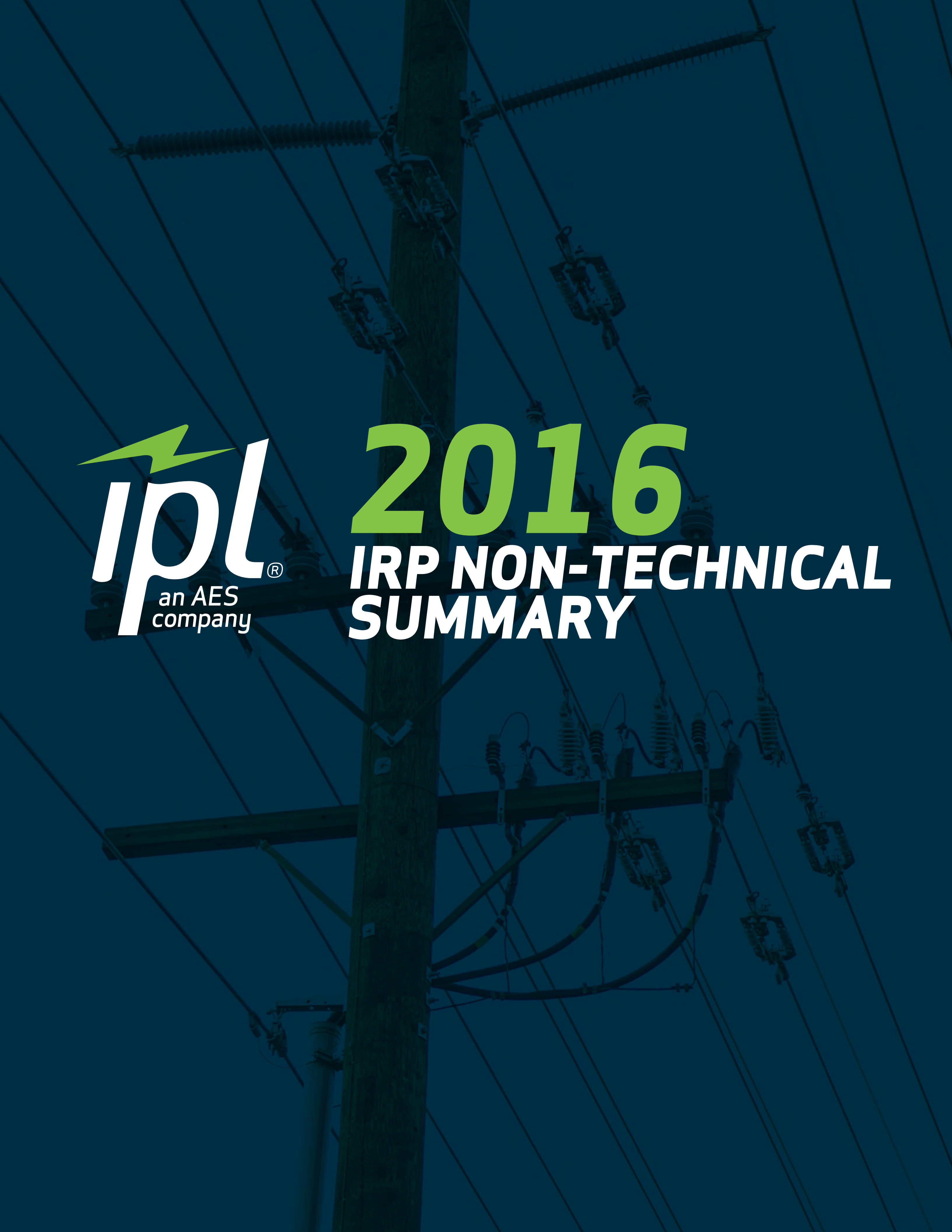
Indianapolis Power & Light Company

2016 Integrated Resource Plan

Public Version

Volume 2 of 3

November 1, 2016



2016
IRP NON-TECHNICAL SUMMARY

BACKGROUND

Indianapolis Power & Light Company ("IPL") is committed to improving lives by providing safe, reliable, and sustainable energy solutions to more than 480,000 residential, commercial and industrial customers in Indianapolis and surrounding central Indiana communities. The compact service area measures approximately 528 square miles. The Company, which is headquartered in Indianapolis, 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").

Effective planning is integral to serving customers , including anticipating and reacting to changes in technology, public policy, and public perception. A particular section of planning results in an Integrated Resource Plan ("IRP"), which is the subject of this document. Every two years, IPL submits an IRP to the Indiana Utility Regulatory Commission ("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 propose candidate resource portfolios 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.

IRP OBJECTIVE

The objective of IPL's 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.

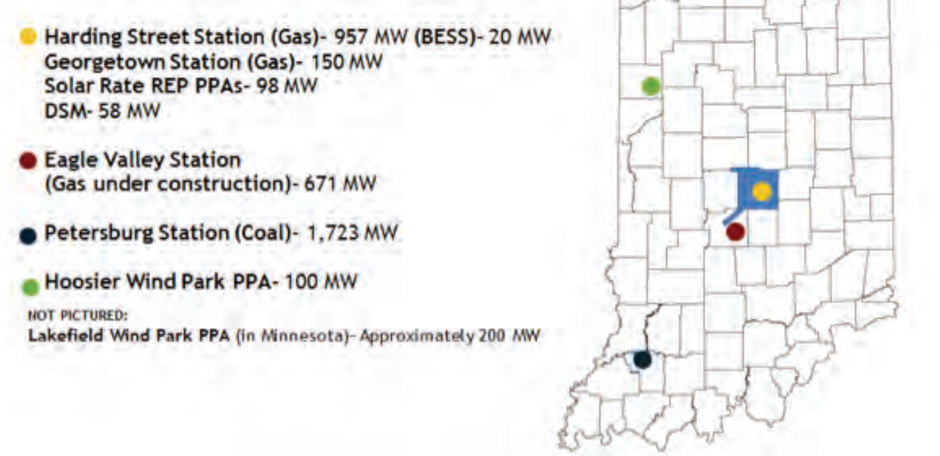
IRP Process

IPL starts the IRP process by modeling its existing resource mix and forecasts customer energy and peak requirements. The existing resources include Demand Side Management (DSM), approximately 2,700 MW of generating resources, and long term contracts known as purchase power agreements ("PPAs") for approximately 96 MW of solar generation and approximately 300 MW of wind generation. Under the terms of the PPAs, IPL receives all of the energy and Renewable Energy Credits ("RECs") associated with the wind and solar PPAs which it currently sells to offset the cost of this energy to customers.

However, IPL reserves the right to use RECs to meet any future environmental requirement, such as the EPA's Clean Power Plan ("CPP").

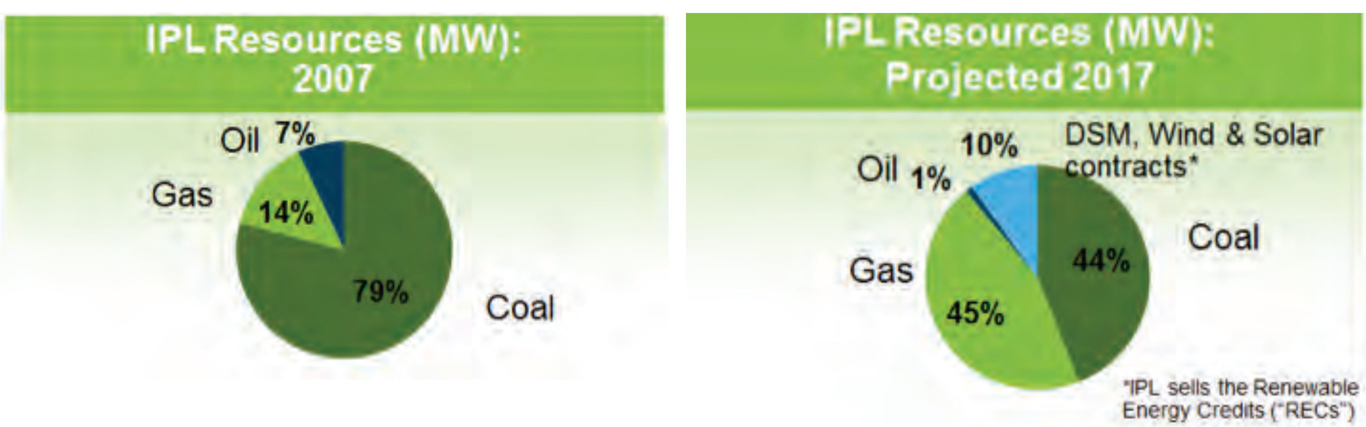
Figure 1 highlights IPL's service territory and resources.

Figure 1 - IPL Resources



Since 2007, IPL has been a leader in moving towards cleaner resources as shown in Figure 2.

Figure 2 - IPL Resources



IPL identifies potential supply-side resources such as wind, solar, energy storage, or natural gas generation, and demand-side resources such as additional energy efficiency programs , for the IRP model to select to meet future customer energy requirements.

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*The null energy of the Wind PPAs is used to supply the load for IPL customers, and in the absence of any Renewable Portfolio Standards (RPS) mandates, IPL is currently selling the associated RECS, but reserves the right to use RECs from the Wind PPAs to meet any future RPS requirement. The Wind PPAs were approved by the IURC and if IPL chooses to monetize the RECs that result from the agreements, IPL shall use the revenues to first offset the cost of the Wind PPAs and next to credit IPL customers through its fuel adjustment clause proceedings. The Green-e Dictionary (http://green-e.org/learn_dictionary.shtml) defines null power as, "Electricity that is stripped of its attributes and undifferentiated. No specific rights to claim fuel source or environmental impacts are allowed for null electricity. Also referred to as commodity or system electricity."

The electric utility industry 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. In this IRP, IPL incorporated potential risks quantitatively and qualitatively in six scenarios summarized in Figure 3.

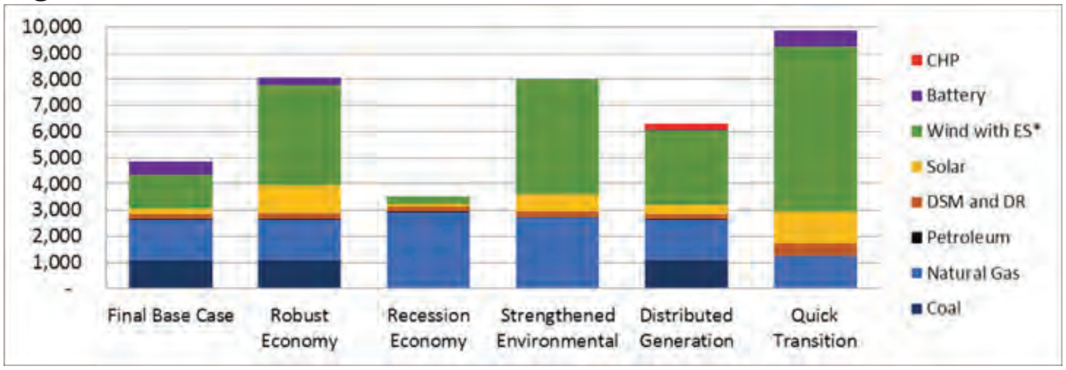
Figure 3 - IRP Scenario Drivers

Scenario Name		Load Forecast	Natural Gas and Market Prices	Clean Power Plan (CPP) and Environment	Distributed Generation (DG)
1	**Base Case**	Use current load growth methodology	Prices derived from an ABB Mass-based CPP Scenario	CPP starting in 2022, Low cost environmental regulations	Expected moderate decreases in technology costs for wind, storage, and solar
2	**Robust Economy**	**High**	**High**	Base Case	Base Case
3	**Recession Economy**	**Low**	**Low**	Base Case	Base Case
4	**Strengthened Environmental Rules**	Base Case	Base Case	**20% RPS, high cost CPP and environmental regulations**	Base Case
5	**Distributed Generation**	Base Case	Base Case	Base Case	**Fixed additions of 150 MW DG in 2022, 2025, and 2032**
6	**Quick Transition**	Base Case	Base Case	Base Case	**Fixed portfolio to retire coal, add max DSM, minimum baseload (NG), plus solar, wind and storage**

The IRP model produces potential candidate future resource portfolios in light of uncertainties and risk factors identified to date. "Unknown unknowns", such as public policy changes not yet proposed or unexpected future environmental regulations are not included, which could affect implementation plans. Subsequent specific resource changes are based upon competitive processes with detailed regulatory filings such as DSM or Certificate of Public Convenience and Necessity ("CPCN") proceedings before the Commission.

The candidate resource portfolios resulting from each scenario at the end of the 20 year IRP study period are shown in Figure 4.

Figure 4 - Candidate Resource Portfolios (MW in 2036)



The "Preferred Resource Portfolio" represents what IPL believes to be the most likely based on factors known at the time of the IRP filing. The "Preferred Resource Portfolio" based upon the lowest cost to customers in terms of the Present Value Revenue Requirement ("PVRR") would be the Base Case scenario. In addition to the traditional customer cost metric of PVRR, IPL developed metrics related to environmental stewardship, financial risk, resiliency, and rate impact metrics to compare the portfolios derived from multiple scenarios which are summarized in Figure 5.

Figure 5 - Metrics Summary

Scenarios	Cost		Financial Risk	Environmental Stewardship				Resiliency			
	20 yr PVRR ($ MN)	Rate Impact, 20 yr average (real cents/kWh)	Risk Exposure ($)	Average annual CO2 emissions (tons)	Average annual NOx emissions (tons)	Average annual SO2 emissions (tons)	Total CO2 intensity (tons/MWh)	Planning Reserves (lowest amount over 20 yrs)*	Distributed Generation (Max DG as percent of capacity over 20 yr)	Market Reliance for Energy (Max over 20 yrs)	Market Reliance for Capacity (Max MW over 20 yrs)
Base	$ 10,309	3.53	$1,324,989,546	12,883,603	13,181	11,808	0.79	15%	3%	9%	150
Robust Econ	$ 10,550	3.62	$1,303,754,944	12,883,183	13,181	11,808	0.70	27%	15%	9%	200
Recession Econ	$ 11,042	3.78	$1,463,842,563	3,334,067	1,925	593	0.44	3%	3%	58%	0
Streng Enviro	$ 11,990	4.11	$1,126,983,327	3,309,326	1,910	629	0.28	15%	10%	52%	50
Adopt of DG	$ 11,092	3.80	$1,294,337,690	13,219,942	12,910	10,874	0.78	15%	11%	9%	50
Quick Transition	$ 11,988	4.20	$1,311,247,113	5,403,645	4,320	3,243	0.32	15%	35%	57%	0

HYBRID PREFERRED RESOURCE PORTFOLIO

These metric results spurred discussions about how best to meet the future needs of customers. In the fourth public advisory meeting, IPL shared the Base Case as the preferred resource portfolio. However, subsequent review and stakeholder discussions prompted further developments which lead IPL to believe the ultimate preferred resource portfolio, designed to meet the broad mix of customer and societal needs, will likely be a hybrid of multiple model scenario results.

While the Base Case has the lowest PVRR, it also has the highest collective environmental emission results and least amount of DG penetration. The economic variables used to model environmental and DG costs reflect what is measurable today, for example, potential costs for future regulation. . The model does not include estimated costs for regulations not yet proposed, public policy changes which may occur in the study period or specific customer benefits of DG adoption such as avoided plant operational losses, grid independence or cyber security advantages.

Given that a blend of variables from the base case, strengthened environmental and DG scenarios appear likely to come to fruition , IPL contends that, at this point, a hybrid preferred resource portfolio may be a more appropriate solution.

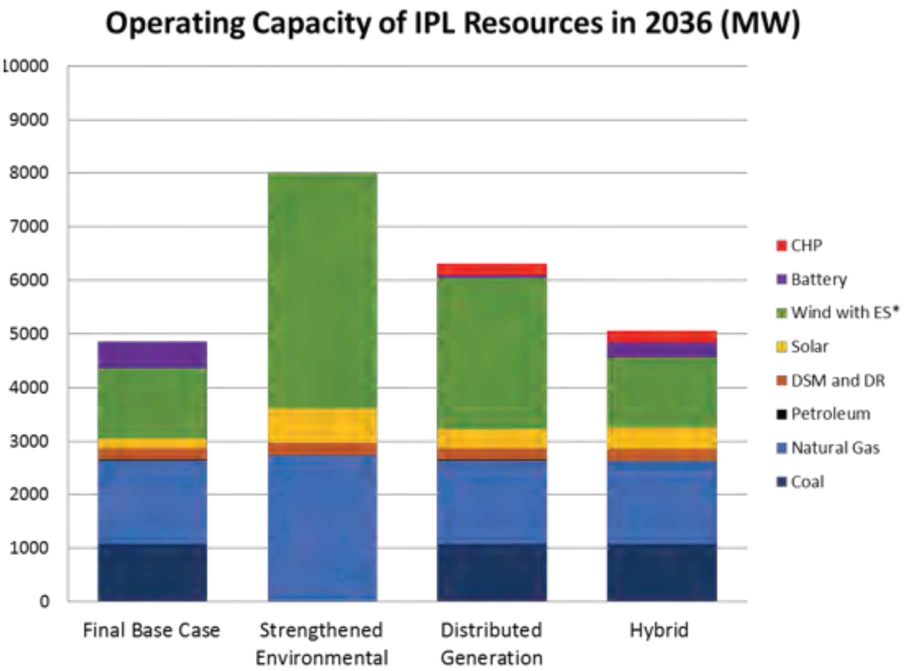
Under this scenario, a hybrid portfolio in 2036 could include two Pete coal units, (although these units would not necessarily serve as baseload generation but could be utilized more as a capacity resource), natural gas generation focused on local system reliability, wind to serve load during non-peak periods, and an average of DSM, solar, energy storage levels from the three scenarios as summarized in Figures 6 and 7.

