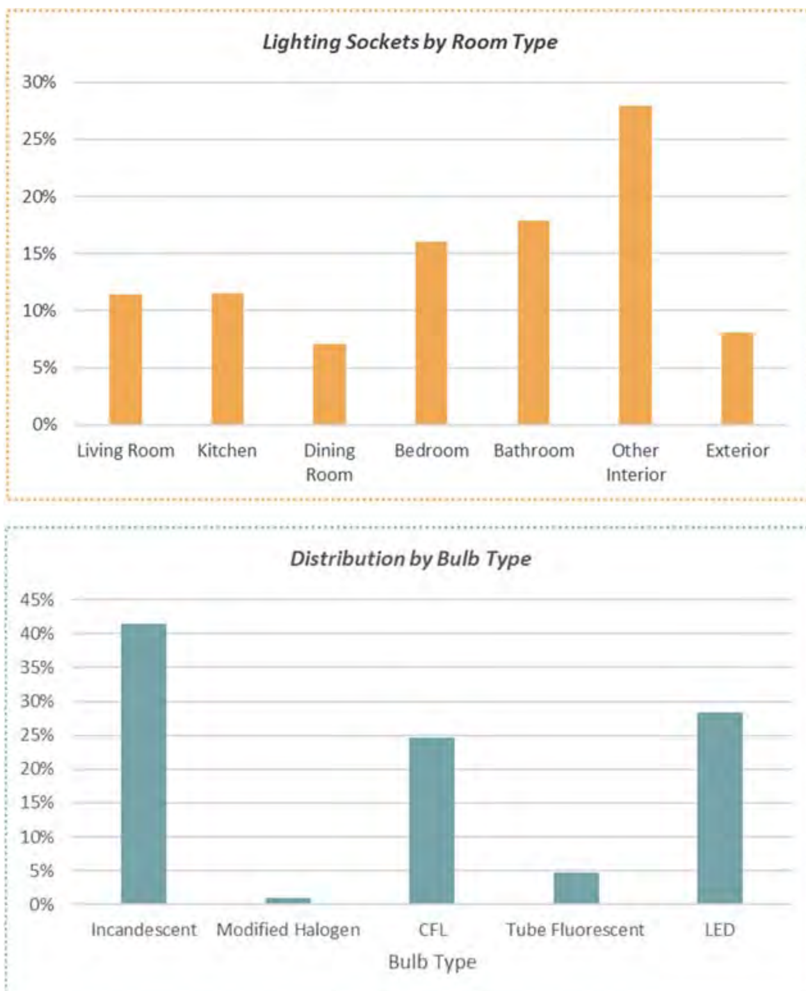
2.1.5 Summary Results of Residential End Use Analysis

Although detailed information was collected for many end-uses in the residential sector, this section provides an overview of the data collection for lighting and space heating equipment. The end use databases developed through the primary research methods were used by the GDS to inform potential study and load forecast inputs for many end uses.

Lighting. In self-response surveys, homeowners tend to underestimate the number of lighting sockets in the home, which was the case with IPL as well. The IPL self-responders indicated they had an average of 20 bulbs per home, whereas the site visits indicated the average exceeds 40 bulbs per home. This was the biggest discrepancy between self-reported information and information collected from onsite technicians. The GDS team considered the site visits data to be more accurate since onsite technicians take the time to record every lighting socket in the home and collect information on the type and wattage of the bulbs installed in those sockets.

As part of the onsite visits, technicians also collect the number of bulbs in storage to provide an indication of the potential lighting efficiency in

FIGURE 2-3 LIGHTING END USE RESULTS - RESIDENTIAL SECTOR



[6] BEopt can be used to analyze both new construction and existing home retrofits, as well as single-family detached and multi-family buildings, through evaluation of single building designs, parametric sweeps, and cost-based optimizations.

the near future when bulbs are replaced. The study indicated that the average home had 5.5 bulbs in storage, and that 48% of those bulbs were incandescent bulbs, which is higher than the share of incandescent bulbs (42%) in service in homes.

Space Heating. Other than the lighting counts, the only other major appliance that had a market penetration differential between self-reporting and the site visits was the share of electric primary space heating equipment. The self-report survey indicated that 45% of homes had electric heat while the site visits found 21% of homes with electric heat. With such a discrepancy, a third source of information was consulted. IPL's retail rate codes are designed such that homes with electric heat can be identified. In theory, the homes had electric heat when they signed up for service, although if they have since switched to non-electric heat, they could possibly still be on the electric heat service code. The IPL billing database shows approximately 35% of homes having electric heat. For purposes of the market potential study, the 35% market share was assumed.

Load Forecast Disaggregation. Figure 2-4 and Figure 2-5 summarize the end-use disaggregation for residential energy sales as a result of the end use analysis.

FIGURE 2-4 SHARE OF ANNUAL HOUSEHOLD ENERGY CONSUMPTION BY END USE - RESIDENTIAL SECTOR

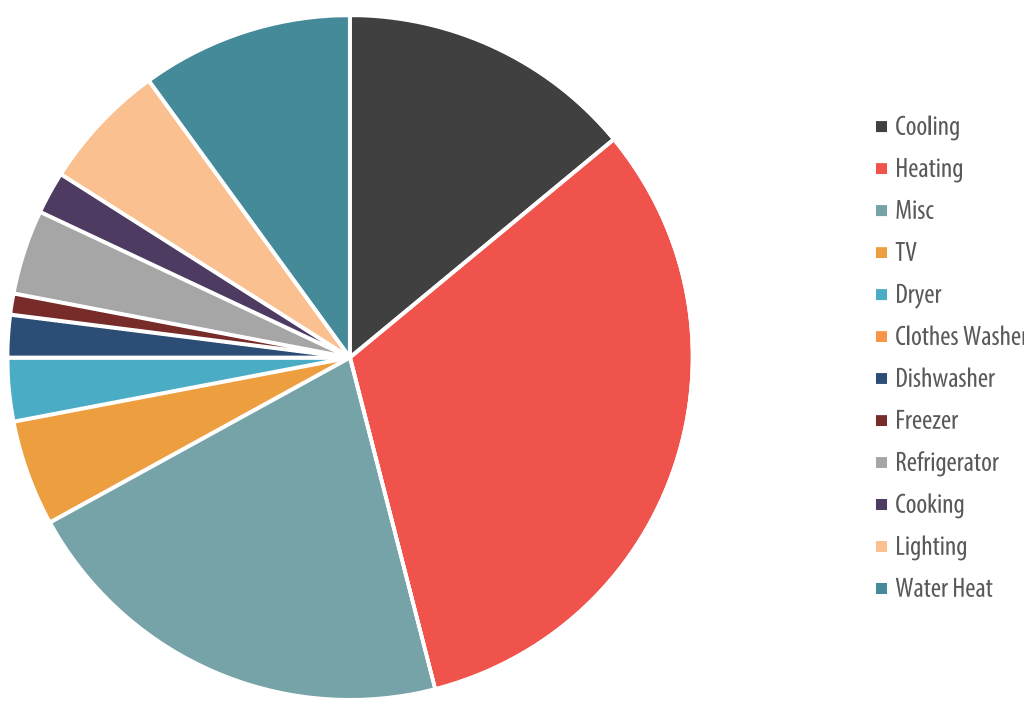
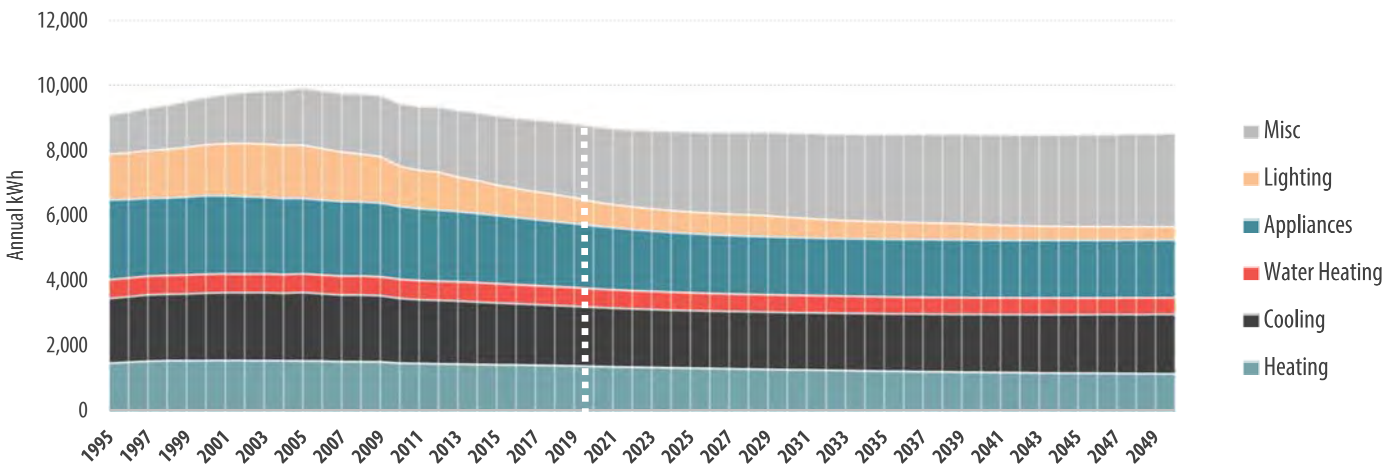


FIGURE 2-5 RESIDENTIAL LOAD FORECAST BY END USE



2.2 COMMERCIAL SECTOR

In the commercial sector, the GDS Team conducted a series of site visits to collect end use information. The first step was to segment the commercial class by building type to determine the recruitment frame for site visits. Then, sites were recruited from bins segmented by building type to recruit a total of 68 sites. A detailed end use survey was then completed by technicians to collect detailed research data and WTP information from site representatives.

2.2.1 Segmentation by Building Type

The GDS Team segmented commercial energy sales by building type using several analytical techniques. The first step was to assign an industry code (NAICS[7] and/or SIC[8]) to as many customers in IPL's commercial billing database as possible. Then, the codes were mapped to building types consistent with the types used in IPL's forecasting models and in the Commercial Building Energy Consumption Survey (CBECS) conducted by the US Department of Energy.

A multi-step process was used to assign industry codes to commercial accounts. First, codes that were available from IPL's databases were used. Then, a secondary database was used to supplement the IPL designations. The second data source was InfoUSA, which contains a business listing for Indianapolis and includes industry codes for those businesses.

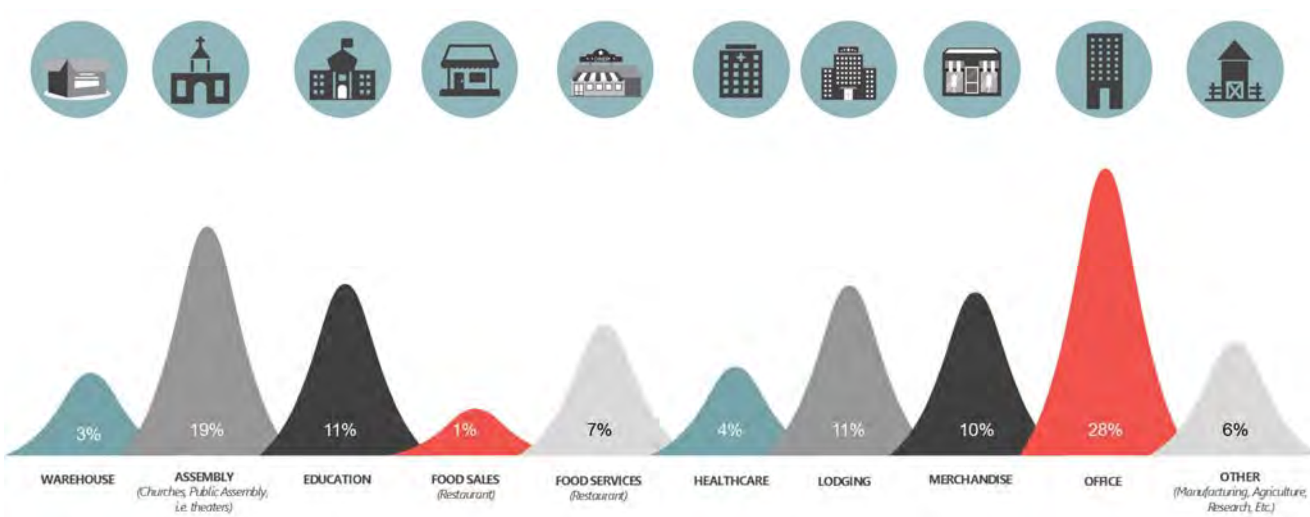
[7] North American Industry Classification System
[8] Standard Industrial Classification

FIGURE 2-6 HEURISTIC WORDS ASSIGNED TO SPECIFIC BUILDING TYPES

CHURCH	GRILL
HOSPITAL	OFFICE
AUTO	OFFICES
BANK	MOTEL
APARTMENTS	HOTEL
UNIVERSITY	WENDY'S
INVESTMENTS	MCDONALDS
REALTY	BURGER
PIZZA	RETAIL
RESTAURANT	SCHOOL
INSURANCE	COLLEGE
FITNESS	BAKERY
SALON	KOHLS
MEDICAL	SUBWAY
DENTAL	PUB
STUDIO	EATERY
BAPTIST	HOSPITALITY
DEPT OF TRANS	SPEEDWAY LLC

One challenge GDS had was matching InfoUSA information to IPL's customer billing database. A three-step process was employed to achieve the matching. First, we included the industry codes in InfoUSA if there was an exact match between the billing database and InfoUSA database for address, zip code, and phone number of the business. Next, GDS used a Levenshtein matching distance scoring algorithm[9] to compare business name, address, zip code, and phone number between the two data sources. The Levenshtein score determines how many textual changes have to be made between two strings of text to make them equivalent. Although some fuzzy logic is deployed in selecting a score that is considered a match and one that is not, GDS used observational evidence to set a score setpoint that would tend to reject more matches than accept. For example, if one database had "Arby's Restaurant #5852" as the business name and the other database simply had "Arby's", the Levenshtein score was 500 and considered a match if addresses also matched. However, "Beech Grove Community School" and "Beech Grove Aquatic" would have a score of 600 and would not be considered a match. Finally, the supplement the number of industry codes identified, GDS performed a heuristic approach by calculating a frequency of the number of times specific words appeared in business names and identified building types associated with certain key words. For instance, the word "Hotel" in a company name that was not otherwise identified with an industry code was assigned to the Lodging building type.

FIGURE 2-7 SALES SEGMENTATION BY BUILDING TYPE



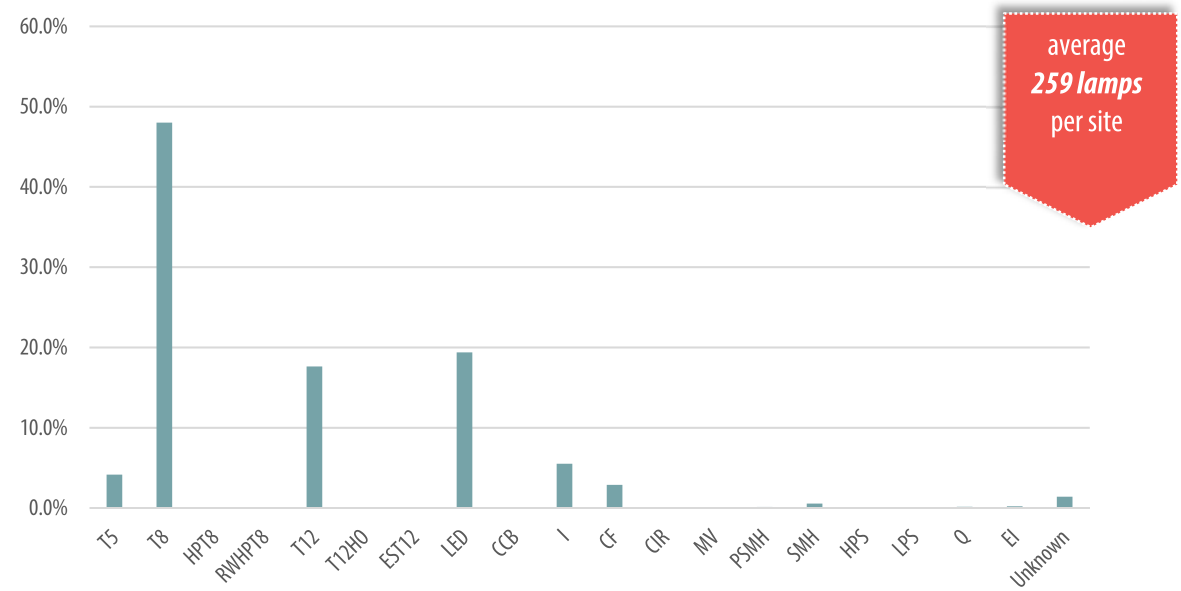
2.2.2 Site Visits

A total of 68 site visits were completed, with representation from the major building types shown in Figure 2-7 above. Technicians collected data on building characteristics, heating and cooling behaviors, and detailed end-use equipment at each site, including information on HVAC, water heating, ventilation, cooking, refrigeration, air pressure, and other equipment.

[9] In information theory, the Levenshtein distance is as string metric for measuring the distance between two sequences. Informally, it is the minimum number of single-character edits (insertions, deletions, or substitutions) required to change one string of text into the other.

As an example of the information collected, an average of 259 lamps per site were found during the site visits. Of those, 52% were T5/T8 bulbs and 20% were light emitting diode (LED).

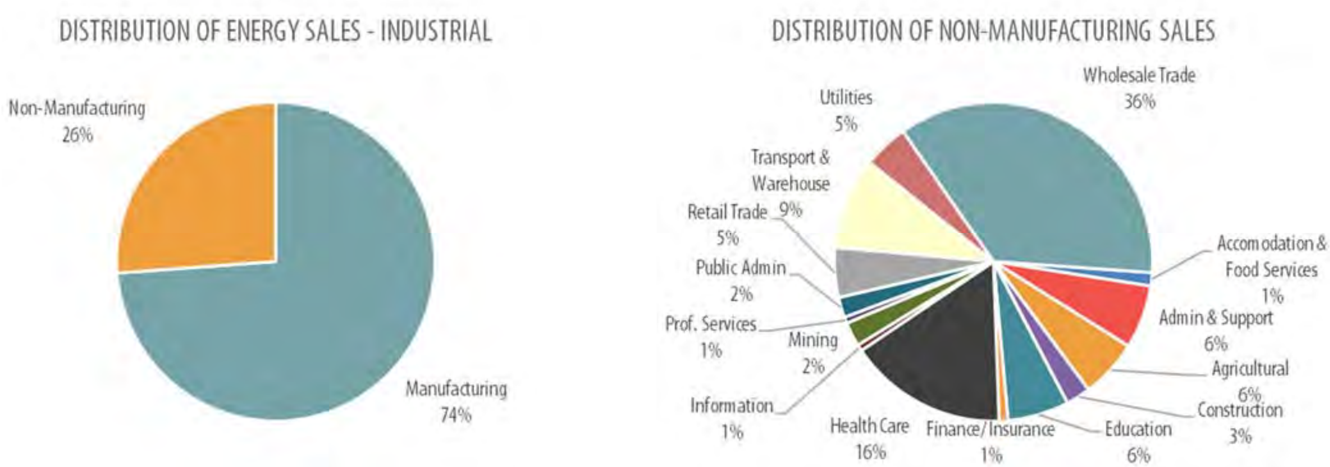
FIGURE 2-8 LIGHTING RESULTS FROM ONSITE SURVEYS - COMMERCIAL SECTOR



2.3 INDUSTRIAL SECTOR

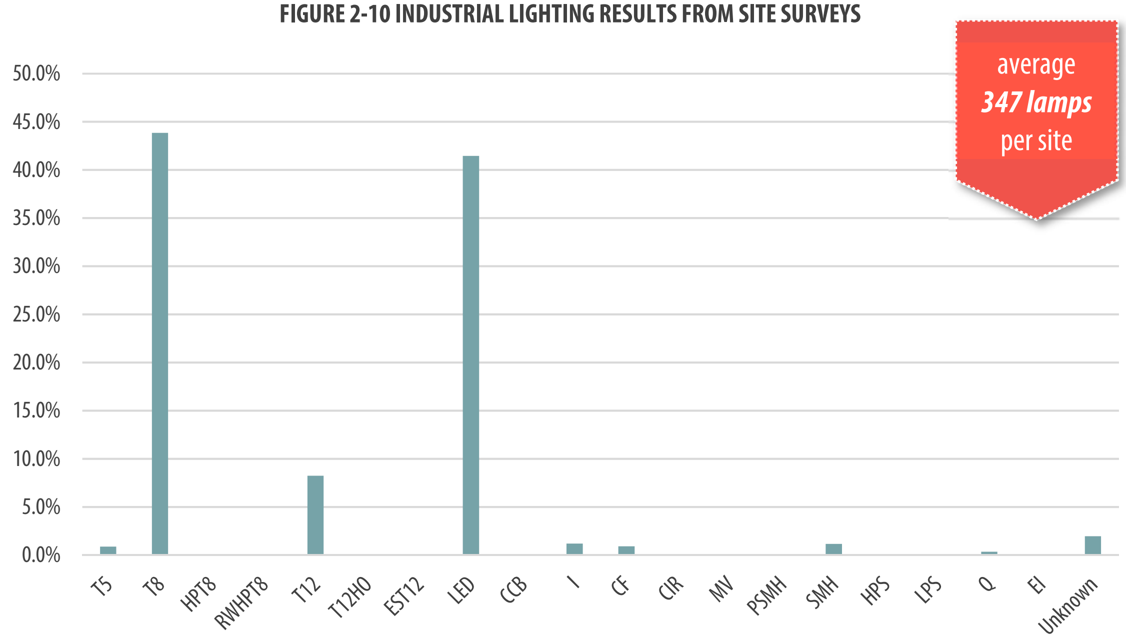
Much like in the commercial sector, end use analysis for the industrial sector involved market segmentation and onsite visits. Market segmentation was conducted using industry codes as described in the Commercial Sector section above. The segmentation analysis indicates that three quarters of industrial energy sales are to manufacturing industries. Of the quarter of non-manufacturing accounts, 50% of energy sales are in wholesale trade and health care industries with transportation and warehousing accounting for an additional nearly 10%.

FIGURE 2-9 INDUSTRIAL SEGMENTATION



A total of 40 site visits were conducted for the industrial sector, in which WTP and detailed end-use information was collected. One goal of the research was to recruit multiple opt-out accounts for onsite surveys. However, only 1 opt-out site agreed to participate in a site visit even though the GDS recruitment frame was designed with a significant number of opt-out accounts in it. Lighting information is provided in Figure 2-10 below as an example of summary information collected for the industrial sector.

FIGURE 2-10 INDUSTRIAL LIGHTING RESULTS FROM SITE SURVEYS



3 Market Potential Study Methodology

This section describes the overall methodology utilized to assess the electric energy efficiency and demand response potential in the IPL service area. The main objectives of this Market Potential Study were to estimate the technical, economic, MAP and RAP of energy efficiency and demand response in the IPL service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency and demand response potential.

3.1 OVERVIEW OF APPROACH

For the residential sector, GDS took a bottom-up approach to the modeling, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential. For the C&I sectors, GDS took a bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load.

Further details of the market research and modeling techniques utilized in this assessment are provided in the following sections.

3.2 MARKET CHARACTERIZATION

The initial step in the analysis was to gather a clear understanding of the current market segments in the IPL service area. The GDS team coordinated with IPL to gather utility sales and customer data and existing market research to define appropriate market sectors, market segments, vintages, saturation data and end uses. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and nonresidential sectors.

3.2.1 Forecast Disaggregation

In the residential sector, GDS calibrated its building energy modeling simulations with IPL's sales forecasts.[10] This process began with the construction of building energy models, using the BEopt™ (Building Energy Optimization) software, which were specified in accordance with the most currently available data describing the residential building stock in the IPL service area. Models were constructed for both single-family and multifamily homes, as well as various types of heating and cooling equipment and fuel types. Key characteristics defining these models include conditioned square footage, typical building envelope conditions such as insulation levels and representative appliance and HVAC efficiency levels. The simulations yielded estimated energy consumption for each building prototype, including estimates of each key end use. These end use estimates were then multiplied by the estimated proportion of customers that applied to each end use, to calculate an estimated service territory total consumption for each end use. For example, when completing this process for the IPL potential analysis, the simulated heat pump electric heating consumption was multiplied by the proportion of homes that rely on heat pumps for their electric heating needs, to calculate the total heat pump electric heating load in the IPL service territory.

The simulation process required several iterations. GDS collaborated with IPL to verify and modify certain assumptions about the market characteristics, such as the heating fuel and equipment types. GDS adjusted its assumptions about key market characteristics and revised its BEopt models to calibrate its building energy models to within 4% of forecasted sales in 2021.

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[10] IPL's sales forecast in all sectors excludes the impact of future DSM savings. Excluding future DSM savings prevents under-estimating energy efficiency savings potential.

In the C&I sectors, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS disaggregated the nonresidential sector for IPL into building or industry types using IPL's C&I customer database and 2017 monthly sales data. GDS supplemented the IPL customer database with a third-party dataset (purchased from InfoUSA) that provided additional SIC/NAICS code data by business.[11] This disaggregation involved two steps. First, the GDS team used rate codes to determine whether the customer was captured in either IPL's commercial or industrial load forecast. Next, GDS determined the appropriate industry for industrial customers and the building type for commercial customers. We used the following information, either from IPL's customer data or third-party dataset, to determine the appropriate building or industry type. Using these fields, GDS assigned customers IPL's non-residential data sets to one of the commercial or industrial segments listed in Table 3-1.

TABLE 3-1 NON-RESIDENTIAL SEGMENTS

COMMERCIAL	INDUSTRIAL	
Education	Chemicals	Paper
Food Sales	Fabricated Metals	Plastics & Rubber
Food Service	Food & Agriculture	Primary Metals
Health Care	Machinery	Transportation Equipment
Hospital	Mining	Wood
Lodging	Nonmetallic Mineral	
Office		
Public Assembly		
Retail		
Warehouse		

GDS further disaggregated sales for each of the segments into end uses. For commercial segments, GDS primarily used IPL's 2019 end-use forecast planning models supplemented with updated Energy Information Administration (EIA) 2012 CBECS data. This information was used to determine energy use intensities, expressed in kWh per square foot, for each end use within each segment.[12] We then used data compiled from metering studies, evaluation, measurement and verification (EM&V), and engineering algorithms to further disaggregate energy intensities into more granular end uses and technologies. For the industrial sector, the analysis relied on the EIA's Manufacturing Energy Consumption survey to disaggregate industry-specific estimates of consumption into end uses.[13]

Table 3-2 lists the electric end-uses considered in the forecast disaggregation and subsequent potential assessment.

TABLE 3-2 ELECTRIC END USES

Residential	Commercial	Industrial
Behavioral	Cooking	Agriculture
Clothes Washer/Dryer	Space Cooling	Computers & Office Equipment
Dishwasher	Lighting	CHP
Electronics	Office Equipment	Lighting
Hot Water	Refrigeration	Machine Drive
HVAC Equipment	Space Heating	Process Heating
HVAC Shell	Ventilation	Process Cooling
Lighting	Water Heating	Space Cooling
Pools		Space Heating

[11] The IPL dataset classifies businesses by Standard Industrial Classification (SIC) code, a four-digit standardized code, that has largely been replaced by the North American Industry Classification System (NAICS) code. The GDS Team converted the IPL SIC codes to NAICS codes, then mapped NAICS/SIC codes to building and industry types considered in this study.
[12] U.S. Energy Information Agency. *Commercial Buildings Energy Consumption Survey*. May 20, 2016.
[13] U.S. EIA. *Manufacturing Energy Consumption Survey 2010.* March 2013.

Residential	Commercial	Industrial
		Ventilation Water Heating

3.2.2 Eligible Opt-Out Customers

In Indiana, commercial or industrial customers with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. In the IPL service area, approximately 6.5% of commercial sales have opted out of utility-funded electric energy efficiency programs, while nearly 45% of industrial sales have opted out. [14]

FIGURE 3-1 OPT-OUT SALES BY C&I SECTOR

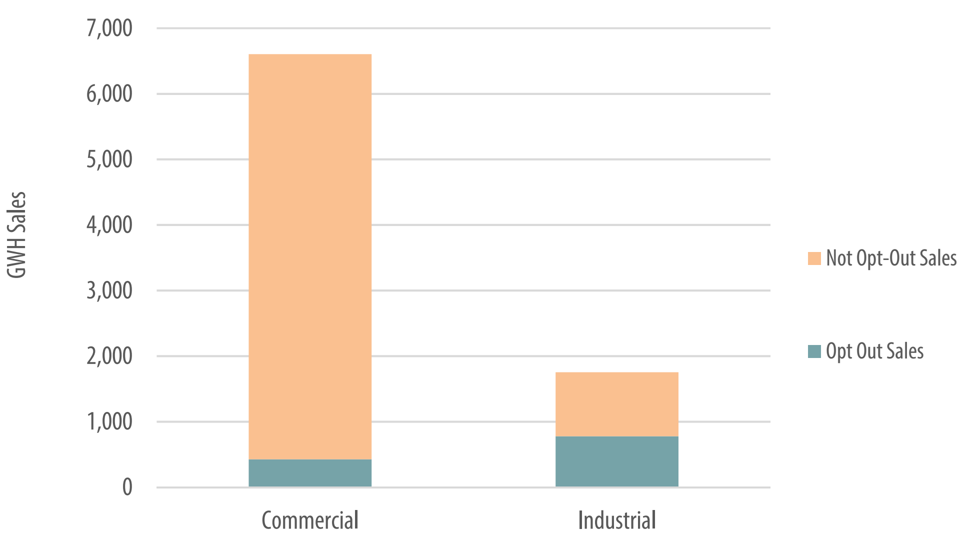

Figure 3-1 shows the total sales for the C&I sectors, as well as the sales, by sector, that have currently opted out of paying the charge levied to support utility-administered energy efficiency programs. The portion of sales that have not opted out include both ineligible load (i.e. does not meet the 1 MW monthly peak requirement) as well as eligible load that has not yet opted out.

The main body of this report focuses on the electric energy efficiency potential savings in the C&I sectors excluding sales from opt-out customers. Results of C&I sector potential in a scenario that includes savings from IPL's opt-out customers are provided in an appendix to this report.

3.2.3 Building Stock/Equipment Saturation

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

3.2.3.1 Residential Sector

For the residential sector, GDS relied on several primary research efforts. The most important effort was a 2018 online survey of IPL customers conducted by the GDS Team as part of the study. More than 200 responses provided a strong basis for many of the IPL measure baseline and efficient saturation estimates. GDS also relied on an onsite survey of IPL customers conducted by the GDS Team in 2018. This study helped fill in data gaps and confirm the results of the online survey.

Other data sources included ENERGY STAR unit shipment data, IPL evaluation reports, EIA Residential Energy Consumption Survey data from 2015 and baseline studies from other states. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

[14] These percentages were calculated based on the 2017 IPL non-residential customer data and 2017 billing history. Note, the total C&I sales were adjusted to shift select industrial sales into the commercial sector based on the identified building type and more applicable mapping to the commercial sector models for the MPS.

3.2.3.2 Commercial Sector

For the commercial sector, data collected through on-site visits as part of this study was leveraged to develop remaining factors for many of the measures. GDS coordinated with IPL and the Oversight Board to develop a research plan, sampling plan, and a survey questionnaire used to collect data. The on-site data collection included facility operation schedules and building characteristics, HVAC equipment type and efficiency levels, lighting fixture inventories, control systems and strategies, and related electric consuming equipment characteristics.

The survey data was used to inform two main assumptions for the potential study, the Base Case factor and saturation of efficient equipment. The Base Case Factor is the fraction of the end use energy that is applicable for the efficient technology in given market segment. Survey data was used to determine fractional energy use for most measures in the study. The survey data provided counts for equipment and energy usage levels for the lighting, heating, cooling, water heating, motors and refrigeration end-uses. For example, T12 and T8 lighting used 84% of the energy for interior fluorescent lamps and fixtures for the surveyed buildings. The remaining usage was a combination of compact fluorescent lights (CFLs), T5s and LED linear tube lighting.

In total, 63% of the base case allocations came directly from the survey data and the other 37% came from regional potential study data from other Indiana Utilities or from GDS estimates based upon past study experience.

In addition to base equipment saturation data, the commercial survey data was used to determine the efficient saturations for 60% of all measures in the study. For example, the survey found that 14% of commercial building lighting has already been concerted to LEDs. The latest ENERGY STAR shipment data report was also used to determine efficient equipment saturation estimates. Emerging technologies typically assumed no significant market saturation levels.

3.2.3.3 Industrial Sector

As in the commercial sector, data collected in industrial facilities through on-site visits as part of this study was leveraged to develop remaining factors for many of the measures. The on-site data collection included facility operation schedules and building characteristics, HVAC equipment type and efficiency levels, lighting fixture inventories, control systems and strategies, and related process electric consuming equipment characteristics.

Survey data was used to determine fractional energy use for most measures in the study. The survey data provided counts for equipment and energy usage levels for the lighting, heating, cooling, water heating, motors and refrigeration end-uses. For example, 56% of lighting energy was found to be associated with high bay and low bay light fixtures, while 33% was found to be associated with other interior tube lighting (T8, T12, LED). 11% was associated with exterior lighting and other interior bulbs such as CFLs and incandescent bulbs.

Base factor assumptions for industrial lighting, process motors, and space cooling came directly from the survey data and the other base factor information came from regional potential study data from other Indiana Utilities or from GDS estimates based upon past study experience.

In addition to base case factor, the survey data was also utilized, where possible, to estimate the saturation of efficient equipment, primarily lighting. GDS relied on secondary research, including the EIA Manufacturing Energy Consumption Survey for assessing the efficiency saturation of the remaining measures for industrial lighting, process motors and variable frequency drives, space cooling equipment, and air compressors. Like the commercial sector, emerging technologies were assumed to have little to no significant market saturation.

3.2.4 Remaining Factor

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. It is the inverse of the saturation of an energy efficient measure, prior to any adjustments. For this study we made two key adjustments to recognize that the energy efficient saturation does not necessarily always fully represent the state of market transformation. In other words, while a percentage of installed measures may already be efficient, this does not preclude customers from backsliding, or reverting to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost and availability and customer preferences (e.g. historically, some customers have disliked CFL light quality, and have reverted to incandescent and halogen bulbs after the CFLs burn out).

For measures categorized as market opportunity (i.e. replace-on-burnout), we assumed that 50% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. Essentially this adjustment implies that we are assuming that 50% of the market is transformed, and no future savings potential exists, whereas the remaining 50% of the market is not transformed and could backslide without the intervention of an IPL program and an incentive. Similarly, for retrofit measures, we assumed that only 10% of the instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This recognizes the more proactive nature of retrofit measures, as the implementation of these measures are more likely to be elective in nature, compared to market opportunity measures, which are more likely to be needs-based. We recognize the uncertainty in these assumptions, but we believe these are appropriate assumptions, as they recognize a key component of the nature of customer decision making.

3.3 MEASURE CHARACTERIZATION

3.3.1 Measure Lists

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Indiana TRM, current IPL program offerings, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with IPL and stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS analyzed 554 measure types for IPL. Many measures were included in the study as multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. GDS developed a total of 4,708 measure permutations for this study. Each permutation was, screened for cost-effectiveness according to the UCT. The parameters for cost-effectiveness under the UCT are discussed in detail later in Section 3.4.3.

TABLE 3-3 NUMBER OF MEASURES EVALUATED

	# of Measures	Total # of Measure Permutations	# with UCT ≥ 1
IPL – Electric			
Residential	187	648	420
Commercial	237	2370	2160
Industrial	130	1690	1482
Total	***554***	***4708***	***4062***

3.3.2 Emerging Technologies

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart technologies, including smart appliances, smart water heater (WH) tank controls, smart window coverings, smart ceiling fans, heat pump dryers and home automation/home energy management systems. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include strategic energy management, advance lighting controls, advanced rooftop controls, cloud-based energy information systems (EIS), high performance elevators, and escalator motor controls. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the 19-year study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

3.3.3 Assumptions & Sources

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to IPL when it was available and current. GDS used the most recent IPL evaluation report findings (as well as IPL program planning documents), 2015 Indiana Technical Reference Manual (TRM), the Illinois TRM, and the Michigan Energy Measures Database (MEMD) to a large amount of the data requirements. Evaluation report findings and the Indiana TRM were leveraged to the extent feasible – additional data sources were only used if these first two sources either did not address a certain measure or contained outdated information. The BEopt simulation modeling results formed the basis for most heating and cooling end use measure savings. The National Renewable Energy Laboratory (NREL) Energy Measures Database also served as a key data source in developing measure cost estimates. Additional source documents included American Council for an Energy-Efficient Economy (ACEEE) research reports covering topics like emerging technologies.

Measure Savings: GDS relied on existing IPL evaluation report findings[15] and the 2015 IN TRM to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the IN TRM, GDS estimated savings from a variety of sources, including:

- Illinois TRM, MEMD, and other regional/state TRMs
- Building energy simulation software (BEopt) and engineering analyses
- Secondary sources such as the ACEEE, Department of Energy (DOE), EIA, ENERGY STAR©, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.[16] One exception is an assumed decrease in costs for LED bulbs over the study horizon. LED bulb consumer costs have been declining rapidly over the last several years and future cost projections indicate a continued decrease in bulb costs.[17] GDS' treatment of LED bulb costs, LED lighting efficacy, and the impacts of the Energy Independence and Security Act (EISA) are discussed in greater detail in Section 3.3.5, "Review of LED Lighting Assumptions."

GDS obtained measure cost estimates primarily from the IPL program planning databases, and the 2015 IN TRM. GDS used the following data sources to supplement the IN TRM:

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[15] 2016 EM&V (Cause No. 44497) and 2017 EM&V (Cause No. 44792)

[16] GDS reviewed the deemed measure cost assumptions included in the Illinois TRM from 2012 (v1) through 2018 (v7). Where a direct comparison of cost was applicable, GDS found no change in measure cost across 80% of residential and nonresidential measures. In a similar search of the MEMD from 2011 to 2018, GDS again found that most of incremental measure costs in 2018 were either the same or higher than the recorded incremental measure cost in 2011.

[17] LED Incremental Cost Study Overall Final Report. The Cadmus Group. February 2016

- Illinois TRM, MEMD, and other regional/state TRMs
- Secondary sources such as the ACEEE, ENERGY STAR, and NREL
- Program evaluation and market assessment reports completed for utilities in other states

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the 2015 IN TRM and IPL program planning databases, and used the following data sources for measures not in the IN TRM:

- Illinois TRM, MEMD, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in Appendices B-D.

3.3.4 Treatment of Codes & Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does attempt to reflect the latest legislated improvements to federal codes and standards. Where possible, improvements to baseline equipment standards can typically be met with incremental improvements to efficient equipment standards. However, in select case, such as screw-in lighting (discussed further below), improvements to the baseline standard effectively will be expected to eliminate the efficient technology from future consideration.

3.3.5 Review of LED Lighting Assumptions

Recognizing that there remains significant uncertainty regarding the future potential of residential screw-in lighting, GDS reviewed the latest lighting-specific program designs and consulted with industry peers to develop critical assumptions regarding the future assumed baselines for LED screw base omnidirectional, specialty/decorative, and reflector/directional lamps over the study timeframe.