Figure 6 – Summary of Resources (MW cumulative changes 2017-2036)

	Final Base Case	Strengthened Environmental	Distributed Generation	Hybrid
Coal	1078	0	1078	1078
Natural Gas	1565	2732	1565	1565
Petroleum	11	11	11	0
DSM and DR	208	218	208	212
Solar	196	645	352	398
Wind with ES*	1300	4400	2830	1300
Battery	500	0	50	283
CHP	0	0	225	225
totals	4858	8006	6319	5060

**Wind resources include small batteries for energy storage ("ES").*

Figure 7 – Candidate Resource Portfolios including Hybrid Option



IPL anticipates that additional potential changes not easily modeled may affect future resource portfolios such as the impacts of pending local gubernatorial and national Presidential election results, public policy changes, or stakeholder input.

Although the model selects specific resources in each scenario based upon current market conditions and what IPL knows today, as yet unidentified, cost effective resources may exist in the future. IPL will evaluate these resource options in subsequent IRPs to develop the best Preferred Portfolio based on updates to market and fuel price outlooks, future environmental regulations, relative costs of technologies, load forecasts and public policy changes.

Results of subsequent IRPs will likely vary from these IRP results. During this interim time period, IPL does not anticipate significant changes to the resource mix aside from DSM program expenditures and welcomes discussion with stakeholders. IPL invites continued stakeholder dialog and feedback following the filing of this IRP and anticipates scheduling an additional public advisory meeting to facilitate this in early 2017.

PUBLIC ADVISORY PROCESS

IPL hosted four Public Advisory meetings to discuss the IRP process with interested parties and solicit feedback from stakeholders. The meeting agendas from each meeting are highlighted in the box below. For all meeting notes, presentations and other materials see IPL's IRP webpage at IPLpower.com/irp.

Meeting #1

- Introduction to IPL's IRP Process
- Selectable Supply-side and Demand-side Resource Options
- Discussion of Risks
- Scenario Development

Meeting #2

- Stakeholder Presentations
- Resource Adequacy
- Transmission & Distribution
- Load Forecast
- Environmental Risks
- Modeling Update

Meeting #3

- Draft Model Results for all Scenarios

Meeting #4

- Final Model Results
    - Preferred Resource Portfolio
    - Metrics & Sensitivity Analysis Results
- Short Term Action Plan

IPL incorporated feedback from stakeholders to shape the scenarios develop metrics and clarify the data presented. IPL is planning an additional public meeting in early 2017 to listen to stakeholders feedback about the final IRP document.

2016 Short Term Action Plan

2016 Short Term Action Plan Items (2017-2019)		
Resource Changes	2017	Implement DSM proposed for 2017, seek approval for 2018-2020 DSM action plan
	2017	Complete EV CCGT Construction
	2018	Complete CCR/NAAQS-SO_2 Petersburg Upgrades
Transmission	2017	Upgrade (1) 138 kV line, replace (1) 345kV to 138 kV auto-transformer and continue long-term planning
	2018	Upgrade 3 substations, (3) 138 kV lines, and replace breakers at 2 substations and continue long-term planning
	2019	Implement projects identified in 2017 and 2018

CONCLUSION

It does not represent a planning play book, specific commitment or approval request to take any specific actions. The IRP forms a foundation for future regulatory requests based upon a holistic view of IPL's resource needs and portfolio options. IPL plans to conduct a public meeting to address questions and comments related to this IRP.

Integrated Resource Plan
Public Advisory Meeting #1

April 11, 2016

INDIANAPOLIS POWER & LIGHT COMPANY

Welcome and Safety Message

Bill Henley, VP of Regulatory and Government Affairs

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Meeting Guidelines and Stakeholder Process

Dr. Marty Rozelle, Facilitator

Agenda for today

8:30	Registration
9:00	Welcome
9:15	Agenda Review and Meeting Guidelines
9:30	Introduction to IPL's IRP Process
10:00	Supply Side & Distributed Resources
10:30	Demand Side Resources
11:15	Demand Side Management (DSM) Modeling
12:00	Lunch
12:45	Discussion of Risks
1:45	Discussion of Scenarios
2:45	Next Steps

Objectives

- Listen to diverse stakeholders
- Describe IRP planning process
- Engage in meaningful dialogue
- Continue relationship built on trust, respect and confidence

Note: IPL will use publicly available data as much as possible

Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions on risks and scenarios
- The phone line will be muted. During the allotted questions, press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
- Use WebEx online tool for questions during meeting
- Email additional questions or comments by April 18
- IPL will respond via website by May 2

Meeting #2

- Date: June 14, 2016
- In response to your request,
  ~60 to 90 minutes will be reserved for listening to stakeholders' points of view.
- Let us know by May 17 if you plan to speak by emailing ipl.irp@aes.com
- Pre-registered speakers will split allocated time

Introduction to IPL's IRP

Joan Soller, Director of Resource Planning

Introduction to IPL

Quick facts
- 480,000 customers
- 1,400 employees
- 528 sq. miles territory
- 144 substations
- ~3,300 MW of Resources
- Serving Indianapolis reliably since 1929

IPL 2016 Resource Mix based upon capacity

Indianapolis area assets 1,222 MW
- **Harding Street Station (HS) –** 977 MW
- **Georgetown Station –** 150 MW
- **Solar PPAs* –** 95 MW

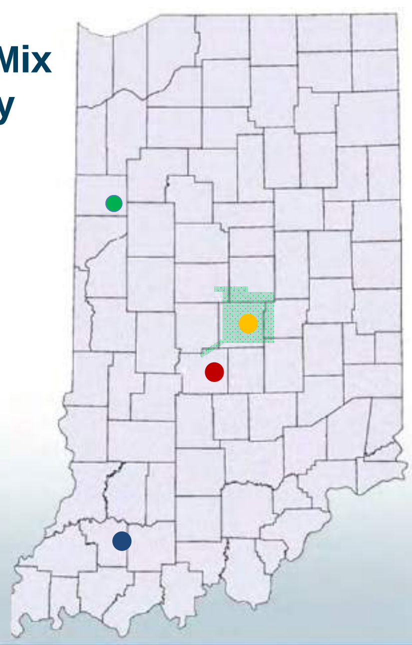
Eagle Valley (EV) Generating Station
- Retiring 263 MW coal in April 2016
- Constructing 671 MW Combined Cycle Gas Turbine (CCGT) for Spring 2017 operation

Petersburg Generating Station – 1,697 MW

Hoosier Wind Park PPA – 100 MW

Lakefield Wind Park PPA – 200 MW
(In Minnesota – Not pictured)

*PPAs = Power Purchase Agreements



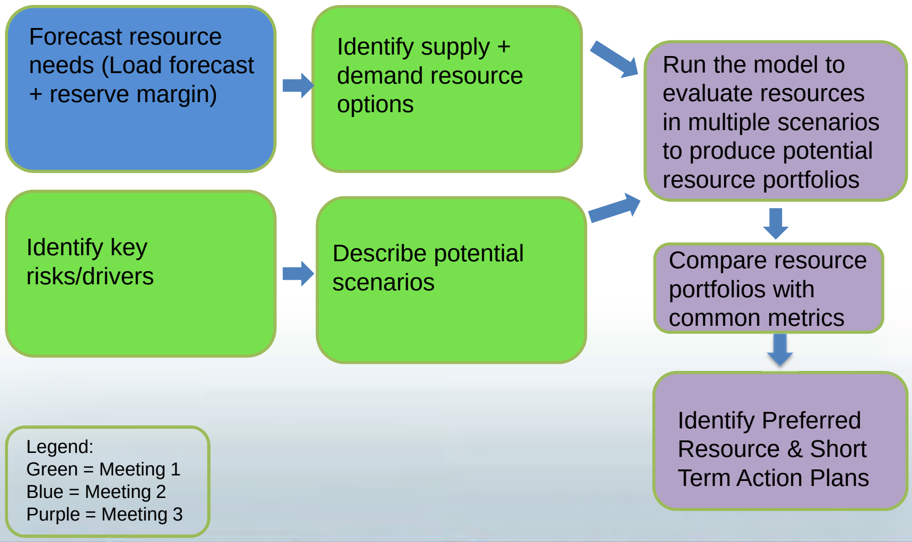
What is an IRP?

- An Integrated Resource Plan represents how a utility expects to provide its customers
  - reasonable least cost service
  - for a 20 year period
  - utilizing existing and future supply and demand side resources
  - following an analysis of multiple potential future scenarios.

Joint IRP 101 meeting

- Indiana utilities co-hosted IRP 101 session on Feb 3, 2016
- Included general information about the planning process
- Review materials at this link: https://www.iplpower.com/IRP/?terms=IRP

IRP process overview



IPL's IRP Objective

- To identify a portfolio to provide
  – safe
  – reliable
  – reasonable least cost energy service
  – to IPL customers from 2017-2036
  – measured in terms of Present Value Revenue Requirement (PVRR)
  – giving due consideration to potential risks and stakeholder input.

Actions since 2014 IRP

- Implemented short term action plan
  - Transmission expansion projects
  - DSM program implementation
  - MISO capacity purchases
  - Mercury and Air Toxics Standard (MATS) compliance
  - EV CCGT 671 MW
  - Blue Indy implementation
  - National Pollutant Discharge Elimination System (NPDES) compliance
  - Harding Street 5, 6 & 7 refuel/conversion to NG
  - Retire EV units 3 - 6

Proposed enhancements based on feedback

	2014 IRP Feedback	IPL Response/Planned Improvements
1	Constrained Risk Analysis	Stakeholder discussion about risks will occur early in the 2016 IRP process.
2	Load Forecasting Improvements Needed	IPL is reviewing load forecast to enhance data in the 2016 IRP.
3	DSM Modeling not robust enough	IPL has piloted modeling DSM as a selectable resource and will discuss this in public meetings.
4	Customer-Owned and Distributed Generation lacked significant growth	IPL will develop DG growth sensitivities to understand varying adoption rate impacts.
5	Incorporation of Probabilistic Methods	IPL will incorporate probabilistic modeling in 2016 IRP.
6	Enhance Stakeholder Process	IPL participated in joint education session with other utilities to develop foundational reference materials. We will incorporate more interactive exercises in 2016.

2016 IRP timeline

Q4 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016
Pilot DSM modeling	Conduct IRP 101 session Identify risks	Hold 1st IRP meeting	Continue modeling & narrative	Finalize and file IRP
Initiate scenario development	Initiate DSM MPS	Complete DSM MPS	Perform Sensitivity Analyses	
Research DG resources		Complete load forecast	Hold 2nd & 3rd IRP meetings	
Update Reference case data		Initiate narrative & modeling		

Questions?

Supply Side Resources

Joan Soller, Director of Resource Planning

Supply side resources

- Model inputs include:
  - Nameplate capacity
  - Capital construction costs
  - Fixed Operating and Maintenance (O&M) costs
  - Variable O&M costs
  - Operating characteristics
  - Typical availability

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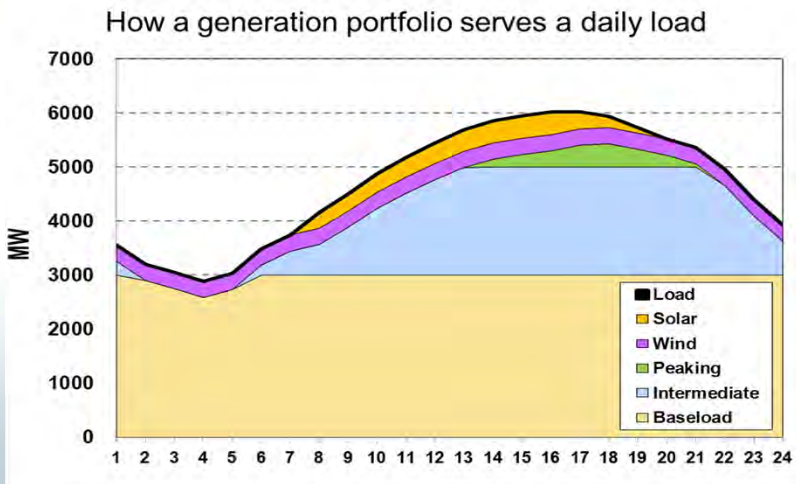
Typical summer load & resource mix



Supply side resource alternatives

IRP Resource Technology Options			
	MW Capacity	Performance Attributes	Representative Cost per Installed KW
Simple Cycle Gas Turbine[1]	160	Peaker	$676
Combined Cycle Gas Turbine - H-Class[1]	200	Base	$1,023
Nuclear[1]	200	Base	$5,530
Wind[2,3]	50	Variable	$2,213
Solar[4]	> 5 MW	Variable	$2,270
Energy Storage[5]	20	Flexible	~ $1,000
CHP – industrial site (steam turbine)[6]	10	Base	Ranges from ~ $670 to $1,100
Other?			

Sources for IRP resource technology options

[1] These costs from *EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants Report* (published April 2013) are shared as proxies for IPL's confidential costs.
http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

[2] Excludes transmission costs

[3] U.S. Energy Information Administration | *Assumptions to the Annual Energy Outlook 2015*

[4] 2015 SunShot National Renewable Energy Laboratory (NREL) Solar Report, *Photovoltaic System Pricing Trends*, normalized and converted from DC to AC, utility scale defined as greater than 5MW. Retrieved from:
https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf

[5] AES Energy Storage Website http://www.aesenergystorage.com/choosestorage/

[6] EPA Combined Heat and Power Partnership. Retrieved from
https://www.wbdg.org/resources/chp.php

Distributed Resources Discussion

John Haselden, Principal Engineer

Customer-Sited Generation

- Typically diesel generators
- Usually not synchronous with IPL
- Size: 100 kW – 20 MW
- EPA regulations restrict availability to run during non-emergencies
- Indy area resources
  - 2010: 40.1 MW
  - 2014: 31.7 MW
  - 2016: 0 MW
- Quick start, high variable cost, limited run time

Combined Heat & Power (CHP)

- Combined Heat and Power
  - Usually customer sited and owned
  - Thermal requirements
- 5 MW – 100 MW
- Technology options
  - Conventional
    - Natural gas reciprocating engines
    - Natural gas turbines
  - Advanced
    - Fuel cell
    - Microturbine
    - Micro-CHP

Wind

- Poor wind resource in this area – low energy output
- Height is important for production
- 5 kW – 1.5 MW
- Siting/zoning issues
- Noise

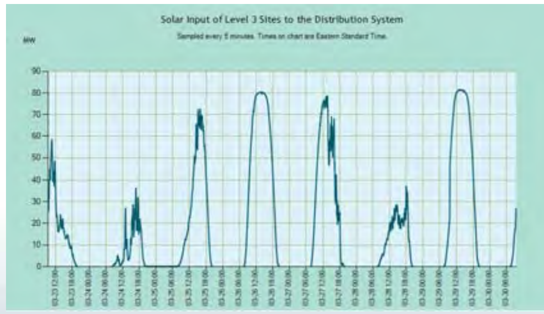
- Low coincidence with system peak, variable production
- Higher production costs than might otherwise be expected

Biomass

- Includes anaerobic digesters and combustion of organic products
- Siting and zoning issues
- Usually base load generation
- Customer choice to install
- Fuel transportation and emissions are a challenge

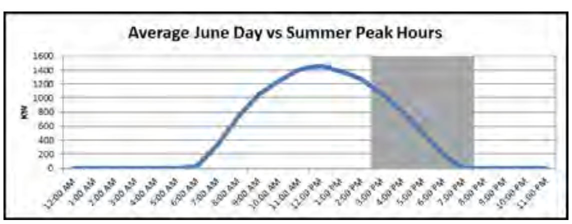
Solar Photovoltaic

- Permitting and construction are usually quick and not complicated
- Location determined by others
- Requires large spaces – 5-7 acres/MW
- Low capacity factor – 15-18%
- Variable production



Solar Photovoltaic (cont.)

- Some coincidence with system peak

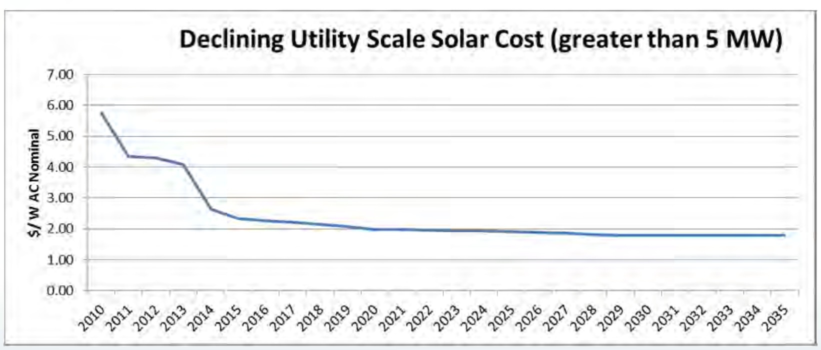


- Solar Renewable Energy Credit (SREC) value is variable and a short-term market

IPL experience with Solar PV

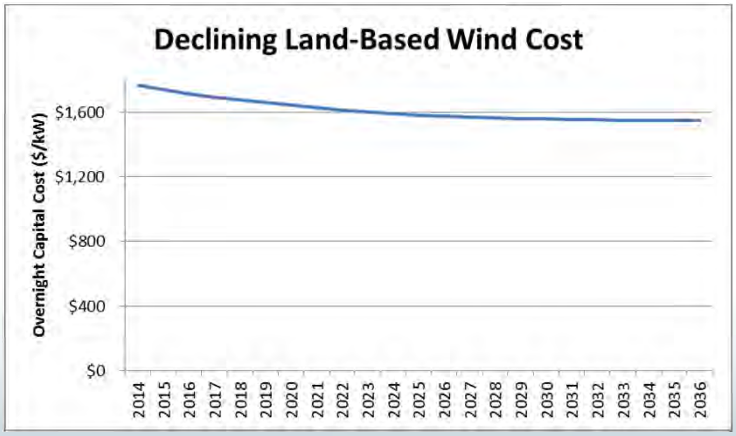
- Net metering
  - Small projects – Total capacity 1.45 MW
- Renewable Energy Production (REP) Rate
  - 95 MW operating solar
  - Approximately 45 MW contribution to capacity

Solar cost trend



Source: 2015 SunShot National Renewable Energy Laboratory (NREL) Solar Report, Photovoltaic System Pricing Trends, normalized and converted from DC to AC, utility scale defined as greater than 5MW. Retrieved from: https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf

Wind cost trend



Source: Discussion Draft of NREL 2016 Annual Technology Baseline Now Available for Review. Retrieved from http://www.nrel.gov/analysis/data_tech_baseline.html

Other Distributed Resources

- Technology innovation is impacting the industry
  - "Distributed Resources" go beyond "Distributed Generation" and will be considered as they mature
  - Microgrids
  - Energy storage
  - Voltage controls
  - Electric vehicles

Questions?

Demand Side Resources

Jake Allen, DSM Program Development Manager

Section Overview

- Demand side management (DSM) definition
- IPL's DSM Experience
- Current DSM programs (2015-2016)
- Update of DSM "Action Plan" for 2017
- Anticipated filing schedule for approvals to continue to offer DSM programs
- New Market Potential Study (MPS) underway

Demand Side Management

- Encompasses both:
  – Energy Efficiency – reduced energy use for a comparable or imposed level of energy service (kWh)
  – Demand Response – a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions (kW)

Demand side resource alternatives

Demand Side Resource Examples			
	2015 MWh Savings	Performance Attributes	Representative First Year Cost per kWh (on net basis)
Energy Efficiency programs			
- Residential Lighting	15,908	Dependent upon customer participation	$ 0.19/kWh
- Small Business Direct Install	4,407		$0.30/ kWh
	MW Savings	Performance Attributes	Representative Cost per Installed KW
Demand Response programs – - Air Conditioning Load Management (ACLM)	30	Peak Use	$300
- Conservation Voltage Reduction	20	Peak Use	Field assets are in place for this capacity

How do supply and demand side resources compare?

Characteristic	Supply	Demand
Size in terms of capacity	+++ (10-700 MW)	+ (1-10 MW)
Flexible response to capacity need	+	+++
Initial Costs	+++	+ to ++
Ongoing Costs	++	+
Lead time	++	+
Dispatchability	+++	+ to ++
Dependent upon customer behavior	+	+++

+ reflects relative scale

IPL's DSM experience

- IPL has offered DSM since 1993
- Commission Generic Order issued in 2009 (covered 2010-2014)
- Currently offering DSM Programs for a two year period (2015-2016)
  - pursuant to approvals in Cause No. 44497
- Current DSM efficiency goal is approximately 1.1% of total sales

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Current DSM programs

Current Program Offerings
Residential
Air Conditioning Load Management
Appliance Recycling
Home Energy Assessment
Income Qualified Weatherization
Lighting
Multi-Family Direct Install
Online Assessment w/ Kit
Peer Comparison Reports
School Education w/ Kit
Business (C&I)
Air Conditioning Load Management
Custom Projects
Prescriptive
Small Business Direct Install

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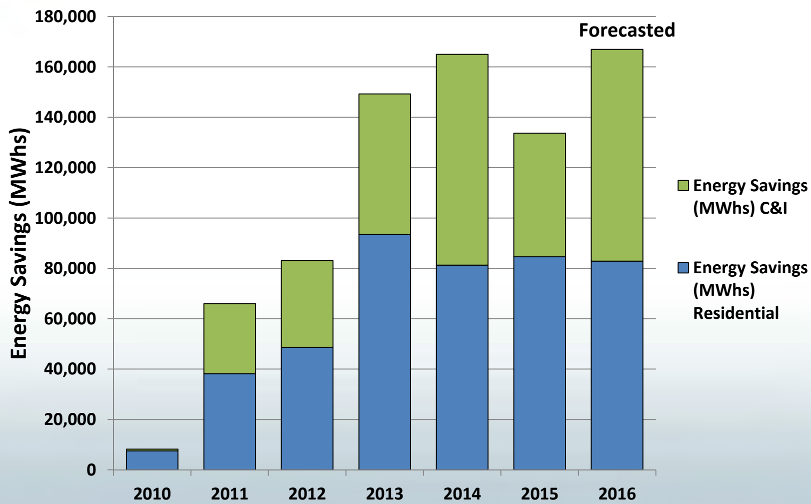
DSM program achievement



DSM guiding principles

- Offer programs that:
  - Are inclusive for customers in all rate classes
  - Are appropriate for our market and customer base
  - Are cost effective
  - Modify customer behavior
  - Provide continuity from year to year

Other planning considerations

- Large Commercial and Industrial Customer Opt out
  - Customers with demand > 1 MW may elect to opt-out of utility sponsored DSM programs
  - Customers representing approximately 26% of IPL's sales are eligible to opt-out
  - Approximately 81% of eligible customers have opted out
- Cost effectiveness challenges due to changing baselines – e.g. lighting

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DSM Market Potential Study (MPS)

- 1st step in DSM planning
- Underway for 2018-2037
- Initial Kick Off Meeting was held late February
- Screening analysis to prepare for IRP modeling inputs completed by May

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DSM planning - 2017

- Expect to propose one-year extension of current programs
  - Approvals would allow us to continue delivery of DSM programs in 2017
  - While the current IRP modeling is completed
  - IPL plans a filing with the Commission in May 2016
  - Updating previously filed 2015-2017 DSM Action Plan for 2017

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Future planning - beyond 2017

- Develop a three year DSM Action Plan (2018-2020) consistent with the 2016 IRP
  - New Market Potential Study (2018-2037)
  - Identify blocks of DSM as a selectable resource for modeling in the IRP
  - DSM will be evaluated in multiple scenarios
  - With the expectation of making a filing in early 2017 for a three-year approval

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Questions?

DSM Modeling Options

Erik Miller, Senior Research Analyst

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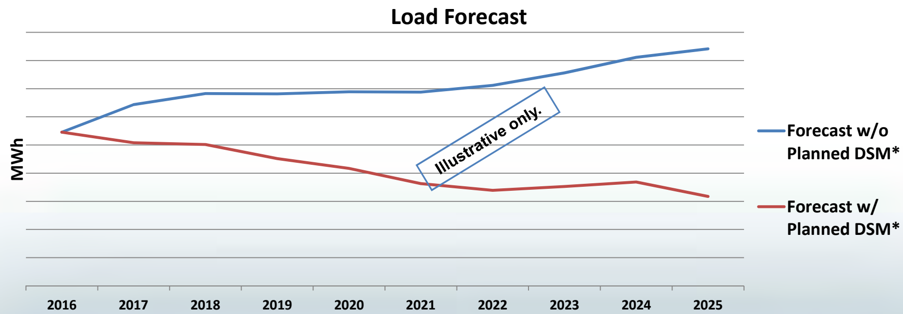
DSM modeling options

Historical IRP Approach

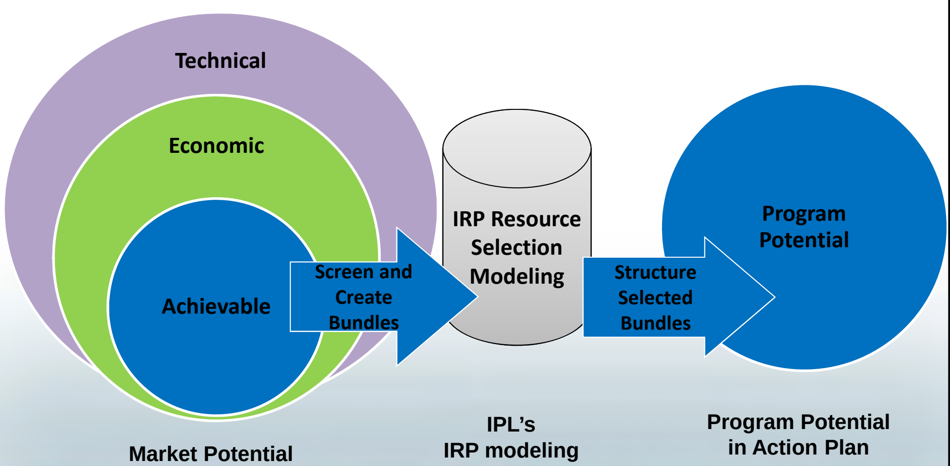
Market Potential Study determines cost effective DSM Action Plan
DSM Action Plan reduced from load forecast



*Past DSM performance and organic efficiency included in forecast.

DSM modeling options

DSM as a Selectable Resource



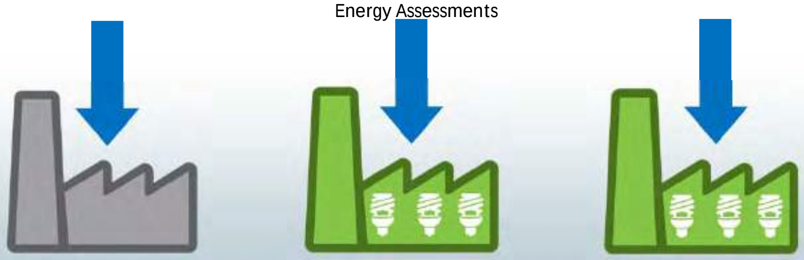
Creating a DSM selectable resource

Different Bundling Approaches

<u>Simple Cycle Gas Turbine</u>
160 MW
Low capacity factor
Peaker

<u>HEA Program Bundle</u>
Measures include:
CFLs
LEDs
Low Flow Showerheads
Faucet Aerators
Programmable Thermostat
Energy Assessments

<u>Portfolio Bundle</u>
Home Assessment Program
Multifamily Program
Peer Comparison Program
Residential Lighting Program
School Education Program
Appliance Recycling Program



"CT" Power Plant

DSM "Program" Bundle

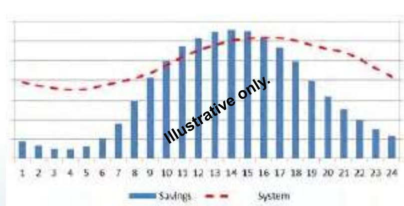
DSM "Portfolio" Bundle

Creating a DSM selectable resource

<u>Similar Measure "HVAC" Bundle</u>
Air Conditioners
Heat Pumps
Ductless Heat Pumps
AC Tune Up
ECM
Programmable Thermostats

DSM "Similar Measure" Bundle

<u>"HVAC" Bundle Load Shape</u>



Creating a DSM selectable resource

- Create a "bundle" of Energy Efficiency or Demand Response that resembles a power plant
- Bundle Characteristics
  - Cost to "build"/implement
  - Installed cost ($/kWh)
  - Load shape (8,760 hours)
  - Timing for implementation
  - Ramp rate
- Sectors
  - Residential
  - Commercial & Industrial

IRP/DSM pilot runs

- Objectives
  - Identify a potential approach for DSM block structures
  - Understand how the resource assessment model handles DSM
- Approach
  - Modeled individual residential program blocks based on 2015 DSM programs
  - DSMore model was used to create block load shapes
  - Load shapes were inputs in the resource assessment model
- Findings
  - Limited program offerings in early years
  - Staggered program selections
  - Less "cost effective" programs don't get selected
  - Program bundles contribute to staggered offerings

Questions?

Lunch Break

Risk Discussion

Joan Soller, Director of Resource Planning

Risks include internal and external factors

- Planning Risks
  - Environmental Regulations
  - Fuel Costs
  - MISO Market Changes
    e.g. capacity auction, fast ramp products
  - Economic Load Impacts
  - Weather
  - Customer Adoption of DG
  - Technology Advancements
    e.g. solar and wind costs
- Operational Risks
  - Fuel Supply
  - Generation Availability
  - Construction Costs
  - Production Cost Risk
  - Access to Capital
  - Regulatory Risk

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Environmental Regulations

- Recent Environmental Regulations/Projects
  - Mercury and Air Toxics Standard (MATS)
  - National Pollutant Discharge Elimination System (NPDES) Water Discharge Permits
  - Cross State Air Pollution Rule (CSAPR)
- Future Environmental Regulations
  - Coal Combustion Residuals (CCR)
  - National Ambient Air Quality Standards (NAAQS)
  - Effluent Limitations Guidelines (ELG) Rule
  - 316(b) – Cooling water intake structures
  - Office of Surface Mining
  - Clean Power Plan (CPP)

Exercise

- Seek stakeholder feedback regarding risk likelihoods and/or importance

Scenario Discussion

Ted Leffler, Senior Risk Management Analyst

Planning under uncertainty

- Uncertainty = Potential for change
  - Examples:
    - Environmental Regulations
    - Commodity Prices
    - Load
    - Renewables Penetration
    - Distributed Generation Penetration
- Scenarios and sensitivity analysis are two forms of uncertainty analysis used in resource planning

Scenarios

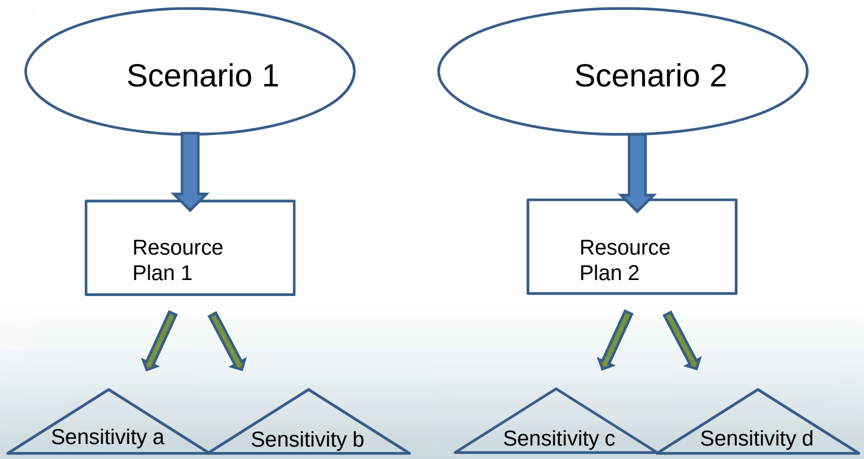
- *"A scenario is*
  - a simulation of a future world technical, regulatory and load environment."*
- *A scenario is not…*
  - A resource plan
  - A sensitivity
  - Not a representation of preferred outcome
- Base Case Scenario
  - "The base case [scenario] should describe the utility's best judgment (with input from stakeholders) as to what the world might look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources or laws /policies affecting customer use and resources."*

*2015 Director's Report

What is a Sensitivity?