EISA Impacts. LED screw base omnidirectional and decorative lamps are impacted by the EISA 2007 regulation backstop provision, which requires all non-exempt lamps to be 45 lumens/watt, beginning in 2020. Based on this current legislation, the federal baseline in 2020 will be roughly equivalent to a CFL bulb. However, in January 2017, the Department of Energy expanded the scope of the standard to include directional and specialty bulb but stated that they may delay enforcement based on ongoing dialog with industry stakeholders. Although there is uncertainty surrounding EISA and the backstop provision, the Market Potential Study assumes the backstop provision for standard (A-lamp) screw-in bulbs will take effect beginning in 2022. The analysis assumes the expanded definition of general service lamps to include specialty and reflector sockets will impact those sockets beginning in 2023. Last, the analysis assumes a limited opportunity for direct install of LED bulbs replacing halogen bulbs through 2024 in both low-income and non-low-income households.

TABLE 3-4 ASSUMED LIGHTING BASELINE TECHNOLOGY BY YEAR

Delivery Approach/Bulb Type	2021	2022	2023	2024
Buydown				
Standard LED	Halogen	CFL	CFL	CFL
Specialty LED	Incandescent	Incandescent	CFL	CFL
Reflector LED	Incandescent	Incandescent	CFL	CFL
Direct Install				
Standard LED	Halogen	Halogen	Halogen	CFL
Specialty LED	Incandescent	Incandescent	Incandescent	CFL
Reflector LED	Incandescent	Incandescent	Incandescent	CFL

LED Bulb Costs. Based on EIA Technology Forecast Report, LED bulb costs were assumed to decrease over the analysis period. LED bulb costs ranged between $2.95 (standard) and $5.45 (reflector) in 2021, decreasing to

$2-$3 by 2039. Incentives were modeled as a % of incremental cost, resulting in decreasing incentives over the analysis timeframe as well.

LED Lighting Efficacy. Using the same EIA Technical Forecast Report, LED efficacy was also assumed to improve over the analysis timeframe. By 2040, the LED wattage of a bulb equivalent to a 60W incandescent will improve from 8W (today's typical LED) down to 4W.

3.3.6 Net to Gross (NTG)

All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive) were considered in the development of DSM Inputs into IPL's upcoming IRP.

3.4 ENERGY EFFICIENCY POTENTIAL

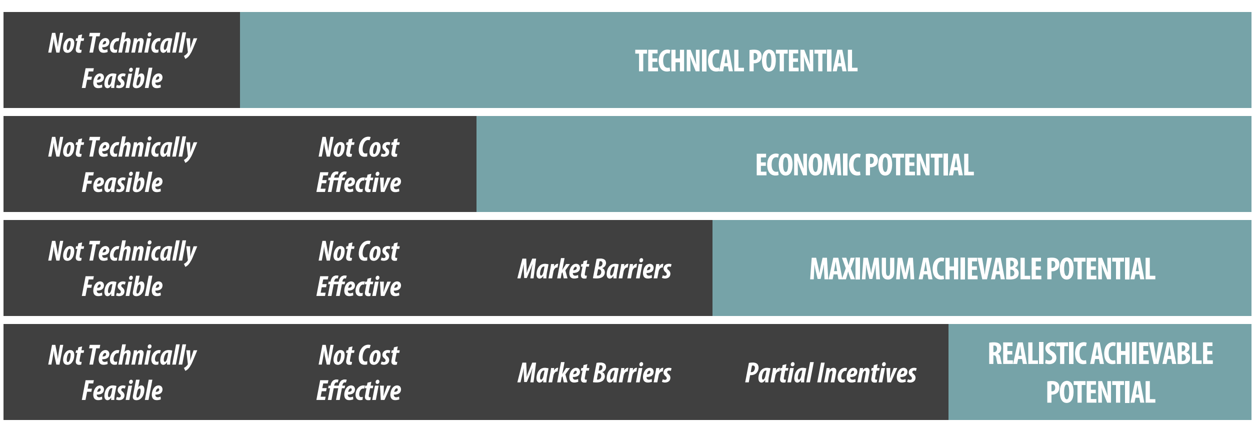
This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

3.4.1 Types of Potential

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 3-2 illustrates the types of energy efficiency potential considered in this analysis.

FIGURE 3-2 TYPE OF ENERGY EFFICIENCY POTENTIAL



3.4.2 TECHNICAL POTENTIAL

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 15 years.

3.4.2.1 Competing Measures & Interactive Effects Adjustments

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

Baseline Saturation Adjustment. Competing measure shares may be factored into the baseline saturation estimates. For example, nearly all homes can receive insulation, but the analysis has created multiple measure permutations to account for varying impacts of different heating/cooling combinations and have applied baseline saturations to reflect proportions of households with each heating/cooling combination.

Applicability Factor Adjustment. Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

Interactive Savings Adjustment. As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat are adjusted down to reflect the efficiency gains of installing an efficient air source heat pump. The analysis also prioritizes efficiency measures relative to conservation (behavioral) measures.

3.4.3 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the UCT) as compared to conventional supply-side energy resources.

3.4.3.1 Utility Cost Test & Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the UCT at the measure level. In the IPL territory, the UCT considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness.[18]

Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective; all low-income specific measures are included in the economic and achievable potential estimates.

For both the calculation of the measure-level UCT, as well as the determination of RAP, historical incentive levels (as a % of incremental measure cost) were calculated for current measure offerings. Figure 3-3 describes the incentive levels by key market segment within the residential and nonresidential sectors.

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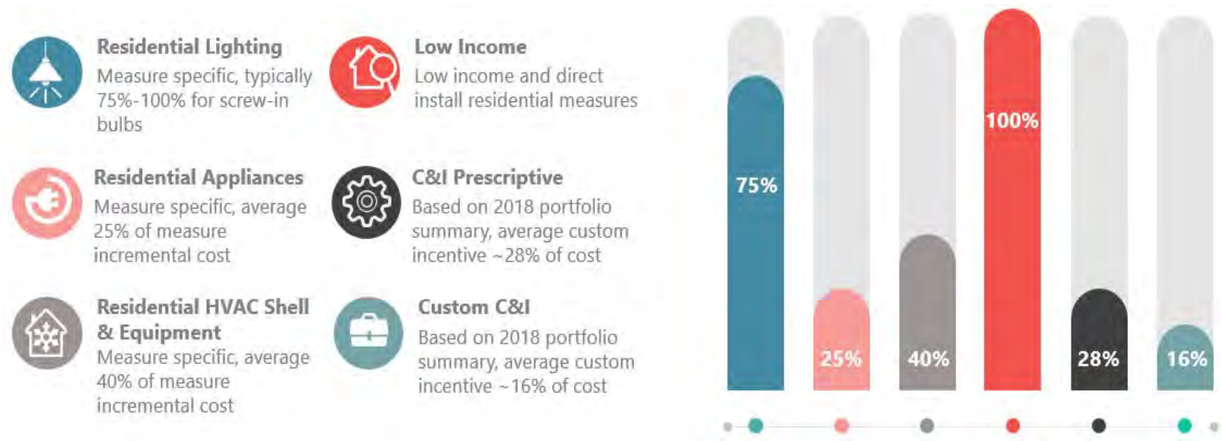
[18] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. *Note: Non-incentive delivery costs are included in the assessment of achievable potential.*

FIGURE 3-3 INCENTIVES BY SECTOR AND MARKET SEGMENT



GDS relied on IPL's DSM Portfolio Summary to map current measure offerings to their historical incentive levels. For study measures that did not map directly to a current offering, GDS calculated the weighted average incentive level (based on 2017 participation) by sector and/or program and applied these "typical" incentive levels to the new measures.

- In the residential sector, lighting incentive levels were assumed to represent 75-100% of the measure cost. Overall, residential appliance incentive levels averaged 25% of the incremental measure cost, while HVAC Shell and Equipment incentives averaged roughly 4-% of the measure cost.
- Low income and direct install measures received incentives equal to 100% of the measure cost.
- In the non-residential sector, prescriptive incentives were approximately 28% of the measure cost, and custom measures received incentives equal to 16% of the measure cost.
- In the MAP scenario, all incentives were set to 100% of the incremental measure cost.

3.4.3.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided T&D were provided by IPL as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

3.4.4 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and WTP in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- ***MAP*** estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- ***RAP*** estimates achievable potential with IPL paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

3.4.4.1 Market Adoption Rates

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

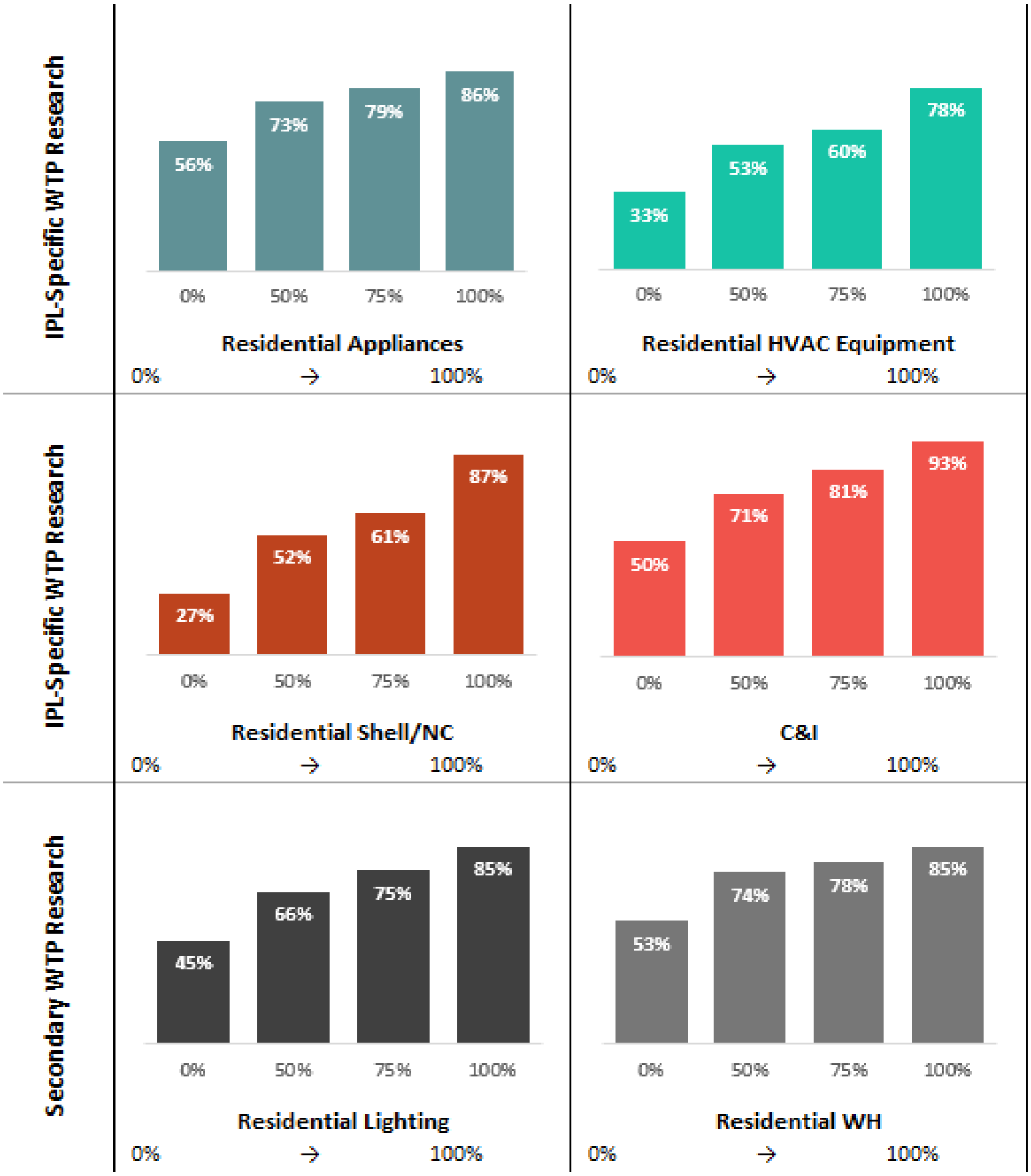
The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on either IPL-specific WTP market research or publicly available DSM research including market adoption rate surveys and other utility program benchmarking. These surveys included questions to residential homeowners and nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive levels.

GDS utilized likelihood and willingness-to-participate data to estimate the long-term market adoption potential for both the maximum and realistic achievable scenarios.[19] Table 3-5 presents the long-term market adoption rates at varied incentive levels used for both the residential and nonresidential sectors. When incentives are assumed to represent 100% of the measure cost (maximum achievable), the long-term market adoption typically ranged by sector and end-use from 78% to 93%. For the RAP scenario, the incentive levels also varied by measure resulting in measure-specific market adoption rates.

[19] For the MAP Scenario, the long-term adoption rate was reached by Year15 (or earlier) and annual participation remained flat in the final five years of the analysis. In the RAP scenario, the analysis assumes the maximum adoption rate is reached over a period of 20-years or less.

TABLE 3-5 LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS

(based on Willingness-to-Participate Survey Results)



GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2020 annual potential to recent historical levels achieved by IPL's current DSM portfolio. This calibration effort ensures that the forecasted achievable potential in 2020 is realistic and attainable. GDS then assumed a non-linear ramp rate from the initial year market adoption rate to the various long-term market adoption rates for each specific end-use.

One caveat to this approach is that the ultimate long-term adoption rate is generally a simple function of incentive levels and payback. There are other factors that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. Other benefits, such as increased comfort or safety and reduced maintenance costs could also factor into a customer's decision to purchase and install energy efficiency measures. To acknowledge these impacts, GDS reviewed the stated adoption levels depending on whether cost was named as the primary barrier towards adoption. For respondents who did not select cost as the primary barrier, stated adoption levels were typically higher than those where cost was the primary barrier. To reflect the opportunity for increased education, marketing, and awareness to impact future long-term adoption levels, GDS ultimately utilized the adoption rates from respondents where cost was not the primary barrier. Although we recognize this approach does not capture every possible factor in determining appropriate long-term adoption levels, it does assign some weight to non-financial considerations in the assessment of long-term energy efficiency potential.

3.4.4.2 Non-Incentive Costs

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[20], utility non-incentive costs were included in the overall assessment of cost-effectiveness at the RAP scenario. 2021 direct measure/program non-incentive costs were calibrated to recent projected levels (using the 2019 portfolio summary) and set at:

- $0.31 per Home Energy Report
- $1.5-$2.5 per bulb for residential LEDs
- $0.05-$.10 per first year kWh saved for most residential appliance, electronics, and water heating retrofit measures;
- $0.16 per first year kWh saved for residential appliance recycling;
- $0.28 per first year kWh saved for residential heating and cooling equipment;
- 0.20-$0.23 per first year kWh saved for the remaining residential measures,
- $0.25-.28 per first year kWh saved for prescriptive C&I measures
- $0.06 per first year kWh saved for custom C&I measures; and
- $0.08 per first year kWh saved for C&I emerging technology measures.

Non-incentive costs were then escalated annually at the rate of inflation. [21]

3.5 DEMAND RESPONSE POTENTIAL

This section provides an overview of the demand response potential methodology. Summary results of the demand response analysis are provided in Section 8. Additional results details are provided in Appendix G.

3.5.1 Demand Response Program Options

Table 3-6 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study. This includes direct load control (DLC) and rate design options.

TABLE 3-6 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

Demand Response Program Option	Program Description	Eligible Markets
DLC AC (Switch)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). GDS looked at both the one-way communicating Cannon switches and two-way communicating L+G switches. Both switch options were assumed to be phased out as customers switch to thermostats over time.	Residential and Non-Residential Customers

[20] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.
[21] As noted earlier in the report, measure costs and utility incentives were not escalated over the 20-year analysis timeframe to keep those costs constant in nominal dollars.

Demand Response Program Option	Program Description	Eligible Markets
DLC AC (Thermostat)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load. GDS looked at the three options IPL currently has: a customer is given a free thermostat to participate along with an annual incentive, a customer is given a rebate through the marketplace or a storefront along with an annual incentive, or the customer brings an existing thermostat and is only given an annual incentive.	Residential and Non-Residential Customers
DLC Space Heating	The system operator can remotely lower the HVAC's thermostat set point during winter peak load conditions, lowering the heating load. This program is an add-on to the DLC AC Thermostat program. Only participants in the AC Thermostat program would be allowed to participate in the Space Heating program.	Residential and Non-Residential Customers
DLC Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and Non-Residential Customers
Ice Storage Cooling Rate	The use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods.	Large Non-Residential Customers
DLC Lighting	Part of the lighting load is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Non-Residential Customers
Curtailable Rate (Day of)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers
Curtailable Rate (Day Ahead)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control (DLC) program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. However, in this study, none of the programs interacted with each other. All residential programs considered were direct load control. Only small non-residential customers were eligible for direct load control programs, and large non-residential customers were eligible for the Ice Storage Cooling Rate and Curtailable Rate.

3.5.2 Demand Response Potential Assessment Approach Overview

The analysis of demand response, where possible, closely followed the approach outlined for energy efficiency. The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[22] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[23] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits.

Direct load control demand response analysis was conducted using the GDS Demand Response Model. Demand response via rate programs (specifically, curtailable rates) were analyzed by Demand Side Analytics (DSA). GDS and DSA determine the estimated savings for each demand response program by performing a review of all benefits and cost associated with each program. Both firms a modeling approach that considers numerous required inputs for each program including: expected life, coincident peak (CP) kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses.

The UCT was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

The demand response analysis includes estimates of technical, economic, and achievable potential. Achievable potential is broken into maximum and RAP in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 19-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 19-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

3.5.3 Avoided Costs

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by IPL. The primary benefit of demand responses is avoided generation capacity, resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

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[22] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.

[23] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

3.5.4 Demand Response Program Assumptions

This section briefly discusses the general assumptions and sources used to complete the demand response potential analysis. Appendix G provides additional detail by program and sector related to load reduction, program costs, and projected participation.

3.5.4.1 Direct Load Control Program Assumptions

Load Reduction: Demand reductions were based on load reductions found in IPL's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies. DLC and thermostat-based demand response options were typically calculated based on a per-unit kW demand reduction whereas rate-based demand response options were typically assumed to reduce a percentage of the total facility peak load.

Useful Life: The useful life of a smart thermostat is assumed to be 12 years . Load control switches have a useful life of 12 years. This life was used for all direct load control measures in this study.

Program Costs: One-time program development costs included in the first year of the analysis for new programs. No program development costs are assumed for programs that already exist. Each new program includes an evaluation cost, with evaluation cost for existing programs already being included in the administration costs. It was assumed that there would be a cost of $50[24] per new participant for marketing for the DLC programs. Marketing costs are assumed to be 33.3% higher for MAP. All program costs were escalated each year by the general rate of inflation assumed for this study.

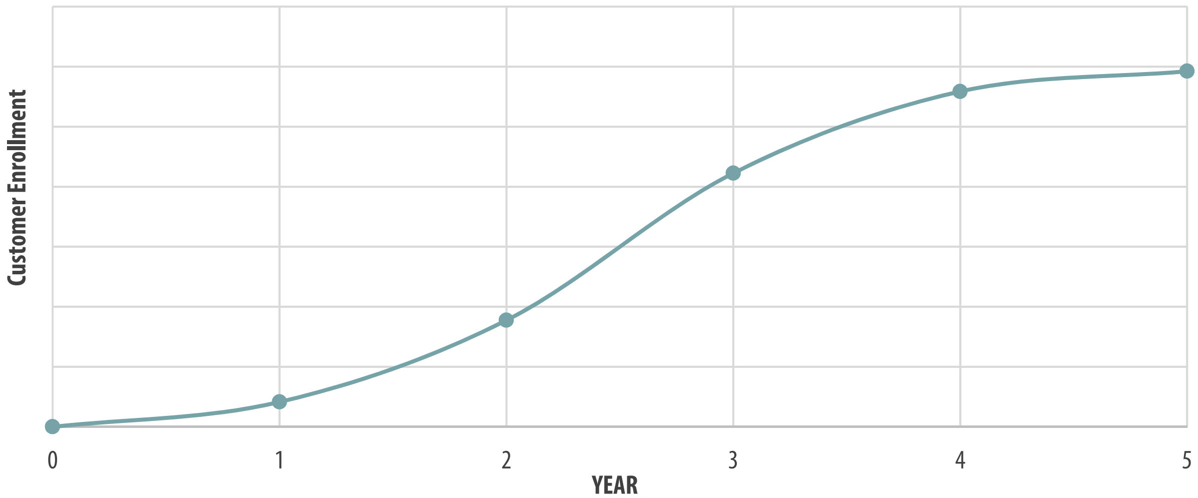
Saturation: The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.055 thermostats.

Program Adoption Levels: Long-term program adoption levels (or "steady state" participation) represent the enrollment rate once the fully achievable participation has been reached. GDS reviewed industry data and program adoption levels from several utility demand response programs. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Appendix G. As noted earlier in this section, for direct load control programs, MAP participation rates rely on industry best adoption rates and RAP participation rates are based on industry average adoption levels. For the rate programs, the MAP steady-state participation rates assumed programs were opt-out based and RAP participation assumed opt-in status.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an "S-shaped" curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure 3-4). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

[24] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

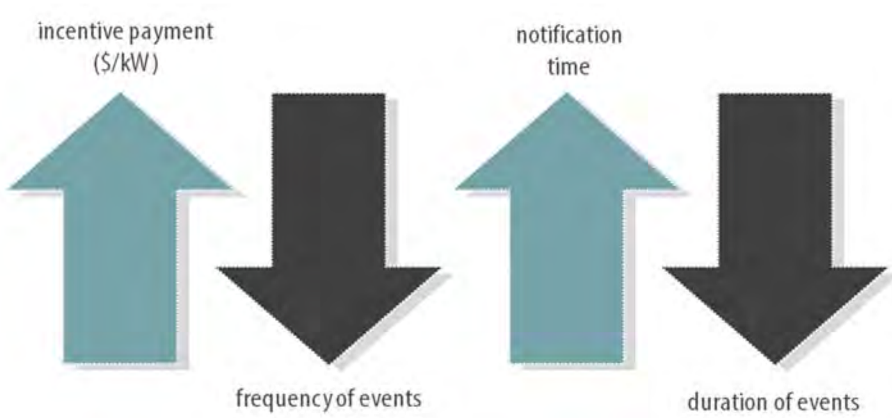
FIGURE 3-4 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE



3.5.4.2 C&I Curtailment Load Program Assumptions

One of the most prominent forms of demand response among non-residential customers is load curtailment agreements where the utility, or an aggregator on the utility's behalf, enters financial agreements with businesses to reduce load when dispatched. Load curtailment potential is driven by a few key factors – incentive payments, the frequency of events, the duration of events, and the level of notification participants are given about pending events. The directional effect these factors have on demand response potential is shown in Figure 3-5.

FIGURE 3-5 DRIVERS OF DR POTENTIAL



Several different estimates of Curtailment Load potential can be produced by turning levers related to these four inputs. Rather than producing several different scenario-based estimates, the research team made several simplifying assumptions regarding program design. Components of program design include how many demand response events will be called, how long the demand response events will last, how far in advance participants are notified of the upcoming demand response event, and the incentive payment participants receive (the amount and how it is distributed – annually, monthly, per event, etc.).

Program Design: Previous Indiana research suggests relatively short demand response events would serve the region better than relatively long events, as summer peaks are concentrated between 2:00 PM and 6:00 PM. Thus, our estimates of potential assume a four-hour event duration. We're also assuming that there will be an average of seven summer events will be called (28 total event hours for the summer).

Results were calculated for both a "day-ahead" notification design and a "day-of" notification design. "Day-ahead" notification assumes a 24-hour notice, and "day-of" notification assumes a 3-to-6-hour notice. Potential is higher under the "day-ahead" notification design, as this provides participants greater opportunities to shift energy-intensive tasks to off-peak periods

Participant Incentive: For C&I Curtailable demand response, our team modeled the incentive as a reservation payment. This is an annual payment provided to the participant. In exchange, the participant agrees to curtail load when events are dispatched. For RAP, our approach to setting incentive levels involved optimizing net benefits. To determine the optimal incentive level, the research team performed a simulation where the critical input was the incentive level and the critical output was the net benefit of the demand response program. The simulation leveraged several of the inputs discussed herein. The results indicated that the optimal incentive level in 2020 is $21/kW-year.

For MAP, the goal of the simulation was not to optimize net benefits. Instead, we used the simulation to determine the greatest possible incentive level that would produce a cost-effective program (e.g., largest incentive value such that the UCT ratio does not fall below 1). The results indicated an incentive level of $39/kW-year should be used in estimating MAP for summer 2020.

In both cases, the incentive level is escalated annually at a rate that matches the growth rate of avoided costs. This growth rate is largely driven by the generation component (avoided cost of generation capacity was provided by IPL).

Price Elasticity of Demand Coefficients: The price elasticity of demand coefficients used in this research were derived from two years of demand response performance data for C&I demand response participants in Pennsylvania. Information about sector (small/large), incentive levels, and the peak load share of each participant was used in the development of the elasticity coefficients. Traditional elasticity formulas were used.

Leveraging the inputs discussed above, C&I Curtailable load potential estimates were developed via a "top-down" approach. At a high level, the approach entails disaggregating the peak load forecast into peak load forecasts by sector, and then combining these forecasts with the price elasticity of demand coefficients to estimate potential. Price elasticity of demand can be thought of as the percentage change in the quantity of electricity demanded divided by the percentage change in the price (including an incentive) of demand response:

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price}$$

Rearranging the terms in the elasticity equation yields the following:

$$\%\ change\ in\ Quantity = (Elasticity) \times (\%\ change\ in\ Price)$$

Note that "% change in Quantity" can also be expressed as:

$$\%\ change\ in\ Quantity = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

Combing these two "% change in Quantity" equations yields:

$$(Elasticity) \times (\%\ change\ in\ Price) = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

By making assumptions about price elasticity, the percentage change in price (related to electric retail rates and the incentive level), and the summer peak load, it is possible to estimate how much demand response potential exists in each market segment by solving for "demand response potential". It is important to note that the estimates of C&I Curtailable Load demand response potential discussed in this section are not incremental to existing IPL programs. That is, we are not estimating how much Curtailable Load demand response potential exists beyond the existing IPL resources. It is also important to note that this top-down methodology produces estimates of Curtailable Load demand response potential at the system-level (inclusive of line losses).

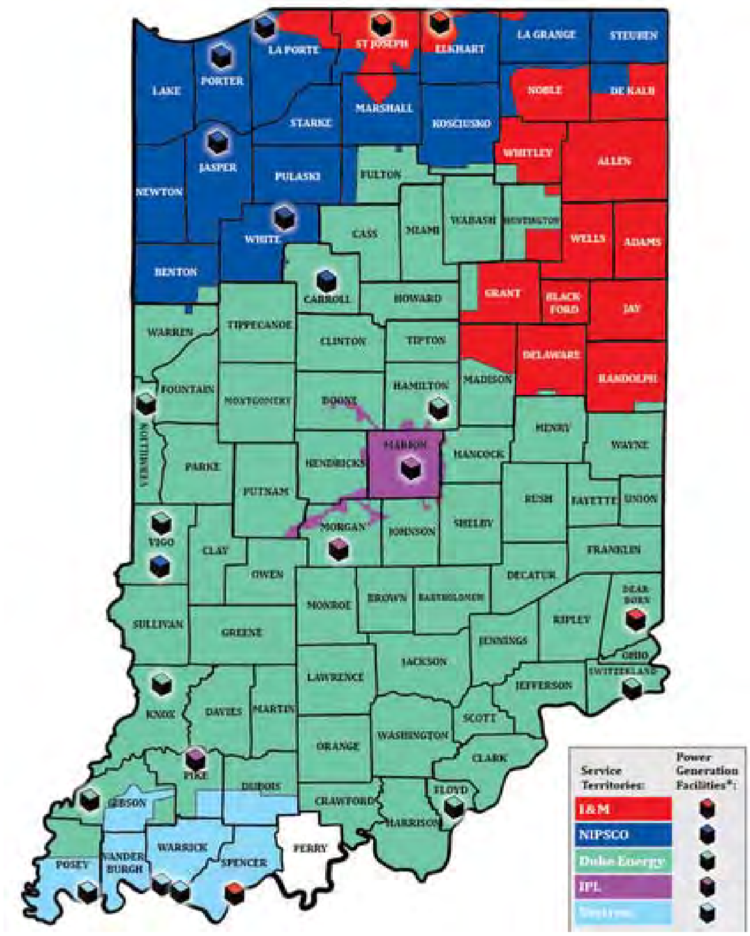
4 Market Characterization

Developing a market characterization in the context of utility electric consumption among each sector is a key foundational element to market potential studies. A market characterization describes how energy is used among the various end-uses and building types that are the subject of the potential study. This section provides a brief overview of the sales and customer forecasts for IPL's electric customers. It also includes a more detailed breakdown of the end-use and building type consumption, along with an overview of how these segmentations were developed.

4.1 INDIANAPOLIS POWER & LIGHT COMPANY SERVICE AREA

This study assessed the electric energy efficiency potential for IPL. Figure 4-1 identifies the overall IPL territory relative to the geographic area of Indiana.

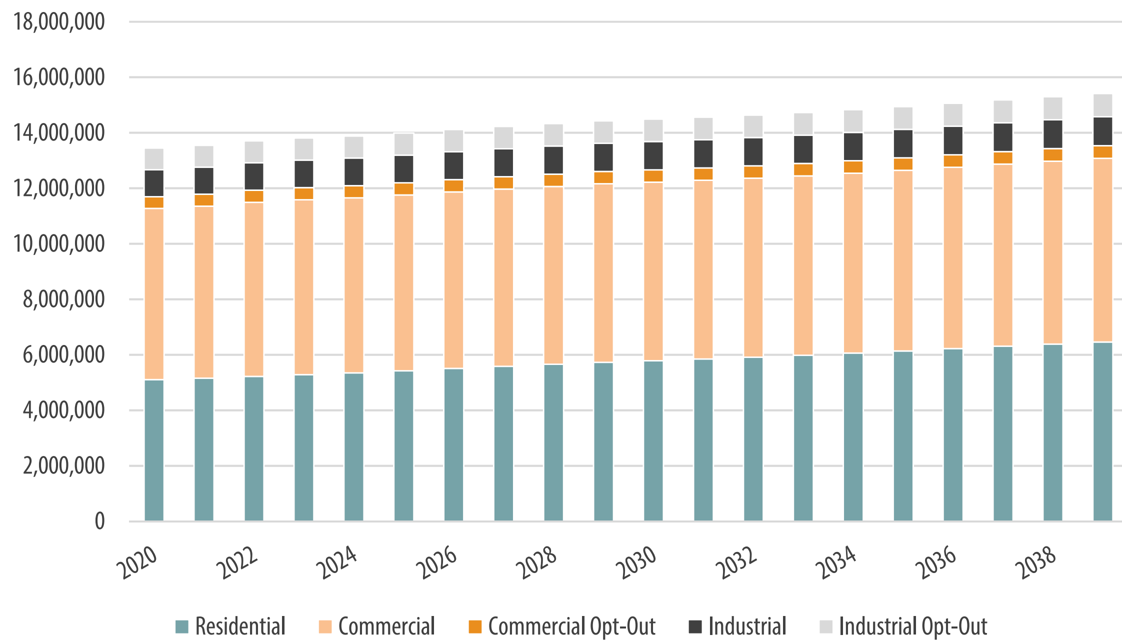
FIGURE 4-1 IPL SERVICE TERRITORY MAP



4.2 LOAD FORECASTS

Figure 4-2 provides the electric sales by sector across the 2020-2039 timeframe. Sales are forecasted to gradually increase from 13.4 million MWh to 15.4 million MWh from 2020 to 2039. The sales figure shows C&I sales break outs of the sales projections for opt-out customers.

FIGURE 4-2 20-YEAR ELECTRIC SALES (MWH) FORECAST BY SECTOR

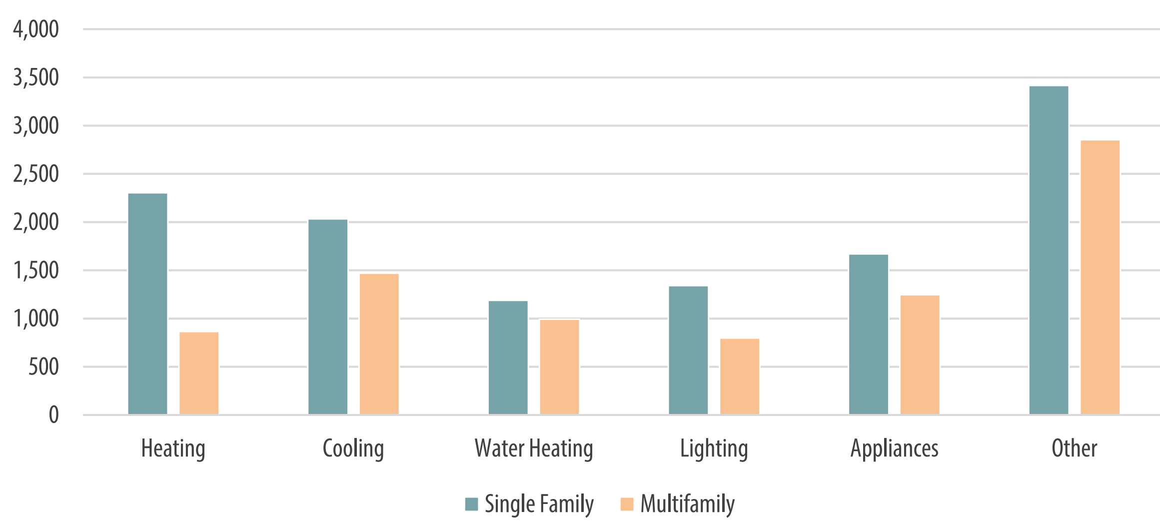


4.3 SECTOR LOAD DETAIL

4.3.1 Residential Sector

The residential electric calibration effort led to a housing-type specific end-use intensity breakdown as shown below in Figure 4-3. Overall, we estimated single-family consumption to be just shy of 12,000 kWh per year, and multifamily homes to be about 8,200 kWh per year. The “Other” end use is the leading end-use among both housing types. This reflects the increasing prominence of electronics and other plug in load devices.

FIGURE 4-3 RESIDENTIAL ELECTRIC END-USE BREAKDOWN BY HOUSING TYPE



4.3.2 Commercial Sector

Figure 4-4 provides a breakdown of commercial electric sales by building type. Mercantile (25%) and Office (20%) are the leading contributors of stand-alone building types to the total commercial electric sales.[25]

FIGURE 4-4 COMMERCIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

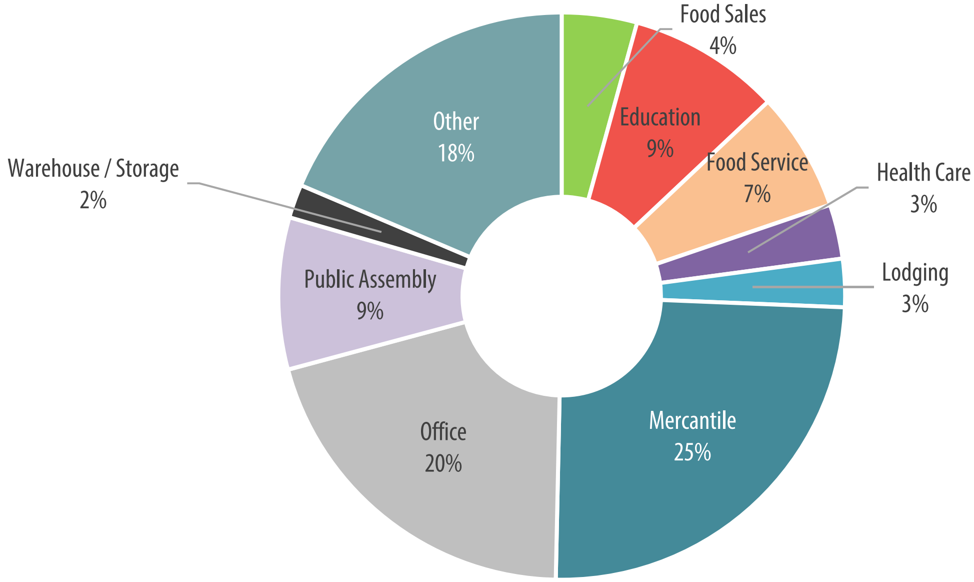
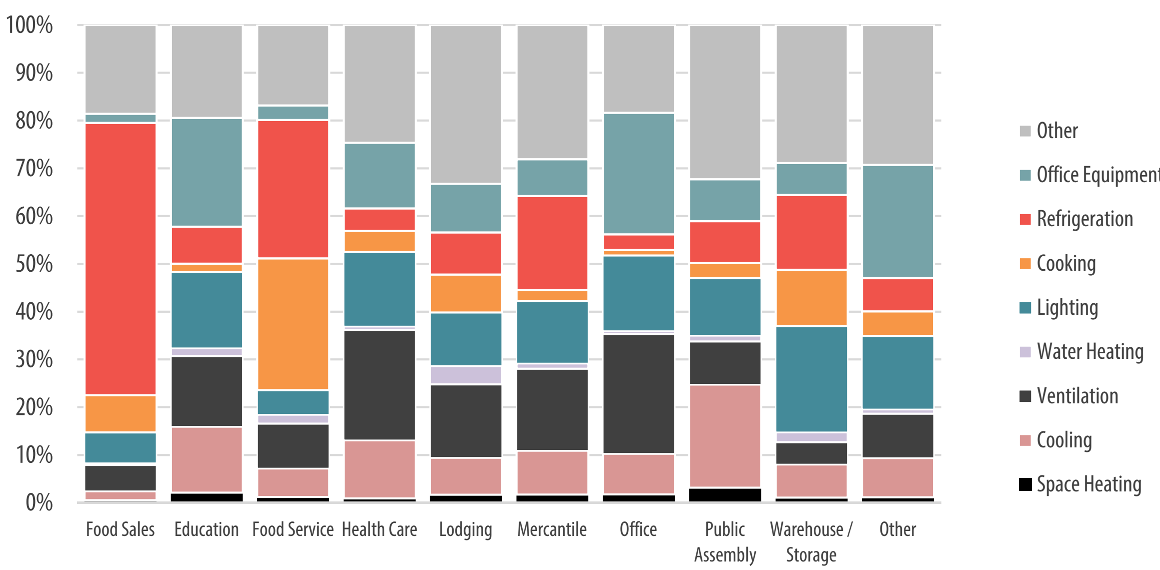


Figure 4-5 provides an illustration of the leading end-uses across all building types in the commercial sector. Ventilation, lighting, and refrigeration are prominent across most of the building types.

FIGURE 4-5 COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE



[25] "Other" building types include buildings that engage in several different activities, a majority of which are commercial (e.g. retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

4.3.3 Industrial Sector

Figure 4-6 provides a breakdown of industrial electric sales by industry type. Food (24%), Chemicals (8%), Paper (8%), Fabricated Metals (8%), and Miscellaneous (44%) are the leading industry types contributing to industrial electric sales.