- A sensitivity measures how a resource plan performs across a range of possibilities for a specific risk or variable

Scenarios and Sensitivities



Scenario development process

- Cross functional IPL team considered future risks
- Reviewed other utilities IRP scenarios
- Reviewed MISO MTEP 2017 scenarios
- Qualitatively discussed recent trends/significant changes and impact likelihoods

Scenario development process

- Developed a list of risks or 'major forces that might move the world in different directions'*
  - Economic Growth
  - Change in electricity use
  - Commodity Prices
  - Capital Costs
  - CO_2 regulation
  - Other environmental regulation
  - Change in Renewable & Storage Costs
  - Distributed Generation Adoption

* Source: Electric Power Resource Planning Under Uncertainty: Critical Review and Best Practices, White Paper, November 2014 Prepared by Adam Borison

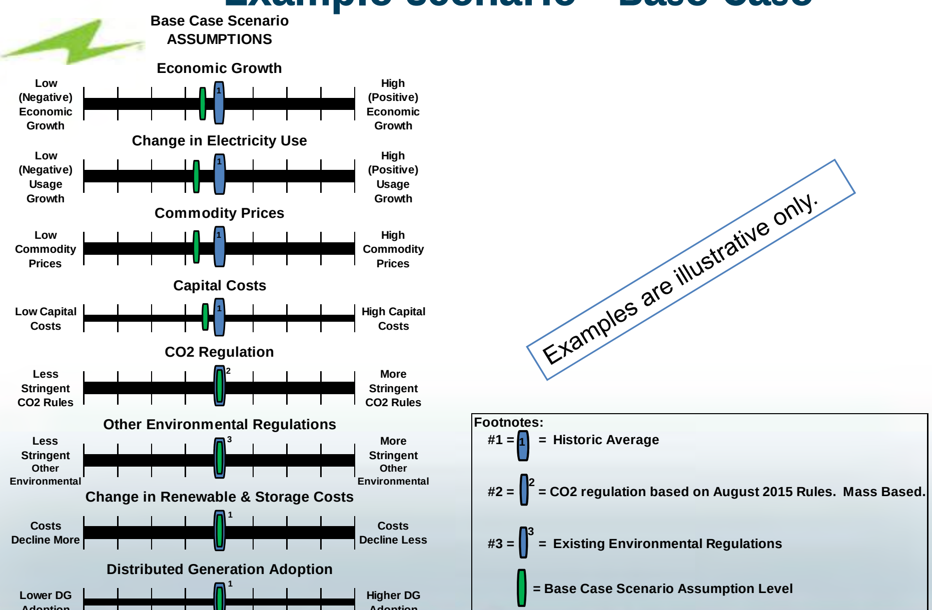
Scenario development process

- Developed a list of potential futures
  - Base Case
  - Robust Economy
  - Recession Economy
  - Strengthened Environmental Rules
  - High Customer Adoption of Distributed Generation (DG)

Potential Scenarios

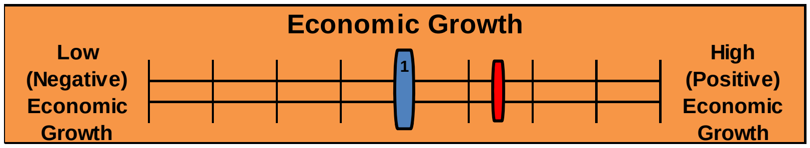
- Base Case
  - Only known events and expected trends
  - Commodity prices influenced by Clean Power Plan (CPP) beginning in 2022
  - Existing environmental regulations realized
  - Moderate decreases in technology costs for renewables and storage
- Robust Economy
  - High local and national economic growth
- Recession Economy
  - National and local economic downturns
- Strengthened Environmental Rules
  - Higher compliance costs for known regulations including CO_2 + RPS
- High Adoption of Distributed Generation
  - Customers adopt DG with lower technology costs

Example Scenario – Base Case



Example Scenario - Robust Economy

Robust Economy Case Scenario
ASSUMPTIONS



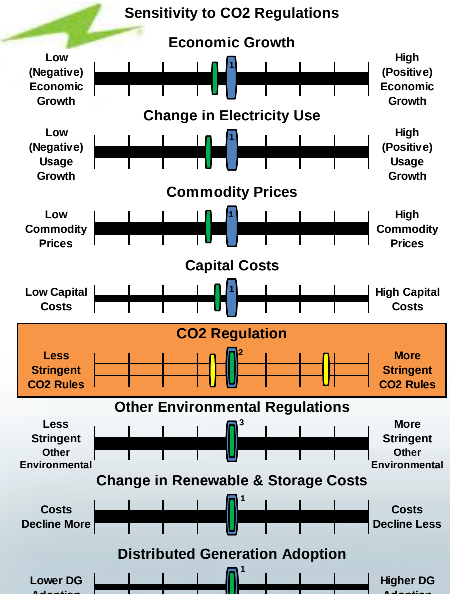
Other risks / major driver levels = Base Case Levels

Examples are illustrative only.

Footnotes:
#1 = 1 = Historic Average
= Robust Economy Case Scenario Assumption Level

Example Sensitivity - Base to CO2

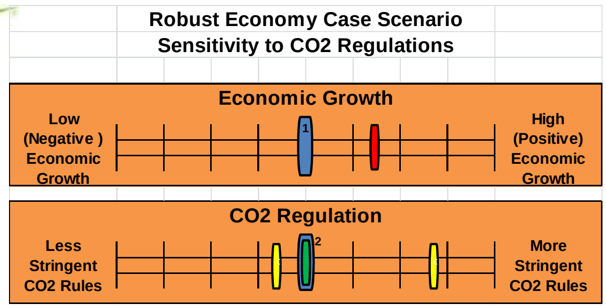
Base Case Scenario
Sensitivity to CO2 Regulations



Examples are illustrative only.

Footnotes:
#1 = 1 = Historic Average
#2 = 2 = CO2 regulation based on August 2015 Rules. Mass Based.
#3 = 3 = Existing Environmental Regulations
= Base Case Scenario Assumption Level
= CO2 Sensitivity Levels

Example Sensitivity – Robust Economy to CO2



Other risks / major driver levels = Base Case Levels

Examples are illustrative only.

Footnotes:
#1 = 1 = Historic Average
#2 = 2 = CO2 regulation based on August 2015 Rules. Mass Based.
= Base Case & Robust Economy Scenario Assumption Level
= Robust Economy Case Scenario Assumption Level
= CO2 Sensitivity Levels

Exercise

- Seek stakeholder feedback regarding scenarios

Next Steps

Dr. Marty Rozelle, Facilitator

Next meetings

June 14, 2016

- Stakeholder Points of View presentations
- Load Forecast and Forecasting Methodology
- RTO/ MISO/Resource Adequacy
- Transmission & Distribution
- Environmental Risks including Clean Power Plan
- Modeling Parameters

September 16, 2016

- Resource Portfolio results
- Sensitivities
- Preferred Resource Plan
- Short Term Action Plan

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Written comments and feedback

- Deadline to send written comments and questions regarding this meeting to ipl.irp@aes.com is Monday, April 18
- All IPL responses will be posted on the IPL IRP website by Monday, May 2

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Thank you!

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Integrated Resource Plan Public Advisory Meeting #2

June 14, 2016

Welcome & Safety Message

Bill Henley, VP of Regulatory and Government Affairs

Meeting Guidelines

Dr. Marty Rozelle, Facilitator

Agenda for today

9:00am Welcome
- Meeting Agenda and Guidelines
- Summary & Feedback from IRP Public Advisory Meeting #1
- Stakeholder Presentations

10:25am Break
- Portfolio Comparison based on Metrics
- Metrics Exercise
- Resource Adequacy

12:00 – 12:30pm Lunch
- Transmission & Distribution
- Load Forecast
- Environmental Risks

2:00pm Break
- Modeling Update
- Portfolio Exercise
- Closing Remarks & Next Steps

3:15pm Meeting Concludes

Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions
- The phone line will be muted. During the allotted questions, press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
- Use WebEx online tool for questions during meeting
- Email additional questions or comments by June 21
- IPL will respond via website by July 5

Active Cases before the Commission

- Cause No. 42170, ECR-26
- Cause No. 44121, Green Power (GPR 9)
- Cause No. 43623, DSM 13
- Cause No. 44576, Rates (under appeal)
- Cause No. 44792, DSM 2017 Plan
- Cause No. 44794, SO_2 NAAQS and CCR
- Cause No. 44795, Capacity and Off System Sales Riders

Summary & Feedback from IRP Public Advisory Meeting #1

Joan Soller, Director of Resource Planning

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Topics covered in Meeting #1

- IPL's IRP process and objective
- Supply side, distributed and demand side resources
- Modeling Demand Side Management (DSM) as a selectable resource
- Planning risks
- Scenario development with interactive exercise

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Scenarios Exercise from Meeting #1 - Base Case

Scenario	Agree	Disagree	Proposed Integration
Base Case	• CPP – how specifically will it be included? • Pretty much agree with it.	• Smart homes should be included as a technology. • Why not include utility- owned DG? • Fuel prices including natural gas will increase more than indicated. Where is this reflected in the scenarios? (Can run sensitivities for this.)	• CPP will be modeled as mass-based • IPL will incorporate energy management and its technology-based smart thermostat pilot in DSM blocks • DG will be an input and may be customer or utility owned • IPL will run high/low sensitivities on commodities

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Scenarios Exercise from Meeting #1 - Robust Economy

Scenario	Agree	Disagree	Proposed Integration
Robust Economy	• Could happen, would be nice if it did. • Agree that it's a potential future, but would not necessarily lead to increased electricity use. • Could lead to higher DG adoption.	• May not lead to increased use of electricity. • Capital costs might go up due to higher costs of materials.	• The load forecast will be a sensitivity in this scenario. • Still thinking about how to address varying capital costs for supply side resources.

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Scenarios Exercise from Meeting #1 - Recession Economy

Scenario	Agree	Disagree	Proposed Integration
Recession Economy	• Hope it doesn't happen but it could – depends on things outside of our control, e.g. exodus or influx of people to Indiana. • A possibility. Question of whether shrinking industrial base is unique to this scenario – could happen in others.	• N/A	• Will likely run high/low load forecast sensitivities in other scenarios to incorporate potential recession effects

Scenarios Exercise from Meeting #1 - Strengthened Environmental Rules

Scenario	Agree	Disagree	Proposed Integration
Strengthened Environmental Rules	• Carbon tax is possible	• What if the Renewable Portfolio was federal or state? Could be part of the CPP. (Would probably have about the same impact.)	• In this scenario, there will be a 20% RPS in 2022 based on a national average. This could be federal or state proposed.

Scenarios Exercise from Meeting #1 – High Customer Adoption of DG

Scenario	Agree	Disagree	Proposed Integration
High Customer Adoption of DG	• There are reasons other than economic to go to DG. Residents seem to be more attracted, businesses less attracted. • Possible. If it's cost-effective there would be more community solar.	• N/A	• There will be some DG embedded in this scenario as a proxy for customers who will choose DG for reasons in addition to economics.

Additional stakeholder interaction

- Since the April meeting, IPL met with the following stakeholders:
  - IURC
  - OUCC
  - CAC
  - Sierra Club
  - Citizens Energy

Additional stakeholder interaction (cont'd)

- Continue to involve stakeholders in developing assumptions
- Consider C&I customer input in load forecast
- Consider discrete DSM bundles
- Coordinate planning efforts with Citizens Energy
- Consider more expansive sensitivities

Meeting #1 materials

- Approximately 20 stakeholders participated
- Presentation materials, audio recording, acronym list, and meeting notes are available on IPL's IRP webpage here: https://www.iplpower.com/irp/

Questions?

Stakeholder Presentations

Presenter #1: Denise Abdul-Rahman, Environmental Climate Justice Chair, NAACP Indiana

Presenter #2: Dr. Stephen Jay, Professor,
IU Fairbanks School of Public Health

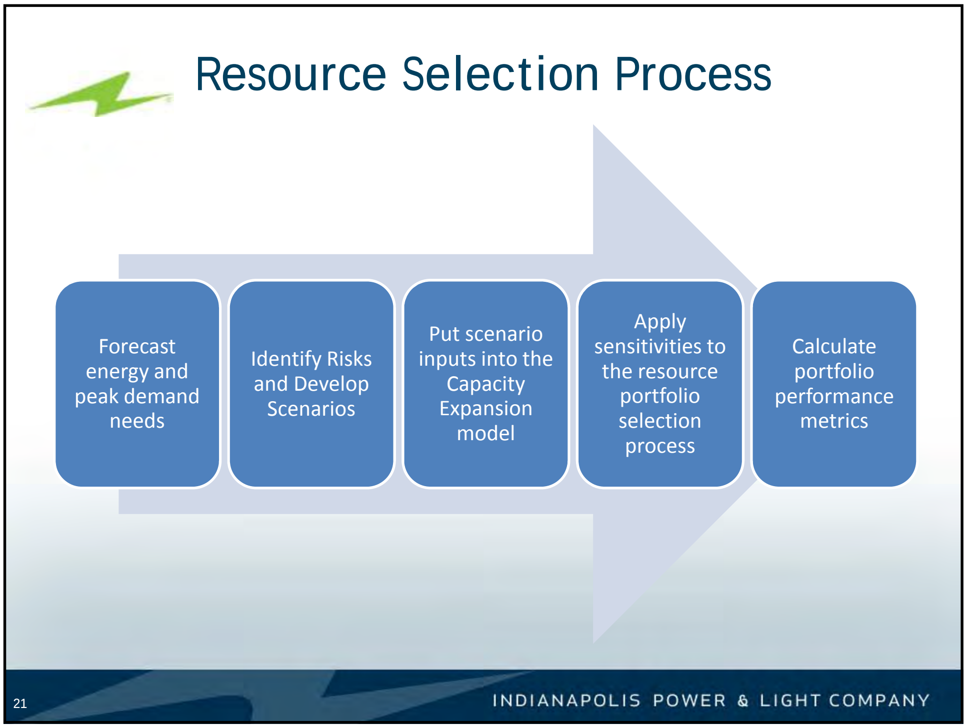
Presenter #3: Larry Kleiman, Executive Director, Hoosier Interfaith Power & Light

Presenter #4: Jodi Perras, Indiana Campaign Representative, Sierra Club Beyond Coal

Short Break

Portfolio Comparison based on Metrics

Megan Ottesen, Regulatory Analyst


Resource Selection Process
Forecast energy and peak demand needs
Identify Risks and Develop Scenarios
Put scenario inputs into the Capacity Expansion model
Apply sensitivities to the resource portfolio selection process
Calculate portfolio performance metrics
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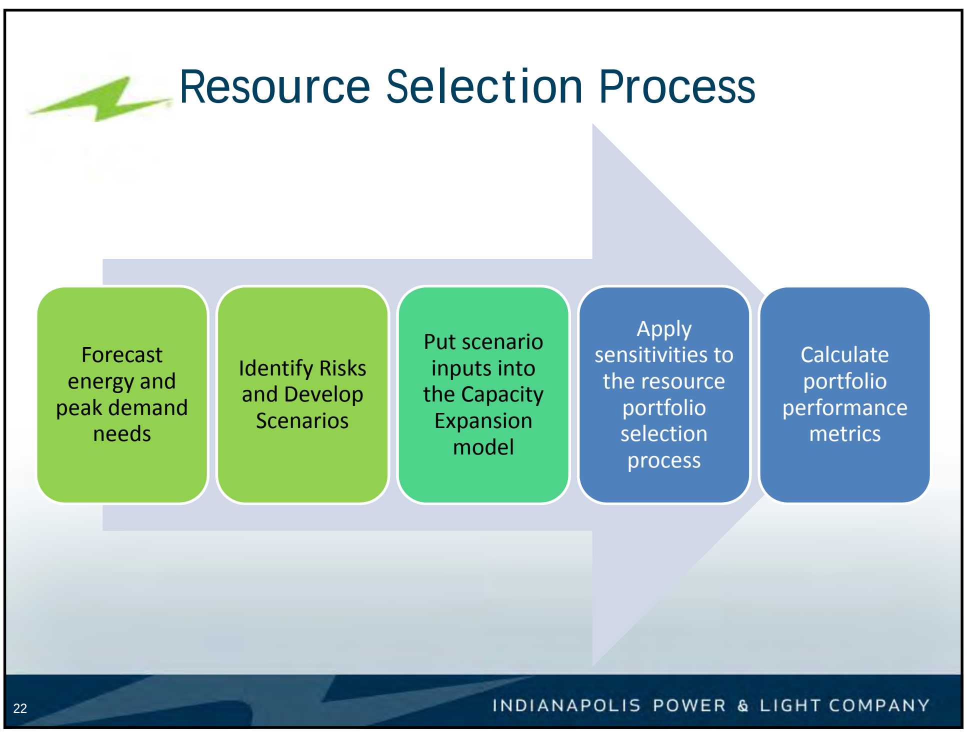
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Forecast energy and peak demand needs
Identify Risks and Develop Scenarios
Put scenario inputs into the Capacity Expansion model
Apply sensitivities to the resource portfolio selection process
Calculate portfolio performance metrics
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Portfolios will result from each of these scenarios

- Base Case
- Robust Economy
- Recession Economy
- Strengthened Environmental Rules
- High Customer Adoption of Distributed Generation

Introduction to metrics

- IPL will use several metrics to compare the benefits and costs of each scenario's portfolios
- In past IRPs, IPL primarily evaluated portfolios in costs measured by Present Value Revenue Requirement (PVRR)
- In addition to cost, IPL is considering the following categories to measure portfolio performances:
  - Financial risk
  - Environmental stewardship
  - Reliability

Metrics to consider

Cost	Financial Risk	Environmental Stewardship	Reliability
• Present Value Revenue Requirement (PVRR) • Rate Impact	• Cost Variance Risk Ratio	• Annual average CO_2 emissions • CO_2 intensity	• Planning Reserves • Flexibility