FIGURE 4-6 INDUSTRIAL ELECTRIC INDUSTRY TYPE BREAKDOWN

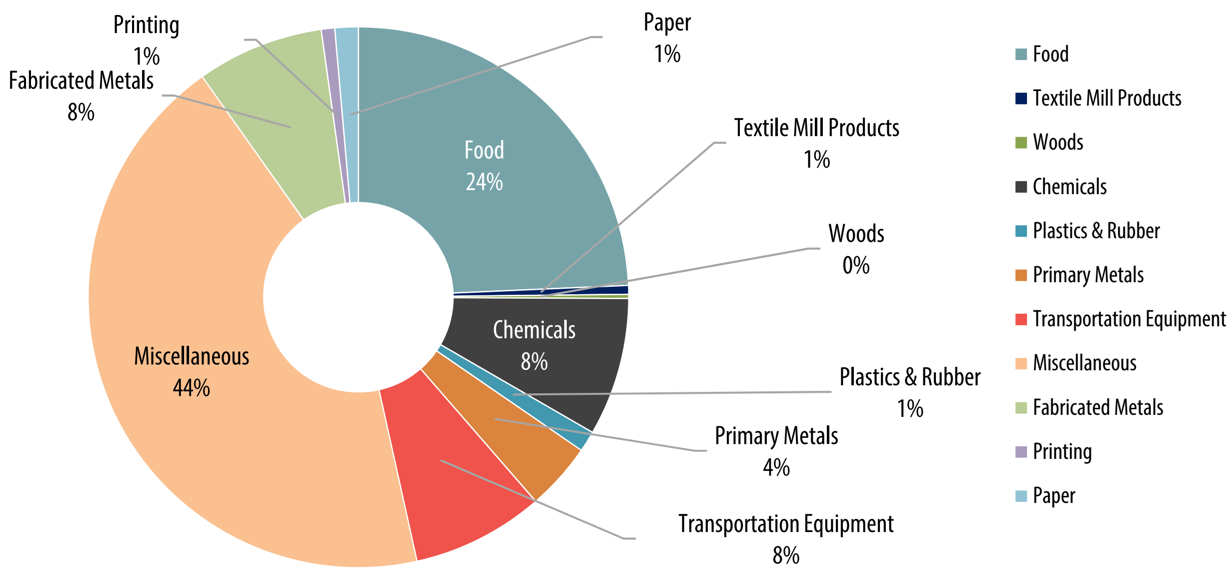
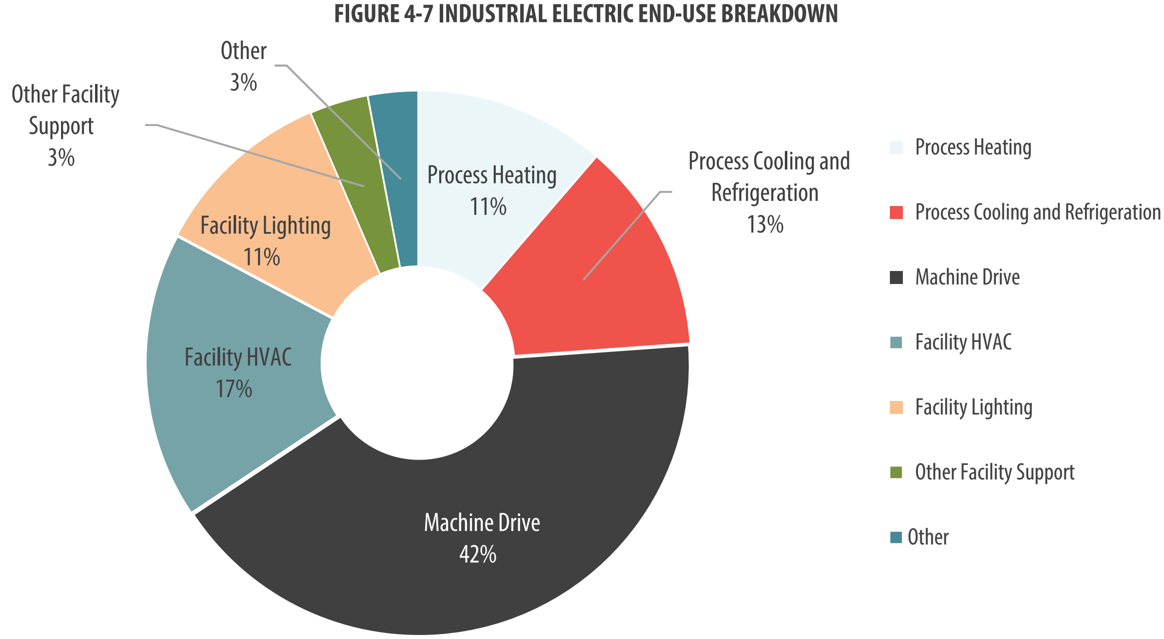


Figure 4-7 provides a breakdown of the industrial electric sales end use. Machine Drive (42%) and Facility HVAC (17%) are the leading end-uses.

FIGURE 4-7 INDUSTRIAL ELECTRIC END-USE BREAKDOWN



5 Residential Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the residential sector. The cost-effectiveness results and budgets for the RAP scenario are also provided.

5.1 SCOPE OF MEASURES & END USES ANALYZED

There were 187 total unique electric measures included in the analysis. Table 5-1 provides the number of measures by end-use and fuel type (the full list of residential measures is provided in Appendix B). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 5-1 RESIDENTIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Appliances	28
Audit	3
Behavioral	6
HVAC Equipment	45
Lighting	15
Miscellaneous	6
New Construction	4
Plug Loads	9
HVAC Shell	55
Water Heating	16

5.2 RESIDENTIAL ELECTRIC POTENTIAL

Figure 5-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 3-year technical potential is 22.4% of forecasted sales, and the economic potential is 19.0% of forecasted sales. The 3-year MAP is 11.3% and the RAP is 6.9%.

FIGURE 5-1 RESIDENTIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF RESIDENTIAL SALES)

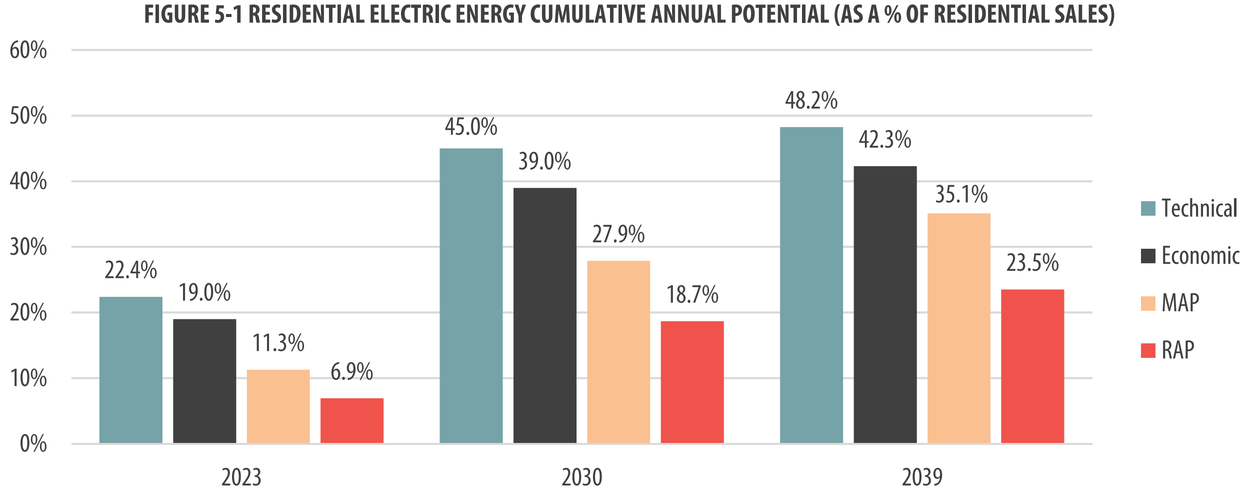


Table 5-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP increases to nearly 7% cumulative annual savings over the next three years.

TABLE 5-2 RESIDENTIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	443,322	818,857	1,182,808	2,604,874	3,116,819
Economic	401,929	706,729	1,003,079	2,255,197	2,732,750
MAP	244,657	414,183	595,903	1,612,643	2,267,253
RAP	175,436	266,884	365,671	1,079,971	1,518,517
Forecasted Sales	5,157,382	5,223,774	5,284,520	5,788,077	6,462,180
Energy Savings (as % of Forecast)					
Technical	8.6%	15.7%	22.4%	45.0%	48.2%
Economic	7.8%	13.5%	19.0%	39.0%	42.3%
MAP	4.7%	7.9%	11.3%	27.9%	35.1%
RAP	3.4%	5.1%	6.9%	18.7%	23.5%

Table 5-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 3.1% to 3.4% per year over the next three years.

TABLE 5-3 RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	443,322	426,679	416,391	247,610	270,960
Economic	401,929	377,942	365,341	214,307	233,397
MAP	244,657	244,314	251,929	190,090	222,905
RAP	175,436	164,092	164,881	171,594	164,489
Forecasted Sales	5,157,382	5,223,774	5,284,520	5,788,077	6,462,180
Energy Savings (as % of Forecast)					
Technical	8.6%	8.2%	7.9%	4.3%	4.2%
Economic	7.8%	7.2%	6.9%	3.7%	3.6%
MAP	4.7%	4.7%	4.8%	3.3%	3.4%
RAP	3.4%	3.1%	3.1%	3.0%	2.5%

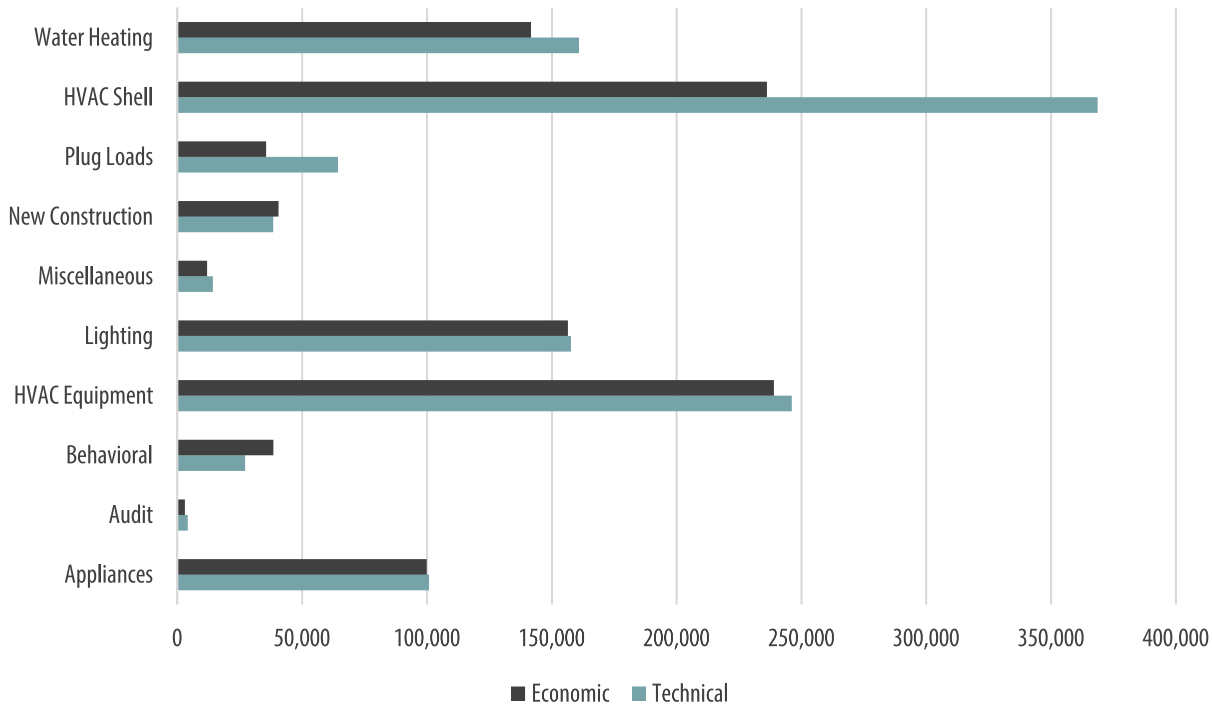
Technical & Economic Potential

Table 5-4 provides cumulative annual technical and economic potential results across the 2021-2023 timeframe, as well as for 2030 and 2039. Figure 5-2 shows a comparison of the technical and economic potential (3-year) by end use. The HVAC Shell and HVAC Equipment are by far the leading end-uses among technical and economic potential.

TABLE 5-4 TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	443,322	818,857	1,182,808	2,604,874	3,116,819
Economic	401,929	706,729	1,003,079	2,255,197	2,732,750
Peak Demand (MW)					
Technical	85	167	247	563	686
Economic	72	135	196	466	575

FIGURE 5-2 3-YEAR TECHNICAL AND ECONOMIC RESIDENTIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 5-3 illustrates the cumulative annual MAP results by end use across the 2021-2023 timeframe. Like technical and economic potential, HVAC Shell and HVAC Equipment are the leading end uses. Water Heating, Lighting, and Appliances also have significant MAP.

FIGURE 5-3 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

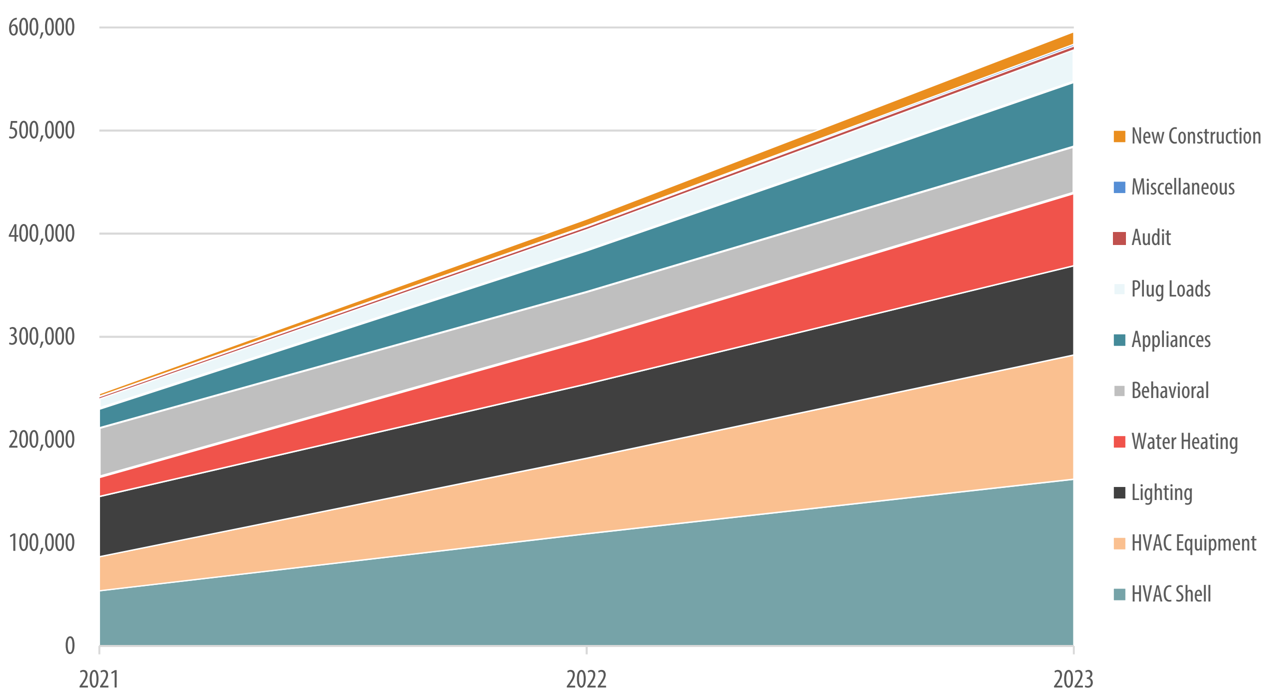


Table 5-5 provides the incremental and cumulative annual MAP across the 2021-2023 timeframe, as well as for 2030 and 2039. HVAC Shell, HVAC Equipment, Lighting, and the Behavioral end uses provide the greatest incremental annual MAP over the next three years.

TABLE 5-5 RESIDENTIAL ELECTRIC MAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Appliances	18,656	21,543	22,839	17,977	20,341
Audit	1,537	2,221	3,066	3,570	1,806
Behavioral[26]	47,718	46,600	45,238	40,186	38,538
HVAC Equipment	33,084	40,516	48,038	39,687	56,260
Lighting	58,384	37,015	30,062	4,374	10,397
Miscellaneous[27]	414	619	884	2,160	2,477
New Construction	2,477	3,971	5,511	12,490	10,973
Plug Loads	9,878	10,652	11,096	13,775	16,956
HVAC Shell	53,561	56,619	55,922	16,992	21,388
Water Heating	18,946	24,558	29,273	38,880	43,768
Total	244,657	244,314	251,929	190,090	222,905
% of Forecasted Sales	4.7%	4.7%	4.8%	3.3%	3.4%
Incremental Annual MW					
Total	44.7	46.9	48.5	33.2	43.8
% of Forecasted Demand	4.0%	4.2%	4.3%	2.8%	3.4%
Cumulative Annual MWh[28]					
Appliances	18,656	40,188	62,543	181,163	234,853
Audit	1,537	2,221	3,066	3,570	1,806
Behavioral	47,718	46,600	45,238	42,069	43,846
HVAC Equipment	33,084	73,223	120,515	468,563	766,806
Lighting	58,384	71,944	86,589	116,397	73,591
Miscellaneous	414	1,033	1,918	14,859	26,877
New Construction	2,477	6,517	12,066	83,992	189,730
Plug Loads	9,878	20,531	31,627	74,682	90,447
HVAC Shell	53,561	108,912	161,775	334,152	380,447
Water Heating	18,946	43,015	70,567	293,198	458,849
Total	244,657	414,183	595,903	1,612,643	2,267,253
% of Forecasted Sales	4.7%	7.9%	11.3%	27.9%	35.1%
Cumulative Annual MW					
Total	44.7	81.3	118.9	318.4	464.4
% of Forecasted Demand	4.0%	7.2%	10.5%	26.9%	36.2%

[26] The behavioral end-use includes home energy reports and home energy management systems (HEMs).
[27] Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.
[28] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.

Realistic Achievable Potential

Figure 5-4 illustrates the cumulative annual RAP results by end use across the 2021-2023 timeframe. HVAC Equipment and Lighting are the leading end uses over the first three years. The HVAC Shell, Behavioral, and Water Heating end uses also have significant potential in the RAP scenario of this timeframe.

FIGURE 5-4 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

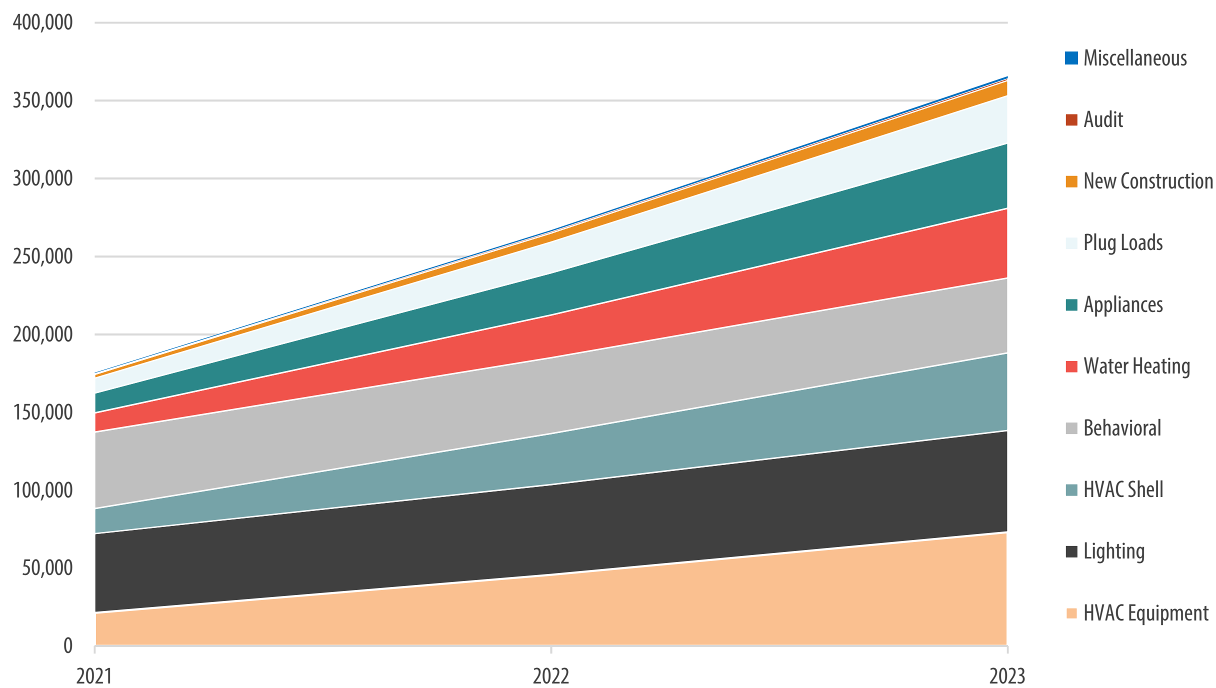


Table 5-6 provides the incremental and cumulative annual RAP across the 2021-2023 timeframe, as well as for 2030 and 2039. HVAC Shell, HVAC Equipment, Lighting, and the Behavioral end uses provide the greatest incremental annual MAP over the next three years.

TABLE 5-6 RESIDENTIAL ELECTRIC RAP BY END-USE

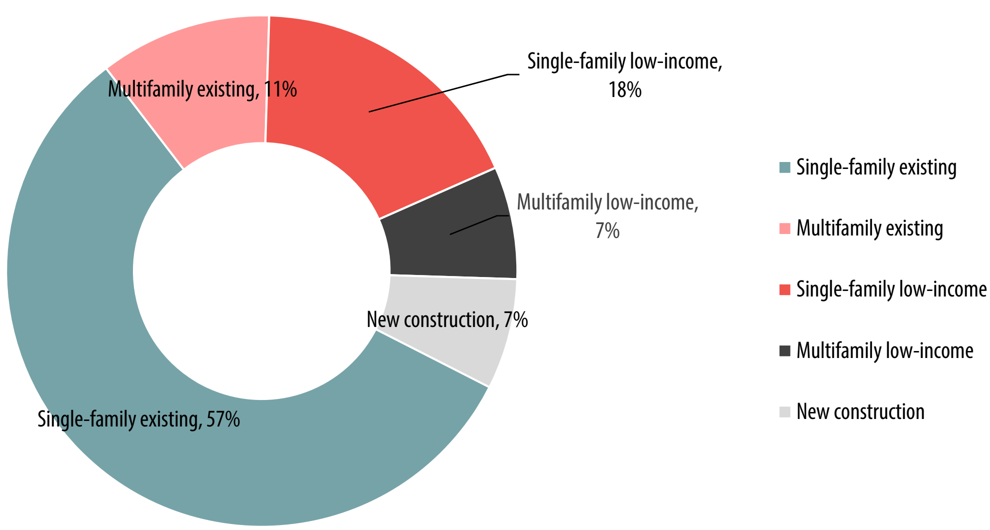
End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Appliances	12,718	14,299	15,192	14,736	15,642
Audit	781	1,035	1,354	4,041	2,302
Behavioral[29]	49,063	48,657	48,057	44,940	45,323
HVAC Equipment	21,534	24,526	27,485	33,577	25,174
Lighting	50,665	29,513	22,359	5,108	9,745
Miscellaneous[30]	328	438	572	1,683	1,889
New Construction	2,424	3,291	3,917	6,016	5,363
Plug Loads	9,546	10,217	10,633	13,558	16,927
HVAC Shell	16,070	16,901	17,574	14,698	8,515
Water Heating	12,306	15,217	17,740	33,238	33,611
Total	175,436	164,092	164,881	171,594	164,489

[29] The behavioral end-use includes home energy reports and home energy management systems (HEMs).
[30] Miscellaneous consists of pool heater, efficient pool pumps, motors and timers, and well pumps.

End Use	2021	2022	2023	2030	2039
% of Forecasted Sales	3.4%	3.1%	3.1%	3.0%	2.5%
Incremental Annual MW					
Total	30.0	30.4	31.0	29.5	28.8
% of Forecasted Demand	2.7%	2.7%	2.7%	2.5%	2.2%
Cumulative Annual MWh[31]					
Appliances	12,718	27,015	41,890	136,801	174,298
Audit	781	1,035	1,354	4,041	2,302
Behavioral	49,063	48,657	48,057	45,878	50,641
HVAC Equipment	21,534	45,977	73,258	298,296	460,561
Lighting	50,665	57,643	65,110	93,649	75,854
Miscellaneous	328	766	1,338	10,062	20,789
New Construction	2,424	5,796	9,767	47,187	98,778
Plug Loads	9,546	19,763	30,395	73,679	89,992
HVAC Shell	16,070	32,741	49,796	158,391	225,785
Water Heating	12,306	27,491	44,706	211,988	319,517
Total	175,436	266,884	365,671	1,079,971	1,518,517
% of Forecasted Sales	3.4%	5.1%	6.9%	18.7%	23.5%
Cumulative Annual MW					
Total	30.0	50.5	71.3	215.6	301.6
% of Forecasted Demand	2.7%	4.5%	6.3%	18.2%	23.5%

Figure 5-5 illustrates a market segmentation of the RAP in the residential sector by 2023. More than half of the RAP is associated with single-family existing homes that are not low-income, whereas the total low-income potential is about 25% of the RAP.[32]

FIGURE 5-5 2023 RESIDENTIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT



[31] Audit measures and most Behavioral measures have a one-year assumed measure life. For this reason, Audit savings are the same for both incremental and cumulative annual, and there is only a minor difference between incremental and cumulative annual savings for Behavioral measures.
[32] The low-income measures in the RAP analysis did not have to pass the UCT.

RAP Benefits & Costs

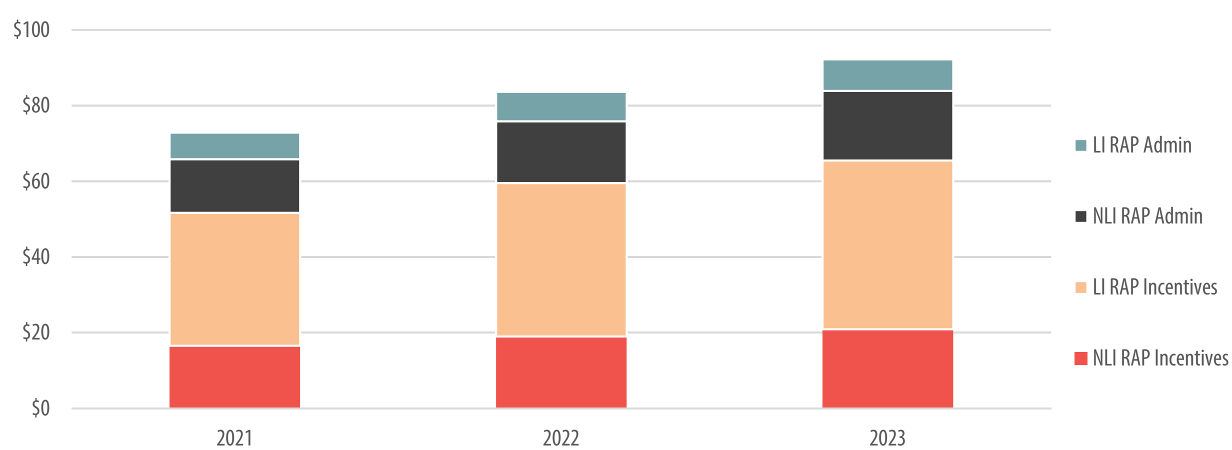
Table 5-7 provides the net present value (NPV) benefits and cost, as calculated using the UCT, across the 2021-2039 timeframe for the RAP scenario. The overall UCT ratio is 0.961. However, if low-income measures were removed, the overall UCT ratio would be nearly 1.5.

TABLE 5-7 RESIDENTIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Overall Results			
Appliances	$110.6	$107.3	1.03
Audit	$1.7	$47.8	0.03
Behavioral	$38.9	$30.4	1.28
HVAC Equipment	$427.5	$504.1	0.85
Lighting	$60.3	$75.9	0.80
Miscellaneous	$18.7	$4.8	3.89
New Construction	$75.9	$42.5	1.79
Plug Loads	$47.1	$32.4	1.46
HVAC Shell	$151.4	$146.6	1.03
Water Heating	$141.3	$122.7	1.15
Total	$1,073.4	$1,114.3	0.96
Excluding Low-Income			
Appliances	$81.9	$35.5	2.31
Audit	$1.5	$32.5	0.05
Behavioral	$38.9	$30.4	1.28
HVAC Equipment	$292.5	$153.8	1.90
Lighting	$56.1	$68.2	0.82
Miscellaneous	$18.7	$4.8	3.89
New Construction	$75.9	$42.5	1.79
Plug Loads	$45.8	$26.3	1.74
HVAC Shell	$105.5	$80.4	1.31
Water Heating	$127.2	$106.2	1.20
Total	$844.0	$580.6	1.45

Figure 5-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. These budgets are further divided into low-income (LI) and not low-income (NLI) components. The low-income incentive portion of the budget is about 48% of the RAP budget. The RAP budgets rise from $73 million to about $92 million from 2021 to 2023.

FIGURE 5-6 ANNUAL BUDGETS FOR RESIDENTIAL RAP ($ IN MILLIONS)



6 Commercial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided.

6.1 SCOPE OF MEASURES & END USES ANALYZED

There were 237 total electric measures included in the analysis. Table 6-1 provides the number of measures by end-use (the full list of commercial measures is provided in Appendix C). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 6-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Space Heating	31
Cooling	75
Ventilation	11
Water Heating	17
Lighting	32
Cooking	8
Refrigeration	29
Office Equipment	14
Behavioral	4
Other	16

6.2 COMMERCIAL ELECTRIC POTENTIAL

Figure 6-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 3-year technical potential is 15.6% of forecasted sales, and the economic potential is 13.9% of forecasted sales. The 3-year MAP is 10.9% and the RAP is 4.3%.

FIGURE 6-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF COMMERCIAL SALES)

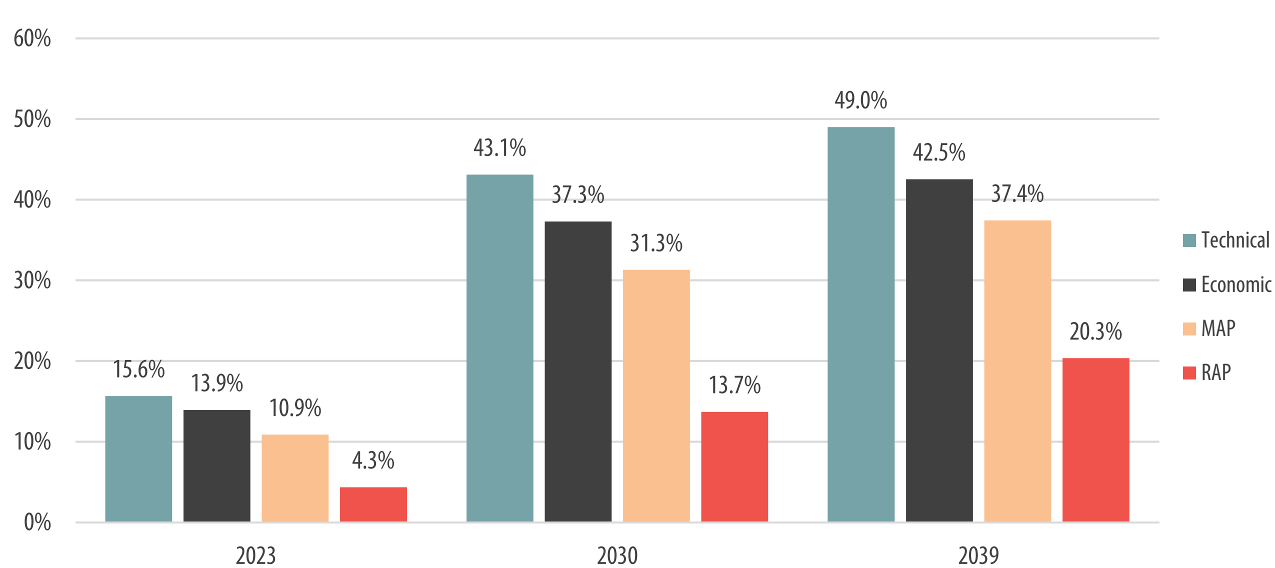


Table 6-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 3.8% after three years and rises to 17.7% by 2039.

TABLE 6-2 COMMERCIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	297,674	601,207	923,248	2,595,884	3,034,939
Economic	262,141	535,268	821,276	2,245,705	2,634,454
MAP	191,773	407,732	640,739	1,884,672	2,317,654
RAP	87,433	172,729	256,487	824,507	1,259,861
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737
Energy Savings (as % of Forecast)					
Technical	4.5%	8.9%	13.6%	37.6%	42.7%
Economic	3.9%	8.0%	12.2%	32.6%	37.2%
MAP	2.9%	6.1%	9.5%	27.3%	32.7%
RAP	1.3%	2.6%	3.8%	11.9%	17.7%

Table 6-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.5% to 2.6% per year over the next six years.

TABLE 6-3 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	297,674	336,201	364,988	325,343	444,368
Economic	262,141	293,165	314,792	283,520	387,432
MAP	191,773	226,960	253,410	249,796	343,413
RAP	87,433	87,790	88,538	128,764	163,720
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737
Energy Savings (as % of Forecast)					
Technical	4.5%	5.0%	5.4%	4.7%	6.3%
Economic	3.9%	4.4%	4.7%	4.1%	5.5%
MAP	2.9%	3.4%	3.7%	3.6%	4.8%
RAP	1.3%	1.3%	1.3%	1.9%	2.3%

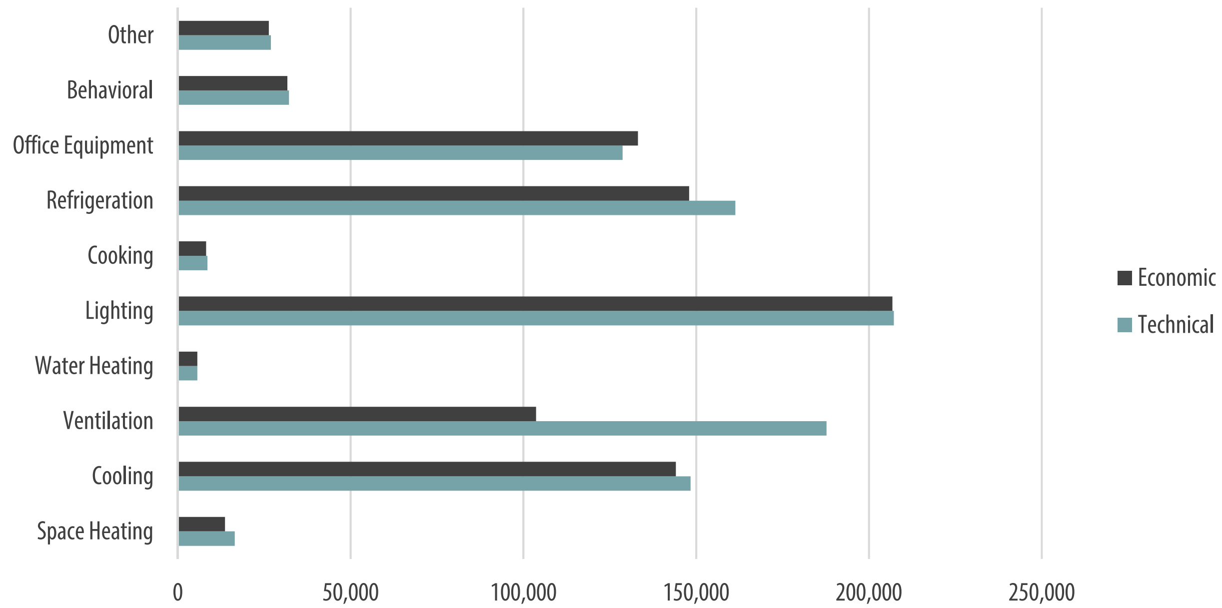
Technical & Economic Potential

Table 6-4 provides cumulative annual technical and economic potential results across the 2021-2023 timeframe, as well as for 2030 and 2039. Figure 6-2 shows a comparison of the technical and economic potential (6-year) by end use. Lighting, Ventilation, and Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE 6-4 TECHNICAL & ECONOMIC COMMERCIAL ELECTRIC POTENTIAL

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	297,674	601,207	923,248	2,595,884	3,034,939
Economic	262,141	535,268	821,276	2,245,705	2,634,454
Peak Demand (MW)					
Technical	58	123	197	683	782
Economic	36	75	119	362	415

FIGURE 6-2 3-YEAR TECHNICAL AND ECONOMIC COMMERCIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 6-3 illustrates the cumulative annual MAP results by end use across the 2021-2023 timeframe. Like technical and economic potential, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant MAP.

FIGURE 6-3 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) MAP POTENTIAL BY END-USE

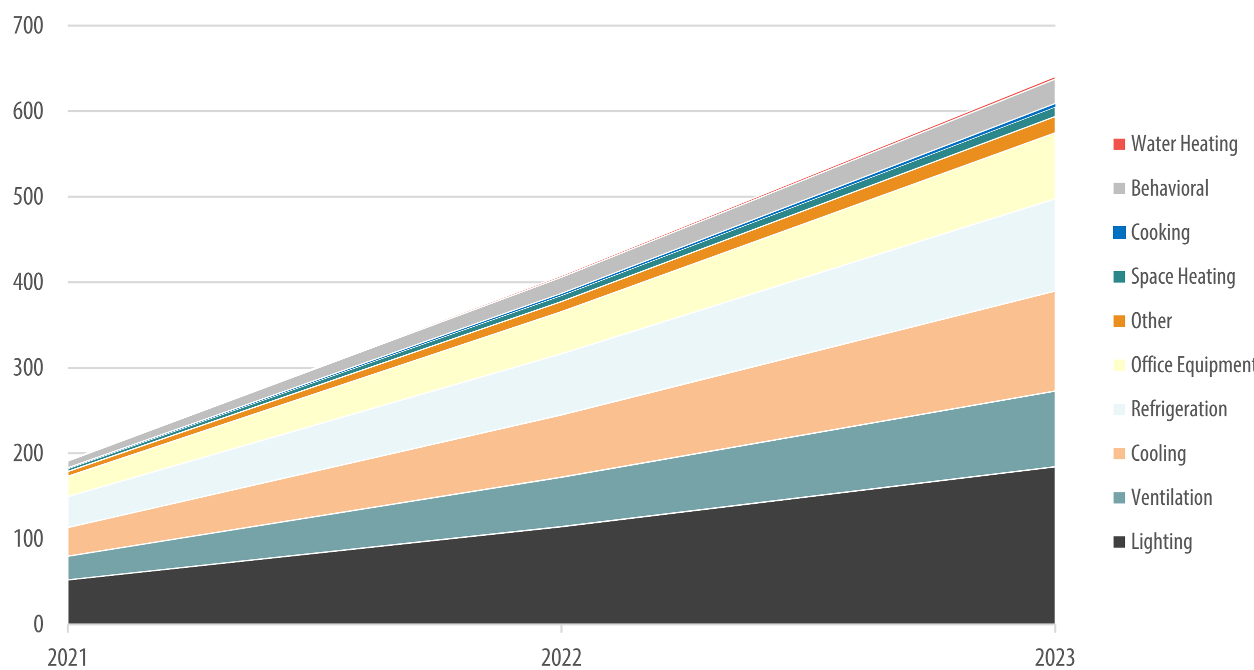


Table 6-5 provides the incremental and cumulative annual MAP across the 2021-2023 timeframe, as well as for 2030 and 2039. The incremental MAP ranges from 2.9% to 3.7% of forecasted sales across the initial three-year timeframe. Cumulative annual MAP rises to 32.7% by 2039.

TABLE 6-5 COMMERCIAL ELECTRIC MAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Space Heating	3,353	3,803	4,090	2,987	2,288
Cooling	33,453	39,299	44,232	39,320	35,727
Ventilation	27,730	30,029	30,780	5,743	36,793
Water Heating	818	1,037	1,244	1,587	1,258
Lighting	52,076	62,293	69,953	24,807	69,473
Cooking	1,043	1,298	1,550	2,387	2,415
Refrigeration	36,037	40,930	43,420	38,565	48,926
Office Equipment	23,819	25,685	27,851	38,233	39,339
Behavioral	7,843	14,811	20,103	76,212	81,477
Other	5,599	7,774	10,186	19,955	25,717
Total	191,773	226,960	253,410	249,796	343,413
% of Forecasted Sales	2.9%	3.4%	3.7%	3.6%	4.8%
Incremental Annual MW					
Total	28.8	34.5	39.8	31.2	43.0
% of Forecasted Demand	3.8%	4.5%	5.2%	3.9%	4.9%
Cumulative Annual MWh					
Space Heating	3,353	7,156	11,246	33,498	40,177
Cooling	33,453	72,752	116,985	409,286	491,096
Ventilation	27,730	57,760	88,540	205,732	254,366
Water Heating	818	1,856	3,100	11,943	15,633
Lighting	52,076	114,369	184,322	493,419	576,132
Cooking	1,043	2,342	3,892	19,035	28,770
Refrigeration	36,037	71,355	107,638	297,886	386,331
Office Equipment	23,819	49,504	77,355	233,030	310,834
Behavioral	7,843	18,915	28,559	111,574	123,588
Other	5,599	11,723	19,104	69,270	90,728
Total	191,773	407,732	640,739	1,884,672	2,317,654
% of Forecasted Sales	2.9%	6.1%	9.5%	27.3%	32.7%
Cumulative Annual MW					
Total	28.8	62.5	100.7	319.4	375.3
% of Forecasted Demand	3.8%	8.2%	13.1%	39.6%	43.2%

Realistic Achievable Potential

Figure 6-4 illustrates the cumulative annual RAP results by end use across the 2020-2023 timeframe. Like MAP, Lighting, Ventilation, and Cooling are the leading end uses. Refrigeration and Office Equipment also have significant RAP.

FIGURE 6-4 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL GWH) RAP POTENTIAL BY END-USE

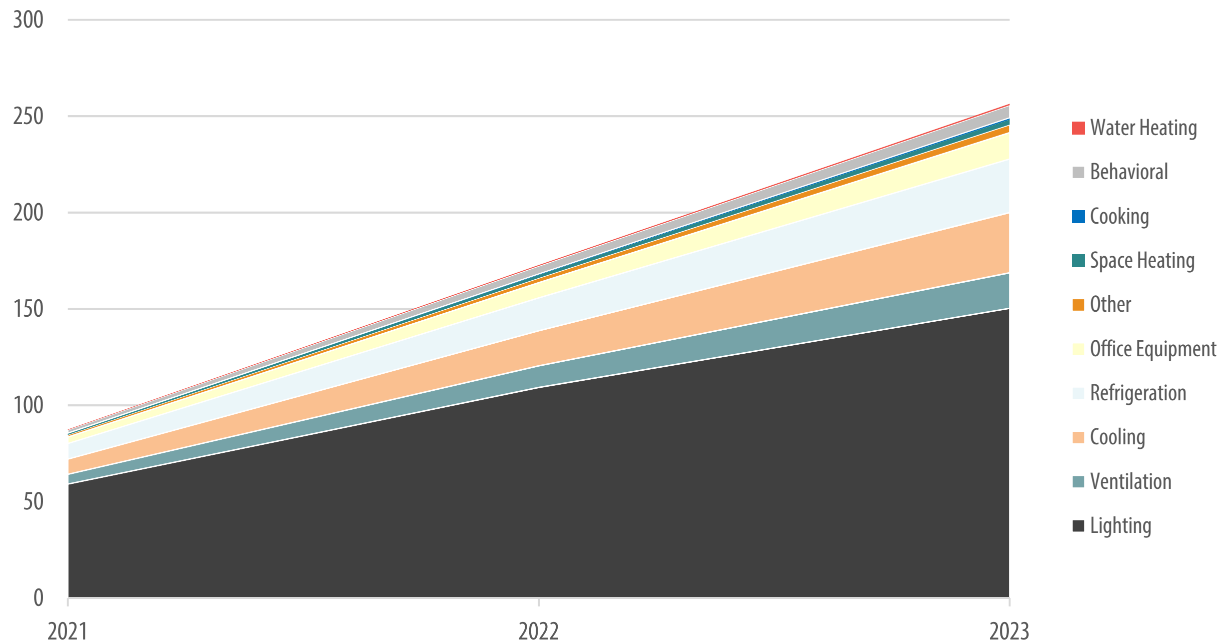


Table 6-6 provides the incremental and cumulative annual RAP across the 2021-2023 timeframe, as well as for 2030 and 2039. The incremental RAP is consistent at 1.3% of forecasted sales across the initial three-year timeframe. Cumulative annual RAP rises to 17.7% by 2039.

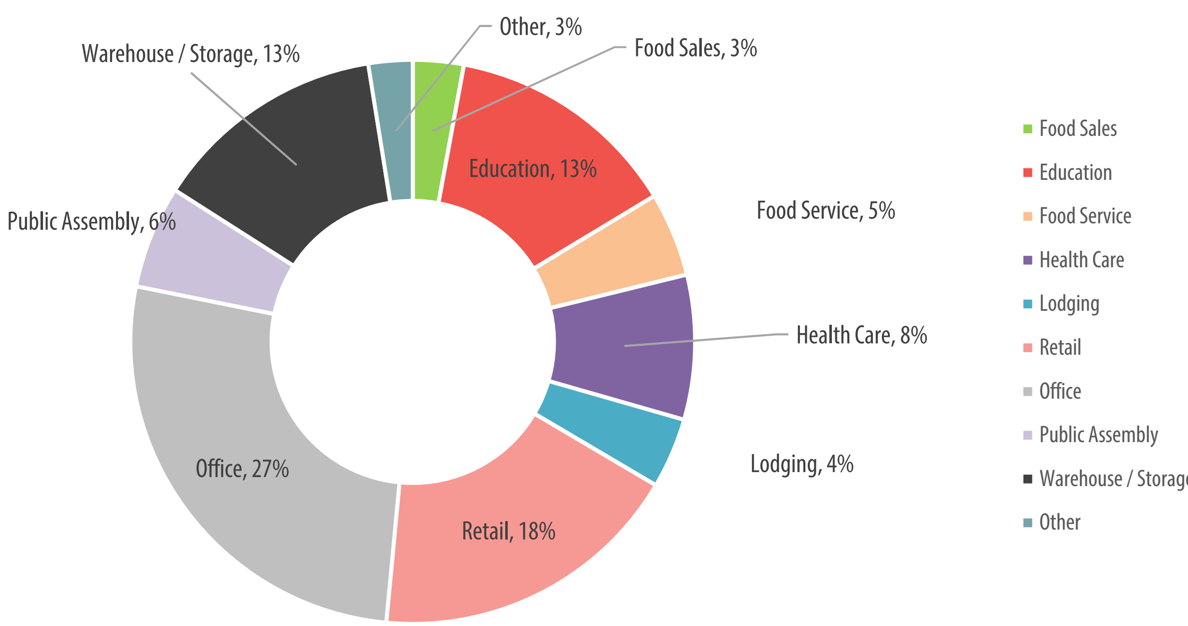
TABLE 6-6 COMMERCIAL ELECTRIC RAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Space Heating	683	868	1,062	1,816	1,212
Cooling	7,859	10,342	13,051	27,415	22,656
Ventilation	5,055	6,192	7,159	8,232	7,878
Water Heating	209	272	344	822	924
Lighting	59,173	50,101	41,063	14,771	29,873
Cooking	239	318	407	1,112	1,381
Refrigeration	8,105	10,291	12,700	24,308	28,666
Office Equipment	3,371	4,526	5,815	14,418	15,777
Behavioral	1,629	3,233	4,648	27,225	43,475
Other	1,111	1,649	2,288	8,646	11,877
Total	87,433	87,790	88,538	128,764	163,720
% of Forecasted Sales	1.3%	1.3%	1.3%	1.9%	2.3%
Incremental Annual MW					
Total	16.4	16.2	16.2	18.8	24.3
% of Forecasted Demand	2.2%	2.1%	2.1%	2.3%	2.8%
Cumulative Annual MWh					
Space Heating	683	1,550	2,612	13,635	22,370
Cooling	7,859	18,201	31,253	178,959	293,650
Ventilation	5,055	11,246	18,405	81,482	116,321
Water Heating	209	481	825	4,938	8,748

End Use	2021	2022	2023	2030	2039
Lighting	59,173	109,273	150,336	264,291	335,180
Cooking	239	557	965	6,717	14,953
Refrigeration	8,105	17,006	27,775	133,355	207,863
Office Equipment	3,371	7,897	13,712	75,871	149,742
Behavioral	1,629	4,092	6,496	39,168	64,956
Other	1,111	2,424	4,107	26,092	46,079
Total	87,433	172,729	256,487	824,507	1,259,861
% of Forecasted Sales	1.3%	2.6%	3.8%	11.9%	17.7%
Cumulative Annual MW					
Total	16.4	32.5	48.3	155.7	225.6
% of Forecasted Demand	2.2%	4.3%	6.3%	19.3%	26.0%

Figure 6-5 illustrates a market segmentation of the RAP in the commercial sector by 2023. Retail, Office, and Education are the leading building types.

FIGURE 6-5 2023 COMMERCIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT



RAP Benefits & Costs

Table 6-7 provides the NPV benefits and cost, as calculated using the UCT, across the 2021-2039 timeframe for the RAP scenario. Cooling and Cooking are the most cost-effective end-uses. Cooling, lighting, and refrigeration provides the most significant NPV benefits.

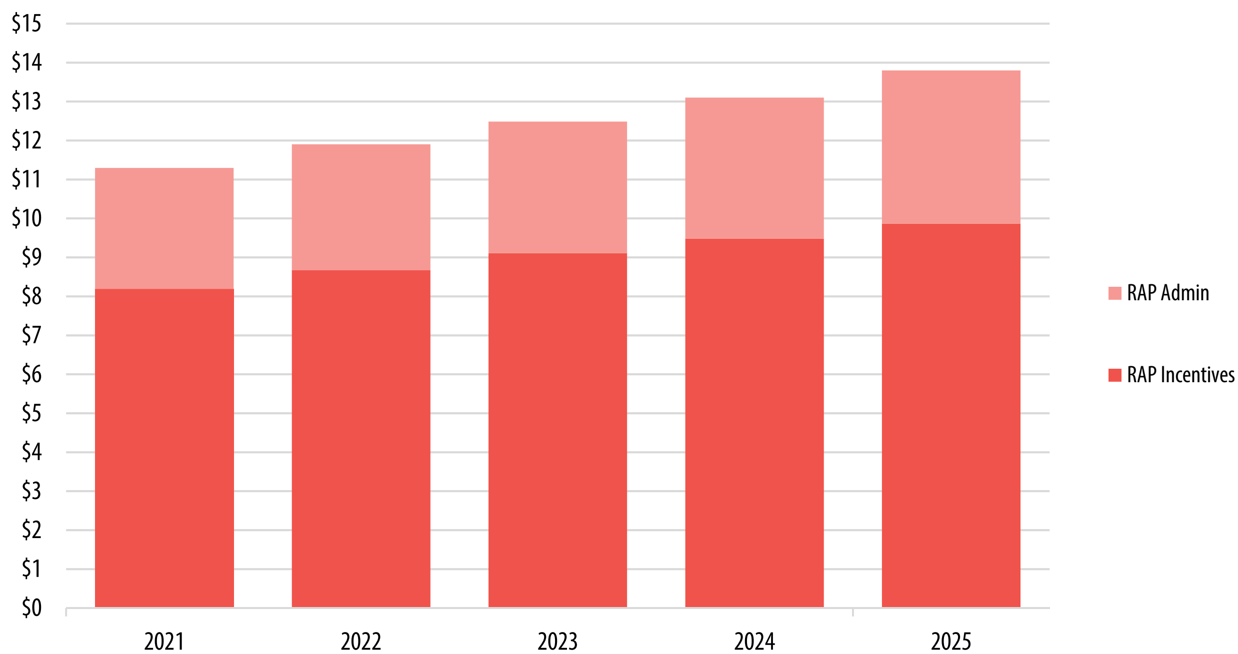
TABLE 6-7 COMMERCIAL NPV BENEFITS & COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Space Heating	$7.88	$2.85	2.76
Cooling	$636.45	$44.60	14.27
Ventilation	$37.62	$21.05	1.79
Water Heating	$2.83	$0.42	6.72
Lighting	$181.94	$39.89	4.56
Cooking	$9.54	$1.19	8.04

End Use	NPV Benefits	NPV Costs	UCT Ratio
Refrigeration	$114.59	$20.53	5.58
Office Equipment	$45.41	$11.47	3.96
Behavioral	$27.33	$17.41	1.57
Other	$25.33	$6.12	4.14
Total	**$1,088.92**	**$165.53**	**6.58**

Figure 6-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The incentives rise from $8.2 million to $9.1 million, and overall budgets rise from $11.3 million to $12.8 million by 2023.

FIGURE 6-6 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS)



6.3 COMMERCIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 6-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 6.2. The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column. Table 6-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers. The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column.

The 19-year RAP is 1,259,861 MWh excluding opt-out customers. This figure rises to 1,368,560 MWh with opt-out customers included.

TABLE 6-8 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	297,674	336,201	364,988	325,343	444,368	3,034,939
Economic	262,141	293,165	314,792	283,520	387,432	2,634,454
MAP	191,773	226,960	253,410	249,796	343,413	2,317,654

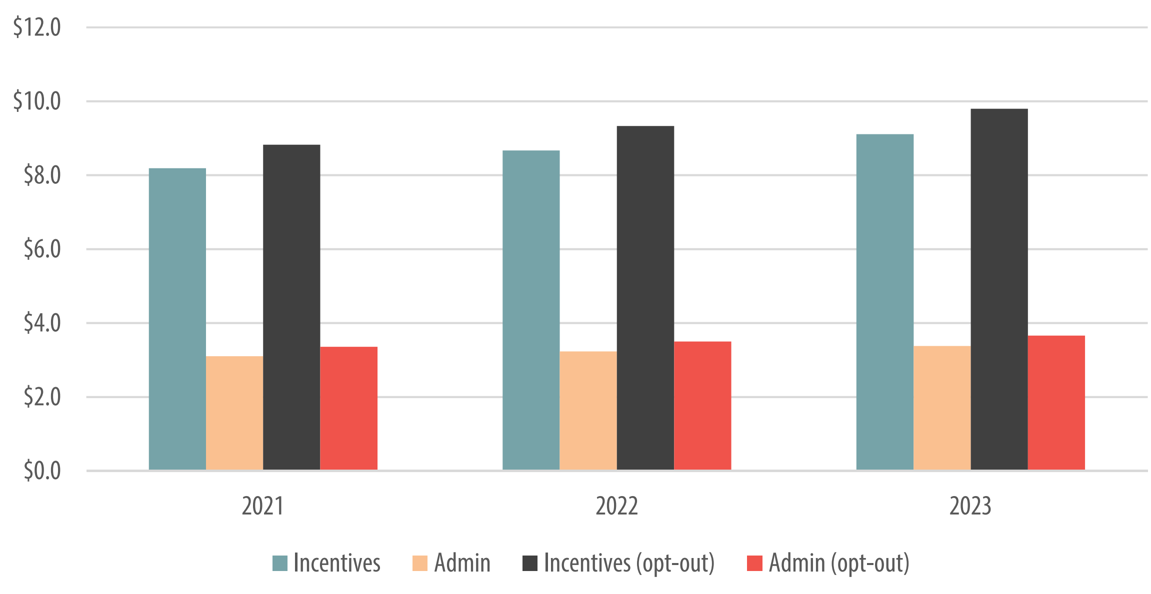
	2021	2022	2023	2030	2039	2039 (cumulative)
RAP	87,433	87,790	88,538	128,764	163,720	1,259,861
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737	7,107,737
Energy Savings (as % of Forecast)						
Technical	4.5%	5.0%	5.4%	4.7%	6.3%	42.7%
Economic	3.9%	4.4%	4.6%	4.1%	5.5%	37.1%
MAP	2.9%	3.4%	3.7%	3.6%	4.8%	32.6%
RAP	1.3%	1.3%	1.3%	1.9%	2.3%	17.7%

TABLE 6-9 COMMERCIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS[33]

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	319,987	361,894	393,318	355,466	483,353	3,271,659
Economic	282,388	316,313	340,107	311,127	422,935	2,845,631
MAP	217,686	257,080	286,837	309,561	396,535	2,503,275
RAP	105,544	105,937	106,745	109,342	190,102	1,368,560
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737	7,107,737
Energy Savings (as % of Forecast)						
Technical	4.8%	5.4%	5.8%	5.1%	6.8%	46.0%
Economic	4.2%	4.7%	5.0%	4.5%	6.0%	40.0%
MAP	3.3%	3.8%	4.2%	4.5%	5.6%	35.2%
RAP	1.6%	1.6%	1.6%	1.6%	2.7%	19.3%

Figure 6-7 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The overall budgets without opt-out customers rise from $11.3 million to $12.5 million by 2023. The budgets with opt-out customers included increase from $12.2 million to $13.5 million by 2023.

FIGURE 6-7 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS) – WITH AND WITHOUT OPT-OUT CUSTOMERS



[33] Due to limited number of commercial opt-out customers and minor changes in building segmentation, savings as a percentage of sales is negligible out to three decimal places.

7 Industrial Energy Efficiency Potential

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector. Results are broken down by end use. The cost-effectiveness results and budgets for the RAP scenario are also provided. The results in this section exclude the savings and sales forecast associated with opt-out customers

7.1 SCOPE OF MEASURES & END USES ANALYZED

There were 130 total unique electric measures included in the analysis. Table 7-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE 7-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY END USE

End-Use	Number of Unique Measures
Computers & Office Equipment	6
Water Heating	6
Ventilation	7
Space Cooling	25
Space Heating	16
Lighting	16
Other	7
Machine Drive	21
Process Heating and Cooling	10
Agriculture	16

7.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure 7-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 3-year technical potential is 6.5% of forecasted sales, and the economic potential is 6.4% of forecasted sales. The 3-year MAP is 4.9% and the RAP is 1.9%.

FIGURE 7-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

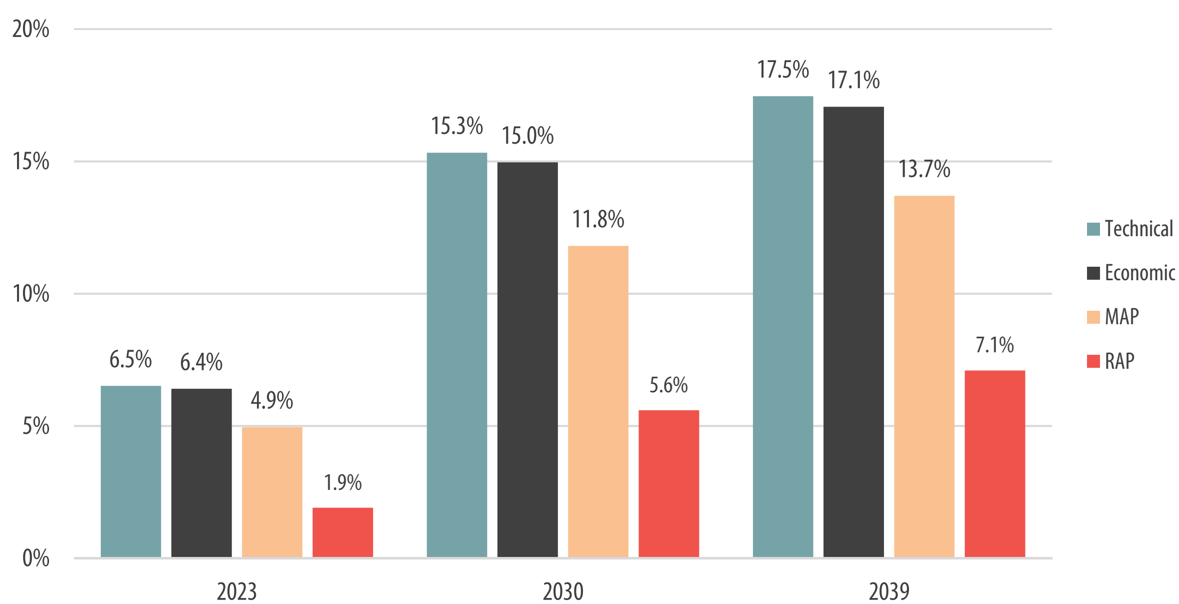


Table 7-2 provides cumulative annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The RAP reaches 1.9% after three years.

TABLE 7-2 INDUSTRIAL CUMULATIVE ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	36,120	75,747	116,387	279,651	327,626
Economic	35,568	74,549	114,461	272,943	320,107
MAP	27,112	57,268	88,461	215,300	257,046
RAP	11,073	22,402	34,051	102,090	133,159
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218
Energy Savings (as % of Forecast)					
Technical	2.1%	4.3%	6.5%	15.3%	17.5%
Economic	2.0%	4.2%	6.4%	15.0%	17.1%
MAP	1.5%	3.2%	4.9%	11.8%	13.7%
RAP	0.6%	1.3%	1.9%	5.6%	7.1%

Table 7-3 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 0.6% to 0.7% per year over the next three years.

TABLE 7-3 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2021	2022	2023	2030	2039
MWh					
Technical	36,120	41,420	44,609	31,108	56,280
Economic	35,568	40,774	43,880	30,622	55,999
MAP	27,112	31,400	33,941	23,031	43,434
RAP	11,073	12,149	13,001	15,566	21,577
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218
Energy Savings (as % of Forecast)					
Technical	2.1%	2.3%	2.5%	1.7%	3.0%
Economic	2.0%	2.3%	2.5%	1.7%	3.0%
MAP	1.5%	1.8%	1.9%	1.3%	2.3%
RAP	0.6%	0.7%	0.7%	0.9%	1.2%

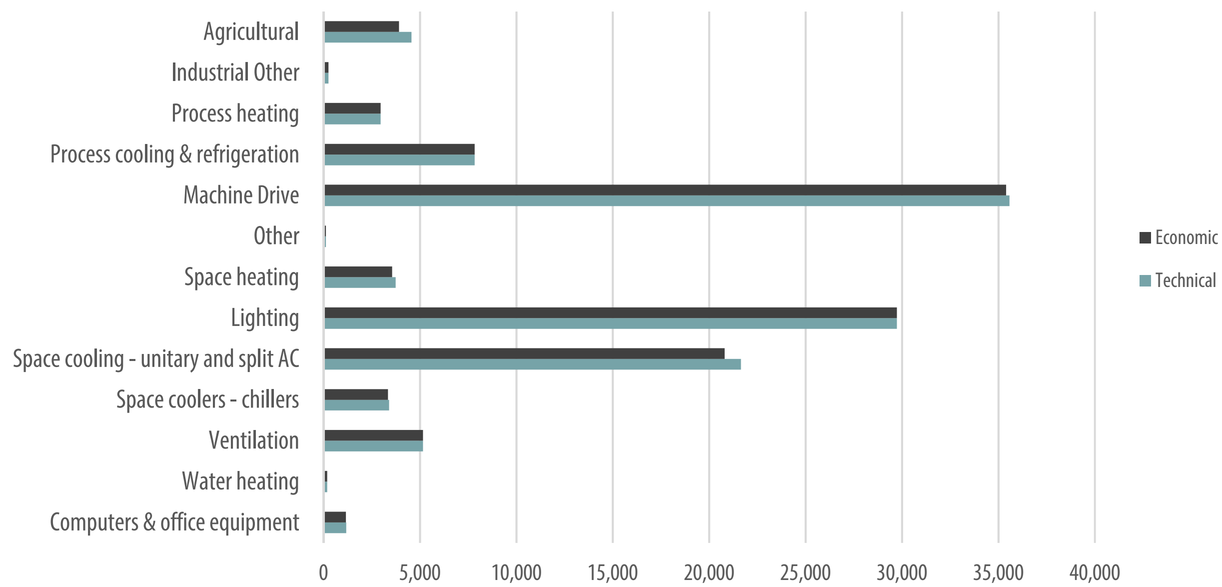
Technical & Economic Potential

Table 7-4 provides cumulative annual technical and economic potential results from 2021-2023, 2030, and 2039. Figure 7-2 shows a comparison of the technical and economic potential (6-year) by end use. Machine drive, Lighting, and Space Cooling are the leading stand-alone end uses among technical and economic potential.

TABLE 7-4 TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL

	2021	2022	2023	2030	2039
Energy (MWh)					
Technical	36,120	75,747	116,387	279,651	327,626
Economic	35,568	74,549	114,461	272,943	320,107
Peak Demand (MW)					
Technical	9	17	25	62	71
Economic	7	16	25	58	71

FIGURE 7-2 THREE-YEAR TECHNICAL AND ECONOMIC INDUSTRIAL ELECTRIC POTENTIAL – BY END-USE



Maximum Achievable Potential

Figure 7-3 illustrates the cumulative annual MAP results by end use across the 2021-2023 timeframe. Like technical and economic potential, Machine Drive, Lighting, and Space Cooling are the leading end uses. Ventilation and Agriculture also have significant MAP.

FIGURE 7-3 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) MAP POTENTIAL BY END-USE

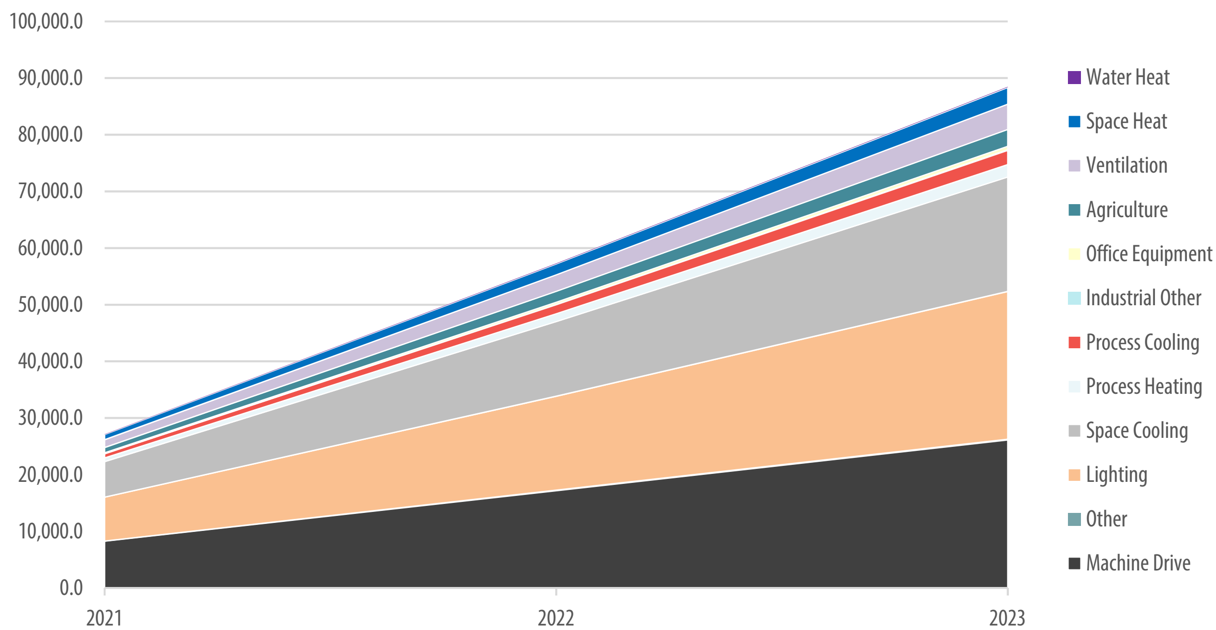


Table 7-5 provides the incremental and cumulative annual MAP across the 2021-2023 timeframe, as well as for 2030 and 2039. The incremental MAP ranges from 1.5% to 1.9% of forecasted sales across the three-year timeframe and 2.3% by 2039. Cumulative annual MAP rises to 4.95% by 2023 and 13.7% by 2039.

TABLE 7-5 INDUSTRIAL ELECTRIC MAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Computers & office equipment	166	205	239	335	351
Water heating	30	31	34	36	42
Ventilation	1,373	1,575	1,658	655	1,859
Space coolers - chillers	882	929	915	476	1,117
Space cooling - unitary and split AC	5,381	6,102	6,434	4,227	8,691
Lighting	7,747	8,993	9,775	5,452	10,733
Space heating	915	1,031	1,071	560	1,433
Other	30	37	44	40	53
Machine Drive	8,260	9,567	10,348	7,567	13,649
Process cooling & refrigeration	730	978	1,210	1,741	2,367
Process heating	639	880	1,112	1,519	2,135
Industrial Other	28	53	83	220	229
Agricultural	931	1,019	1,016	204	777
Total	27,112	31,400	33,941	23,031	43,434
% of Forecasted Sales	1.54%	1.77%	1.90%	1.26%	2.31%
Incremental Annual MW					
Total	6	7	7	5	10
% of Forecasted Demand	0.6%	0.7%	0.7%	0.5%	0.8%
Cumulative Annual MWh					

End Use	2021	2022	2023	2030	2039
Computers & office equipment	166	372	611	1,398	1,492
Water heating	30	61	95	362	464
Ventilation	1,373	2,906	4,469	9,874	11,038
Space coolers - chillers	882	1,798	2,683	5,652	7,344
Space cooling - unitary and split AC	5,381	11,362	17,525	43,824	58,430
Lighting	7,747	16,610	26,092	67,760	73,986
Space heating	915	1,925	2,948	6,684	9,165
Other	30	67	112	472	544
Machine Drive	8,260	17,185	26,133	59,275	68,772
Process cooling & refrigeration	730	1,587	2,525	7,614	11,360
Process heating	639	1,384	2,192	5,426	6,035
Industrial Other	28	64	109	487	916
Agricultural	931	1,950	2,966	6,471	7,499
Total	27,112	57,268	88,461	215,300	257,046
% of Forecasted Sales	1.54%	3.22%	4.95%	11.80%	13.70%
Cumulative Annual MW					
Total	6	12	19	46	57
% of Forecasted Demand	0.6%	1.2%	1.9%	4.3%	4.9%

Realistic Achievable Potential

Figure 7-4 illustrates the cumulative annual RAP results by end use across the 2021-2023 timeframe. Like MAP, Machine Drive, Lighting, and Space Cooling are the leading end uses. Ventilation and Agriculture also have significant RAP.

FIGURE 7-4 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL MWH) RAP POTENTIAL BY END-USE

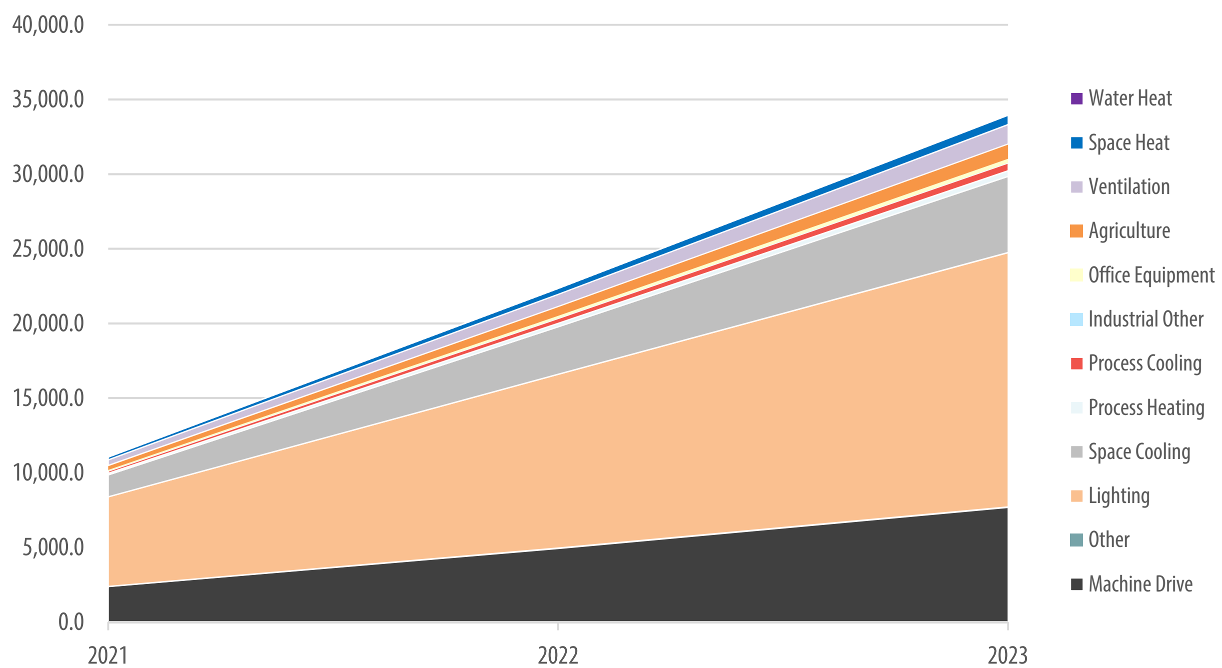


Table 7-6 provides the incremental and cumulative annual RAP across the 2021-2023 timeframe, as well as 2030 and 2039. The incremental RAP ranges from 0.6% to 0.7% of forecasted sales across the three-year timeframe and 1.2% by 2039. Cumulative annual RAP rises to 1.9% by 2023 and 7.1% by 2039.

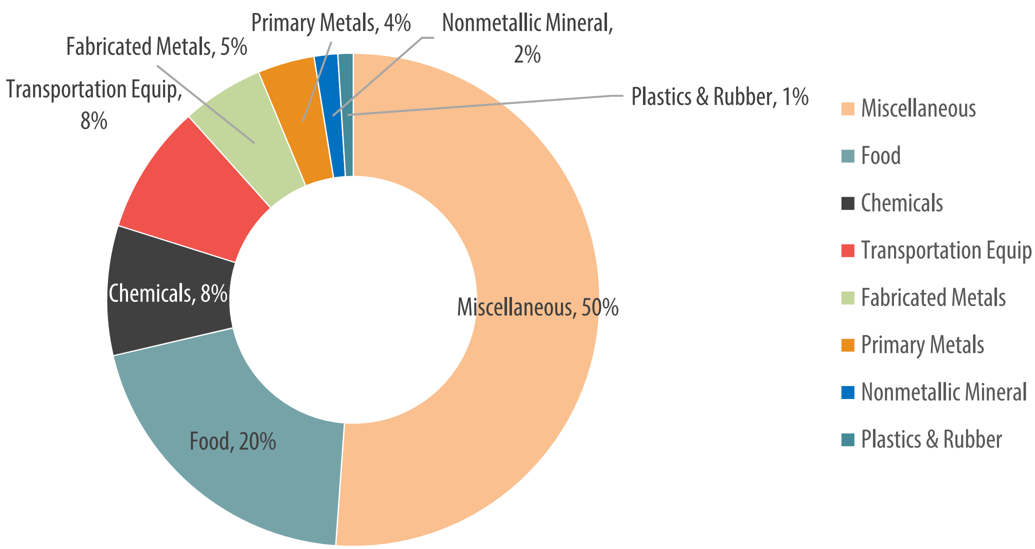
TABLE 7-6 INDUSTRIAL ELECTRIC RAP BY END-USE

End Use	2021	2022	2023	2030	2039
Incremental Annual MWh					
Computers & office equipment	73	89	105	191	200
Water heating	5	7	9	24	21
Ventilation	379	437	487	311	548
Space coolers - chillers	186	211	231	221	341
Space cooling - unitary and split AC	1,282	1,501	1,699	1,959	2,889
Lighting	6,001	6,306	6,497	9,228	12,481
Space heating	205	237	265	241	397
Other	7	10	13	32	24
Machine Drive	2,375	2,711	2,992	2,760	3,812
Process cooling & refrigeration	149	174	195	204	318
Process heating	108	127	142	96	169
Industrial Other	3	5	7	25	33
Agricultural	299	334	358	273	343
Total	11,073	12,149	13,001	15,566	21,577
% of Forecasted Sales	0.6%	0.7%	0.7%	0.9%	1.2%
Incremental Annual MW					
Total	2	2	2	2	3
% of Forecasted Demand	0.2%	0.2%	0.2%	0.2%	0.3%
Cumulative Annual MWh					
Computers & office equipment	73	161	266	738	845
Water heating	5	13	22	149	261
Ventilation	379	816	1,303	4,436	5,576
Space coolers - chillers	186	397	628	2,053	2,836
Space cooling - unitary and split AC	1,282	2,783	4,482	17,412	25,388
Lighting	6,001	11,642	17,033	42,602	50,791
Space heating	205	442	707	2,491	3,447
Other	7	17	30	195	326
Machine Drive	2,375	4,931	7,677	25,282	34,019
Process cooling & refrigeration	149	323	518	2,056	3,481
Process heating	108	235	377	1,334	1,718
Industrial Other	3	8	15	134	414
Agricultural	299	634	992	3,207	4,058
Total	11,073	22,402	34,051	102,090	133,159
% of Forecasted Sales	0.6%	1.3%	1.9%	5.6%	7.1%
Cumulative Annual MW					

End Use	2021	2022	2023	2030	2039
Total	2	3	4	13	19
% of Forecasted Demand	0.2%	0.3%	0.4%	1.2%	1.6%

Figure 7-5 illustrates a market segmentation of the RAP in the industrial sector by 2023. Food, chemicals, fabricated metals, nonmetallic minerals, and miscellaneous industrial are the leading market segments.

FIGURE 7-5 2025 INDUSTRIAL ELECTRIC ENERGY (CUMULATIVE ANNUAL) RAP POTENTIAL BY MARKET SEGMENT[34]



RAP Benefits & Costs

Table 7-7 provides the NPV benefits and cost, as calculated using the UCT, across the 2021-2039 timeframe for the RAP scenario. Machine Drive is the most cost-effective end-use, and Facility HVAC provides the greatest NPV benefits.

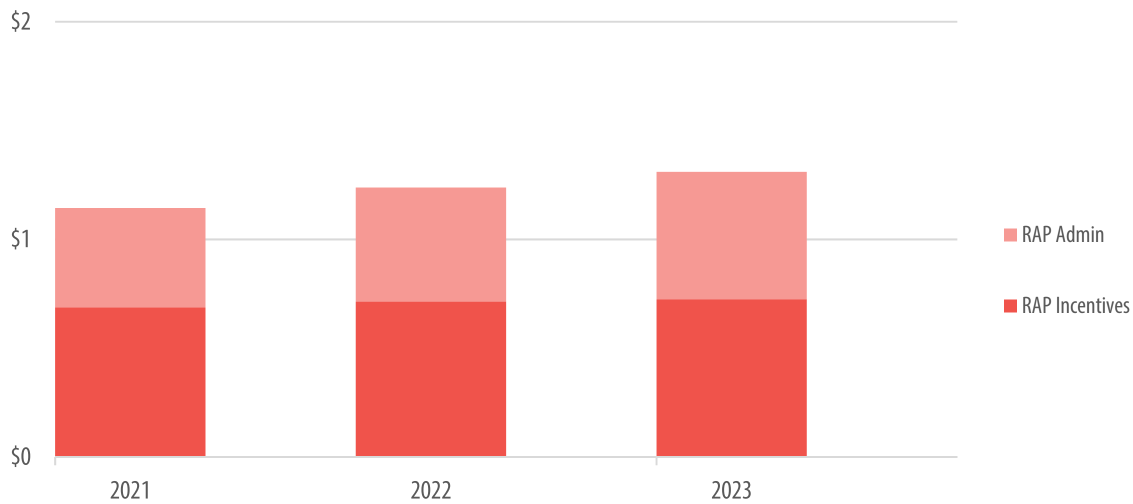
TABLE 7-7 INDUSTRIAL NPV BENEFITS AND COSTS RAP BY END-USE ($ IN MILLIONS)

End Use	NPV Benefits	NPV Costs	UCT Ratio
Machine Drive	$24.64	$2.23	11.1
Facility HVAC	$31.46	$4.77	6.6
Facility Lighting	$29.35	$8.10	3.6
Other Facility Support	$0.85	$0.11	7.7
Process Cooling and Refrigeration	$1.97	$0.19	10.4
Process Heating	$1.05	$0.12	8.6
Other	$0.40	$0.07	5.5
Total	$89.71	$15.59	5.8

Figure 7-6 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The incentives rise from $0.68 million to $0.72 million, and overall budgets rise from $1.2 million to $1.3 million by 2023.