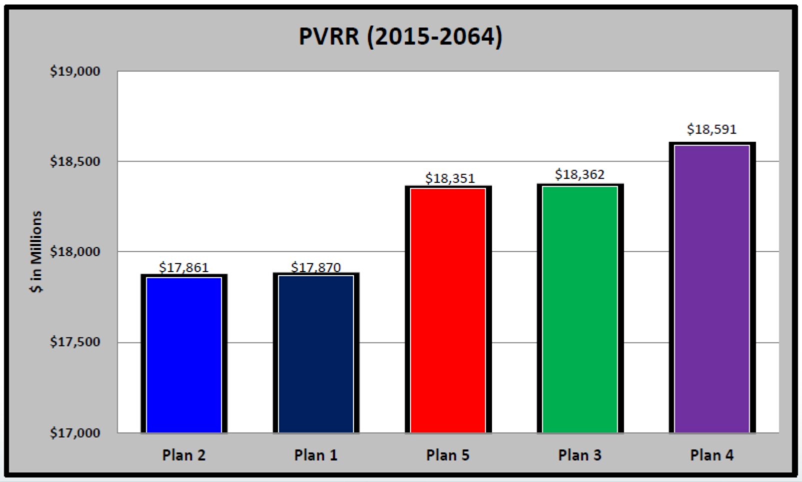
Cost Metrics

Present Value Revenue Requirement (PVRR):

– The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period

PVRR = Present Value of Revenue Requirements over the study period

PVRR Example



Source: IPL 2014 IRP

Cost Metrics

Present Value Revenue Requirement (PVRR):

- The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period

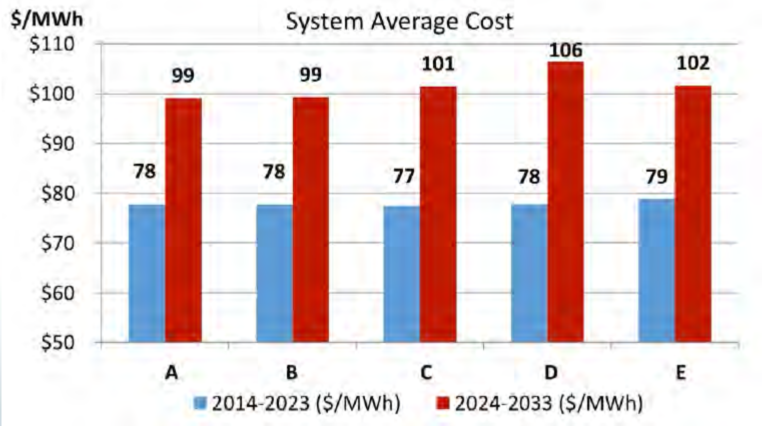
PVRR = Present Value of Revenue Requirements over the study period

Rate Impact:

- expressed in terms of cents/kWh for years 1-10 and 11-20
- Levelized average system cost

$$\textbf{Rate Impact} = \frac{\$\ \text{Total Revenue Requirements (10 yr period)}}{\text{Total kWh Sales (10 yr period)}}$$

Rate Impact Example



Source: TVA 2015 IRP

Financial Risk Metrics

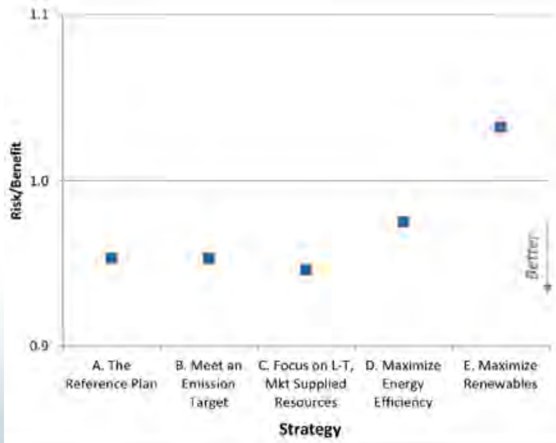
Cost Variance Risk Ratio:

– Shows how likely costs are to be higher or lower than the expected cost
– Ratio of how high costs could be to how low costs could be
– Calculated based on
  - Mean PVRR
  - Range of possible costs higher than mean PVRR
  - Range of possible costs lower than mean PVRR

$$\textbf{Cost Variance Risk Ratio} = \frac{95^{th}\text{ Percentile (PVRR)} - \text{Mean (PVRR)}}{\text{Mean (PVRR)} - 5^{th}\text{ Percentile (PVRR)}}$$

– Score less than 1.0: costs are more likely to be **lower** than mean PVRR
– Score greater than 1.0: costs are more likely to be **higher** than mean PVRR

Cost Variance Risk Ratio
(lower has less risk)



Source: TVA 2015 IRP

Strategy = Portfolio

Environmental Stewardship Metrics

Annual Average CO_2 emissions (tons)

– the annual average tons of CO_2 emitted over the study period

Annual Average CO_2 Emissions = $\frac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$

CO_2 intensity (tons/MWh)

– CO_2 Intensity for study period

CO_2 Intensity for study period = $\frac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{MWh energy generated}}$

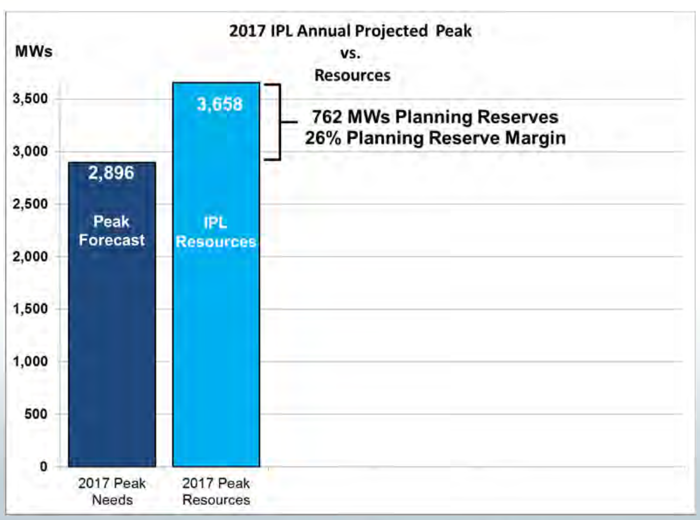
Reliability Metrics

Planning Reserves:

- MW of supply above peak forecast

Planning Reserves = IPL's resources (MW) - utility load forecast (MW)

Planning Reserves for IPL



Reliability Metrics

Planning Reserves:

- MW of supply above peak forecast

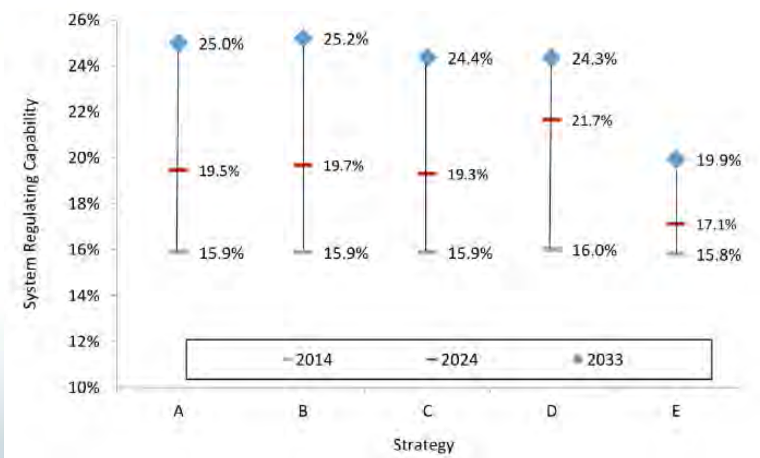
Planning Reserves = IPL's resources (MW) - utility load forecast (MW)

Flexibility:

- Ability of IPL's system to respond to load changes

Calculation = TBD open to input

Flexibility: (higher is more flexible)



Source: TVA 2015 IRP

Questions?

Cost	Financial Risk	Environmental Stewardship	Reliability
• Present Value Revenue Requirement (PVRR) • Rate Impact	• Cost Variance Risk Ratio	• Annual average CO_2 emissions • CO_2 intensity	• Planning Reserves • Flexibility

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Metrics Exercise

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Resource Adequacy

Ted Leffler, Senior Risk Management Analyst

Introduction

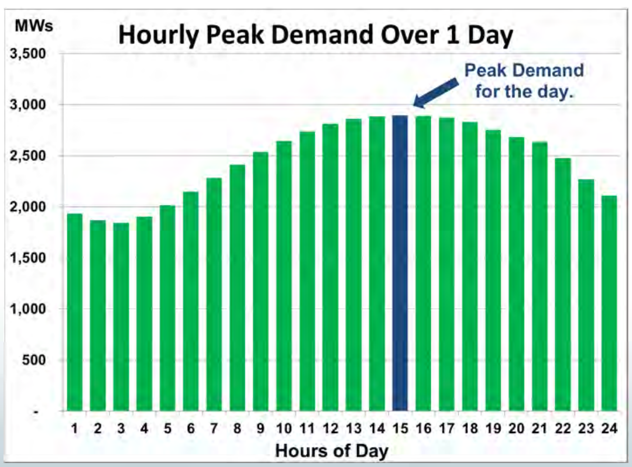
- IRP process focuses on the future portfolio of resources needed to meet the
  - peak and
  - energy
  - needs of our customers.
- Resource Adequacy (RA) focuses on peak needs
- Resource Adequacy is the responsibility of the regulated utilities (part of the obligation to serve)
- MISO administers a short term Resource Adequacy construct
  - MISO is not responsible for Resource Adequacy
  - MISO's construct is focused on existing not future resources

Definitions (1 of 5)

- **Resource Adequacy**
  - ensuring that IPL has sufficient Resources to meet anticipated peak demand requirements plus an appropriate planning reserve
- **RA Time Horizon**
  - Resource Adequacy = > year out
- **MWs**
  - Measure of power
  - 1 MW = 1,340 Horsepower

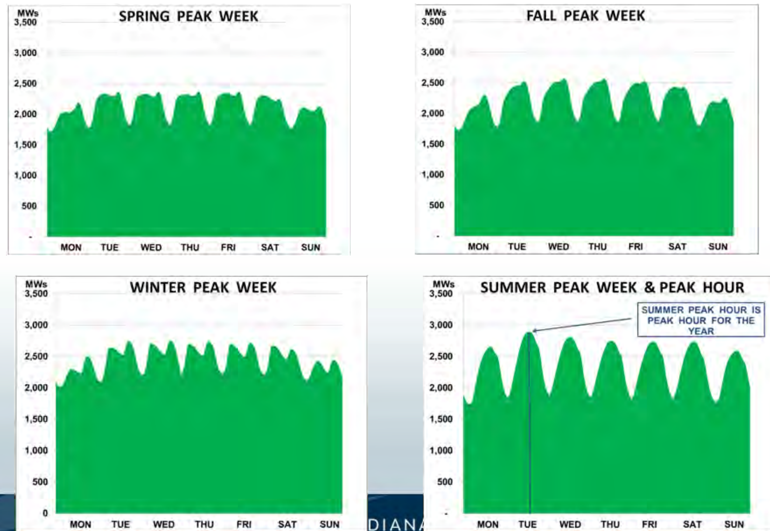
Definitions (2 of 5)

- **Peak Demand**
  - Instantaneous measure of the highest usage for a given period of time
  - Measured in MWs
    - MISO peak demand for summer 2017 estimate at about 123,000 MWs (165 million horsepower)
    - IPL peak demand for summer of 2017 estimate at about 2,900 MWs (3.9 million horsepower)



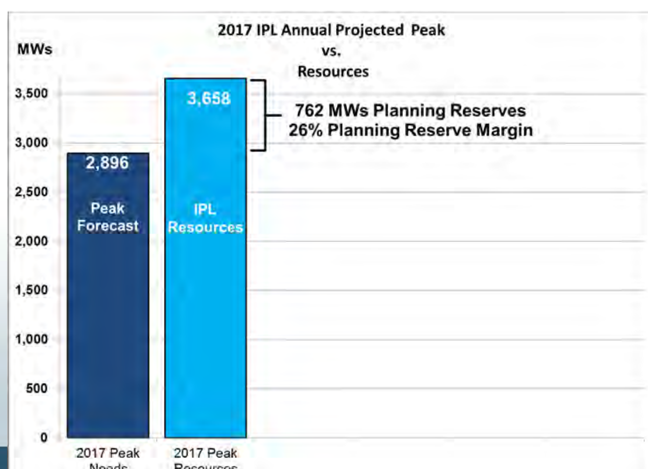
Definitions (3 of 5)

- **Peak Demand**
  - Instantaneous measure of the highest usage for a given period of time
  - In the Midwest and at IPL the peak demand typically occurs in the summer



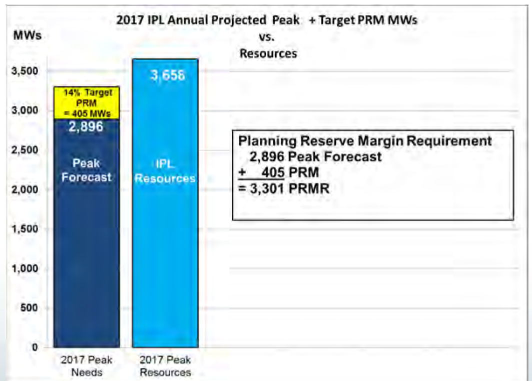
Definitions (4 of 5)

- Planning Reserve MWs
  - MW difference between the Peak forecast and generating unit availability
- Planning Reserve Margin (PRM)
  - The percentage of resources above the Peak forecast



Definitions (5 of 5)

- Target Planning Reserve Margin (Target PRM)
  - The percentage of resources above the Peak forecast needed to cover forecast and unit availability uncertainty
  - Calculated by MISO each November for the following summer
  - Result of the "Loss of Load Expectation Study"
  - This analysis produces a PRM that is expected to result in a loss of load event once every 10 years
- Planning Reserve Margin Requirement (PRMR)
  - MWs needed to meet the Peak forecast plus minimum MWs needed to cover potential for higher than normal peaks and lower than normal generating unit availability
  - PRMR = PEAK LOAD FORECAST X (1+Target PRM)
  - Calculated by MISO each November for the following summer
  - Typically around 14%: 7% for forecast uncertainty, 7% for availability uncertainty



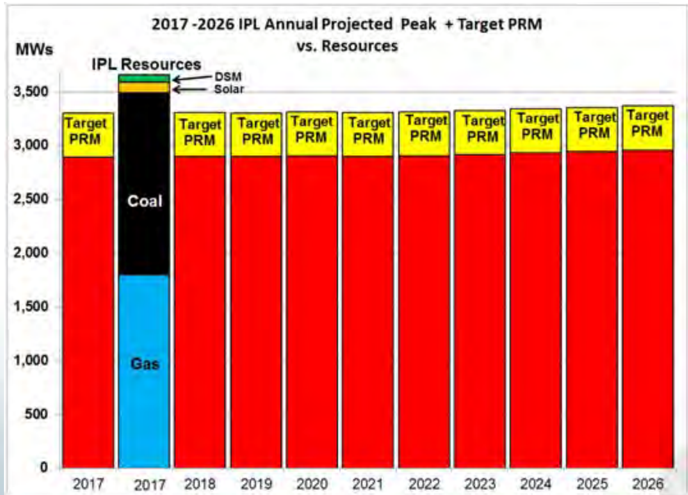
Planning to Provide Resource Adequacy

- IPL plans to meet the peak plus reserves with the following:
  - Demand Side Management Programs
  - IPL Generating Assets
  - Long Term Contracted Generating Assets
  - Balance of needs or excesses are purchased or sold in MISO capacity markets[1]

Footnote 1:
- Each year, prior to the summer, resource owners in MISO test the capacity level for each resource
- MISO populates an accounting system with 1 capacity credit for each MW of capacity
- Capacity credits can be purchased and sold
- Capacity credit sales do not impact energy sales
- Each utility with load must have capacity credits equal to its PRMR in the accounting system prior to the summer

IRP RA Process

- Resource Adequacy (RA) Process
  - Given current portfolio of resources
    - and future projected peak needs
    - and future projected energy needs
  - What portfolio of resources will be used to meet those needs?



MISO's RA Process

- In Indiana, RA Process is the responsibility of the Utilities
- IRP process and the certificate of need process are regulated by the State, and the responsibility of the 'obligation to serve' resides with the utilities
- MISO has a Resource Adequacy process but MISO is not responsible for Resource Adequacy
- IRP process is focused on the long term (several years out)
  - Focus is on future portfolio of resources
- The MISO Resource Adequacy process is focused on the short term: less than a year out
  - Focused on existing resources

MISO's role is an administrator of a reserving sharing pool

- This reserve sharing pool allows utilities to benefit from the diversity of resources across MISO
- Investments in and deployment of resources is lumpy
- Some utilities are slightly short, others slightly long of meeting their RA targets
- MISO's RA construct allows utilities that are temporarily short of meeting their RA target to purchase capacity credits from utilities that have more than enough resources to meet their short term RA targets
- Capacity credits are based on existing resources
- MISO capacity credits do not reflect the future value of adding resources or DSM

Key Takeaways

- IRP process must consider the future peak and energy needs of our customers
- Resource Adequacy (RA) focuses on peak needs
- Resource Adequacy is the responsibility of the regulated utilities (part of the obligation to serve)
- MISO administers a short term Resource Adequacy construct
  - MISO is not responsible for Resource Adequacy
  - MISO's construct is focused on <u>existing</u> not future resources

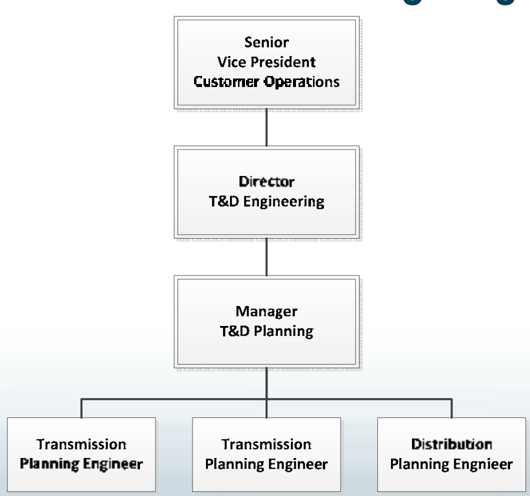
Questions?