[34] "Wholesale/Retail" and "Services" industrial types include industrial buildings that devote a minority percentage of floor space to commercial activities like wholesale and retail trade, and construction, healthcare, education and accommodation & food service. Automotive related industries are divided between plastics, rubber, and machinery based on their NAICS codes.

FIGURE 7-6 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS)



7.3 INDUSTRIAL POTENTIAL INCLUDING OPT-OUT CUSTOMERS

Table 7-8 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, excluding opt-out customers. This is the same information provided in Section 7.2. The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column. Table 7-9 provides the incremental annual technical, economic, MAP and RAP energy savings, in total MWh and as a percentage of the sector-level sales forecast, including opt-out customers.[35] The cumulative annual energy savings across the 19-year study timeframe are also shown in the far-right column.

The 19-year RAP is 7.1%, excluding opt-out customers. This figure increases to 11.8%, with opt-out customers included. The energy savings of the RAP rises from 133,159 MWh to 222,156 MWh when the opt-out customers are included in the analysis.

TABLE 7-8 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – EXCLUDING OPT-OUT CUSTOMERS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	36,120	41,420	44,609	31,108	56,280	327,626
Economic	35,568	40,774	43,880	30,622	55,999	320,107
MAP	27,112	31,400	33,941	23,031	43,434	257,046
RAP	11,073	12,149	13,001	15,566	21,577	133,159
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218	1,876,218
Energy Savings (as % of Forecast)						
Technical	2.1%	2.3%	2.5%	1.7%	3.0%	17.5%
Economic	2.0%	2.3%	2.5%	1.7%	3.0%	17.1%
MAP	1.5%	1.8%	1.9%	1.3%	2.3%	13.7%
RAP	0.6%	0.7%	0.7%	0.9%	1.2%	7.1%

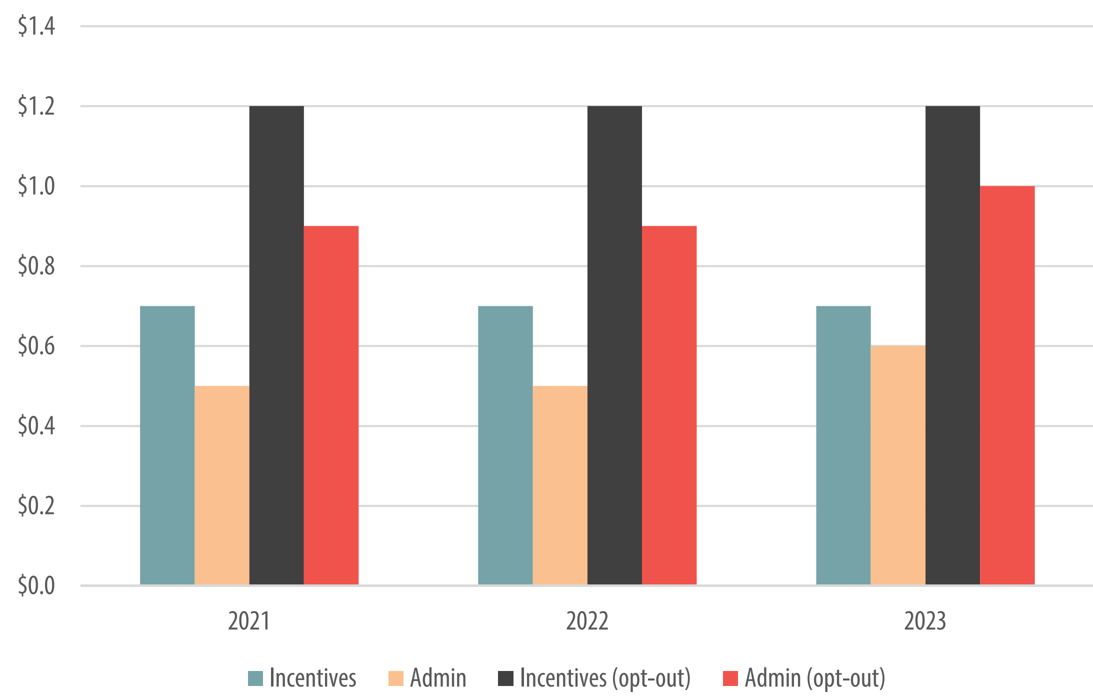
[35] Note the increase in the forecasted sales with opt-out customers included.

TABLE 7-9 INDUSTRIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY – INCLUDING OPT-OUT CUSTOMERS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	64,747	74,252	79,969	55,786	100,910	587,157
Economic	63,759	73,093	78,664	54,916	100,404	573,695
MAP	48,586	56,273	60,829	41,292	77,855	460,561
RAP	19,181	21,114	22,647	25,391	38,043	222,156
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218	1,876,218
Energy Savings (as % of Forecast)						
Technical	3.7%	4.2%	4.5%	3.1%	5.4%	31.3%
Economic	3.6%	4.1%	4.4%	3.0%	5.4%	30.6%
MAP	2.8%	3.2%	3.4%	2.3%	4.1%	24.5%
RAP	1.1%	1.2%	1.3%	1.4%	2.0%	11.8%

Figure 7-7 provides the budget for the RAP scenario, with and without opt-out customers. The budget is broken into incentive and admin budgets for each year of the 2021-2023 timeframe. The overall budgets without opt-out customers rise from $1.2 million to $1.3 million by 2023. The budgets with opt-out customers included increase from $2.1 million to $2.2 million by 2023.

FIGURE 7-7 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS) – WITH & WITHOUT OPT-OUT CUSTOMERS



8 Demand Response Potential

This section provides the results of the MAP and RAP potential for the demand response analysis. Results are broken down by sector and program. The cost-effectiveness results and budgets for the MAP and RAP scenarios are also provided. Section 3.5 provides a description of the demand response methodology. Additional demand response results details are provided in Appendix G.

8.1 TOTAL DEMAND RESPONSE POTENTIAL

Table 8-1 and Table 8-2 show the achievable cumulative annual potential savings for the Years 1-3, 10 and 19. Achievable potential includes a participation rate to estimate the realistic number of customers that are expected to participate in each cost-effective demand response program option. These values are at the customer meter. The MAP assumes the maximum participation that would happen in the real-world, while the realistically achievable potential (RAP) discounts MAP by considering barriers to program implementation that could limit the amount of savings achieved. Asterisked programs were those that were found to be not cost-effective, providing 0 achievable potential.

TABLE 8-1 MAP SAVINGS BY PROGRAM

	Program	2021 (MW)	2022 (MW)	2023 (MW)	2030 (MW)	2039 (MW)
Residential	DLC AC - Switch	39	37	36	23	0
	DLC AC - Thermostat	15	22	29	79	151
	DLC Space Heating	4	13	27	42	45
	DLC Water Heating	9	30	64	101	108
	DLC Electric Vehicles*	0	0	0	0	0
	Total	67	102	155	245	304
Non-Residential	DLC AC - Switch*	0	0	0	0	0
	DLC AC - Thermostat	0	1	1	5	9
	DLC Space Heating	0	1	3	5	5
	DLC Water Heating	1	3	6	9	9
	Ice Storage Cooling Rate*	0	0	0	0	0
	DLC Lighting*	0	0	0	0	0
	Curtailable (Day Of)	22	54	63	68	70
	Curtailable (Day Ahead)	41	100	117	127	129
	Total (Curtailable Day Of)	24	59	73	86	92
	Total (Curtailable Day Ahead)	43	105	127	145	152
Residential & Commercial Total (Curtailable Day Of)		91	161	228	331	397
Residential & Commercial Total (Curtailable Day Ahead)		111	207	282	390	456

TABLE 8-2 RAP SAVINGS BY PROGRAM

	Program	2021 (MW)	2022 (MW)	2023 (MW)	2030 (MW)	2039 (MW)
Residential	DLC AC - Switch	39	37	36	23	0
	DLC AC - Thermostat	13	18	22	56	105
	DLC Space Heating	3	9	20	32	34
	DLC Water Heating	6	19	41	65	69
	DLC Electric Vehicles*	0	0	0	0	0
	Total	61	84	119	176	208
Non-Residential	DLC AC - Switch*	0	0	0	0	0
	DLC AC - Thermostat	0	0	1	2	4
	DLC Space Heating	0	0	1	1	1
	DLC Water Heating	0	1	3	4	4
	Ice Storage Cooling Rate*	0	0	0	0	0
	DLC Lighting*	0	0	0	0	0
	Curtailable (Day Of)	12	28	33	36	36
	Curtailable (Day Ahead)	21	52	61	66	68
	Total (Curtailable Day Of)	12	30	37	43	45
	Total (Curtailable Day Ahead)	22	54	65	73	76
Residential & Commercial Total (Curtailable Day Of)		73	114	155	218	253
Residential & Commercial Total (Curtailable Day Ahead)		83	138	184	249	284

Benefits & Costs

Table 8-3 and Table 8-4 show the MAP and RAP budget requirement (for only cost-effective programs) across the 2021-2039 timeframe that would be required to achieve the cumulative annual potential for each of the thermostat scenarios. The current and future hardware and software cost of a Demand Response Management System and the cost of non-equipment incentives are included in these budgets.

TABLE 8-3 SUMMARY OF MAP BUDGET REQUIREMENTS

	Curtailable Day Of	Curtailable Day Ahead
2021	$9,323,563	$10,637,361
2022	$17,924,342	$21,806,580
2023	$22,697,064	$28,100,280
2030	$20,810,931	$27,941,815
2039	$26,113,047	$34,781,953

TABLE 8-4 SUMMARY OF RAP BUDGET REQUIREMENTS

	Curtailable Day Of	Curtailable Day Ahead
2021	$6,148,493	$6,513,787
2022	$10,313,497	$11,400,882
2023	$14,876,821	$16,397,937
2030	$11,069,432	$13,080,488
2039	$13,753,683	$16,198,493

Table 8-5 and Table 8-6 show the MAP and RAP residential NPVs of the total benefits, costs, and savings, along with the UCT ratio for each program for the length of the study. The study period is 2021 to 2039. Two scenarios were looked at for the curtailable rate program: day of notifications and day ahead notifications. Asterisked programs were those that were found to be not cost-effective, providing 0 achievable potential.

TABLE 8-5 MAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

	Program	NPV Benefits	NPV Costs	UCT Ratio
Residential	DLC AC - Switch	$38,751,981	$11,101,437	3.49
	DLC AC - Thermostat	$118,021,492	$49,502,428	2.38
	DLC Space Heating	$59,753,588	$12,623,599	4.73
	DLC Water Heating	$143,661,898	$85,044,280	1.69
	DLC Electric Vehicles*	$4,503,262	$20,442,597	0.22
Non-Residential	DLC AC - Switch*	$65,605	$508,128	0.13
	DLC AC - Thermostat	$6,658,610	$3,890,618	1.71
	DLC Space Heating	$6,422,980	$1,980,113	3.24
	DLC Water Heating	$12,486,975	$6,641,713	1.88
	Ice Storage Cooling Rate*	$3,315,135	$23,508,572	0.14
	DLC Lighting*	$1,058,230	$4,907,195	0.22
	Curtailable (Day Of)	$136,746,749	$136,417,949	1.00
	Curtailable (Day Ahead)	$136,746,749	$136,417,949	1.00

TABLE 8-6 RAP NPV BENEFITS, COSTS, AND UCT RATIOS FOR EACH DEMAND RESPONSE PROGRAM

	Program	NPV Benefits	NPV Costs	UCT Ratio
Residential	DLC AC - Switch	$38,751,751	$11,095,762	3.49
	DLC AC - Thermostat	$84,460,054	$35,120,192	2.40
	DLC Space Heating	$44,761,294	$9,434,070	4.74
	DLC Water Heating	$91,709,001	$54,500,796	1.68
	DLC Electric Vehicles*	$2,730,501	$13,508,218	0.20
Non-Residential	DLC AC - Switch*	$65,605	$508,116	0.13
	DLC AC - Thermostat	$2,803,417	$1,999,243	1.40
	DLC Space Heating	$1,374,696	$1,136,329	1.21
	DLC Water Heating	$5,458,587	$3,404,591	1.60
	Ice Storage Cooling Rate*	$654,273	$5,632,429	0.12
	DLC Lighting*	$227,344	$1,851,493	0.12
	Curtailable (Day Of)	$38,575,756	$20,719,844	1.86
	Curtailable (Day Ahead)	$71,567,702	$38,444,116	1.86

VOLUME II

Appendices

prepared for

AUGUST 2019

APPENDIX A. DSM Market Potential Study Sources

This appendix catalogs many of the data sources used in this study, grouped by major activity. In general, GDS attempted to utilize IPL-specific data, where available. When IPL-specific data was not available or reliable, GDS leveraged secondary data from nearby or regional sources.

A.1 MARKET RESEARCH

Market research studies were used to understand home and business characteristics and equipment stock characteristics. The GDS Team conducted primary data collection activities in the residential, commercial, and industrial sectors to gather information on residential dwellings and nonresidential facilities. In addition, the primary data collection collected additional equipment and efficiency characteristics. The MPS also relied on available secondary research to supplement the primary data collection activities.

- *IPL Residential Self-Report Survey:* GDS collected data on 231 residential dwellings from a mail/web survey. A total of 30 questions were included in the survey, seeking to collect information about ownership of electric appliances; the type, fuel, and age of heating, ventilation, and air conditioning (HVAC) and water heating equipment in the home; the types of energy improvements that may have been made to the home, and demographic information.
- *IPL Residential On-Site Survey:* GDS collected data on 68 residential dwellings via an on-site survey from trained field staff. The purpose of the site-visits was to collect more detailed end-use and housing characteristics that are difficult to collect in a self-report survey. On-site data collection focused on accurate inventory counts of residential lighting and make/model information of key electric equipment and appliances.
- *IPL Residential Willingness to Participate Survey:* GDS collected willingness to participate data on 4 major residential end-uses given varying incentive levels. GDS collected responses from 875 residential consumers via an on-line/e-mail survey.
- *IPL Commercial Primary Market Research:* A detailed end use survey was then completed by technicians to collect detailed research data and WTP information from site representatives. GDS collected data in 68 commercial facilities to better understand electric equipment saturation and efficiency characteristics.
- *IPL Industrial Primary Market Research*: A total of 40 site visits were conducted for the industrial sector, in which WTP and detailed end-use information was collected. Survey data was leveraged to determine the remaining factors for several end-uses, including motors, interior and exterior lighting and fixture measures.
- *EIA/DOE Industrial Data:* Including the DOE Industrial Electric Motor Systems Market Opportunities Report, the DOE Assessment of the Market for Compressed Air Efficiency Services, and EIA Industrial Demand Module of the National Energy Modeling System.
- *US American Community Survey:* Public Use Microdata Survey data was used to estimate the percent of low-income households (using annual household income and number of people per household) in the IPL service territory.
- *Energy Star Shipment Data:* Energy Star shipment data provides a detailed historical estimate of the percent of shipped equipment/appliances that meet ENERGY STAR standards. Over the long-term, this serves as a proxy for the percent of the market that could be considered energy efficient.

A.2 FORECAST CALIBRATION

The forecast calibration effort was used to create a detailed segmentation of IPL's load forecast and ensure that estimated savings would not overstate future potential. IPL supplied GDS with the most recent load forecast and data collected via primary research activities was used to further refine the existing load forecast.

- *IPL Load Forecast:* The 2016 Long-Term Electric Energy and Demand load forecast consists of the most recent ITRON load forecast completed for IPL for 2016-2036. Future years were escalated by a compound average annual growth rate.
- *IPL Commercial and Industrial Customer Database:* The 2017 historical commercial and industrial data utilized rate codes and existing NAICS code to segment historical sales by commercial building type and/or industry type.
- *InfoUSA*: GDS utilized a third-party dataset that provided additional commercial and industrial business information, including NAICS codes, to supplement the building/industry types codes supplied by IPL.
- *EIA Commercial Building Energy Consumption Survey:* GDS updated the ITRON load forecast to utilize more recent information for the East North-Central region from the EIA 2012 CBECS survey.
- *EIA Manufacturing Energy Consumption Survey:* GDS used the 2014 study to further refine the industrial load forecast by end-use.
- *BEopt:* GDS developed residential building prototypes from the market research effort to develop detailed consumption estimates by end-use and calibrated these models to IPL's residential load forecasts.

A.3 ENERGY EFFICIENCY MEASURE DATA

The energy efficiency measure analysis developed per unit savings, cost, and useful life assumptions for each energy efficiency measure in the residential, commercial, and industrial sectors. Preference was given to IPL-specific evaluated savings and/or deemed savings/algorithms in the Indiana TRM.

- *2016 & 2017 IPL EM&V Report (Cadmus):* For the development of savings estimates of measures already offered by IPL, GDS either used the estimates from the most recent evaluation reports or used the evaluation methodology to develop forward looking savings projections.
- *Indiana TRM v2.2:* In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- *IPL 2018 & 2019 DSM Portfolio Summary:* Historical incentive estimates and in some cases, incremental measure costs, were based on the IPL DSM Portfolio Summary.
- *Other TRMs:* In some cases, TRM's or deemed measure databases from other states were more applicable than the IN TRM due to more currently available estimates and the more appropriate use of updated federal standards. The Illinois TRM and the Michigan Energy Measures Database were the primary non-Indiana TRMs used.
- *Other Secondary Sources:* In some cases, following the source hierarchy listed above was not enough to develop savings estimates. In these cases, GDS leveraged other secondary research documents such as ACEEE emerging technology reports.

A.4 DEMAND RESPONSE MEASURE ANALYSIS

The DR analysis developed per unit savings, cost, and useful life assumptions for select demand response programs.

- *IPL programs / 2012 FERC DR Survey:* Demand reductions were based on load reductions found in IPL's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.
- *Indiana TRM v2.2:* In the absence of evaluation data, GDS attempted to leverage the Indiana TRM. Assumptions and algorithms were based off the IN TRM to the extent practical.
- *Comverge:* Comverge provided an estimate of the load control switch cost and useful life.
- *Nest and Ecobee:* Nest and Ecobee product data was used to develop equipment cost assumptions.
- *Other DR Potential Studies:* In the absence of the previous data, GDS used other demand response potential studies completed for other utilities.

A.5 AVOIDED COST/ECONOMIC ANALYSIS

Avoided costs and related economic assumptions were used to assess cost-effectiveness. In addition, historical incentive levels were tied to willingness-to-participate (WTP) research to assess long-term market adoption in the achievable potential scenario.

- ***Electric Avoided Costs:*** Avoided cost values for electric energy, electric capacity, and avoided transmission and distribution (T&D) were provided by IPL as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.
- ***Other Economic Assumptions:*** Includes the discount rate, inflation rate, line loss assumptions and reserve margin requirement. All economic assumptions were provided by IPL and consistent with economic modeling assumptions used for other utility planning efforts.
- ***2019 DSM Portfolio Summary:*** 2021 direct measure/program non-incentive costs were calibrated to recent projected levels using the 2019 Portfolio Summary
- ***Primary Market Research:*** As noted above, the GDS Team completed IPL-specific research in the residential, commercial, and industrial sectors regarding customer willingness-to-purchase and install energy efficient equipment at various incentive levels. This IPL-specific customer data was used to determine long-term adoption rates by end-use for the MAP and RAP achievable potential scenarios.

APPENDIX B. Residential Market Potential Study Measure Detail

available in electronic format

APPENDIX C. Commercial Market Potential Study Measure Detail

available in electronic format

APPENDIX D. Industrial Market Potential Study Measure Detail

available in electronic format

APPENDIX E. DSM Market Potential Study Commercial Opt-Out Results

This section provides the potential results for technical, economic, MAP and RAP for the commercial sector, with opt-out customers included. The cost-effectiveness results and budgets for the RAP scenario are also provided.

E.1 SCOPE OF MEASURES & END USES ANALYZED

There were 237 total unique electric measures included in the analysis. Table E-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE E-1 COMMERCIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Space Heating	31
Cooling	75
Ventilation	11
Water Heating	17
Lighting	32
Cooking	8
Refrigeration	29
Office Equipment	14
Behavioral	4
Other	16

E.2 COMMERCIAL ELECTRIC POTENTIAL

Figure E-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 19-year technical potential is 46.0% of forecasted sales, and the economic potential is 40.0% of forecasted sales. The 19-year MAP is 35.2% and the RAP is 17.7%.

FIGURE E-1 COMMERCIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

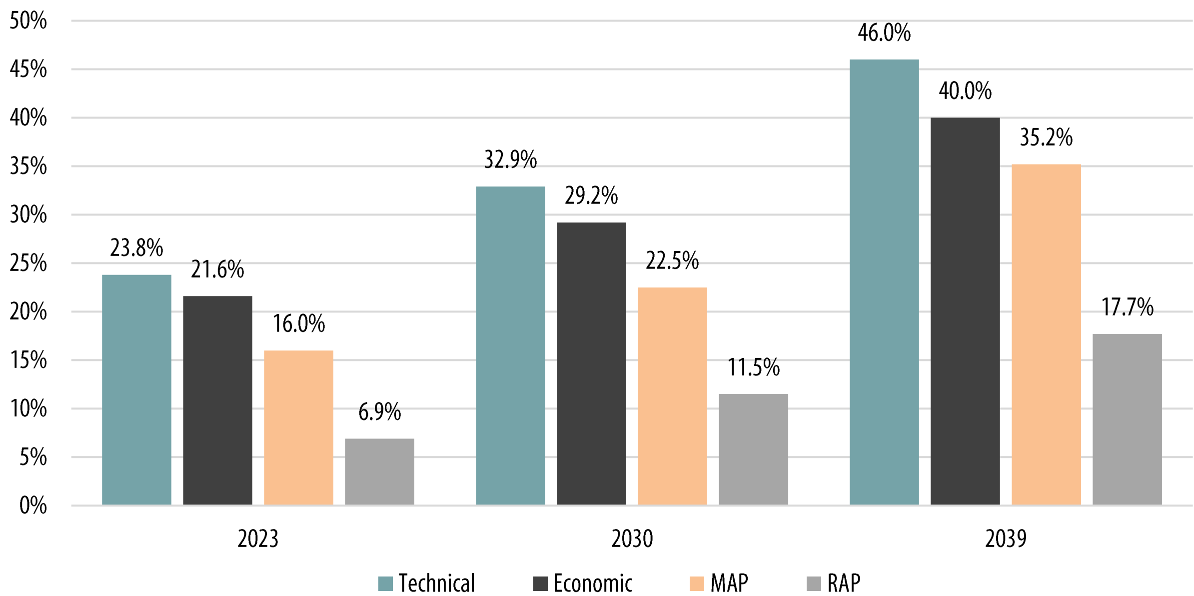


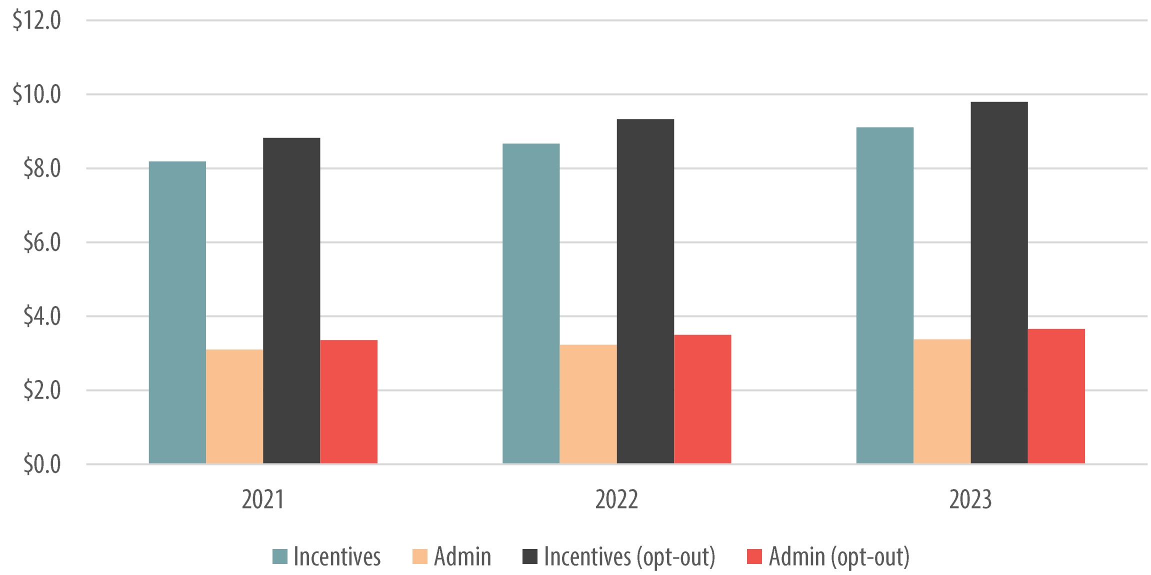
Table E-2 provides the incremental annual technical, economic, MAP and RAP energy savings, as well as 2039 cumulative total energy savings in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP is steady at 1.6% per year over the next three years, and 2.7% by 2039, with a cumulative total of 19.3% by 2039.

TABLE E-2 INCREMENTAL ANNUAL ENERGY SAVINGS & 2039 CUMULATIVE TOTAL ENERGY SAVINGS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	319,987	361,894	393,318	355,466	483,353	3,271,659
Economic	282,388	316,313	340,107	311,127	422,935	2,845,631
MAP	217,686	257,080	286,837	309,561	396,535	2,503,275
RAP	105,544	105,937	106,745	109,342	190,102	1,368,560
Forecasted Sales	6,660,103	6,737,966	6,769,949	6,911,159	7,107,737	7,107,737
Energy Savings (as % of Forecast)						
Technical	4.8%	5.4%	5.8%	5.1%	6.8%	46.0%
Economic	4.2%	4.7%	5.0%	4.5%	6.0%	40.0%
MAP	3.3%	3.8%	4.2%	4.5%	5.6%	35.2%
RAP	1.6%	1.6%	1.6%	1.6%	2.7%	19.3%

Figure F-2 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2023 timeframe. The incentives rise from $8.9 million to $9.7 million over the next three years, and overall budgets rise from $12.2 million to $13.3 million by 2023 for the Opt-outs included scenario.

FIGURE E-2 ANNUAL BUDGETS FOR COMMERCIAL RAP ($ IN MILLIONS) – WITH & WITHOUT OPT-OUT CUSTOMERS



APPENDIX F. DSM Market Potential Study Industrial Opt-Out Results

This section provides the potential results for technical, economic, MAP and RAP for the industrial sector, with opt-out customers included. The cost-effectiveness results and budgets for the RAP scenario are also provided.

F.1 SCOPE OF MEASURES & END USES ANALYZED

There were 130 total unique electric measures included in the analysis. Table F-1 provides number of measures by end-use (the full list of industrial measures is provided in Appendix D). The measure list was developed based on a review of current IPL programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. Data collection activities to characterize measures formed the basis of the assessment of incremental costs, electric energy and demand savings, and measure life.

TABLE F-1 INDUSTRIAL ENERGY EFFICIENCY MEASURES – BY FUEL TYPE

End-Use	Number of Unique Measures
Computers & Office Equipment	6
Water Heating	6
Ventilation	7
Space Cooling	25
Space Heating	16
Lighting	16
Other	7
Machine Drive	21
Process Heating and Cooling	10
Agriculture	16

F.2 INDUSTRIAL ELECTRIC POTENTIAL

Figure F-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 19-year timeframes. The 19-year technical potential is 31.3% of forecasted sales, and the economic potential is 30.6% of forecasted sales. The 19-year MAP is 24.5% and the RAP is 11.8%.

FIGURE F-1 INDUSTRIAL ELECTRIC ENERGY CUMULATIVE ANNUAL POTENTIAL (AS A % OF INDUSTRIAL SALES)

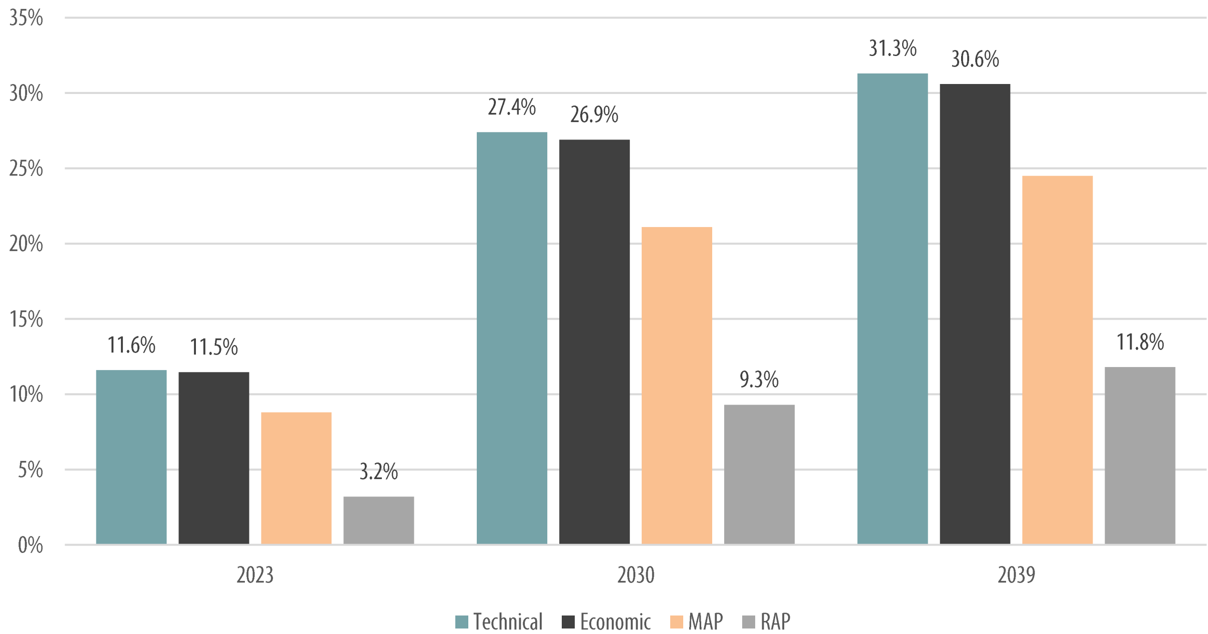


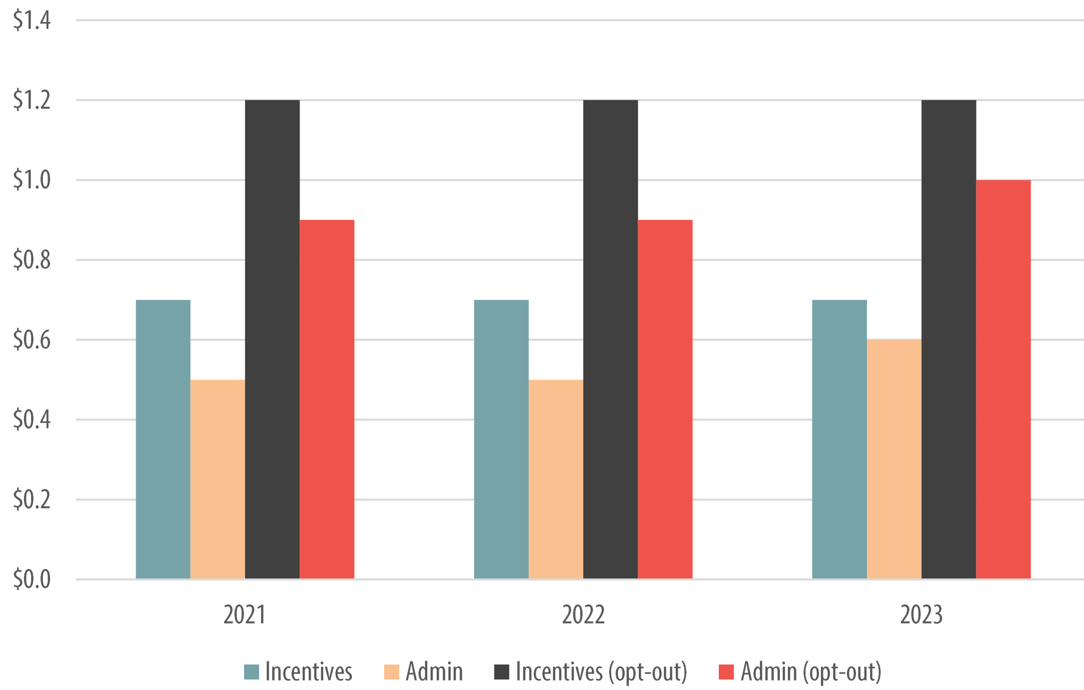
Table F-2 provides the incremental annual technical, economic, MAP and RAP energy savings, as well as 2039 cumulative total energy savings in total MWh and as a percentage of the sector-level sales forecast. The incremental RAP ranges from 1.1% to 1.4% per year over the next three years, and 2.0% by 2039, with a cumulative total of 11.8% by 2039.

TABLE F-2 INCREMENTAL ANNUAL ENERGY SAVINGS & 2039 CUMULATIVE TOTAL ENERGY SAVINGS

	2021	2022	2023	2030	2039	2039 (cumulative)
MWh						
Technical	64,747	74,252	79,969	55,786	100,910	587,157
Economic	63,759	73,093	78,664	54,916	100,404	573,695
MAP	48,586	56,273	60,829	41,292	77,855	460,561
RAP	19,181	21,114	22,647	25,391	38,043	222,156
Forecasted Sales	1,758,134	1,778,752	1,787,199	1,824,401	1,876,218	1,876,218
Energy Savings (as % of Forecast)						
Technical	3.7%	4.2%	4.5%	3.1%	5.4%	31.3%
Economic	3.6%	4.1%	4.4%	3.0%	5.4%	30.6%
MAP	2.8%	3.2%	3.4%	2.3%	4.1%	24.5%
RAP	1.1%	1.2%	1.3%	1.4%	2.0%	11.8%

Figure F-2 provides the budget for the RAP scenario. The budget is broken into incentive and admin budgets for each year of the 2020-2023 timeframe. The incentives are steady at $1.2 million, and overall budgets rise from $2.1 million to $2.2 million by 2023 for the Opt-outs included scenario.

FIGURE F-2 ANNUAL BUDGETS FOR INDUSTRIAL RAP ($ IN MILLIONS) – WITH & WITHOUT OPT-OUT CUSTOMERS



APPENDIX G. Demand Response Methodology

G.1 DEMAND RESPONSE PROGRAM OPTIONS

Table G-1 provides a brief description of the demand response program options considered and identifies the eligible customer segment for each demand response program that was considered in this study.

TABLE G-1 DEMAND RESPONSE PROGRAM OPTIONS AND ELIGIBLE MARKETS

DR Program Option	Program Description	Eligible Markets
DLC AC (Switch)	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle). GDS looked at both the one-way communicating Cannon switches and two-way communicating L+G switches. Both switch options were assumed to be phased out as customers switch to thermostats over time.	Residential and Non-Residential Customers
DLC AC (Smart Thermostat)	The system operator can remotely raise the AC's thermostat set point during peak load conditions, lowering AC load. GDS looked at the three options IPL currently has: a customer is given a free thermostat to participate along with an annual incentive, a customer is given a rebate through the marketplace or a storefront along with an annual incentive, or the customer brings an existing thermostat and is only given an annual incentive.	Residential and Non-Residential Customers
DLC Space Heating	The system operator can remotely lower the HVAC's thermostat set point during winter peak load conditions, lowering the heating load. This program is an add-on to the DLC AC Thermostat program. Only participants in the AC Thermostat program would be allowed to participate in the Space Heating program.	Residential and Non-Residential Customers
DLC Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours.	Residential and Non-Residential Customers
Ice Storage Cooling Rate	The use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods.	Large Non-Residential Customers
DLC Lighting	Part of the lighting load is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours.	Non-Residential Customers
Curtailable Rate (Day Of)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers

DR Program Option	Program Description	Eligible Markets
Curtailable Rate (Day Ahead)	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period.	Non-Residential Customers

G.2 DEMAND RESPONSE POTENTIAL ASSESSMENT APPROACH

The analysis for this study was conducted using the GDS DR Model. The GDS DR Model is an Excel spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following two basic equations that can be chosen to be the model user.

ACHIEVABLE POTENTIAL. The cost-effective demand response potential that can practically be attained in a real-world program delivery scenario, if a certain level of market penetration can be attained are included in this scenario. Achievable potential considers real-world barriers to convincing customers to participate in cost-effective demand response programs. Achievable savings potential savings is a subset of economic potential.

If the model user chooses to base the estimated potential demand reduction on a per customer CP load reduction value, then:

$$\textit{Achievable DR Potential} = \textit{Potentially Eligible Customers} \times \textit{Eligible Customer Participation Rate} \times \textit{CP kW Load Reduction Per Participant}$$

The framework for assessing the cost-effectiveness of demand response programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, prepared for the National Forum on the National Action Plan (NAPA) on Demand Response*.[1] Additionally, GDS reviewed the May 2017 National Standard Practice Manual published by the National Efficiency Screening Project.[2] GDS utilized this guide to define avoided ancillary services and energy and/or capacity price suppression benefits. Appendix A contains a table from the report summarizing the energy efficiency cost and benefits including in all five major benefit cost tests.

The GDS Demand Response Model determines the estimated savings for each demand response program by performing an extensive review of all benefits and cost associated with each program. GDS developed the model such that the value of future programs could be determined and to help facilitate demand response program planning strategies. The model contains approximately 50 required inputs for each program including: expected life, CP kW load reductions, proposed rebate levels, program related expenses such as vendor service fees, marketing and evaluation cost and on-going O&M expenses. This model and future program planning features can be used to standardize the cost-effectiveness screening process between IPL departments interested in the deployment of demand response resources.

For this study, the Utility Cost Test (UCT) test was used to determine the cost-effectiveness of each demand response program. Benefits are based on avoided demand, energy (including load shifting), wholesale cost reductions and T&D costs. Costs include incremental program equipment costs (such as

[1] Study was prepared by Synapse Energy Economics and the Regulatory Assistance Project, February 2013.
[2] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, Prepared by The National Efficiency Screening Project

control switches or smart thermostats), fixed program capital costs (such as the cost of a central controller), program administrative, marketing, and evaluation costs. Incremental equipment program costs are included for both new and replacement units (such as control switches) to account for units that are replaced at the end of their useful life.

Achievable potential is broken into maximum and realistic achievable potential in this study:

MAP represents an estimate of the maximum cost-effective demand response potential that can be achieved over the 19-year study period. For this study, this is defined as customer participation in demand response program options that reflect a "best practices" estimate of what could eventually be achieved. MAP assumes no barriers to effective delivery of programs.

RAP represents an estimate of the amount of demand response potential that can be realistically achieved over the 19-year study period. For this study, this is defined as achieving customer participation in demand response program options that reflect a realistic estimate of what could eventually be achieved assuming typical or "average" industry experience. RAP is a discounted MAP, by considering program barriers that limit participation, therefore reducing savings that could be achieved.

This potential study evaluated DR potential for two achievable potential scenarios:

1 *Curtailable Day of Scenario*
2 *Curtailable Day Ahead Scenario*

G.3 AVOIDED COSTS & OTHER ECONOMIC ASSUMPTIONS

Demand response avoided costs were consistent with those utilized in the energy efficiency potential analysis and were provided by IPL. Avoided electric generation capacity refers to the demand response program benefit resulting from a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response option is considered "load shifting", such as direct load control of electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. For this study, GDS assumed that the energy is shifted with no loss of energy. For power suppliers, this shift in the timing of energy use can produce benefits from either the production of energy from lower cost resources or the purchase of energy at a lower rate. If the program is not considered to be "load shifting" the measure is turned off during peak control hours, and the energy is saved altogether. Demand response programs can also potentially delay the construction of new transmission and distribution lines and facilities, which is reflected in avoided T&D costs.

The discount rate used in this study is 6.24%. A peak demand line loss factor of 5.28% and a reserve margin of 7.9 % (for firm load reduction such as direct load control) were also applied to demand reductions at the customer meter. These values were provided by IPL.

The useful life of a smart thermostat is assumed to be 12 years[3]. Load control switches have a useful life of 12 years[4]. This life was used for all direct load control measures in this study.

The number of control units per participant was assumed to be 1 for all direct load control programs using switches (such as water heaters and air conditioning switches), because load control switches can control

[3] 2018 DSM Portfolio Summary, Measure DATA tab
[4] 2018 DSM Portfolio Summary, Measure DATA tab

up to two units. However, for controllable thermostats, some participants have more than one thermostat. The average number of residential thermostats per single family home was assumed to be 1.055[5]. The average number of non-residential thermostats per buildings was assumed to be 1.808[6].

G.4 CUSTOMER PARTICIPATION

The assumed level of customer participation for each demand response program option is a key driver of achievable demand response potential estimates. Customer participation rates reflect the total number of eligible customers that are likely to participate in a demand response program. An eligible customer is defined as a customer that is eligible to participate in a demand response program. For DLC programs, eligibility is determined by whether a customer has the end use equipment that will be controlled[7]. The eligible customers for each program is shown in Table G-2 and Table G-3.

TABLE G-2 ELIGIBLE RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION

DR Program Option	Saturation	Source / Description
DLC AC (Switch)	93.8% of residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC AC (Thermostat)	93.8% of residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC Space Heating	42.7% of residential customers	GDS IPL Saturation Study - Saturation of Space Heating
DLC Water Heaters	47.6% of residential customers	GDS IPL Saturation Study - Saturation of Electric Water Heaters
DLC Room AC	24.2% of residential customers	GDS IPL Saturation Study - Saturation of Room AC

TABLE G-3 ELIGIBLE NON-RESIDENTIAL CUSTOMERS IN EACH DEMAND RESPONSE PROGRAM OPTION

DR Program Option	Saturation	Source / Description
DLC AC (Switch)	84% of non-residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC AC (Thermostat)	81.5% of non-residential customers	GDS IPL Saturation Study - Saturation of Central AC
DLC Space Heating	38.37% of non-residential customers	CBECS Table B26 - Saturation of Space Heating in the East North Central Region
DLC Water Heaters	54.41% of non-residential customers	GDS IPL Saturation Study - Saturation of Electric Water Heaters
Ice Storage Cooling Rate	62% of non-residential customers	CBECS Table B40 - Saturation of Chillers in the East North Central Region

[5] Calculated number of central AC units per number of homes from IPL saturation study.
[6] Calculated number of central AC units per number of buildings from IPL saturation study.

DR Program Option	Saturation	Source / Description
DLC Lighting	15.1% of non-residential customers	GDS IPL Saturation Study - Saturation of T12 Lighting
Curtailable Rate (Day Of)	100% of non-residential customers	DSA/GDS Assumption
Curtailable Rate (Day Ahead)	100% of non-residential customers	DSA/GDS Assumption

G.4.1 Existing Demand Response Programs

IPL has offered their Direct Load Control program for many years. This program offers incentives to members who enroll central AC using switches (residential and non-residential) or smart thermostats (residential only). However, IPL plans to transition the DLC AC switch program to be controlled with smart thermostats instead. GDS assumed that the DLC AC switch program would be ended by phased out by the end of the 19-year study and these customers would be transitioned to using thermostats to participate in the program. A cost-effective analysis was still run for these programs, with the assumption that no new switches would be installed and participation would steadily decline until 2039.

G.4.2 Hierarchy

Double-counting savings from demand response programs that affect the same end uses is a common issue that must be addressed when calculating the demand response savings potential. For example, a direct load control program of air conditioning and a rate program both assume load reduction of the customers' air conditioners. For this reason, it is typically assumed that customers cannot participate in programs that affect the same end uses. However, in this study, none of the programs interacted with each other. All residential programs considered were direct load control. Only small non-residential customers were eligible for direct load control programs, and large non-residential customers were eligible for the Ice Storage Cooling Rate and Curtailable Rate. Therefore, a hierarchy was not necessary for these programs.

G.4.3 Participation Rates

The assumed "steady state" participation rates used in this potential study and the sources upon which each assumption is based are shown in Table G-5 for residential and non-residential customers, respectively. The steady state participation rate represents the enrollment rate once the fully achievable participation has been reached. Participation rates are expressed as a percentage of eligible customers. Program participation and impacts (demand reductions) are assumed to begin in 2020. The main sources of participant rates are several studies completed by the Brattle Group. Additional detail about participation rates and sources are shown in Table G-5.

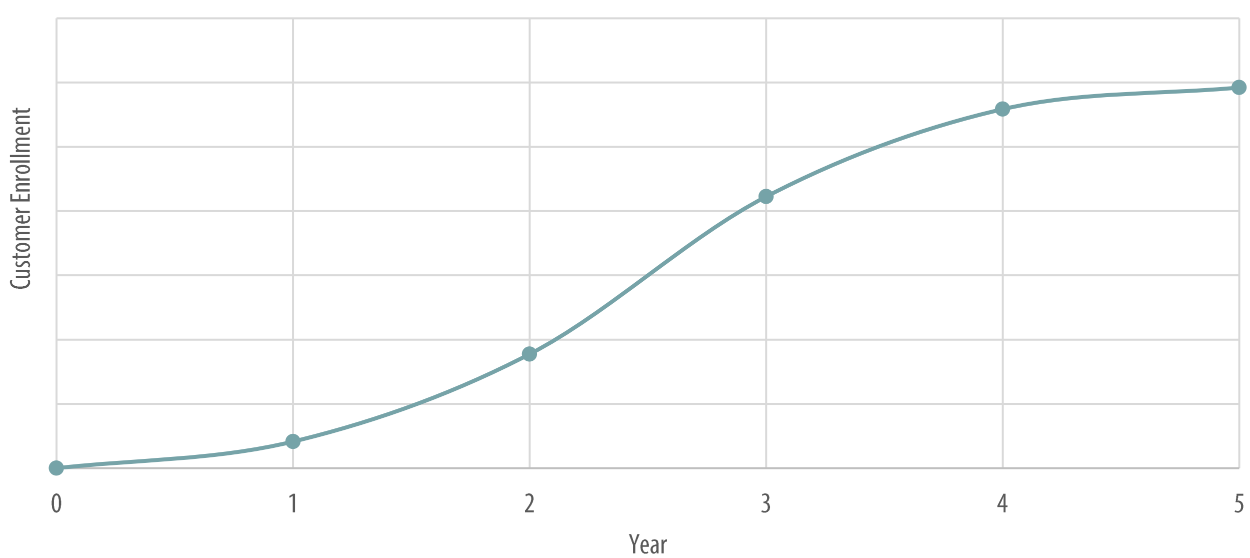
TABLE G-5 STEADY STATE PARTICIPATION RATES FOR DEMAND RESPONSE PROGRAM OPTIONS

DR Program Options	MAP Steady State Participation Rate	RAP Steady State Participation Rate	Source
RESIDENTIAL			
DLC AC (Switch)	0% *(existing program declining to 0 participants)*	0% *(existing program declining to 0 participants)*	IPL
DLC AC (Thermostat)	36%	25%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Space Heating	20%	15%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	36%	23%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Room AC	31%	20%	GDS Survey of 20 utilities (75th percentile for MAP and 50th percentile for RAP).
DLC Electric Vehicle Charging	94%	57%	MAP: Used TOU with enabling technology take rate as most electric cars are equipped with a built-in technology that allows the vehicle to charge at specific times. (Opt-Out); RAP: Plug-in Electric Vehicle and Infrastructure Analysis September 2015, Prepared for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy by Idaho National Lab. (Opt-In)
NON-RESIDENTIAL			
DLC AC (Switch)	0% *(existing program declining to 0 participants)*	0% *(existing program declining to 0 participants)*	IPL
DLC AC (Thermostat)	19%	8%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.

DR Program Options	MAP Steady State Participation Rate	RAP Steady State Participation Rate	Source
DLC Space Heating	14%	3%	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	16%	7%	FERC 2012 DR Survey Data (75th percentile for MAP, 50th percentile for RAP)
Ice Storage Cooling Rate	0.81	0.16	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Lighting	14%	3%	Used Direct Load - Air Conditioning take rate from PGE Brattle Group Study. FERC 2012 DR survey data contained only one program targeting lighting with a take rate of .6%. A general search for such programs by GDS also produced no useful results.

Customer participation in new demand response programs is assumed to reach the steady state take rate over a five-year period. The path to steady state customer participation follows an “S-shaped” curve, in which participation growth accelerates over the first half of the five-year period, and then slows over the second half of the period (see Figure G-1). Existing programs have already gone through this ramp-up period, so they were escalated linearly to the final participation rate.

FIGURE G-1 ILLUSTRATION OF S-SHAPED MARKET ADOPTION CURVE



G.5 LOAD REDUCTION ASSUMPTIONS

Table G-6 presents the residential and non-residential per participant CP demand reduction impact assumptions for each demand response program option at the customer meter. Demand reductions were based on load reductions found in IPL's existing demand response programs, and various secondary data sources including the FERC and other industry reports, including demand response potential studies.

TABLE G-6 PER PARTICIPANT CP DEMAND REDUCTION ASSUMPTIONS

DR Program Options	Per Participant CP Demand Reduction	Source
RESIDENTIAL		
DLC AC (Switch)	0.78 for one way Cannon switch, 0.58 kW for two way L+G switch	IPL
DLC AC (Thermostat)	0.7 kW	IPL
DLC Space Heating	1 kW	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	0.4 kW Summer, 0.8 kW Winter	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Room AC	0.04 kW	Cost-effectiveness of CECONY Demand Response Programs , 2013
DLC Electric Vehicle Charging	0.28 kW	Xcel Energy pilot program on EV control
NON-RESIDENTIAL		
DLC AC (Switch)	0.31 kW	IPL
DLC AC (Thermostat)	0.2759	Used ratio of switch to thermostat for residential and applied to C&I switch reduction
DLC Space Heating	1.5 kW	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
DLC Water Heaters	0.6 kW Summer, 1.2 kW Winter	Demand Response Market Research: Portland General Electric, 2016 to 2035, The Brattle Group, January 2016.
Ice Storage Cooling Rate	19.4 kW	MISO DR, EE, DG Potential Study: Supplemental Program Slides. Value for Local Resource Zone 5

DR Program Options	Per Participant CP Demand Reduction	Source
DLC Lighting	8.94% of coincident peak load	Business Energy Advisor/E Source, Strategies for C&I Demand Response; LIGHTING CALIFORNIA'S FUTURE: COST-EFFECTIVE DEMAND RESPONSE, Prepared For: California Energy Commission By: NEV Electronics, LLC, California Lighting Technology Center, 2011; Lighting Controls Association, Lighting Control and Demand Response, By Craig DiLouie, on May 20, 2014; Demonstration and Evaluation of lighting technologies and Applications, Lighting Research Center, Field Test Issue 6, 2011; What is the relation between energy consumption savings and peak load savings and how can this affect future energy conservation requirements? - Study conducted by the City of Toronto.

G.6 PROGRAM COSTS

One-time program development costs of $400,000[8] were included in the first year of the analysis for new programs. This cost was split between similar programs that would be comparable to start up. No program development costs are assumed for programs that already exist. It was assumed that there would be a cost of $50[9] per new participant for marketing. Marketing costs are assumed to be 33.3% higher for MAP. There was assumed to be an annual administrative cost of $30,000 per program. All program costs were escalated each year by the general rate of inflation assumed for this study. Table G-7 shows the equipment cost assumptions.

TABLE G-7 EQUIPMENT COST ASSUMPTIONS

Device	Cost	Applicable DR Programs	Source
One-way communicating load control switch	$70 equipment + $150 for installation	DLC programs controlled by switches	Comverge
Two-way communicating load control switch using Wi-Fi	$95 + $150 for installation	DLC programs controlled by switches	Comverge
Smart controllable thermostat (such as Nest or Ecobee)	$150 for thermostat + $150 installation	DLC AC Thermostat (Free thermostat option)	IPL
Smart controllable thermostat (such as Nest or Ecobee)	$50 one time incentive to join program + $50 rebate if buying through the program ($0 rebate if joining with existing thermostat)	DLC AC Thermostat (BYOT option)	IPL

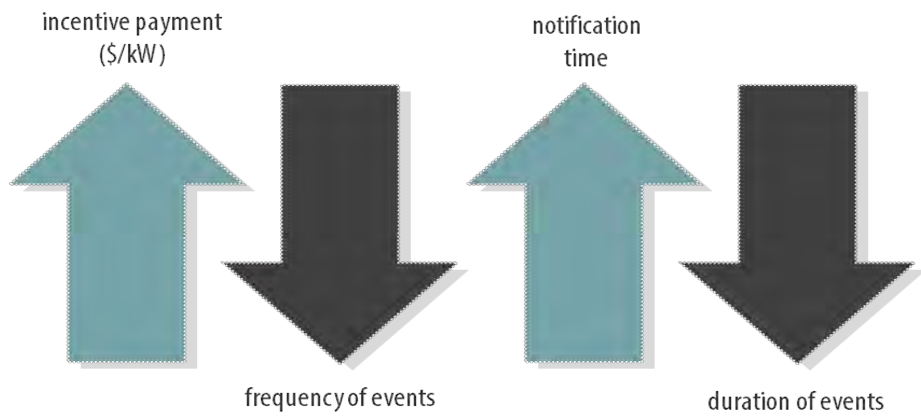
[8] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011
[9] TVA Potential Study Volume III: Demand Response Potential, Global Energy Partners, December 2011

G.7 LOAD CURTAILMENT PROGRAM

G.7.1 Modeling Demand Response Potential

One of the most prominent forms of demand response among non-residential customers is load curtailment agreements where the utility, or an aggregator on the utility's behalf, enters financial agreements with businesses to reduce load when dispatched. Load curtailment potential is driven by a few key factors – incentive payments, the frequency of events, the duration of events, and the level of notification participants are given about pending events. The directional effect these factors have on DR potential is shown in Figure G-2.

FIGURE G-2 DRIVERS OF DR POTENTIAL



Several different estimates of DR potential can be produced by turning levers related to these four inputs. Rather than producing several different scenario-based estimates, the research team made several simplifying assumptions regarding program design. Components of program design include how many DR events will be called, how long the DR events will last, how far in advance participants are notified of the upcoming DR event, and the incentive payment participants receive (the amount and how it is distributed – annually, monthly, per event, etc.). Table G-8 describes some of the program design inputs/assumptions the research team used in estimating DR potential. Other relevant inputs – such as the peak load forecast and avoided costs – are described in the table as well.

TABLE G-7 SUMMARY OF INPUT ASSUMPTIONS FOR LOAD CURTAILMENT MODELING

Input Variable	Sources, Notes, and Assumptions
Peak Load Forecast	The peak load forecast used in developing potential estimates was provided by IPL. The forecast, created in October of 2017, runs through 2027. For the remaining years in the study horizon, the peak forecast was escalated by a rate identical to the observed escalation rate (from 2018-2027) in IPL's peak forecast.
	The summer peak load forecast was disaggregated into peak load forecasts by sector using peak load shares provided by IPL. Load curtailment potential was examined separately for the Small C&I and Large C&I classes and customers who opt out of energy efficiency were not excluded from the eligible peak load.
Avoided Cost of Generation Capacity ($/kW-year)	Avoided costs of generation capacity were provided by IPL.

Input Variable	Sources, Notes, and Assumptions
Avoided Transmission and Distribution Capacity ($/kW-year)	We assumed a starting point of $10/kW-year for each transmission and distribution ($20/kW-year T&D total) in 2020. These values were escalated by 2% annually.
Program Design (# of events, event duration, notification level)	Previous Indiana research suggests relatively short DR events would serve the region better than relatively long events, as summer peaks are concentrated between 2:00 PM and 6:00 PM.[10] Thus, our estimates of potential assume a four-hour event duration. We're also assuming that there will be an average of seven summer events will be called (28 total event hours for the summer).
	Results were calculated for both a "day-ahead" notification design and a "day-of" notification design. "Day-ahead" notification assumes a ~24-hour notice, and "day-of" notification assumes a 3-to-6-hour notice. Potential is higher under the "day-ahead" notification design, as this provides participants greater opportunities to shift energy-intensive tasks to off-peak periods.
Participant Incentive	For C&I DR, our team modeled the incentive as a reservation payment. This is an annual payment provided to the participant. In exchange, the participant agrees to curtail load when events are dispatched. For realistic achievable potential, our approach to setting incentive levels involved optimizing net benefits. To determine the optimal incentive level, the research team performed a simulation where the critical input was the incentive level and the critical output was the net benefit of the DR program. The simulation leveraged several of the inputs discussed herein. The results indicated that the optimal incentive level in 2020 is $21/kW-year.
	For maximum achievable potential, the goal of the simulation was not to optimize net benefits. Instead, we used the simulation to determine the greatest possible incentive level that would produce a cost-effective program (e.g, largest incentive value such that the Utility Cost Test ratio does not fall below 1). The results indicated an incentive level of $39/kW-year should be used in estimating maximum achievable potential for summer 2020.
	In both cases, the incentive level is escalated annually at a rate that matches the growth rate of avoided costs. This growth rate is largely driven by the generation component (avoided cost of generation capacity was provided by IPL).
Price Elasticity of Demand Coefficients	The price elasticity of demand coefficients used in this research were derived from two years of DR performance data for C&I DR participants in Pennsylvania. Information about sector (small/large), incentive levels, and the peak load share of each participant was used in the development of the elasticity coefficients. Traditional elasticity formulas were used.

Leveraging the inputs discussed above, our team developed potential estimates via a "top-down" approach. At a high level, the approach entails disaggregating the peak load forecast into peak load forecasts by sector, and then combining these forecasts with the price elasticity of demand coefficients to estimate potential. Price elasticity of demand can be thought of as the percentage change in the

[10] Potential for Peak Demand Reduction in Indiana. Prepared for Indiana AEE by Demand Side Analytics, 2018.

quantity of electricity demanded divided by the percentage change in the price (including an incentive) of DR:

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price}$$

Rearranging the terms in the elasticity equation yields the following:

$$\%\ change\ in\ Quantity = (Elasticity)\ \times\ (\%\ change\ in\ Price)$$

Note that "% change in Quantity" can also be expressed as:

$$\%\ change\ in\ Quantity = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

Combing these two "% change in Quantity" equations yields:

$$(Elasticity)\ \times\ (\%\ change\ in\ Price) = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

By making assumptions about price elasticity, the percentage change in price (related to electric retail rates and the incentive level), and the summer peak load, it is possible to estimate how much DR potential exists in each market segment by solving for "DR potential". It is important to note that the estimates of C&I DR potential discussed in this section are not incremental to existing IPL C&I DR programs. That is, we are not estimating how much DR potential exists beyond the existing IPL C&I DR resources. It is also important to note that this top-down methodology produces estimates of DR potential at the system-level (inclusive of line losses).

APPENDIX H. 2020 DSM Plan Refresh

In addition to completing the IPL Market Potential Study for the 2021-2039 planning period, the GDS team also completed an updated analysis for IPL's 2020 DSM plan (the "2020 Refresh"). 2020 is the 3rd and final year of the 3-year DSM plan approved in Cause No. 44945. In the Settlement Agreement (approved in Cause No. 44945), IPL agreed to work with the stakeholders to try to identify additional cost-effective energy savings in 2020. GDS, with review and input from IPL's stakeholders, completed an analysis to compare the 2020 "refresh" potential with the current approved plan. Among other factors considered, the analysis sought to determine if any recent changes to existing codes and standards have reduced the expected savings potential in 2020, or whether new technologies have entered the market that could cost effectively result in additional savings opportunities.[1]

The potential 2020 energy savings, as identified by GDS, for the residential and business customers are in the two sections below. These savings estimates are projections and do not take into consideration market barriers and program delivery constraints. As prescribed in the IPL Settlement Agreement, IPL and the other members of the IPL Oversight Board conducted a technical workshop on May 2nd with the implementation vendor CLEAResult; the EM&V consultant Cadmus and the MPS consultant GDS to review the 2020 MPS modeling results and determine program modifications that should be considered for the 2020 DSM Portfolio.

The modeling results, shown in Table 1 and Table 2below, served as the starting point for this collaborative exercise. Prior to the technical workshop, IPL requested that CLEAResult review the savings estimates developed by GDS to determine, based on their extensive experience in program delivery, which opportunities had promise and might be reasonable to pursue. Cadmus also reviewed the modeling results and provided their input from an EM&V perspective.

At the workshop, the IPL OSB members reviewed and discussed the findings by Cadmus and CLEAResult. Some DSM program additions suggested by GDS were considered impractical in the market at this time. Other program suggestions will be given additional consideration.

The next step in the 2020 Refresh process is for IPL to work with the implementation vendor CLEAResult to determine the cost to deliver the program modifications that were recommended in the refresh and discussed during the technical workshop. Once cost effectiveness is determined, the cost effective program modifications will then be compiled into a proposed 2020 Portfolio summary for review and approval by the IPL OSB. The proposed 2020 Portfolio summary should be complete by early Q4.

[1] GDS planning assumptions are current and are consistent with either the IN TRM or recent EM&V results. Thus, measure level savings may vary from those used to develop IPL's 2019 Portfolio summary or in plan development for IPL's filing in Cause No. 44945.

As previously indicated, these savings estimates are projections and do not take into consideration market barriers and program delivery constraints. As agreed to in the Settlement Agreement in Cause No. 44945, IPL will rely on input from CLEAResult and Cadmus to determine which revisions are practical and achievable in the market and to finalize the plan for 2020. Ultimately, any changes to the 2020 DSM Portfolio will require approval of the IPL OSB.

2020 Residential Energy Savings Potential

Residential results were developed using the GDS Market Potential Study models, and historical IPL program net-to-gross ("NTG") ratios. The NTG ratios were applied to the gross savings at the measure level. Table H-1 shows projected 2020 Gross and Net savings potential for each residential IPL program, as well as program budgets and cost per net kWh saved. Estimated residential gross energy savings in 2020 are 107,854 MWh, while total 2020 net savings are projected to be 88,710 MWh. Net peak demand savings are projected to be 15.1 MW. The total estimated 2020 residential sector program budget is nearly $22.2 million, which yields an average acquisition cost of $0.222 per kWh of projected savings. The Peer Comparison Reports program yields the greatest amount of projected net savings in 2020 at the lowest acquisition cost on a first-year basis. The Lighting & Appliances program provides the second highest projection of net savings at the second lowest acquisition cost on a first-year basis. The Whole Home program has the third greatest amount of projected net savings, but at an estimated first-year acquisition cost higher than all other programs except the Income Qualified Weatherization program. Though the budget and savings for the IQW program are higher than the 2019 planning estimates, the 2020 projections were calibrated to consider the 2019 estimates.

TABLE H-1 RESIDENTIAL 2020 ENERGY SAVINGS POTENTIAL

	Gross MWh	Net MWh	Net MW	Budget	$/Net kWh
Residential Program					
Lighting & Appliances	36,494	21,632	2.41	$4,347,002	$0.201
Not Currently Offered	2,651	2,651	0.93	$933,648	$0.352
Emerging Technology	2,111	2,111	0.46	$765,436	$0.363
Income Qualified Weatherization	2,830	2,830	0.51	$2,426,981	$0.858
Appliance Recycling	3,494	2,458	0.43	$739,223	$0.301
Whole Home	15,214	11,968	3.57	$8,409,143	$0.703
Peer Comparison Reports	35,069	35,069	5.57	$1,499,575	$0.043
School Kits	4,239	4,239	0.69	$1,006,168	$0.237
Multifamily Direct Install	4,890	4,890	0.55	$1,842,039	$0.377
Online Kits	863	863	0.00	$194,782	$0.226
Total	**107,854**	**88,710**	**15.10**	**$22,163,997**	**$0.250**

2020 Commercial & Industrial Energy Savings Potential

Commercial and Industrial results were developed using the GDS Market Potential Study models, and historical IPL program NTG ratios were applied to the gross savings at the measure level, based on whether measures were described as Prescriptive, Custom, Emerging technologies, or Small Business Direct Install.

Table H-2 shows projected 2020 Gross and Net savings potential by IPL C&I program, as well as program budgets and cost per net kWh saved. The total C&I 2020 gross savings potential is projected to be 97,915 MWh, while total 2020 net savings potential is projected to be 74,776 MWh. Net peak demand savings are projected to be nearly 13.4 MW. The total 2020 C&I budget is projected to be nearly $11.9 million, resulting in an average first-year cost per net KWh saved of $0.159 per kWh. The Prescriptive program is projected to have net 2020 savings of 51,457 MWh and a budget of just over $7.6 million, the Custom program is projected to have net savings of 17,790 MWh and a budget of just over $2.9 million, the Small Business Direct Install program ("SBDI") is projected to have net savings of 4,171 MWh and a budget of just over $1.0 million, and Emerging Technologies are projected to have 2020 net savings of 1,357 MWh and an associated budget of nearly $178,000.

TABLE H-2 – COMMERCIAL & INDUSTRIAL 2020 ENERGY SAVINGS POTENTIAL

	Gross MWh	Net MWh	Net MW	Budget	$/Net kWh
C&I Program					
Prescriptive	71,088	51,457	9.36	$7,665,863	$0.149
Custom	21,078	17,790	3.13	$2,943,701	$0.165
SBDI	4,391	4,171	0.63	$1,077,131	$0.258
Emerging	1,358	1,357	0.25	$177,609	$0.131
Total	**97,915**	**74,776**	**13.37**	**$11,864,304**	**$0.159**

prepared for

INDIANAPOLIS POWER & LIGHT COMPANY

2018 Demand Side Management Market Potential Study

August 13, 2019

FINAL REPORT

prepared by
GDS ASSOCIATES INC
DEMAND SIDE ANALYTICS
THORPE ENERGY SERVICES

IPL 2019 IRP

Attachments 5.2 a-c (MPS Appendices B, C & D) are provided electronically

IPL 2019 IRP

Attachment 5.3 (Decrement Load Shapes Summary) is provided electronically

IPL 2019 IRP

Confidential Attachment 5.4 (Avoided Cost) is provided electronically in the Confidential IRP

IPL 2019 IRP

Confidential Attachment 5.5 (IPL 2019 IRP – Capital Costs) is provided electronically in the Confidential IRP

IPL 2019 IRP

Confidential Attachment 7.1 (Wood Mackenzie H1 2018 No Federal Carbon Case Report) is provided in the Confidential IRP

IPL 2019 IRP

Confidential Attachment 7.2 (Wood Mackenzie H1 2018 Federal Carbon Case Report) is provided in the Confidential IRP

IPL 2019 IRP

Confidential Attachment 7.3 (Wood Mackenzie H1 2018 Federal Carbon Case Report - MISO) is provided in the Confidential IRP

IPL 2019 IRP

Confidential Attachment 7.4 (Wood Mackenzie – H1 2018 Supply, Demand Energy, Federal Carbon Case) is provided electronically in the Confidential IRP

IPL 2019 IRP

Confidential Attachment 7.5 (Wood Mackenzie – H1 2018 Supply, Demand Energy, No Carbon Case) is provided electronically in the Confidential IRP

IPL 2019 IRP

Confidential Attachment 7.6 (Annual Generator Fuel Prices) is provided electronically in the Confidential IRP