Lunch Break

Transmission & Distribution

Mike Holtsclaw, Director of Engineering

Transmission Planning Organization



IPL has a dedicated Transmission Planning group within the Customer Operations Organization

IPL Transmission Planning

- IPL performs near term system studies for 1-5 years out and long term reliability planning studies for 10 years out
  - Studies are performed for on peak load, off peak load, and sensitivity cases looking for deficiencies on the transmission system
  - Steady state Power Flow studies show thermal (Rating) and voltage limits of the IPL transmission system
- Dynamic studies (0 to 20 seconds) show how the system performs to events
- IPL must also comply with the mandatory NERC Reliability Standards

IPL Transmission Planning (cont'd)

- The results of the studies are analyzed for deficiencies in the system such as thermal ratings that are exceeded on equipment such as transmission lines or transformers
- For the dynamic studies, voltage recovery times, and generation synchronization are analyzed to see that they meet IPL's planning criteria

MISO Transmission Planning Coordination

- MISO performs various planning studies for the full MISO footprint and for the three planning regions
- IPL is part of the MISO Central Planning region
- MISO will identify market efficiency projects and reliability projects for possible inclusion in their MISO Transmission Expansion Plan (MTEP)
- IPL participates in the MTEP studies and stakeholder groups to advocate solutions for customers

Recent IPL Transmission System Upgrades

- **Projects to Improve Reliability for Summer 2016**
  - Upgraded 345/138 kV auto transformer from 275 MVA to 500 MVA, included 138 kV bus modification to a ring bus arrangement
  - Installed the 275 MVA 345/138 kV auto transformer at another substation
  - Installed a 138 kV Static VAR Compensator +300/-100 MVAR for transient voltage support

Recent IPL Transmission System Upgrades (cont'd)

- **Projects to Support New Eagle Valley CCGT (COD Spring 2017)**
  - New 23 mile 138 kV line (Eagle Valley – Franklin Twp)
  - 138 kV Breaker Upgrades (Mooresville, Southport)
  - 138 kV Line Rating Upgrades
    - Eagle Valley – Southport
    - Eagle Valley – Glenns Valley
  - New 138 kV Capacitor Bank
- **MISO MTEP** – Upgrade Petersburg – AEP Sullivan 345 kV line

Distribution Planning

- Continuously reviews distribution system and develops a 5 year construction plan for new primary feeder circuits and substation capacity additions
- While distribution system load growth is relatively flat, neighborhood and commercial revitalization serves as a catalyst to improve existing circuits or extend new facilities
- Distributed Generation (DG) is also incorporated into the planning process through interconnection studies
- IPL has flexibility to switch loads due to compact service territory
- Recent distribution automation/smart grid deployment of >95% of the system supports remote switching operation

Smart Grid Project served as a catalyst

- Leveraged Department of Energy $20m grant toward $52m cost from 2010 to 2013
- Integrated holistic approach to include metering, distribution automation projects and customer facing technologies
- Sustainable solutions

Customer Systems have been deployed

- Customer Energy Management
  - Online Energy Feedback (PowerView®) for all customers
- Electric Vehicle Support
  - ~160 home, business & public chargers
  - Special rates
- Customer Web Engagement Tools
  - Smart grid education and outage reporting
  - Program enrollment for DSM

Distribution Automation Devices Currently Used Daily (1 of 3)

1. Central Business District Network Relays & Fault Indicators
   - Relays provide better protection
   - Fault indicators speed fault location and reduces cable damage
2. Digital Feeder Relays
   - Allows integration of DG onto the feeder
   - Reduced O&M costs by allowing reclosing to be turned off remotely
   - Provides 3 Phase currents, for better utilization of capacity
   - Distance to fault, reduces outage time
   - Feeder VAR readings integrated with capacitor control system to minimize substation and feeder losses

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Distribution Automation Devices Currently Used Daily (2 of 3)

3. Recloser Installations on Primary Circuits
   - Reduces number of complete circuit lockouts
   - Reduces number of customers affected by an outage
   - Speeds restoration as they can be controlled remotely through the dSCADA system
4. Smart Capacitor Bank Controls
   - Better voltage regulation on distribution feeders
   - Ability to change setting from central locations

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Distribution Automation Devices Currently Used Daily (3 of 3)

5. Load Tap Changer Controls
   - Key to Conservation Voltage Reduction (CVR) program settings can be changed remotely
   - CVR program is 20 MW of capacity
   - Tap changer operations recorded in historical database
6. Transformer On-line Monitoring
   - Improved asset health monitoring
   - Quicker indication of possible problems
7. Substation Security & Infrared Monitoring
   - Improved security and allows for quicker response when intruders are detected
   - Infrared Monitoring provides continuous monitoring of critical equipment

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Smart Energy Project Successes

- Increased reliability from mid-point reclosers which reduce circuit lockouts and number of customers affected
- Improved personnel safety through remote operation of overhead and underground equipment
- Leverage data for distribution asset management
- Avoided truck rolls in 2015 total over 91,000
- Better information for operational and long-term decision making

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Questions?

Load Forecast

Eric Fox, Director Forecast Solutions, Itron Inc.

Forecast Overview

1. Energy Trends – Why the disconnect between economic growth (GDP) and electricity use
2. Long-term Forecast Approach
   – Capturing end-use efficiency improvements
3. Forecast Model and Base Case Forecast Overview
   1. Residential
   2. Commercial
   3. Industrial
   4. Energy and Peak
4. Forecast Sensitivity
5. Summary

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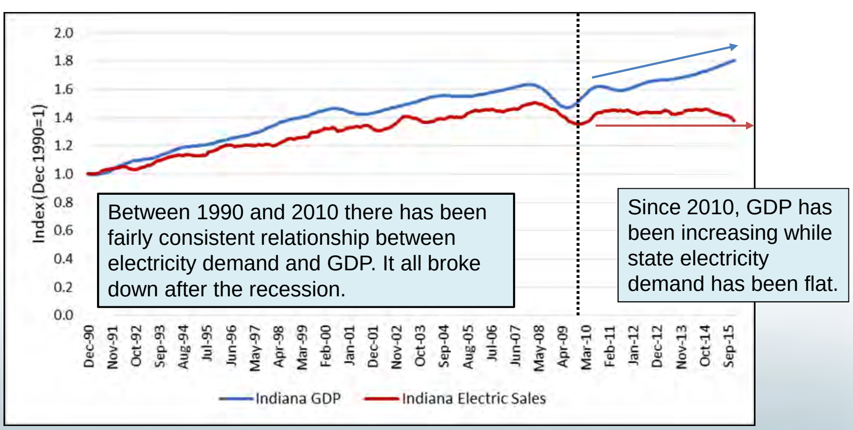
Top-Level Look

- Indiana GDP vs. Electricity Consumption



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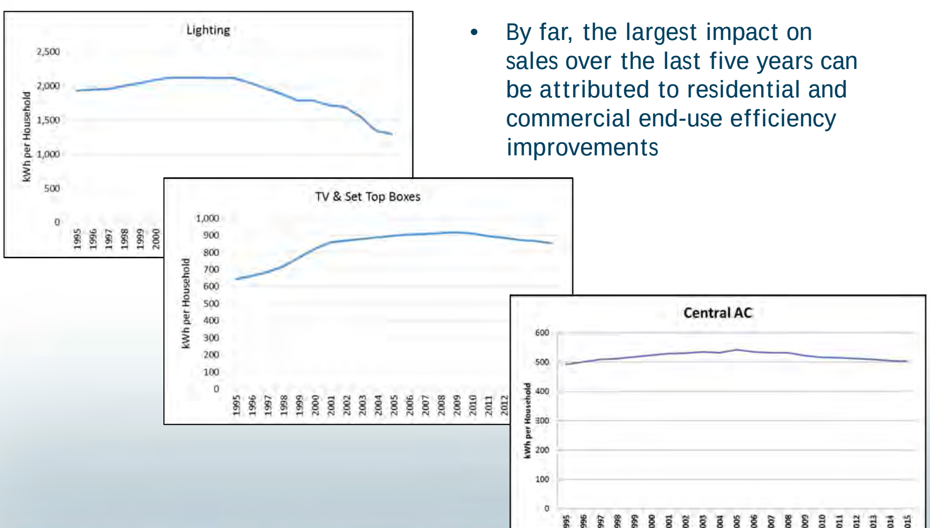
Why the disconnect?

- Strong residential appliance and commercial equipment efficiency improvements
  - Implementation of new end-use efficiency standards
- Increase in utility and state sponsored efficiency program activity
- Increasing share of less energy-intensive industries
- Smaller home square footage – increasing share of multifamily homes
- Changing demographics – smaller families and slower household formation growth
- Slower household income growth

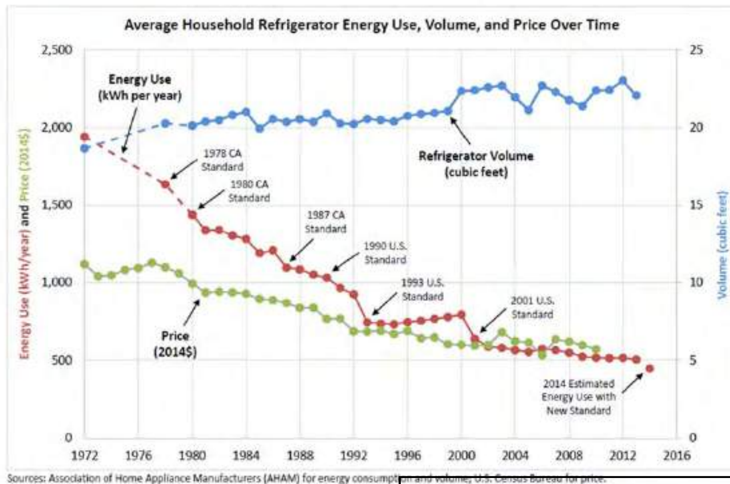
End-Use Efficiency Impact



- By far, the largest impact on sales over the last five years can be attributed to residential and commercial end-use efficiency improvements

Refrigerator Usage Trend

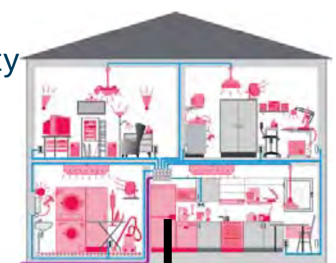
ASAP | APPLIANCE STANDARDS AWARENESS PROJECT



http://www.appliance-standards.org/

The Problem with using GDP as a Primary Forecast Driver

- GDP is correlated with electric sales, but GDP does not cause electric sales
- We use the stuff that uses electricity
  - We light our homes
  - We refrigerate and cook our food
  - We vacuum up after the kids and dog
  - We dry our clothes
  - We watch TV

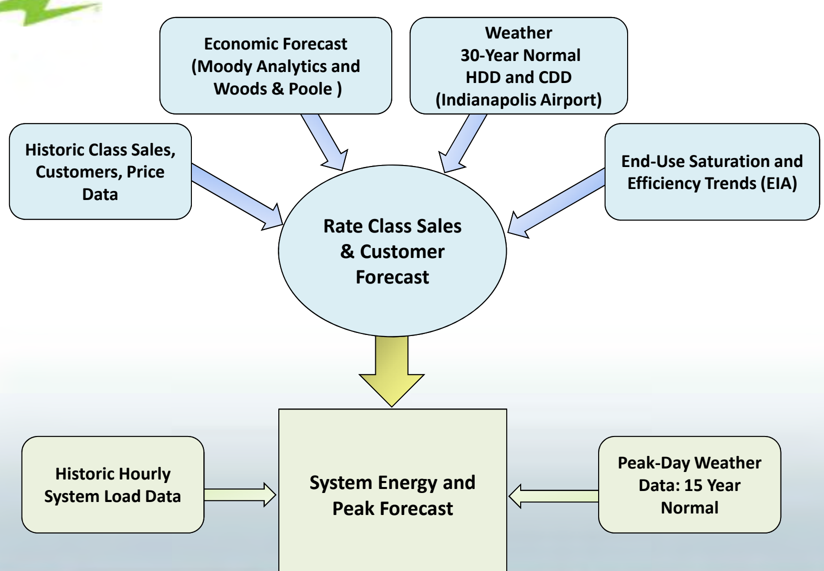


It's the other way around. Electricity generation and the things we buy are inputs into GDP

A Better Approach

- To the extent possible, we want to estimate forecast models of causation and not correlation
- That means understanding how changes in the technology we use at home and at work impacts our energy needs
- In addition to GDP as an economic variable

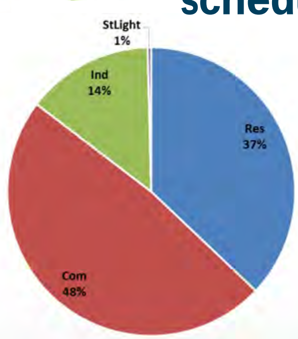
Forecast Modeling Framework



Forecast Models

- Forecasts are based on monthly regression models using ten-years of billed sales and customer data (January 2005 to March 2016)
- Sales Models
  - Residential and commercial models estimated using a blended end-use/econometric modeling framework
  - Industrial sales are 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

Models estimated at rate schedule level

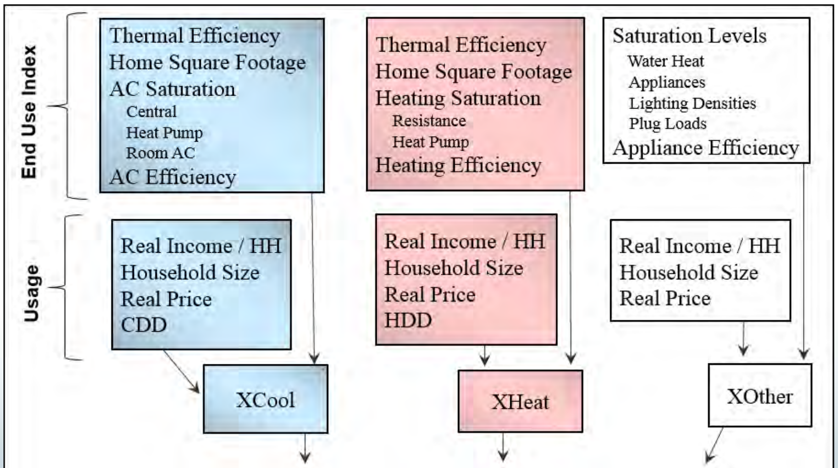


Percentage of 2015 Annual Sales

2015 Sales and Average Annual Customers

Rate Class	Rate Schedule	Definition	Customers	MWh	Avg_kWh
RES	RS	General Service	246481	2342108	9,502
RES	RH	Electric Heat	150498	2,323,908	15,441
RES	RC	Electric Water Heat	32022	406,586	12,697
Sml Com	SS	General Service	46,153	1,228,878	26,626
Sml Com	SH	GS All Electric	4,035	562,864	139,495
Sml Com	SE	GS Electric Heat	3,357	19,383	5,774
Sml Com	CB	GS Water Heat (Controlled)	95	432	4,549
Sml Com	UW	GS Water Heat (Uncontrolled)	84	1,506	17,923
Sml Com	APL	GS Security Lighting	364	31,620	86,868
Lrg Com	SL	Secondary Service	4,539	3,504,652	772,120
Lrg Com	PL	Primary Service	142	1,260,060	8,873,662
IND	HL1	High Load Factor 1	28	1,373,248	49,044,571
IND	HL2	High Load Factor 2	5	225,376	45,075,200
IND	HL3	High Load Factor 3	3	345,920	115,306,667
IND	APL	Ind Security Light	364	5,725	15,728
Other	ST	Street Lighting		53,280	
Total			488,170	13,685,546	28,034