Figure 1 | Annual Energy (TWh) for Reference Case Portfolios 1a – 5a

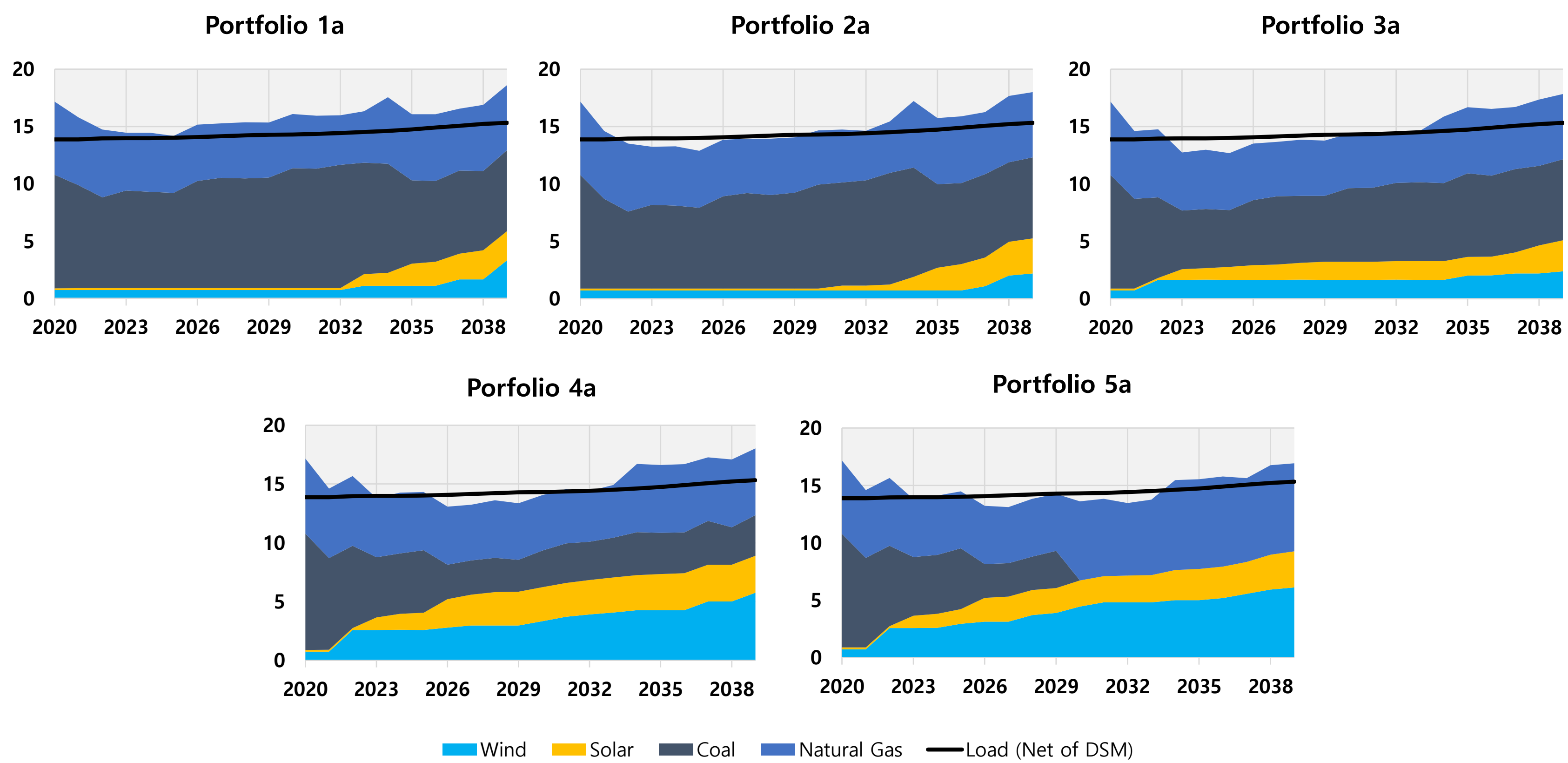


Figure 2 | Annual Energy (TWh) for Scenario A Portfolios 1a – 5a

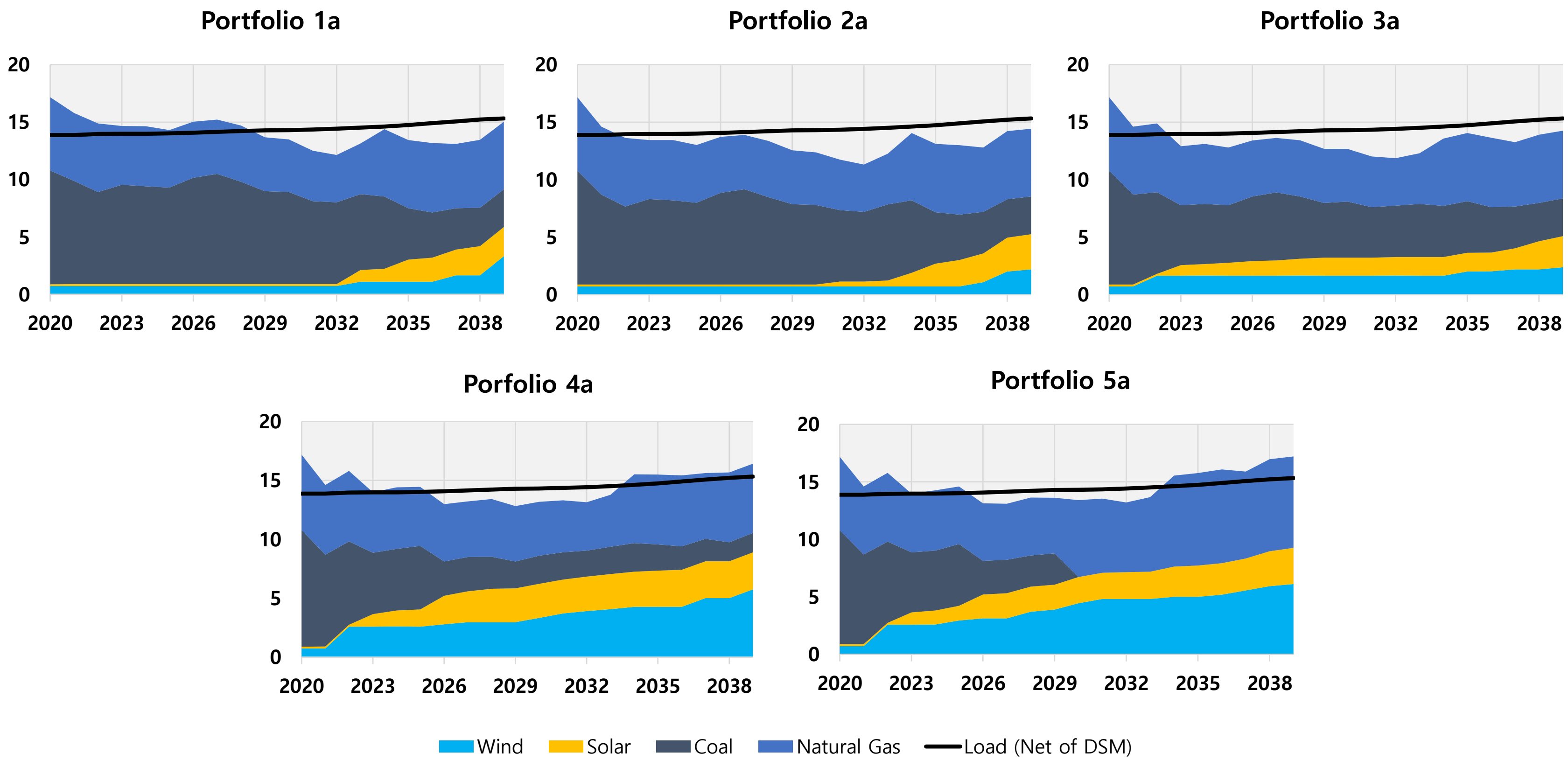


Figure 3 | Annual Energy (TWh) for Scenario B Portfolios 1a – 5a

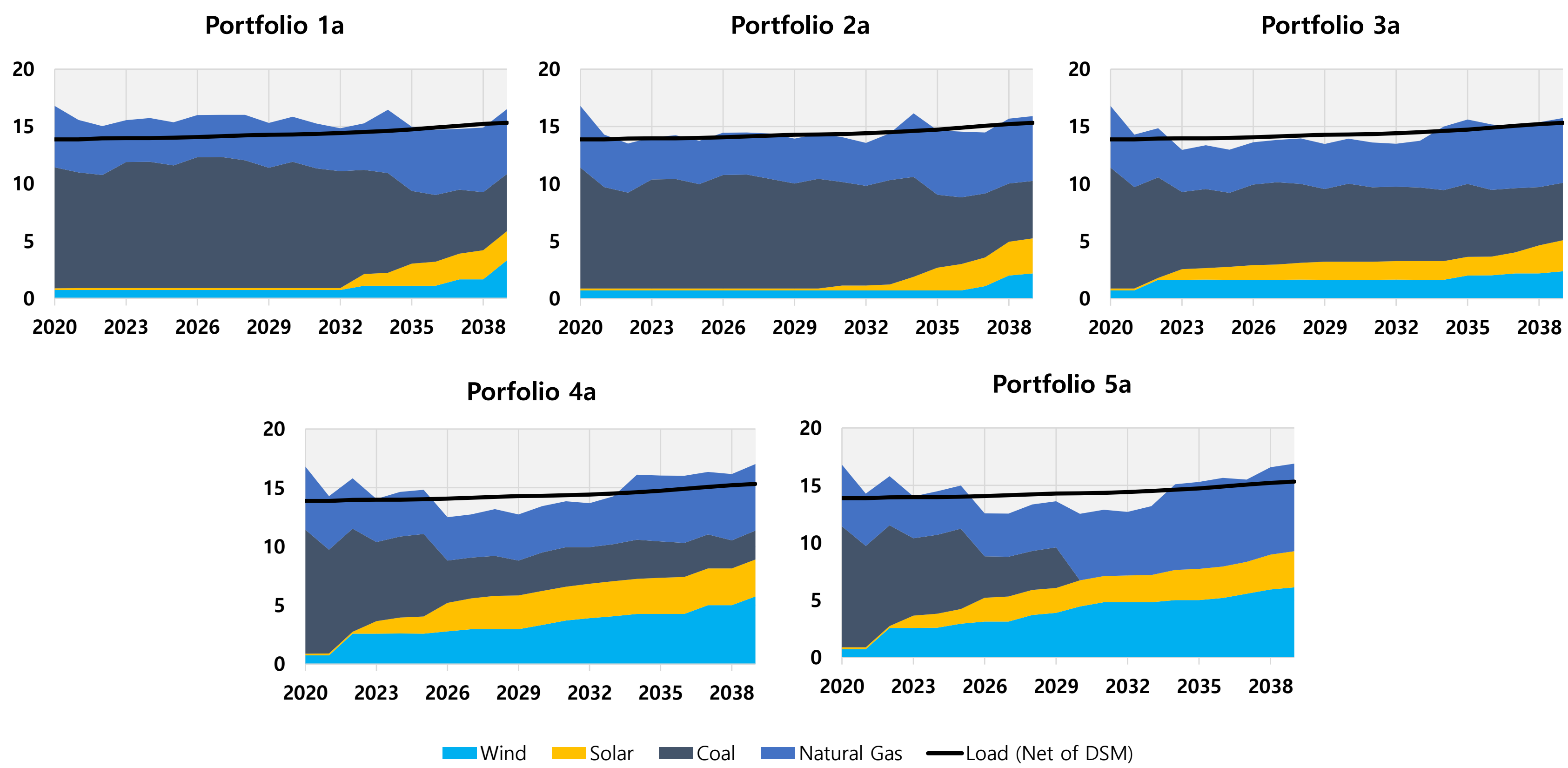


Figure 4 | Annual Energy (TWh) for Scenario C Portfolios 1a – 5a

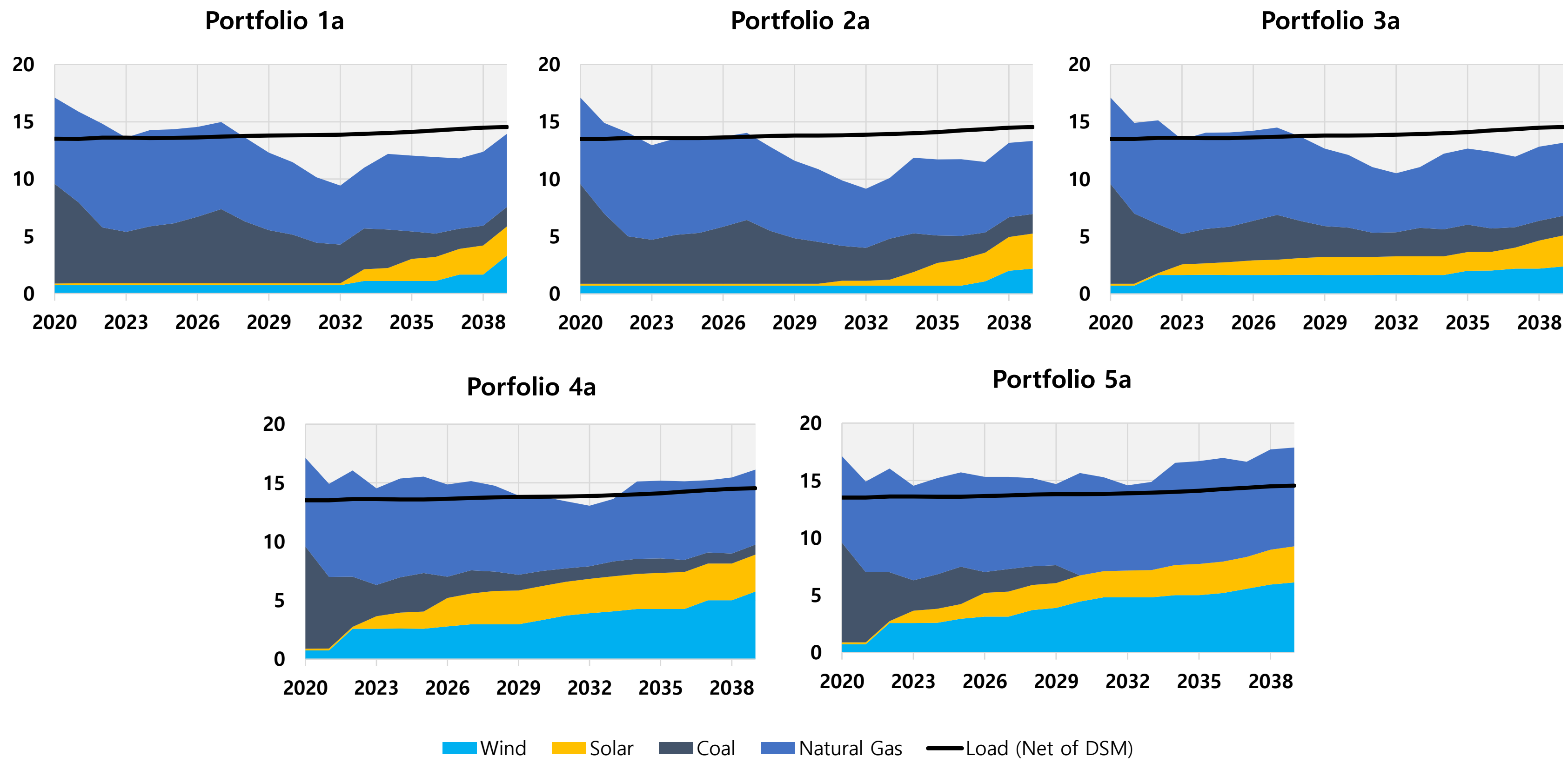


Figure 5 | Annual Energy (TWh) for Scenario D Portfolios 1a – 5a

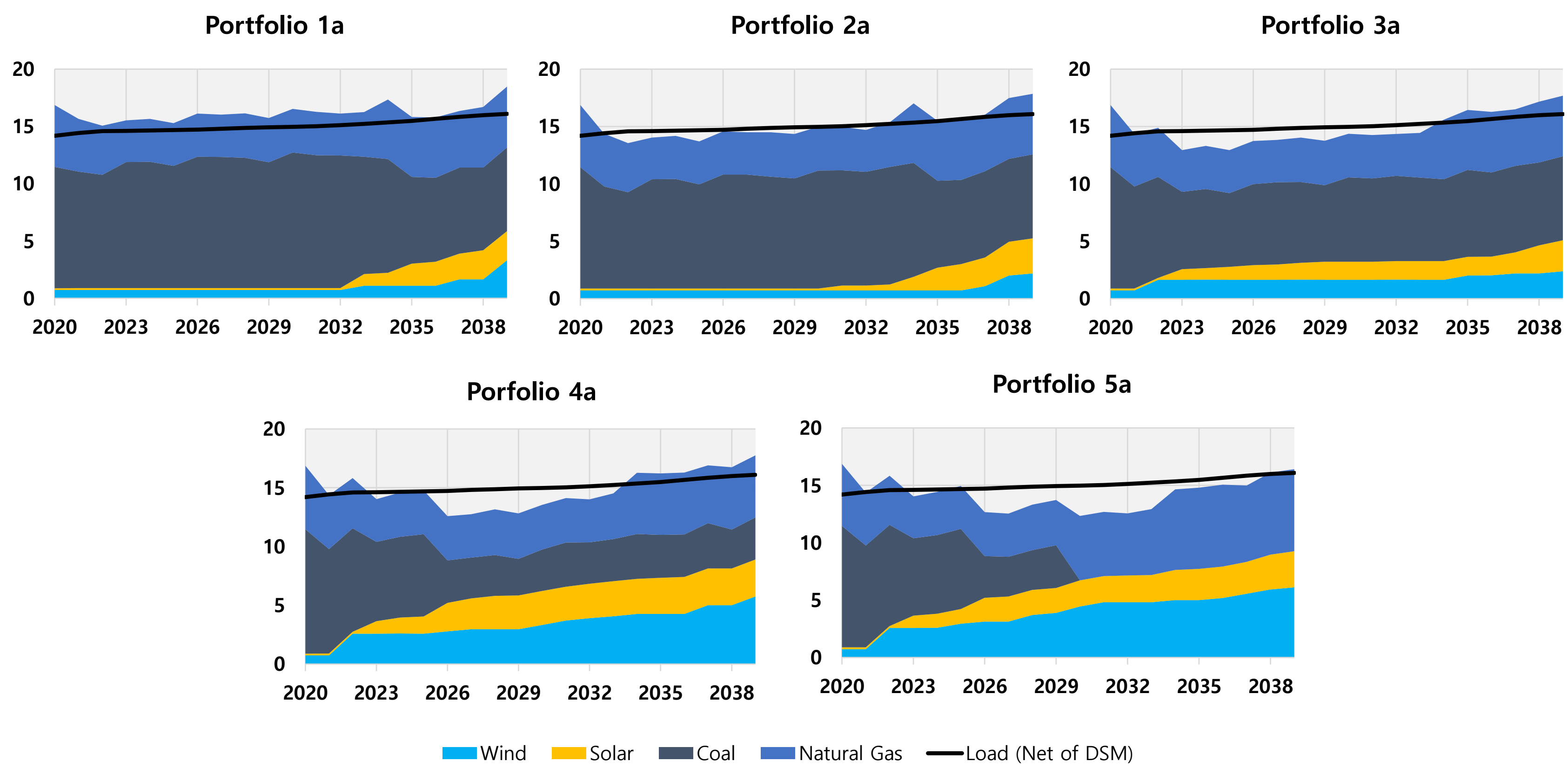


Figure 6 | Annual Energy (TWh) for Reference Case Portfolios 1b – 5b

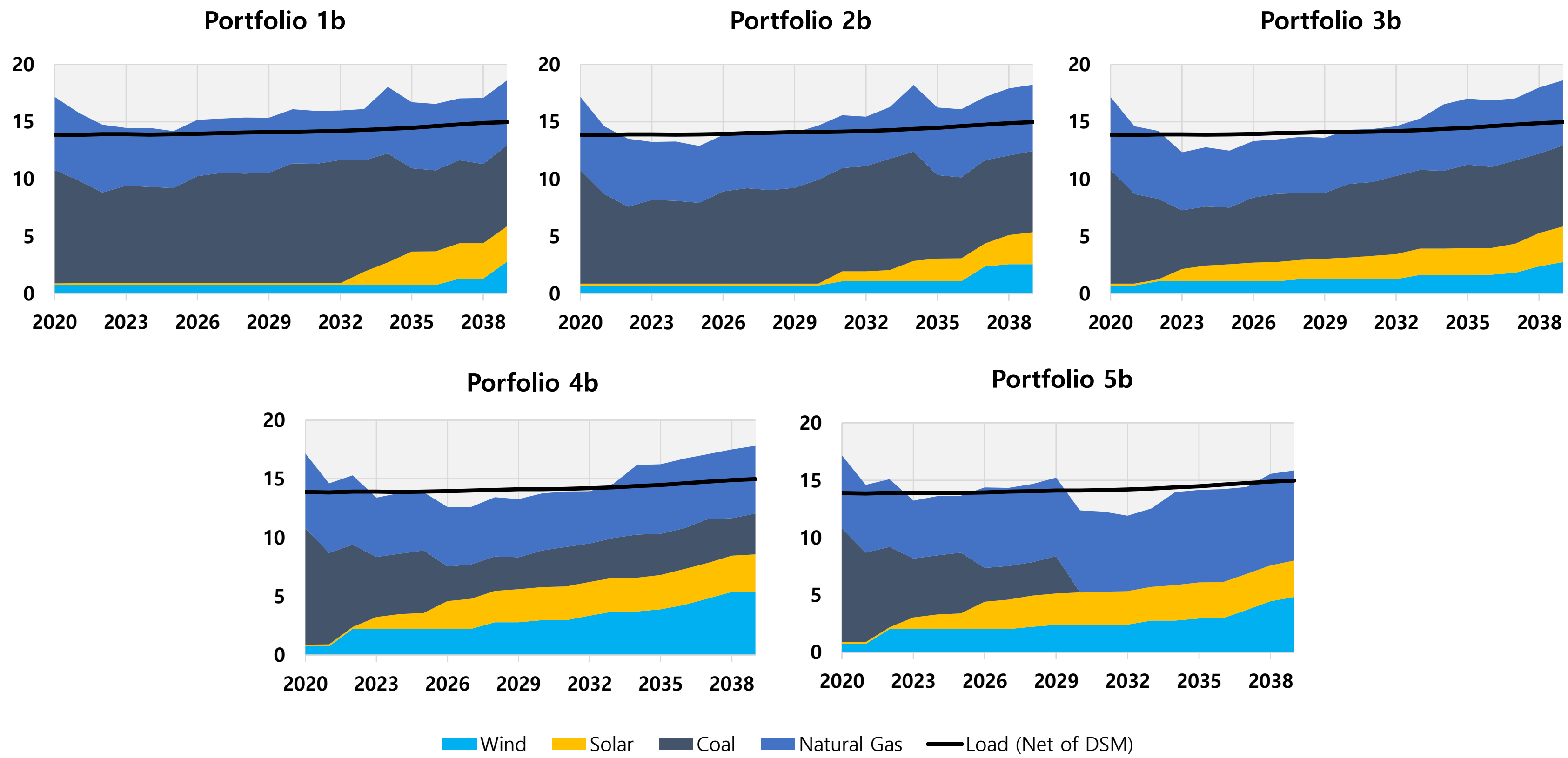


Figure 7 | Annual Energy (TWh) for Scenario A Portfolios 1b – 5b

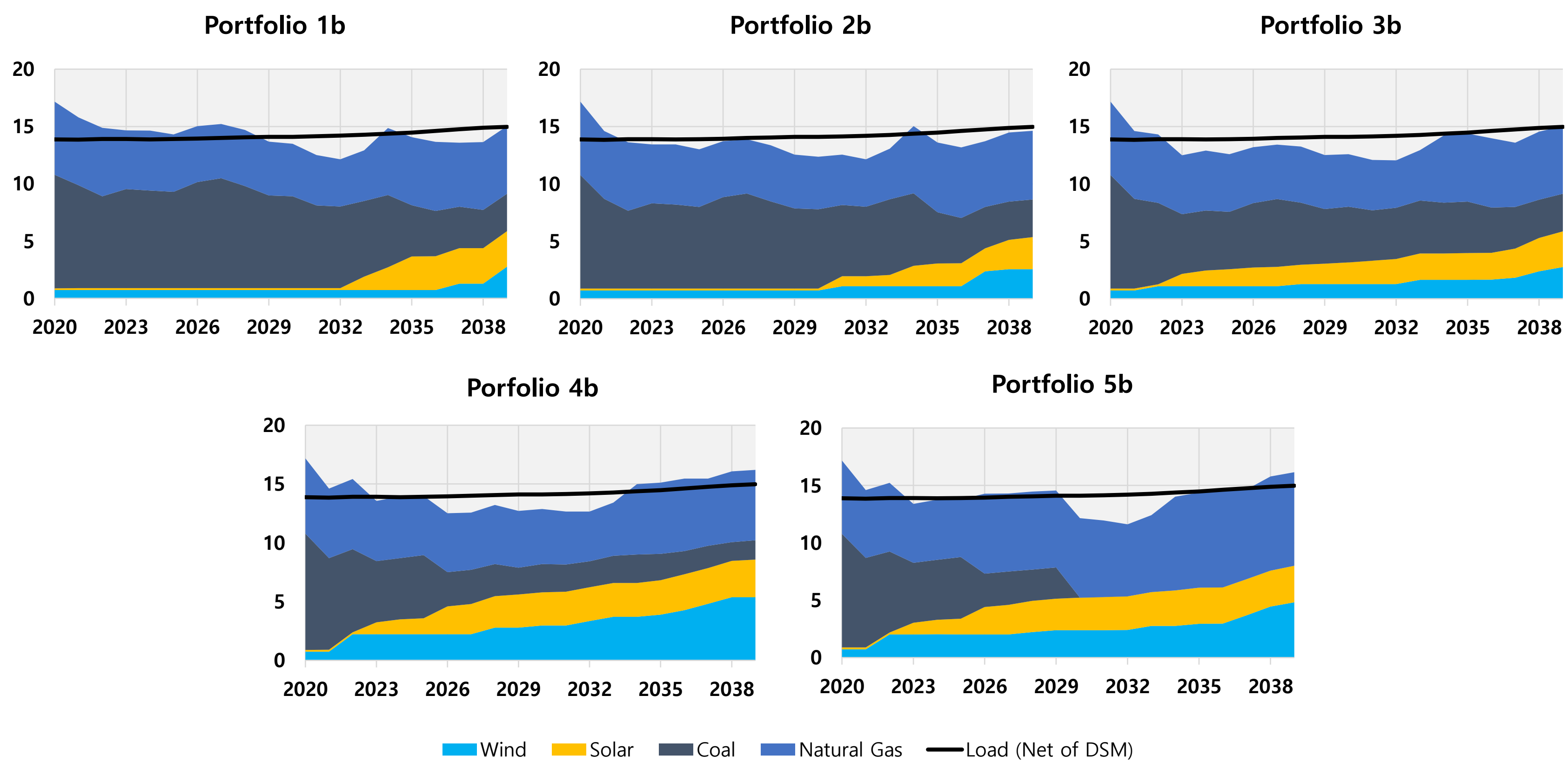


Figure 8 | Annual Energy (TWh) for Scenario B Portfolios 1b – 5b

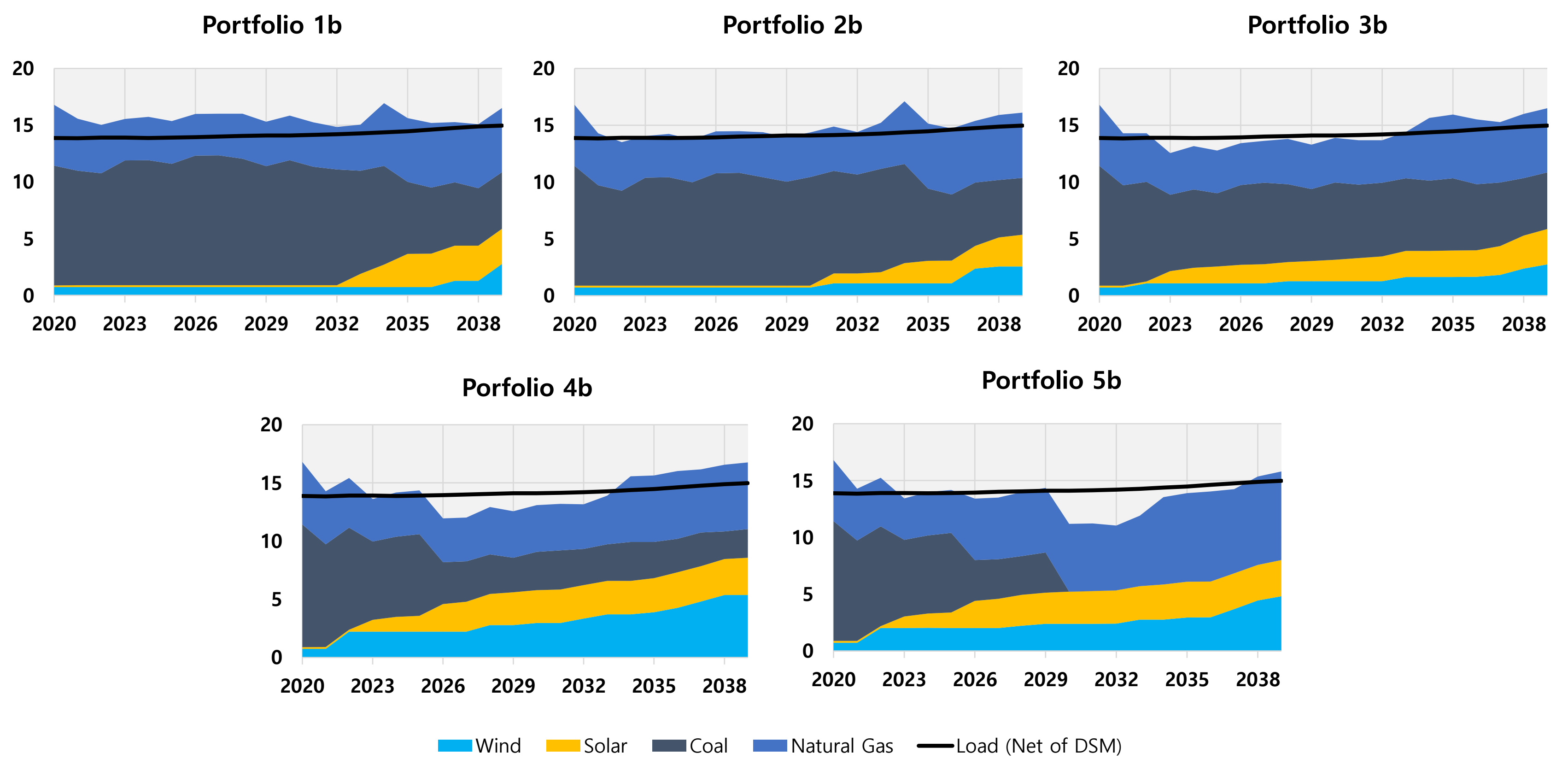


Figure 9 | Annual Energy (TWh) for Scenario C Portfolios 1b – 5b

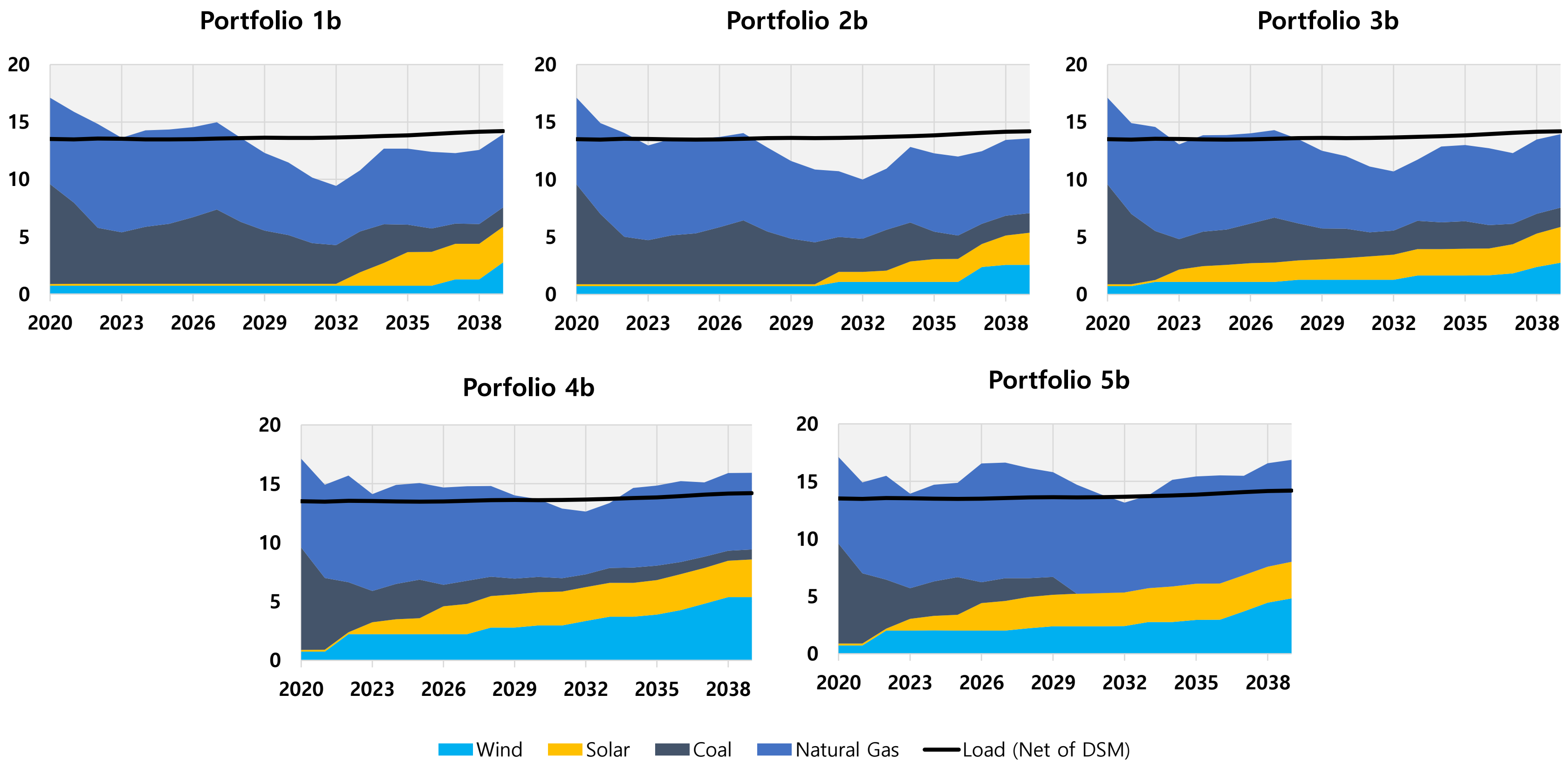


Figure 10 | Annual Energy (TWh) for Scenario D Portfolios 1b – 5b

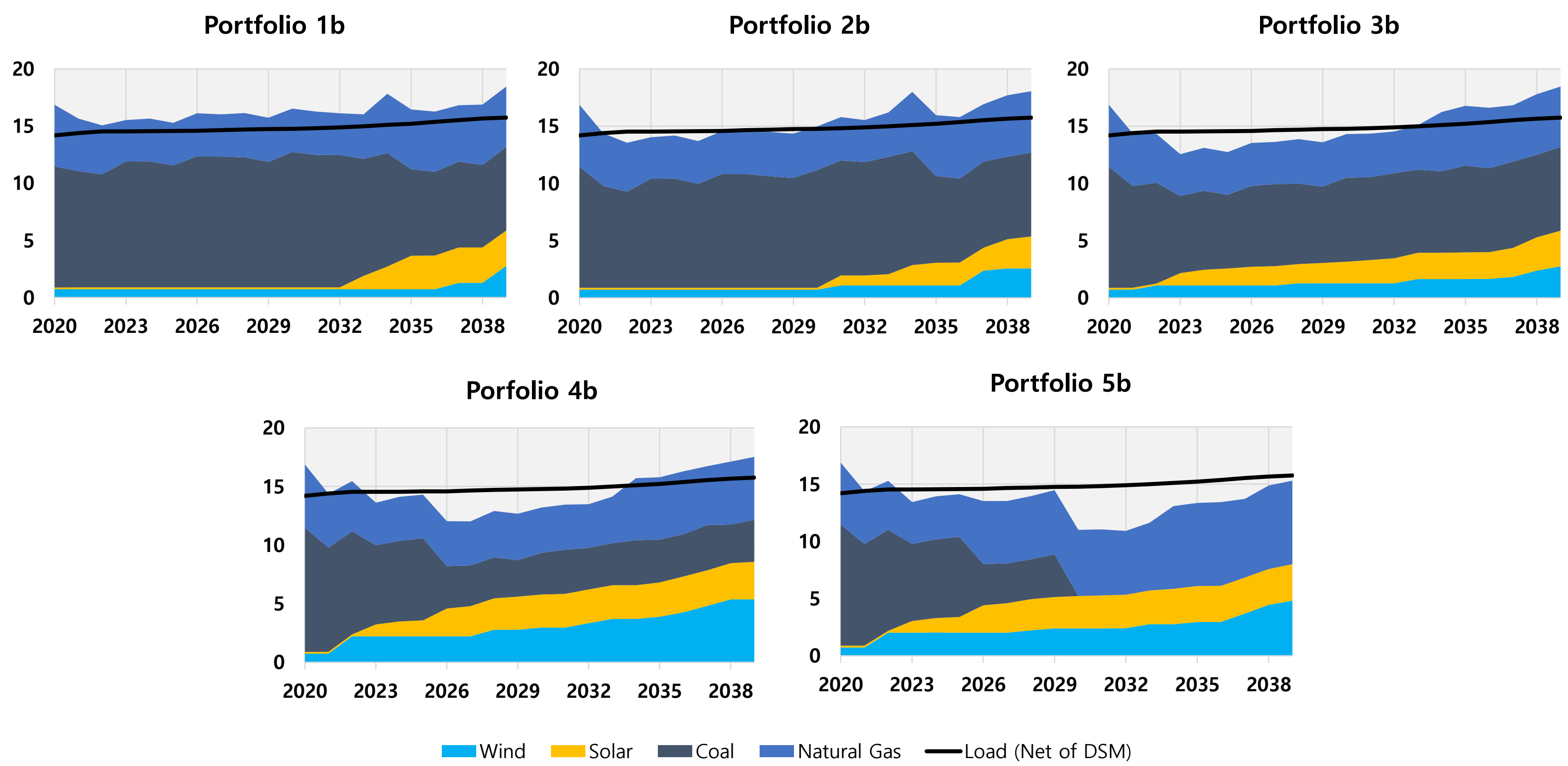


Figure 11 | Annual Energy (TWh) for Reference Case Portfolios 1c – 5c

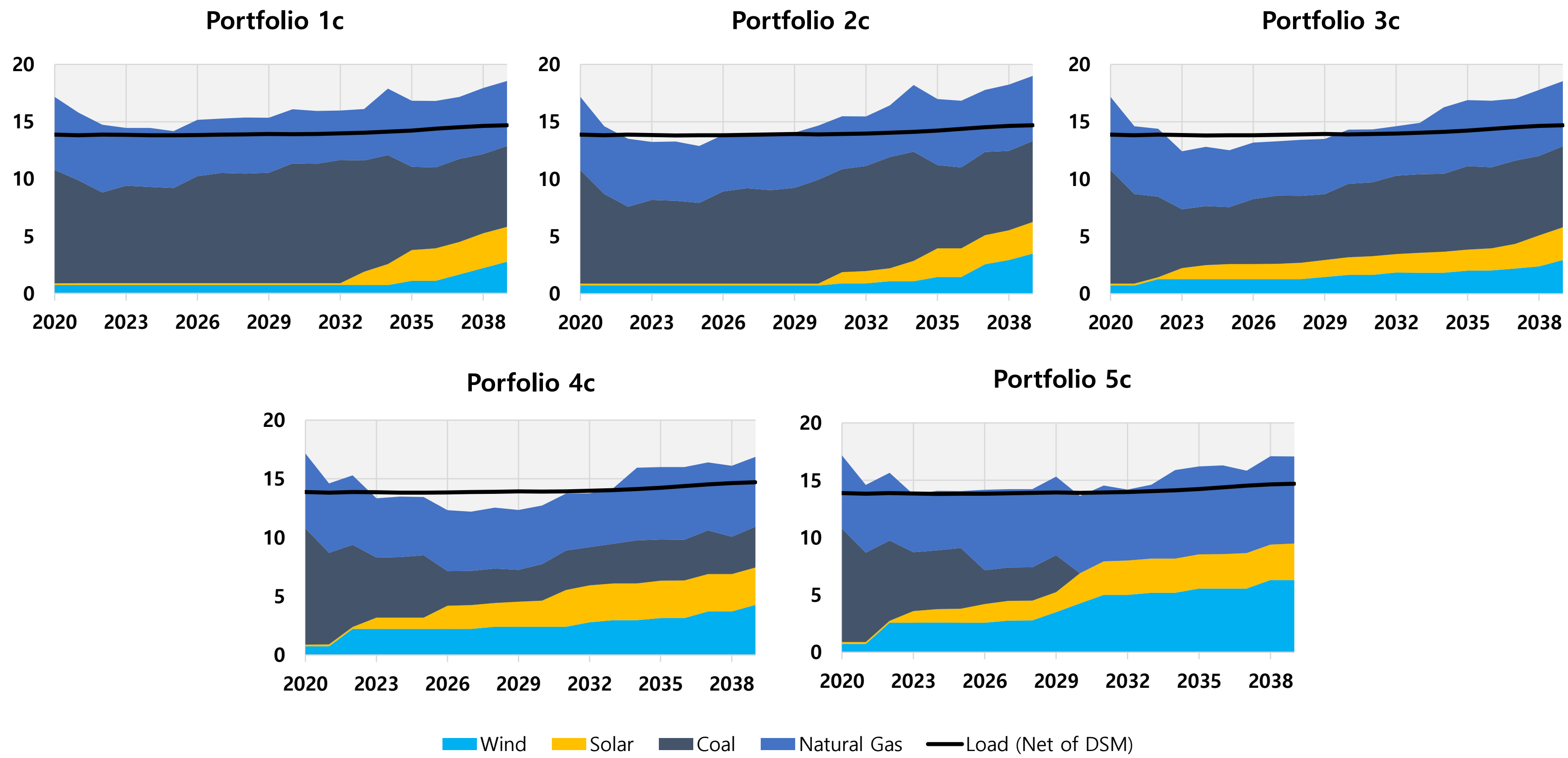


Figure 12 | Annual Energy (TWh) for Scenario A Portfolios 1c – 5c

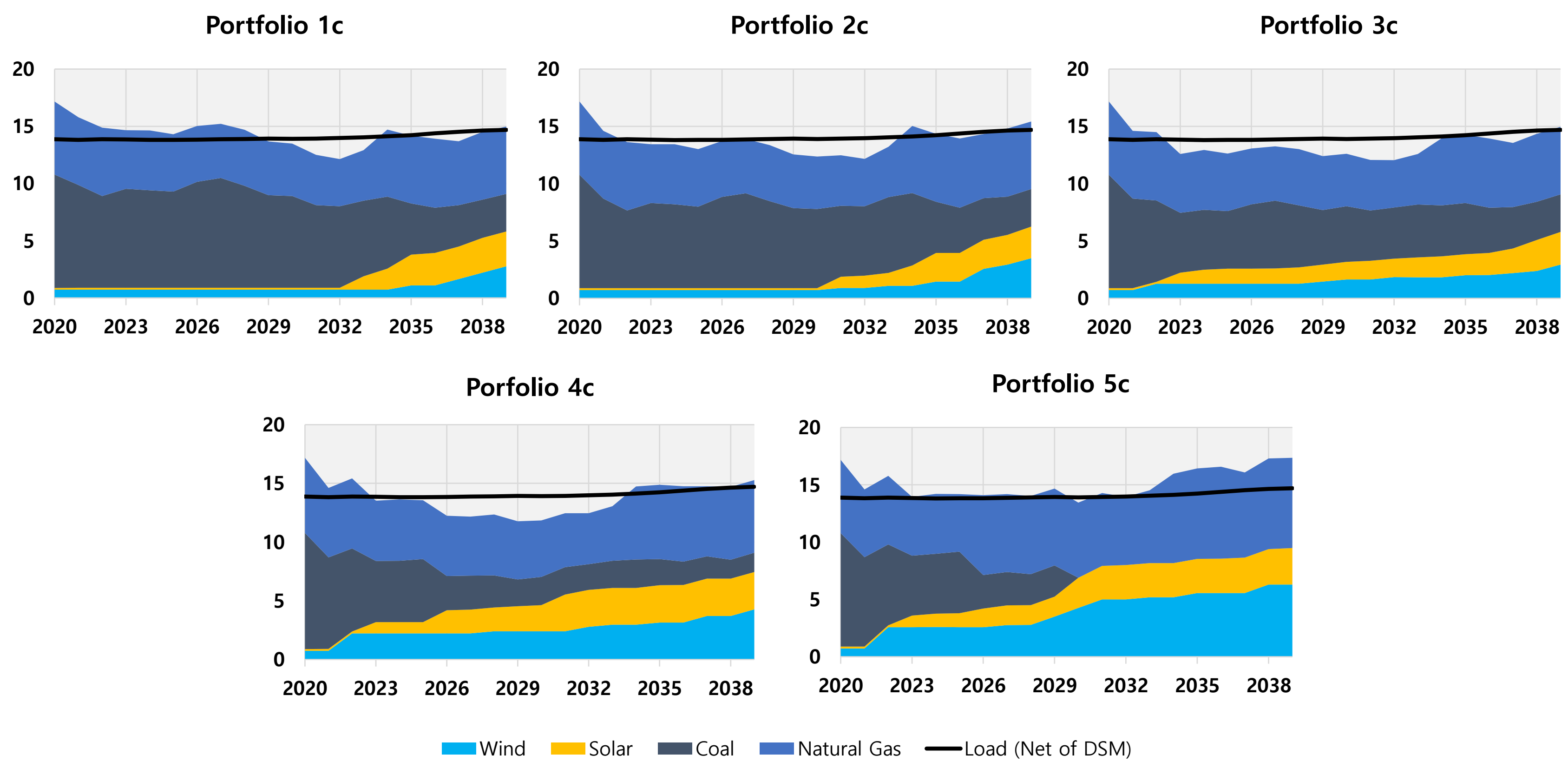


Figure 13 | Annual Energy (TWh) for Scenario B Portfolios 1c – 5c

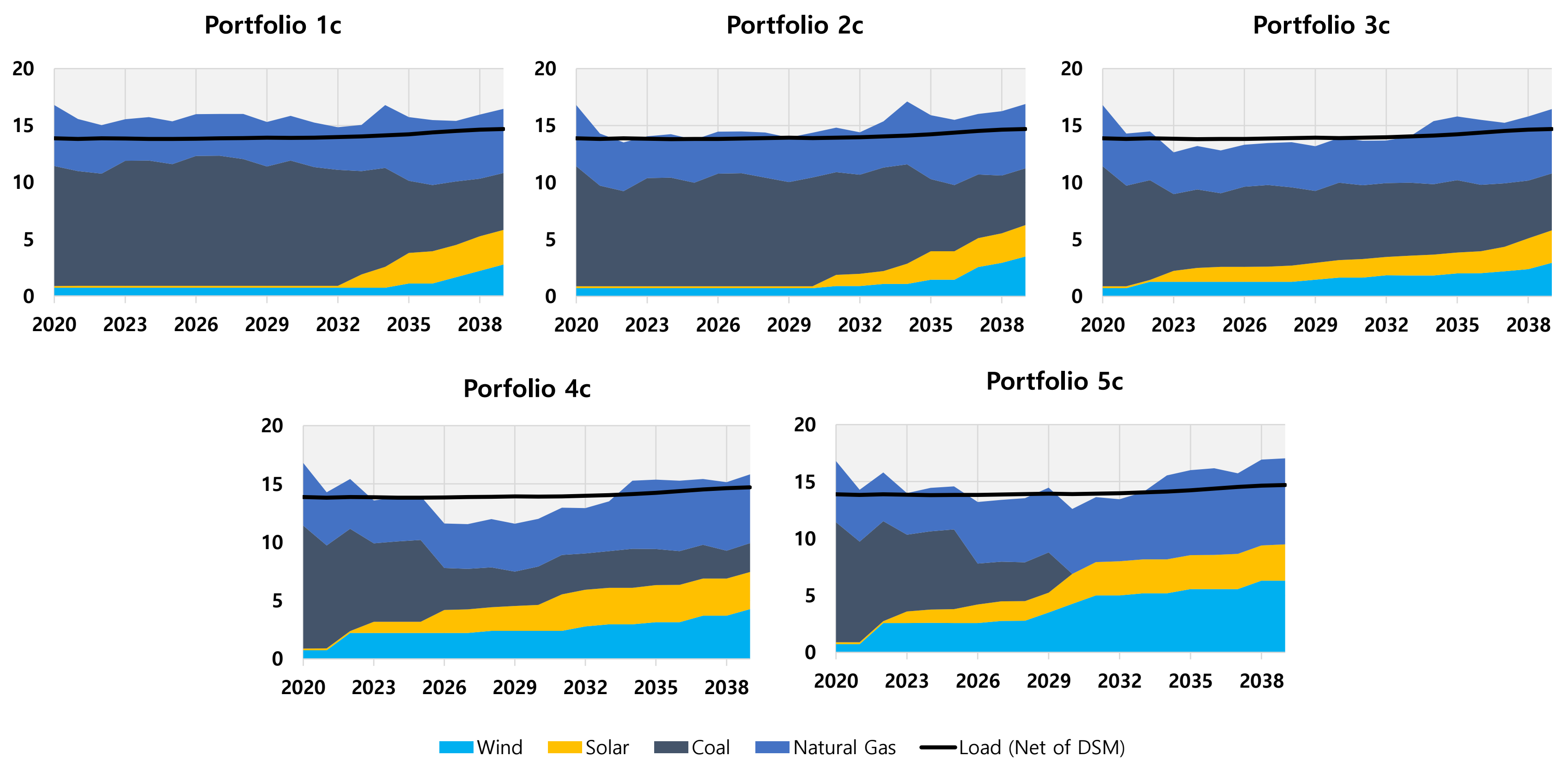


Figure 14 | Annual Energy (TWh) for Scenario C Portfolios 1c – 5c

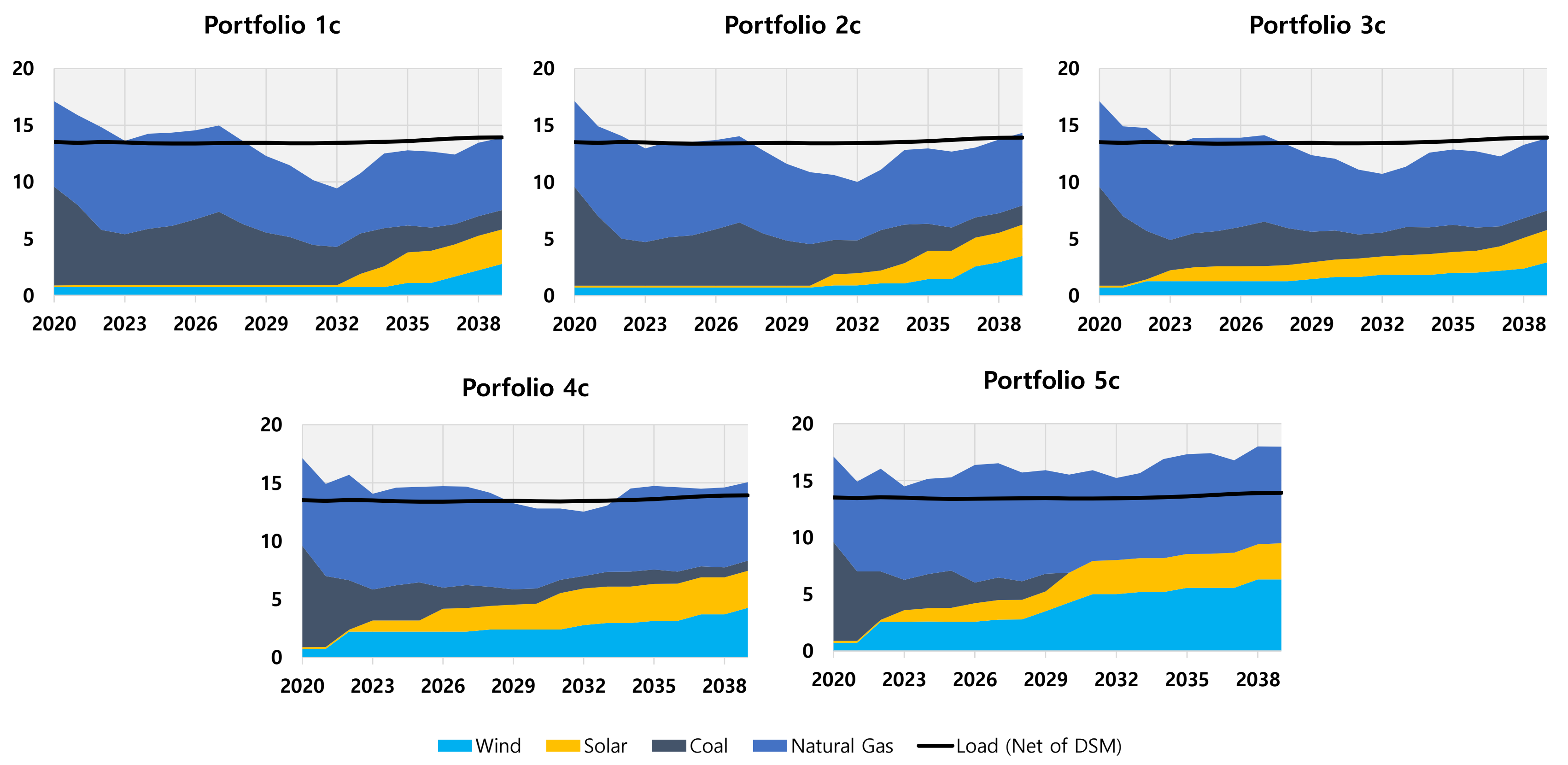
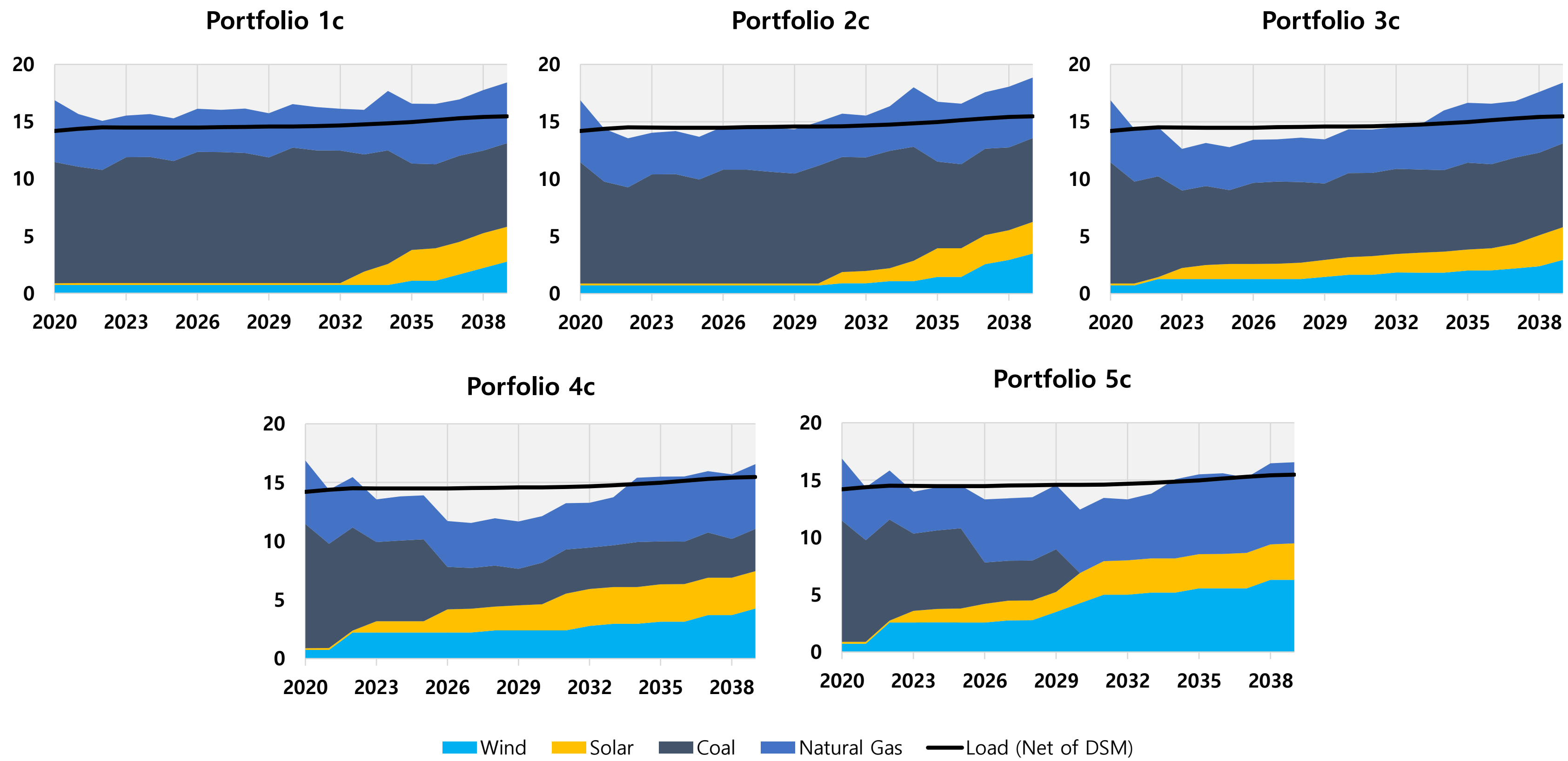


Figure 15 | Annual Energy (TWh) for Scenario D Portfolios 1c – 5c



Indianapolis Power & Light
Portfolio 1a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,373**	**3,370**	**3,366**	**3,328**	**3,327**	**3,326**	**3,326**	**3,325**	**3,324**	**3,324**	**3,134**	**3,133**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	8	8	20	20	55
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	119	129	231	243	254	282	277
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	95	190	475	494	494	532	532
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**29**	**42**	**56**	**69**	**83**	**97**	**110**	**123**	**135**	**146**	**157**	**388**	**810**	**1,206**	**1,238**	**1,263**	**1,331**	**1,364**
Total Resources	**3,381**	**3,391**	**3,400**	**3,409**	**3,383**	**3,396**	**3,409**	**3,422**	**3,435**	**3,447**	**3,459**	**3,281**	**3,290**	**3,296**	**3,323**	**3,352**	**3,383**	**3,408**	**3,475**	**3,508**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**21.8%**	**20.9%**	**20.4%**	**18.5%**	**17.9%**	**17.2%**	**16.4%**	**15.9%**	**15.6%**	**15.2%**	**8.5%**	**7.8%**	**7.3%**	**7.3%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**

Indianapolis Power & Light

Portfolio 2a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**3,141**	**3,102**	**3,102**	**3,101**	**3,100**	**3,100**	**3,099**	**3,098**	**2,909**	**2,908**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	27	31
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	38	37	49	136	238	269	285	330	336
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	152	171	171	190	475	475	475	475	494
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**29**	**42**	**56**	**69**	**83**	**97**	**110**	**123**	**135**	**336**	**364**	**387**	**809**	**1,204**	**1,236**	**1,263**	**1,329**	**1,361**
Total Resources	**3,381**	**3,165**	**3,174**	**3,183**	**3,158**	**3,171**	**3,184**	**3,197**	**3,209**	**3,222**	**3,234**	**3,245**	**3,272**	**3,294**	**3,322**	**3,351**	**3,382**	**3,408**	**3,474**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**12.9%**	**12.4%**	**10.6%**	**10.1%**	**9.5%**	**8.8%**	**8.3%**	**8.0%**	**7.7%**	**7.3%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 3a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,736**	**2,735**	**2,734**	**2,734**	**2,733**	**2,543**	**2,543**	**2,542**	**2,147**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	20	20	20	20	20	20	20	20	20	20	20	20	20	27	27	31	31	35
New Utility-Scale Solar	0	0	0	168	177	186	205	205	221	227	218	210	212	203	197	191	186	205	270	295
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	38	76	76	76	95	95	95	114	323	342	361	475	494	532	532	532	532
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**49**	**268**	**328**	**351**	**383**	**416**	**445**	**464**	**487**	**699**	**730**	**750**	**1,175**	**1,204**	**1,238**	**1,263**	**1,330**	**1,362**
Total Resources	**3,381**	**3,165**	**3,194**	**3,043**	**3,065**	**3,087**	**3,118**	**3,151**	**3,179**	**3,198**	**3,220**	**3,242**	**3,273**	**3,292**	**3,322**	**3,351**	**3,383**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**13.6%**	**7.5%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 4a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	523	523	523	523	523	523	523	523	523	523
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**2,247**	**2,058**	**2,057**	**2,056**	**1,661**	**1,661**	**1,660**	**1,660**	**1,659**	**1,659**
New Wind	0	0	12	20	20	27	43	47	47	47	55	62	66	70	74	74	74	90	90	105
New Utility-Scale Solar	0	0	0	202	250	255	419	436	451	437	421	405	402	392	381	383	378	366	354	348
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	323	323	323	342	361	570	589	608	722	741	779	798	874	893
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**41**	**263**	**325**	**351**	**867**	**903**	**930**	**949**	**972**	**1,184**	**1,214**	**1,237**	**1,660**	**1,690**	**1,723**	**1,749**	**1,815**	**1,846**
Total Resources	**3,381**	**3,165**	**3,186**	**3,039**	**3,062**	**3,087**	**3,117**	**3,152**	**3,179**	**3,197**	**3,219**	**3,242**	**3,271**	**3,293**	**3,322**	**3,350**	**3,383**	**3,408**	**3,474**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**13.3%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 5a

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	0	0	0	0	0	0	0	0	0	0
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**1,724**	**1,535**	**1,534**	**1,533**	**1,138**	**1,138**	**1,137**	**1,137**	**1,136**	**1,136**
New Wind	0	0	39	39	39	47	51	51	62	66	78	86	86	86	90	90	94	101	109	113
New Utility-Scale Solar	0	0	0	202	218	216	353	356	340	324	328	315	314	308	333	337	326	322	342	348
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	19	19	285	304	323	342	551	760	779	798	874	893	931	950	988	1,007
New Gas CC	0	0	0	0	0	0	0	0	0	0	308	308	308	308	615	615	615	615	615	615
New Gas CT	0	0	0	0	0	0	95	95	95	95	95	95	95	95	95	95	95	95	95	95
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	15	27	40	54	67	80	94	107	120	132	143	154	163	172	180	181	184	185	187
Subtotal: New Resources	**2**	**17**	**68**	**283**	**332**	**350**	**866**	**902**	**930**	**950**	**1,494**	**1,710**	**1,738**	**1,761**	**2,182**	**2,213**	**2,246**	**2,271**	**2,339**	**2,370**
Total Resources	**3,381**	**3,165**	**3,213**	**3,058**	**3,069**	**3,086**	**3,116**	**3,152**	**3,179**	**3,198**	**3,218**	**3,244**	**3,272**	**3,294**	**3,321**	**3,351**	**3,383**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.7%**	**14.3%**	**8.0%**	**7.5%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light

Portfolio 1b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,373**	**3,370**	**3,366**	**3,328**	**3,327**	**3,326**	**3,326**	**3,325**	**3,324**	**3,324**	**3,134**	**3,133**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	12	43
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	140	245	363	352	360	348	342
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	38	38	304	342	342	418	418
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**38**	**55**	**71**	**88**	**105**	**122**	**139**	**155**	**170**	**183**	**196**	**387**	**810**	**1,206**	**1,238**	**1,262**	**1,331**	**1,362**
Total Resources	**3,381**	**3,395**	**3,409**	**3,421**	**3,399**	**3,415**	**3,431**	**3,447**	**3,464**	**3,479**	**3,494**	**3,318**	**3,330**	**3,294**	**3,322**	**3,353**	**3,383**	**3,407**	**3,476**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**21.9%**	**21.2%**	**20.8%**	**19.0%**	**18.6%**	**18.0%**	**17.3%**	**16.9%**	**16.7%**	**16.3%**	**9.7%**	**9.1%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**

Indianapolis Power & Light

Portfolio 2b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**3,141**	**3,102**	**3,102**	**3,101**	**3,100**	**3,100**	**3,099**	**3,098**	**2,909**	**2,908**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	8	8	8	8	8	8	35	39	39
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	105	102	112	218	238	230	223	282	307
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	38	57	57	57	323	361	361	361	361
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	95	95	95	95	95
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**38**	**55**	**71**	**88**	**105**	**122**	**139**	**155**	**170**	**334**	**363**	**385**	**809**	**1,202**	**1,238**	**1,263**	**1,330**	**1,360**
Total Resources	**3,381**	**3,170**	**3,183**	**3,196**	**3,174**	**3,190**	**3,206**	**3,222**	**3,239**	**3,254**	**3,269**	**3,243**	**3,271**	**3,293**	**3,322**	**3,349**	**3,383**	**3,408**	**3,475**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**13.2%**	**12.9%**	**11.2%**	**10.8%**	**10.2%**	**9.6%**	**9.3%**	**9.1%**	**8.8%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 3b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,736**	**2,735**	**2,734**	**2,734**	**2,733**	**2,543**	**2,543**	**2,542**	**2,147**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	8	8	8	8	8	8	12	12	12	12	12	20	20	20	20	23	35	43
New Utility-Scale Solar	0	0	0	202	250	255	270	267	255	259	265	278	292	294	286	284	275	291	324	342
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	19	38	38	38	228	228	228	342	361	399	399	418	418
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**46**	**264**	**329**	**351**	**382**	**415**	**444**	**464**	**485**	**701**	**728**	**750**	**1,174**	**1,204**	**1,237**	**1,262**	**1,331**	**1,362**
Total Resources	**3,381**	**3,170**	**3,191**	**3,039**	**3,066**	**3,087**	**3,118**	**3,150**	**3,178**	**3,197**	**3,218**	**3,244**	**3,271**	**3,292**	**3,321**	**3,350**	**3,383**	**3,407**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**13.5%**	**7.3%**	**7.4%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 4b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	523	523	523	523	523	523	523	523	523	523