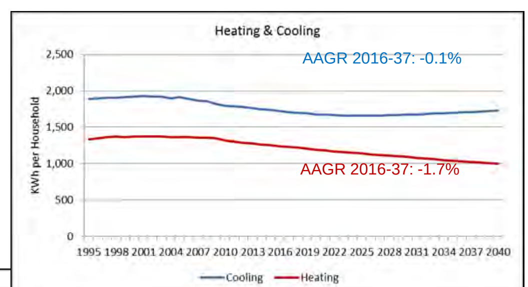
Residential Model

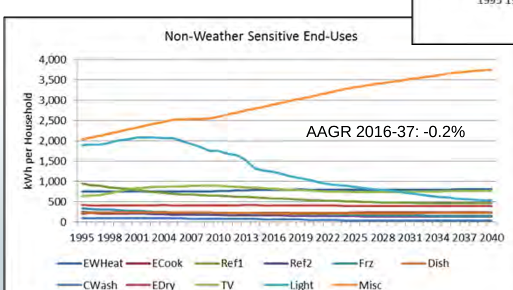


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + e_m$$

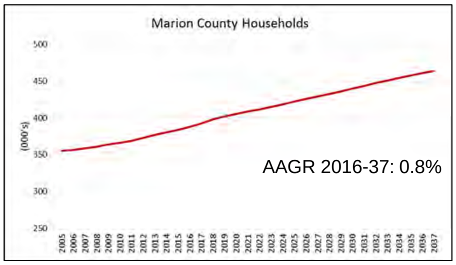
Residential End-Use Intensity Trends

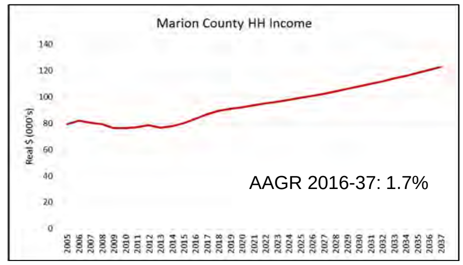
- Energy intensities derived from the EIA 2015 Annual Energy Outlook for the East North Central Census Division



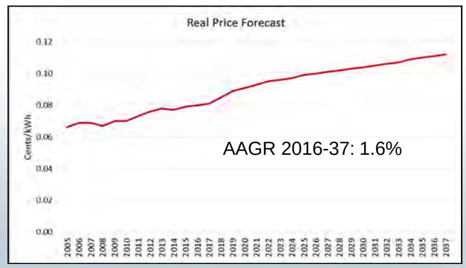


Residential Economic Drivers



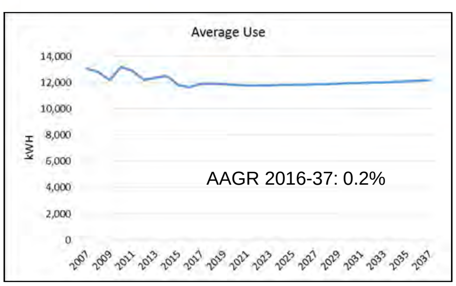


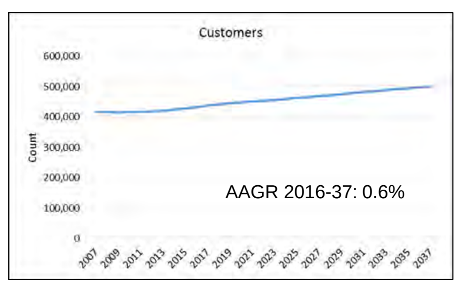
- Marion County Economic Forecast
- Blended Woods & Poole near-term forecast with Moody Analytics long-term forecast
- Price projections developed by IPL

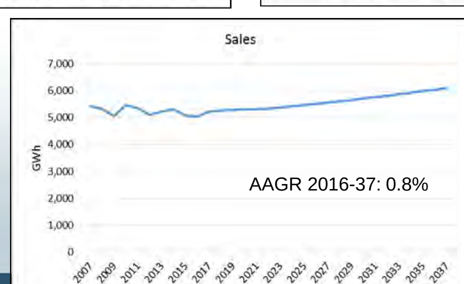


*AAGR=Average Annual Growth Rate

Residential Forecast

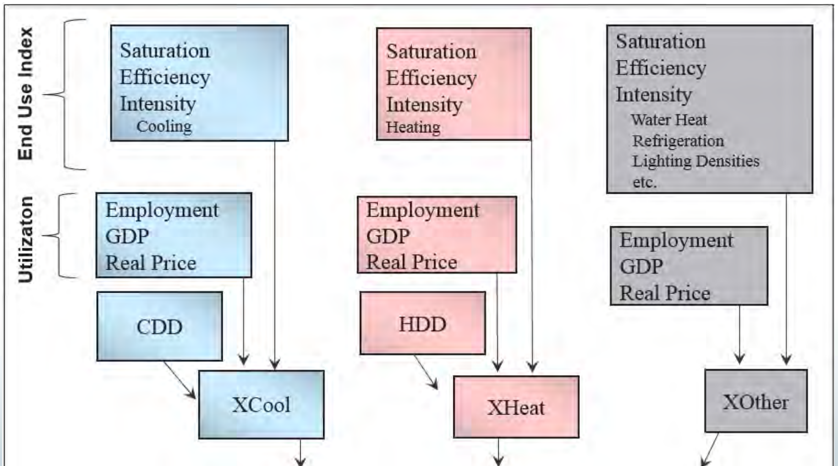






*AAGR=Average Annual Growth Rate

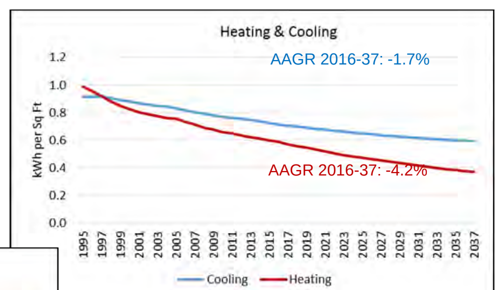
Commercial Model Framework

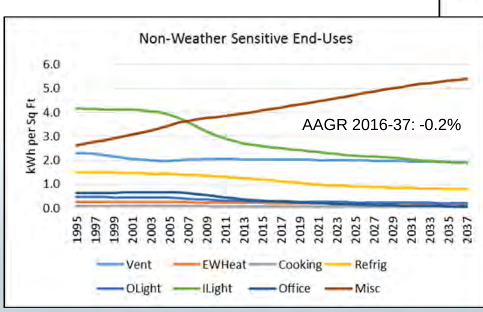


$$Sales_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + e_m$$

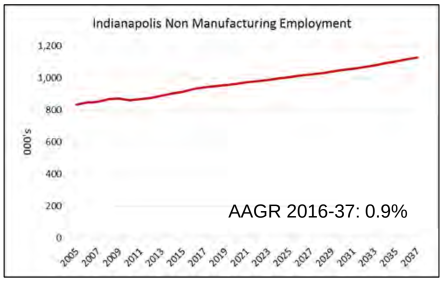
Commercial End-Use Intensities

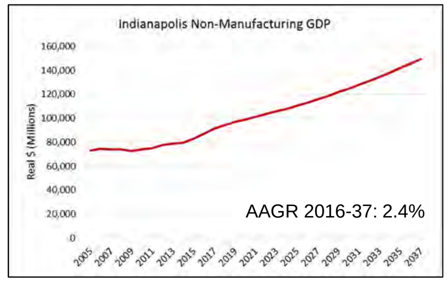
- Energy intensities derived from the EIA 2015 Annual Energy Outlook for the East North Central Census Division



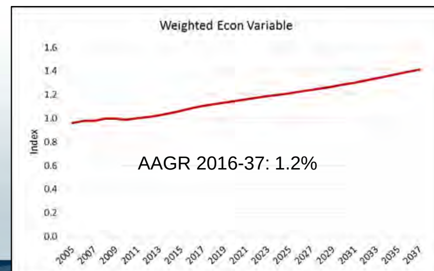


Commercial Economic Drivers





- Indianapolis MSA
- Blended Woods & Poole (in the near-term) and Moody Analytics in the long-term)
- Weighted economic variable: 80% employment/20% GDP



*AAGR=Average Annual Growth Rate

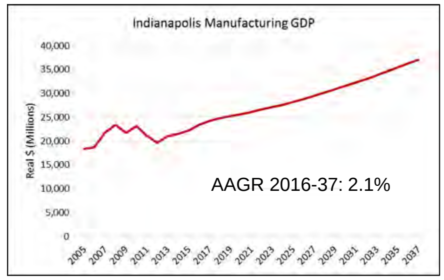
Industrial Model Framework

- Industrial sales are estimated with a generalized econometric model

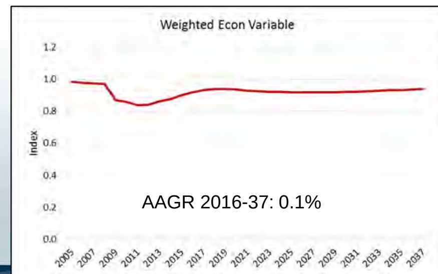
Cooling Degree Days	Manufacturing Employment Manufacturing Output Price

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

Industrial Economic Drivers

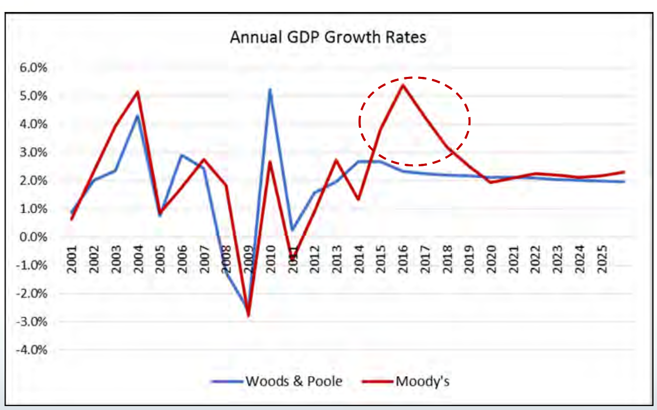


- Indianapolis MSA
- Blended Woods & Poole (near-term) and Moody Analytics long-term
- Strong employment weighting



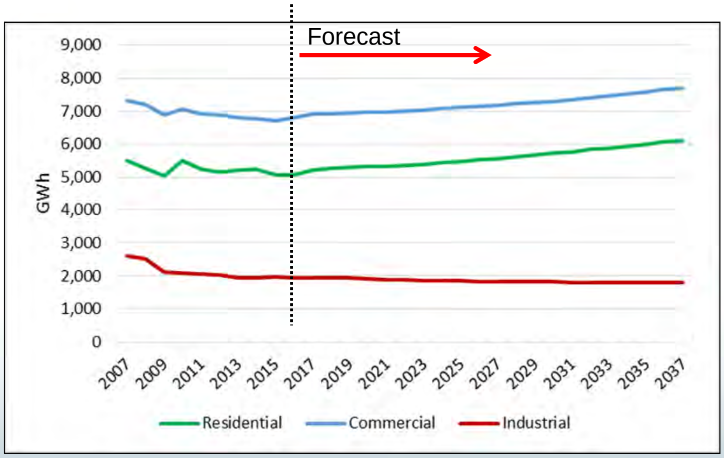
*AAGR=Average Annual Growth Rate

Comparison of GDP forecasts - Indianapolis Metropolitan Statistical Area (MSA)



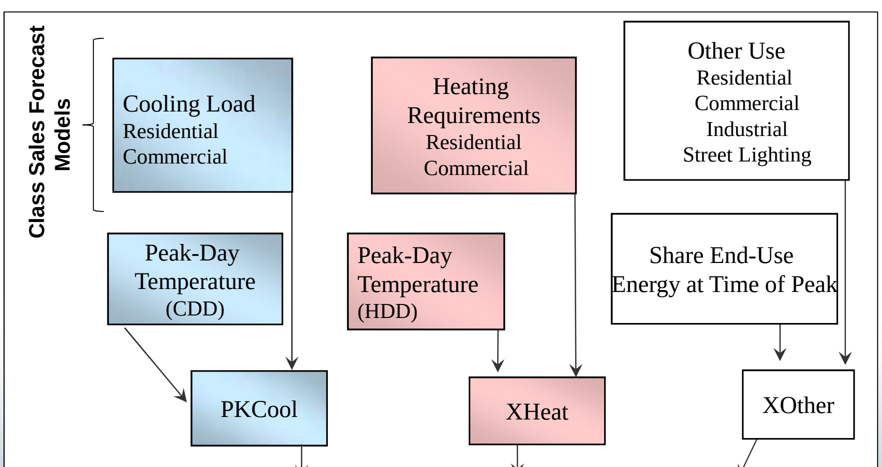
- Near-Term based on Woods & Poole GDP Forecasted Growth

Class Sales Forecast (before EE program savings)



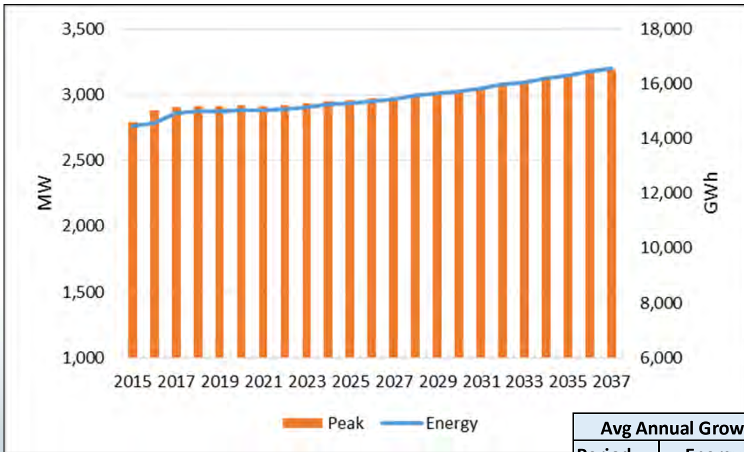
Avg Annual Growth Rate			
Period	Residential	Commercial	Industrial
2016-37	0.8%	0.5%	-0.4%

Peak Model



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

Energy & Peak Forecast

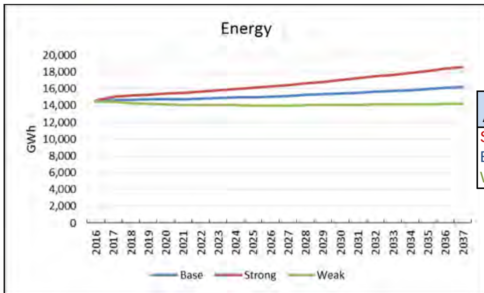


Avg Annual Growth Rate		
Period	Energy	Peaks
2016-37	0.5%	0.4%

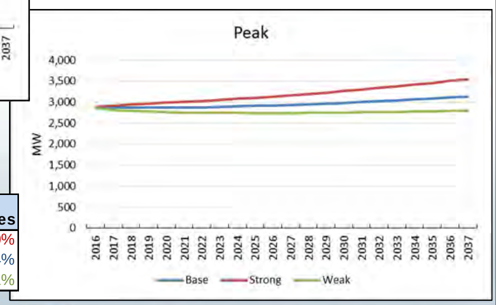
Forecast Sensitivity

- "Strong Economy"
  - Based on Moody Analytics "stronger near-term rebound" scenario for the Indianapolis MSA
- "Weak Economy"
  - Based on Moody Analytics "protracted slump" scenario for the Indianapolis MSA

Sensitivity Comparison



Avg Annual Growth Rates	
Strong	1.2%
Base	0.5%
Weak	-0.1%



Avg Annual Growth Rates	
Strong	1.0%
Base	0.4%
Weak	-0.1%

Summary

- Relatively strong customer growth and business activity
- But slow energy and demand growth
  - Sales growth is mitigated by continued improvement in end-use efficiency coupled with IPL's energy efficiency program activity
- The blended end-use/econometric model works extremely well in capturing the impact of improvements in end-use efficiency as well as customer and economic growth

Questions?