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**2,247**	**2,058**	**2,057**	**2,056**	**1,661**	**1,661**	**1,660**	**1,660**	**1,659**	**1,659**
New Wind	0	0	31	31	31	31	31	31	43	43	47	47	55	62	62	66	74	86	98	98
New Utility-Scale Solar	0	0	0	190	229	235	409	427	425	429	413	405	394	378	367	363	365	353	348	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	228	228	228	228	247	456	475	494	608	627	646	665	722	741
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	95	95	95	95	95	95	95	95	95	95	95	95	95	95
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**69**	**276**	**331**	**354**	**868**	**903**	**930**	**950**	**972**	**1,186**	**1,215**	**1,238**	**1,659**	**1,690**	**1,723**	**1,747**	**1,816**	**1,846**
Total Resources	**3,381**	**3,170**	**3,215**	**3,052**	**3,068**	**3,090**	**3,118**	**3,152**	**3,178**	**3,198**	**3,220**	**3,244**	**3,272**	**3,294**	**3,321**	**3,351**	**3,383**	**3,407**	**3,475**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**14.3%**	**7.8%**	**7.5%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 5b

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	0	0	0	0	0	0	0	0	0	0
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**1,724**	**1,535**	**1,534**	**1,533**	**1,138**	**1,138**	**1,137**	**1,137**	**1,136**	**1,136**
New Wind	0	0	27	27	27	27	27	27	31	35	35	35	35	43	43	47	47	62	78	86
New Utility-Scale Solar	0	0	0	190	229	235	409	427	434	413	413	405	402	385	394	389	378	366	354	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	19	19	19	38	285	494	513	532	627	646	684	703	760	779
New Gas CC	0	0	0	0	0	0	308	308	308	308	308	308	308	308	615	615	615	615	615	615
New Gas CT	0	0	0	0	0	0	0	0	0	0	284	284	284	284	284	284	284	284	284	284
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	19	36	53	69	86	103	119	136	152	167	180	193	205	216	228	232	237	242	247
Subtotal: New Resources	**2**	**22**	**66**	**272**	**327**	**351**	**868**	**903**	**930**	**948**	**1,496**	**1,709**	**1,738**	**1,760**	**2,183**	**2,213**	**2,244**	**2,272**	**2,337**	**2,370**
Total Resources	**3,381**	**3,170**	**3,211**	**3,048**	**3,064**	**3,087**	**3,118**	**3,152**	**3,179**	**3,196**	**3,220**	**3,244**	**3,272**	**3,294**	**3,322**	**3,351**	**3,381**	**3,408**	**3,473**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**13.8%**	**14.2%**	**7.6%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 1c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,373**	**3,370**	**3,366**	**3,328**	**3,327**	**3,326**	**3,326**	**3,325**	**3,324**	**3,324**	**3,134**	**3,133**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	20	31	43
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	140	224	330	339	329	342	336
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	285	304	323	361	380
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**62**	**82**	**102**	**123**	**143**	**163**	**181**	**200**	**215**	**229**	**385**	**809**	**1,202**	**1,236**	**1,262**	**1,330**	**1,363**
Total Resources	**3,381**	**3,398**	**3,414**	**3,429**	**3,410**	**3,429**	**3,449**	**3,469**	**3,488**	**3,505**	**3,524**	**3,349**	**3,362**	**3,293**	**3,322**	**3,348**	**3,382**	**3,407**	**3,475**	**3,507**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**22.1%**	**21.4%**	**21.1%**	**19.4%**	**19.1%**	**18.6%**	**18.0%**	**17.7%**	**17.5%**	**17.3%**	**10.7%**	**10.2%**	**7.2%**	**7.2%**	**7.1%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**

Indianapolis Power & Light
Portfolio 2c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**3,141**	**3,102**	**3,102**	**3,101**	**3,100**	**3,100**	**3,099**	**3,098**	**2,909**	**2,908**	**2,908**	**2,513**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	0	0	0	0	0	0	0	0	0	4	4	8	8	16	16	39	47	59
New Utility-Scale Solar	0	0	0	0	0	0	0	0	0	0	0	120	131	133	218	304	294	291	288	301
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	304	342	342	399	399
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**62**	**82**	**102**	**123**	**143**	**163**	**181**	**200**	**339**	**364**	**386**	**810**	**1,202**	**1,237**	**1,263**	**1,330**	**1,362**
Total Resources	**3,381**	**3,173**	**3,188**	**3,203**	**3,185**	**3,204**	**3,224**	**3,244**	**3,263**	**3,280**	**3,298**	**3,248**	**3,272**	**3,293**	**3,323**	**3,348**	**3,383**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.4%**	**13.1%**	**11.5%**	**11.3%**	**10.8%**	**10.3%**	**10.1%**	**10.0%**	**9.8%**	**7.4%**	**7.3%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light
Portfolio 3c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,736**	**2,735**	**2,734**	**2,734**	**2,733**	**2,543**	**2,543**	**2,542**	**2,147**	**2,146**	**2,146**	**2,145**	**2,145**	**2,144**
New Wind	0	0	12	12	12	12	12	12	12	16	20	20	23	23	23	27	27	31	35	47
New Utility-Scale Solar	0	0	0	179	218	225	214	205	213	211	211	218	212	217	224	218	224	242	300	313
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	19	19	19	38	57	57	57	57	247	266	266	361	380	399	399	399	399
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**55**	**272**	**332**	**358**	**386**	**417**	**444**	**464**	**487**	**699**	**730**	**752**	**1,175**	**1,204**	**1,236**	**1,262**	**1,330**	**1,362**
Total Resources	**3,381**	**3,173**	**3,200**	**3,048**	**3,068**	**3,094**	**3,122**	**3,152**	**3,178**	**3,198**	**3,220**	**3,242**	**3,272**	**3,294**	**3,322**	**3,350**	**3,381**	**3,408**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.8%**	**7.6%**	**7.5%**	**7.5%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Indianapolis Power & Light

Portfolio 4c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	523	523	523	523	523	523	523	523	523	523
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**2,247**	**2,058**	**2,057**	**2,056**	**1,661**	**1,661**	**1,660**	**1,660**	**1,659**	**1,659**
New Wind	0	0	0	0	0	16	31	31	35	35	35	35	43	47	47	51	51	62	62	74
New Utility-Scale Solar	0	0	0	179	166	157	335	329	315	316	320	443	431	413	401	396	384	372	360	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	19	76	76	190	209	228	228	228	304	323	342	361	380	418	437	513	532
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	308	308	308	308	308	308
New Gas CT	0	0	0	0	0	0	190	190	190	190	190	190	190	190	284	284	284	284	284	284
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**261**	**325**	**351**	**868**	**903**	**930**	**949**	**972**	**1,186**	**1,215**	**1,237**	**1,659**	**1,690**	**1,722**	**1,746**	**1,816**	**1,848**
Total Resources	**3,381**	**3,173**	**3,188**	**3,036**	**3,062**	**3,087**	**3,118**	**3,152**	**3,179**	**3,197**	**3,220**	**3,244**	**3,272**	**3,293**	**3,321**	**3,351**	**3,382**	**3,406**	**3,475**	**3,506**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.4%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.3%**

Indianapolis Power & Light
Portfolio 5c

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Existing Coal	1,599	1,374	1,374	1,009	1,009	1,009	523	523	523	523	0	0	0	0	0	0	0	0	0	0
Existing Natural Gas	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,633	1,444	1,444	1,444	1,050	1,050	1,050	1,050	1,050	1,050
Existing Oil	37	37	37	37	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Other (Wind/Solar/DR)	54	49	46	42	40	39	39	38	37	37	36	35	35	34	33	33	32	31	31	30
Existing CVR / ACLM / Rider 17	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Subtotal: Existing Resources	**3,378**	**3,148**	**3,145**	**2,775**	**2,737**	**2,736**	**2,250**	**2,249**	**2,249**	**2,248**	**1,724**	**1,535**	**1,534**	**1,533**	**1,138**	**1,138**	**1,137**	**1,137**	**1,136**	**1,136**
New Wind	0	0	0	12	16	23	35	43	43	59	74	90	90	94	94	101	101	101	117	117
New Utility-Scale Solar	0	0	0	190	208	206	270	276	264	251	382	413	409	392	381	370	358	360	348	354
New Distributed Solar	2	2	2	2	2	2	2	2	3	3	3	3	3	3	4	4	4	4	5	5
New Battery Storage	0	0	0	0	19	19	133	133	152	152	532	684	703	722	836	855	893	912	969	988
New Gas CC	0	0	0	0	0	0	308	308	308	308	308	308	308	308	615	615	615	615	615	615
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Aero CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Reciprocating Engines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New DSM	0	23	41	60	80	100	120	141	160	178	197	212	226	242	255	268	274	279	284	291
Subtotal: New Resources	**2**	**25**	**43**	**264**	**325**	**350**	**868**	**903**	**929**	**950**	**1,496**	**1,709**	**1,738**	**1,760**	**2,184**	**2,212**	**2,246**	**2,271**	**2,338**	**2,370**
Total Resources	**3,381**	**3,173**	**3,188**	**3,040**	**3,062**	**3,086**	**3,118**	**3,152**	**3,177**	**3,198**	**3,220**	**3,244**	**3,272**	**3,294**	**3,322**	**3,350**	**3,383**	**3,407**	**3,474**	**3,505**
Base Peak Load Forecast	2,772	2,783	2,810	2,829	2,852	2,875	2,904	2,934	2,957	2,974	2,993	3,012	3,035	3,054	3,077	3,100	3,128	3,148	3,208	3,234
EV Peak Load	1	1	2	2	3	4	5	6	7	9	11	13	16	18	21	24	27	30	33	35
Base Peak Load Plus EV	2,773	2,784	2,812	2,831	2,855	2,879	2,908	2,940	2,964	2,982	3,003	3,025	3,051	3,072	3,098	3,125	3,155	3,178	3,241	3,269
Reserve Margin	**21.9%**	**14.0%**	**13.4%**	**7.4%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**	**7.2%**

Figure 1 | Market Purchases/Sales of Portfolios 2a – 5a Compared to Portfolio 1a in the Reference Case

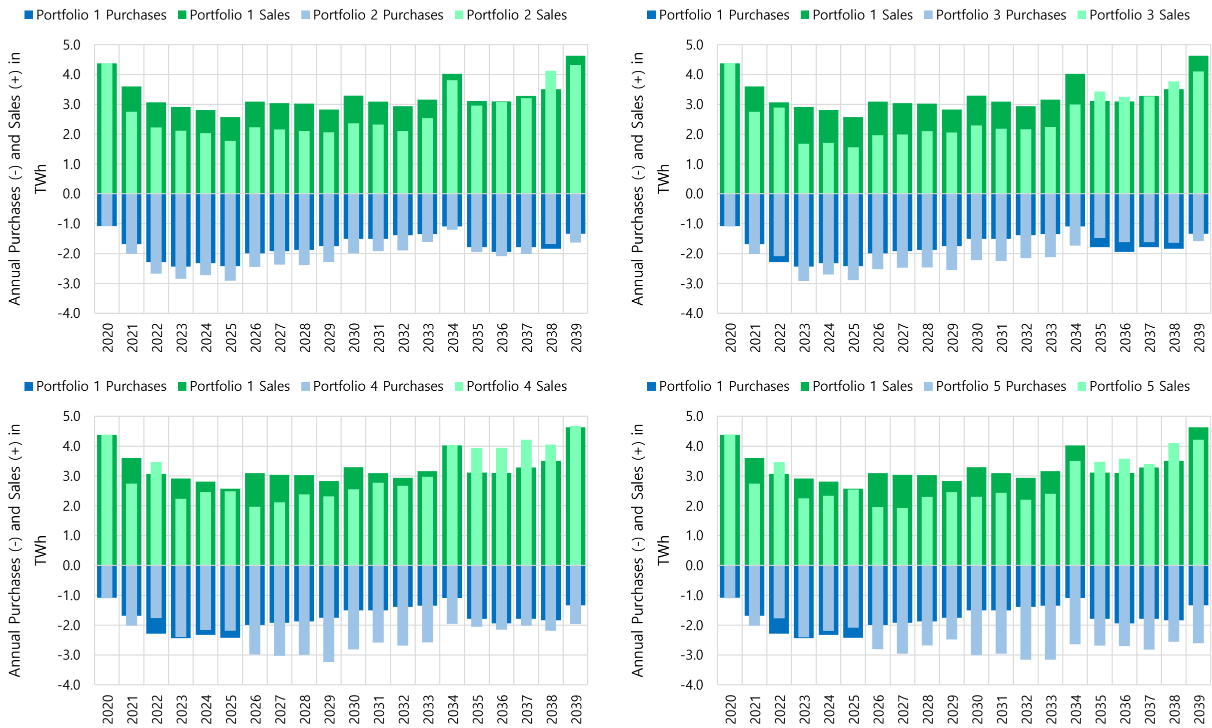


Figure 2 | Market Purchases/Sales of Portfolios 2a – 5a Compared to Portfolio 1a in Scenario A

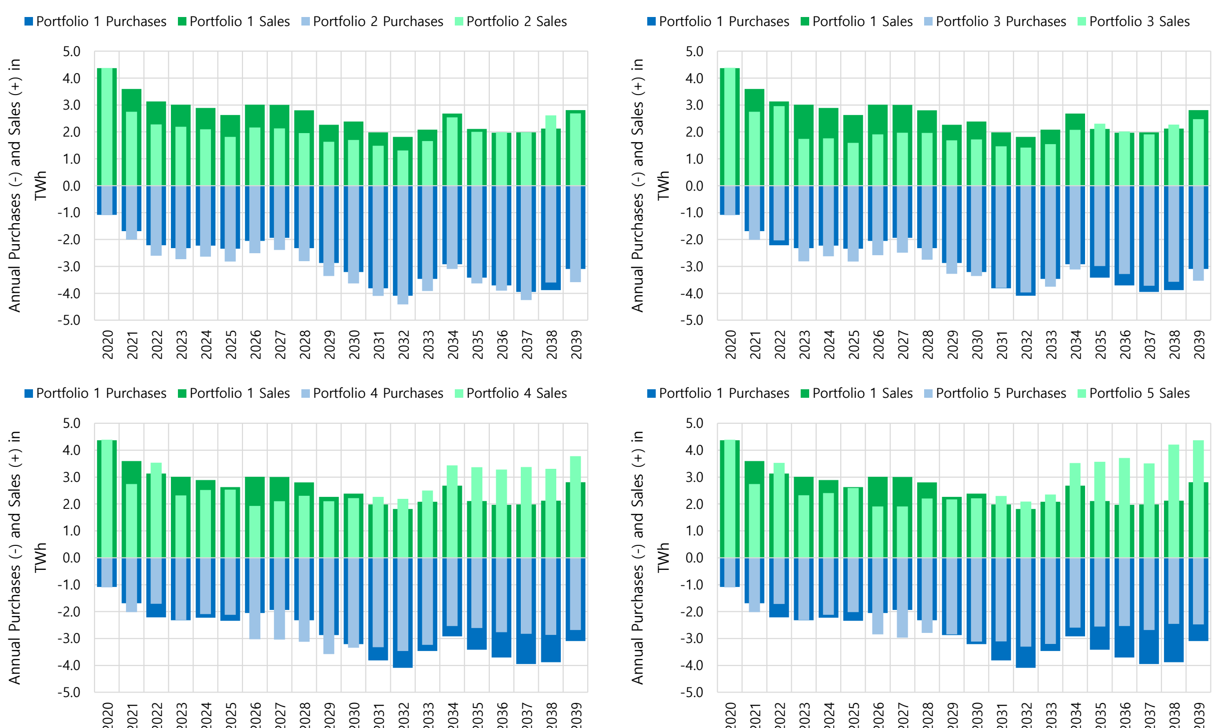


Figure 3 | Market Purchases/Sales of Portfolios 2b – 5b Compared to Portfolio 1b in the Reference Case

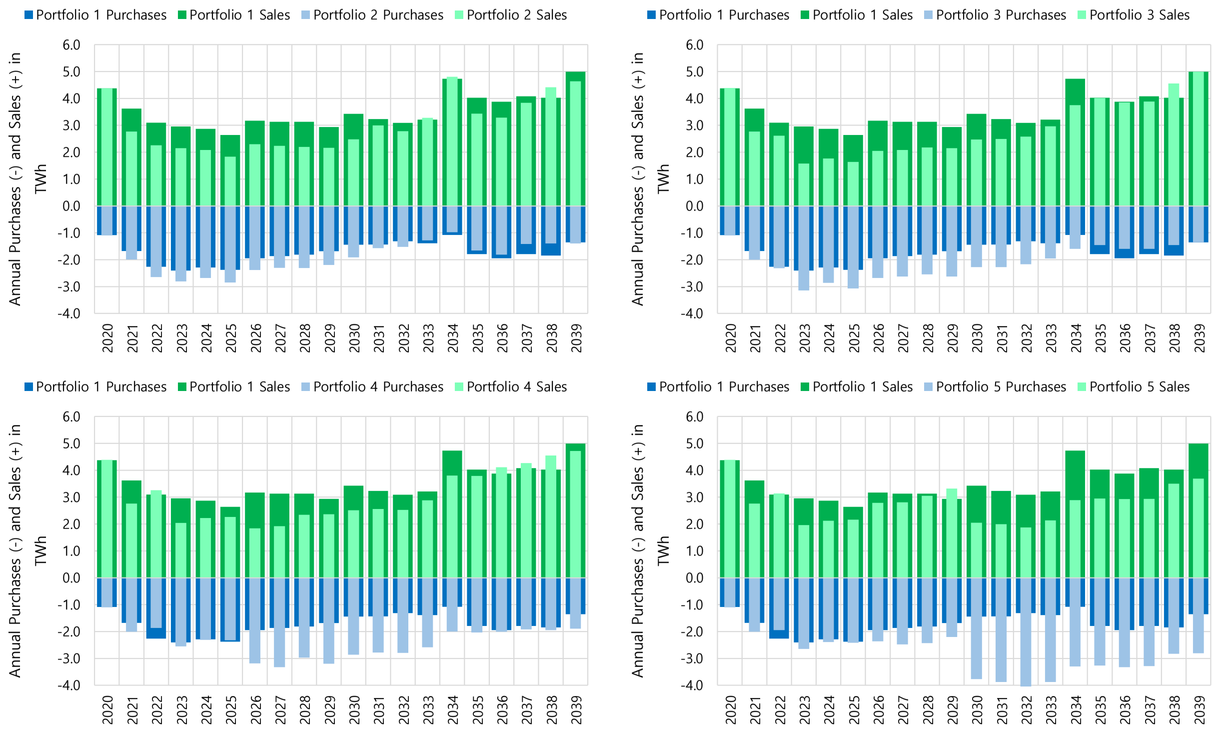


Figure 4 | Market Purchases/Sales of Portfolios 2b – 5b Compared to Portfolio 1b in Scenario A

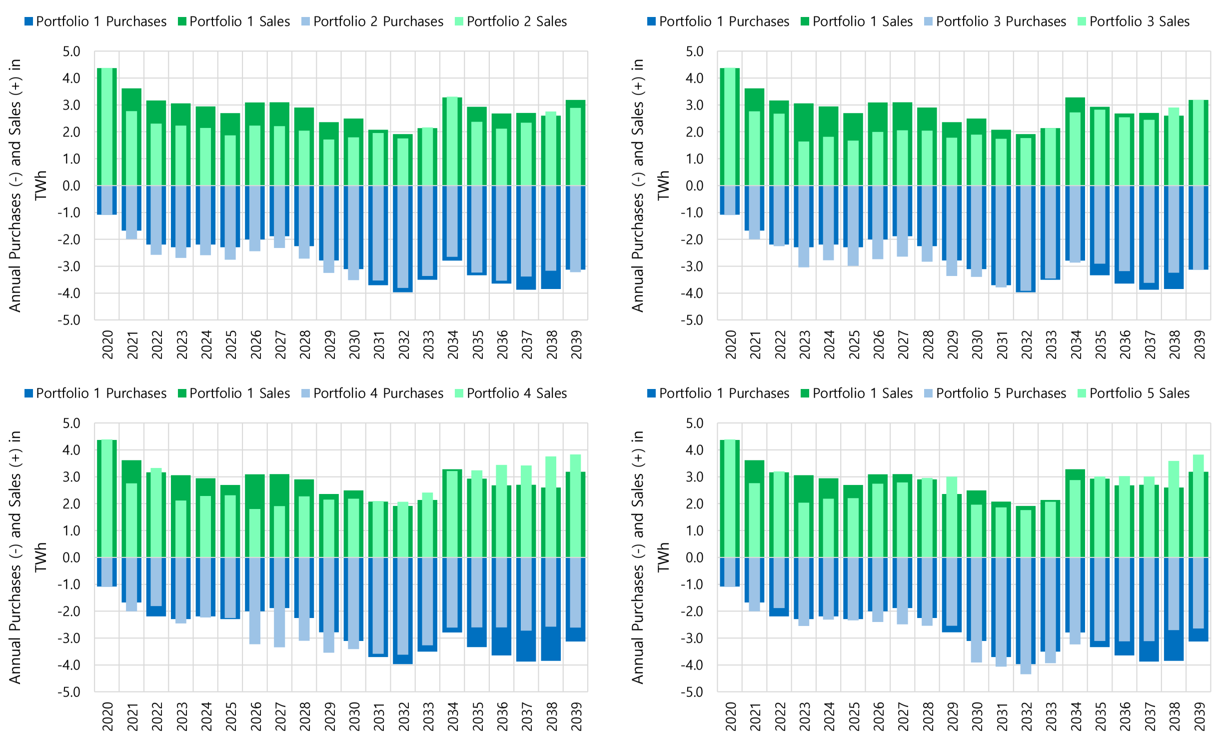


Figure 5 | Market Purchases/Sales of Portfolios 2c – 5c Compared to Portfolio 1c in the Reference Case

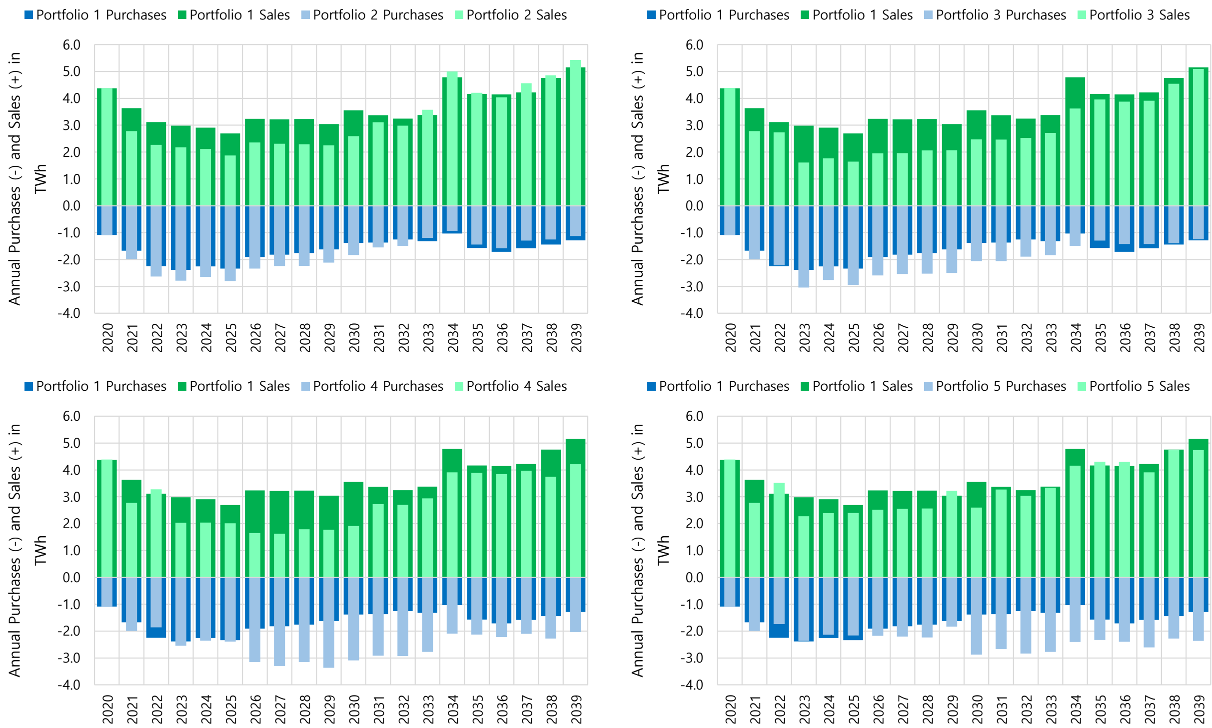


Figure 6 | Market Purchases/Sales of Portfolios 2c – 5c Compared to Portfolio 1c in Scenario A