Environmental Risks

Angelique Collier, Director of Environmental Policy

Current Environmental Controls for Coal-Fired Generation

Unit	In Service Date	Generating Capacity (MW)	SO_2 Control	NO_x Control	PM Control	Hg Controls
Petersburg 1	1967	232	Scrubber (1996)	LNB (1995)	ESP (1967)	ACI (2015) SI (2015)
Petersburg 2	1969	435	Scrubber (1996)	LNB (1994) SCR (2004)	Baghouse (2015)	ACI (2015) SI (2015)
Petersburg 3	1977	540	Scrubber (1977)	SCR (2004)	ESP (1986) Baghouse (2016)	ACI (2016) SI (2016)
Petersburg 4	1986	545	Scrubber (1986)	LNB (2001)	ESP (1986)	ACI (2016) SI (2016)

SO_2 = Sulfur dioxide
NO_x = Nitrogen oxides
MW = Mega Watts
ACI = Activated Carbon Injection

ESP = Electricstatic Precipitator
SCR = Selective catalytic reduction
LNB = Low NO_x Burners
SI = Sorbent Injection

Environmental Regulations

- Recent Environmental Regulations/Projects
  - Mercury and Air Toxics Standard (MATS)
  - NPDES Water Discharge Permits
  - Cross State Air Pollution Rule (CSAPR)
- Future Environmental Regulations
  - 316(b) – Cooling water intake structures
  - Office of Surface Mining
  - Clean Power Plan (CPP)
  - Coal Combustion Residuals (CCR)
  - Effluent Limitations Guidelines (ELG) Rule
  - National Ambient Air Quality Standards (NAAQS)

NPDES= National Pollutant Discharge Elimination System

Recent Environmental Regulations

- MATS
  - Mercury and other air toxics from utilities
  - Compliance date: April 2016
  - Ceased coal-combustion on older, smaller coal-fired units
  - $450 million in new and upgraded air pollution controls at Petersburg
- NPDES
  - New metal limits for Harding Street and Petersburg
  - Compliance date: September 2017
  - Cease coal-combustion at Harding Street Unit 7
  - Scrubber wastewater treatment system and dry fly ash handling at Petersburg
  - $250 million in wastewater treatment
- CSAPR
  - Phase I effective January 2015; Phase II January 2017
  - Existing controls and purchase of allowances on the open market

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Future Environmental Regulations – NAAQS and CSAPR

- National Ambient Air Quality Standards (NAAQS)
  - PM2.5 and Ozone
    - Lowered standards
    - IPL areas designated or expected to be designated at attainment
- Cross State Air Pollution Rule Ozone Update
  - Proposed December 3, 2015
  - Would address lowered 2008 Ozone standard
  - Lower Ozone Season allowances allocated
  - Compliance through additional purchase of allowances or additional NO_x controls

NAAQS = National Ambient Air Quality Standards
CAIR = Clean Air Interstate Rule
$PM_{2.5}$ = Particulate Matter less than 2.5 microns in diameter
SO_2 = Sulfur Dioxide
SCR = Selective catalytic reduction
EPA = Environmental Protection Agency

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Future Environmental Regulations – Cooling Water Intake Structures Rule

- Final Rule published August 2014
- Regulates environmental impact from cooling water intake structures (CWIS)
  - Impingement and entrainment of aquatic species
  - Closed cycle cooling systems may be required
- Studies underway to determine impact
  - Eagle Valley and Harding Street already equipped with closed cycle cooling.
  - Two of four Petersburg units fully equipped with closed cycle cooling
- Compliance required in 2020 or later

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Future Environmental Regulations – Office of Surface Mining Rule

- Proposed Rule expected in 2016
- Would regulate placement of ash as backfill in mines
- If backfill prohibited, IPL Petersburg may require expansion of onsite landfill

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Future Environmental Regulations – Clean Power Plan

- Final Rule published August 23, 2015
- Requires carbon dioxide emissions reductions
  - Indiana must develop a State Plan or be subject to Federal Plan
  - May be achieved through
    - Heat rate improvements;
    - Re-dispatch from coal to new renewables or existing NGCCs; or
    - Other measures.
- New Eagle Valley NGCC not subject to Rule
- Harding Street will comply by combusting natural gas
- Rule stayed by SCOTUS pending legal resolution
  - Initial State Plan deadline of September 6, 2016 no longer in place
  - Compliance deadline likely delayed by 18 months or longer

NGCC = Natural Gas Combined Cycle
SCOTUS = Supreme Court of the U.S.

Future Environmental Regulations – Clean Power Plan Allocations

Plant Name	Boiler ID	Unit's First Period Allocation (short tons) 2022-2024	Unit's Second Period Allocation (short tons) 2025-2027	Unit's Third Period Allocation (short tons) 2028-2029	Unit's Final Allocation (short tons) 2030-2031
Harding Street	50	397,900	382,078	359,864	346,958
Harding Street	60	365,218	350,695	330,305	318,460
Harding Street	70	1,712,557	1,644,458	1,548,847	1,493,304
Petersburg	1	968,248	929,747	875,690	844,287
Petersburg	2	1,808,953	1,737,021	1,636,028	1,577,359
Petersburg	3	2,356,018	2,262,332	2,130,797	2,054,384
Petersburg	4	2,222,084	2,133,724	2,009,666	1,937,597
Total		9,830,978	9,440,055	8,891,197	8,572,349

Model Assumptions and Inputs

Potential Impacts of Environmental Regulations

Regulation	Expected Implementation Year	Cost Range Estimate ($MM)	Assumed Technology
Office of Surface Mining	2018	0-15	Onsite Landfill
Cooling Water Intake Structure	2020	10-160	Closed Cycle Cooling
Ozone National Ambient Air Quality Standards	2020	0-150	Selective Catalytic Reduction

Questions?
Part 1

Short Break

Upcoming Environmental Regulations – Coal Combustion Residuals (CCR) Rule

- Final rule published April 2015
- Regulates ash as non-hazardous waste
  - Minimum criteria for ash ponds
  - Closure and post-closure requirements
- HS and EV ponds will be closed because ceased coal combustion
- Petersburg ponds must meet minimum criteria or cease use and close
  - Pond closure would require system to handle bottom ash
  - Closed-loop bottom ash handling system

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Future Environmental Regulations – Effluent Limitations Guidelines (ELG) Rule

- Final rule published November 2015
- Technology-based standard regulating wastewater
  - Scrubber wastewater treatment
  - Dry fly ash handling
  - Dry or closed-loop bottom ash handling
- No impact at Harding Street or Eagle Valley
- Petersburg compliant due to other requirements
  - NPDES
  - CCR

Upcoming Environmental Regulations – SO_2 NAAQS

- HS and EV comply by combusting natural gas
- Compliance required in 2017
- More stringent limits at Petersburg will require improved SO_2 control
  - Dibasic acid injection
  - Emergency ball mill
  - Emergency limestone conveyance
  - Unit 1 & 2 switch gear

NAAQS = National Ambient Air Quality Standards
SO_2 = Sulfur Dioxide

Model Assumptions and Inputs

Upcoming Impacts of Environmental Regulations

Regulation	Expected Implementation Year	Cost Estimate ($MM)	Assumed Technology
Effluent Limitations Guidelines	2018	0	None
Coal Combustion Residuals	2018	47	Bottom Ash Dewatering System
SO_2 National Ambient Air Quality Standards	2017	48	FGD Improvements

Questions?
Part 2

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Short Break

Modeling Update

Joan Soller, Director of Resource Planning

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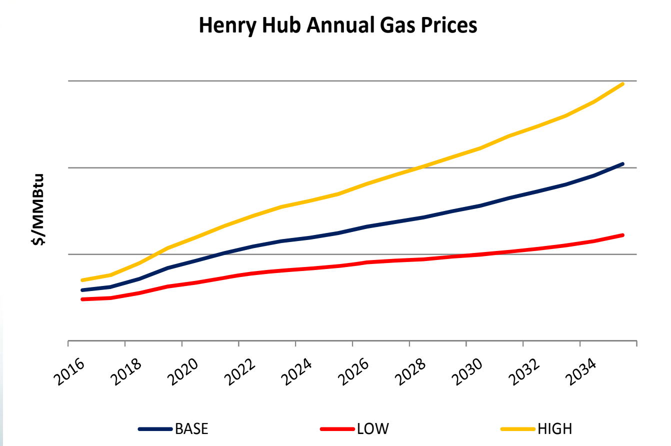
Modeling work continues

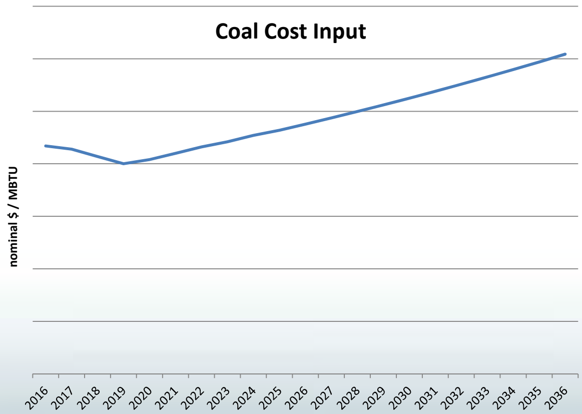
- Updated NG, market price, capacity cost and environmental inputs
- Refreshed existing resource information
- Fine-tuned supply resource parameters
- Created DSM bundles
- Updated load forecast
- Ran initial base case scenario

Natural gas inputs



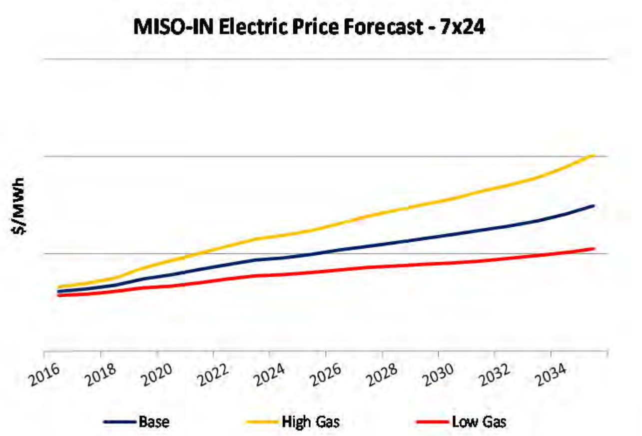
Source: ABB 2015 Fall Reference Case in nominal dollars

Coal cost inputs



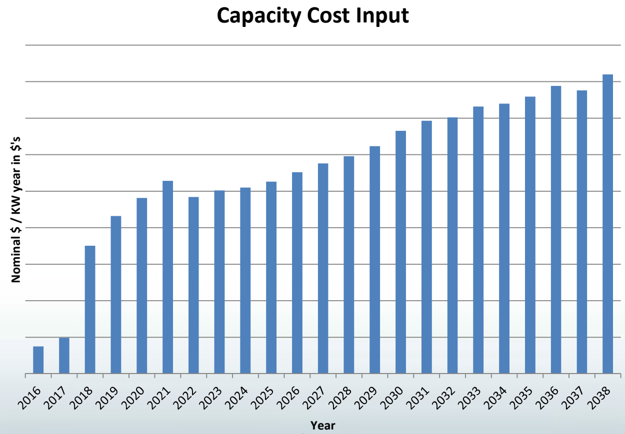
Source: IPL Forecast

Market price inputs



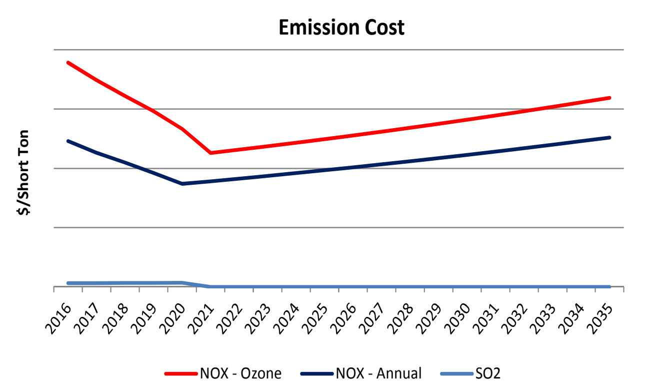
Source: ABB 2015 Fall Reference Case in nominal dollars

Capacity cost inputs



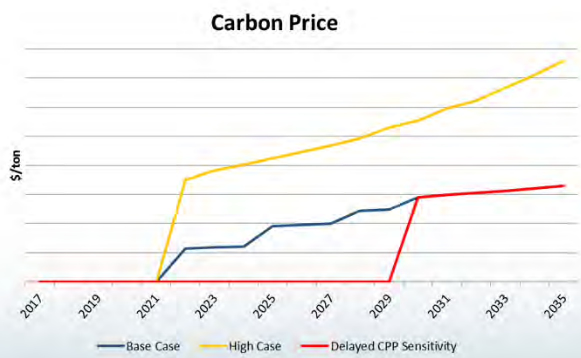
Source: Market Transactions and ABB 2015 Fall Reference Case

Emission cost inputs



Source: ABB 2015 Fall Reference Case in nominal dollars

Carbon cost inputs



Source: ABB Fall 2015 Reference Case and ICF Federal Legislation

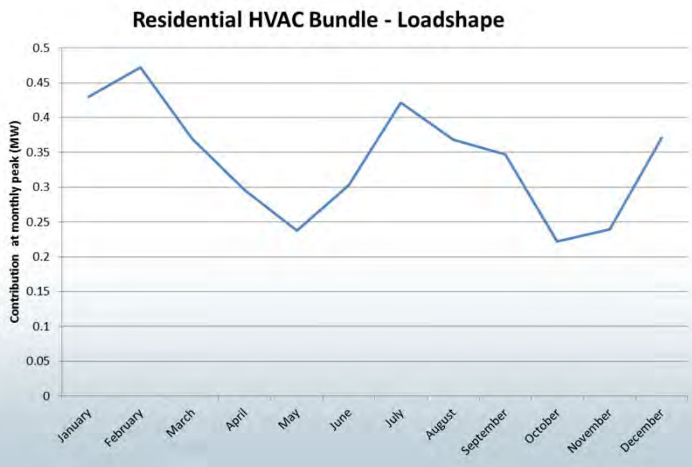
*Price is in nominal dollars

DSM bundles from Market Potential Study

1. EE Res Other (up to $30/MWh)
2. EE Res Other ($60+ /MWh)
3. EE Res Other ($30-60/MWh)
4. EE Res Lighting (up to $30/MWh)
5. EE Res HVAC (up to $30/MWh)
6. EE Res HVAC ($60+ /MWh)
7. EE Res HVAC ($30-60/MWh)
8. EE Res Behavioral Programs
9. EE Bus Process (up to $30/MWh)
10. EE Bus Process ($30-60/MWh)
11. EE Bus Other (up to $30/MWh)
12. EE Bus Other ($60+ /MWh)
13. EE Bus Other ($30-60/MWh)
14. EE Bus Lighting (up to $30/MWh)
15. EE Bus Lighting ($60+ /MWh)
16. EE Bus Lighting ($30-60/MWh)
17. EE Bus HVAC (up to $30/MWh)
18. EE Bus HVAC ($60+ /MWh)
19. EE Bus HVAC ($30-60/MWh)
20. DR Water Heating DLC
21. DR Smart Thermostats
22. DR Emerging Tech
23. DR Curtail Agreements
24. DR Battery Storage
25. DR Air Conditioning Load Mgmt

EE = Energy Efficiency
DR = Demand Response

DSM sample monthly load shape



Initial base model run results

DRAFT RESULTS – NOT FINAL

*Batteries were modeled as "peakers" without additional grid benefits. Technology and market changes may affect implementation timing.

YEAR	Base*
2017	DSM - 21 MW
2018	DSM - 23 MW
2019	DSM - 17 MW
2020	DSM - 13 MW
2021	DSM - 12 MW
2022	DSM - 12 MW
2023	**Retire HS GT 1 & 2 (-32 MW) Oil** DSM - 12 MW
2024	DSM -13 MW
2025	DSM - 13 MW
2026	DSM - 11 MW
2027	DSM - 6 MW
2028	DSM - 7 MW
2029	DSM - 3 MW
2030	DSM - 4 MW
2031	**Retire HS 5 & 6 (-200 MW) NG** DSM - 5 MW
2032	**Retire Pete 1 (-227 MW) Coal** DSM - 12 MW
2033	**Retire HS 7 (-430 MW) NG** DSM - 11 MW Battery 140 MW PV 20 MW
2034	**Retire Pete 2 (-410 MW) Coal** DSM - 5 MW Battery 460 MW
2035	DSM - 5 MW CC 200 MW Battery 240 MW
2036	DSM - 5 MW CC 200 MW Battery 60 MW

Initial findings

- The base scenario model results include environmental compliance capital expenditures at Petersburg
- Incremental DSM additions were selected each year starting at ~1% of forecasted sales
- Supply side additions of batteries and solar occur near the unit retirements
- CCGT is selected in later years of study period

Modeling work will continue

- Review base case including inherent DSM
- Run Capacity Expansion model for the other 4 scenarios
- Run Production Cost model for all scenarios
- Calculate PVRRs
- Calculate metrics
- Share results

Questions?

Portfolio Exercise

Joan Soller, Director of Resource Planning
Dr. Marty Rozelle, Facilitator

INDIANAPOLIS POWER & LIGHT COMPANY

Stakeholders draft portfolios

- Consider mix of supply and demand resources to meet ~3000 MW peak load requirement
- Recall representative costs from the April meeting on the next slide
- We are interested in your points of view

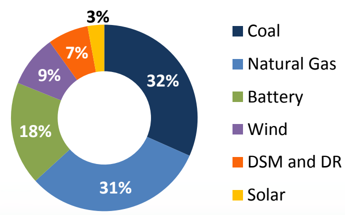
Supply side resource alternatives (from Meeting #1)

IRP Resource Technology Options*			
	MW Capacity	Performance Attributes	Representative Cost per Installed KW
Simple Cycle Gas Turbine	160	Peaker	$676
Combined Cycle Gas Turbine - H-Class	200	Base	$1,023
Nuclear	200	Base	$5,530
Wind	50	Variable	$2,213
Solar	> 5 MW	Variable	$2,270
Energy Storage	20	Flexible	~ $1,000
CHP – industrial site (steam turbine)	10	Base	Ranges from ~ $670 to $1,100
Other?			

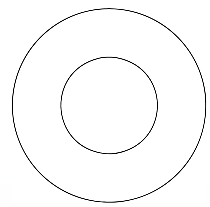
*See Meeting #1 presentation for sources

Exercise worksheet

Potential IPL 2034 portfolio
(nameplate capacity)



"My" portfolio



- ☐ coal ____%
- ☐ battery ___%
- ☐ DSM and DR ____%
- ☐ natural gas ____%
- ☐ oil _____%
- ☐ solar ______%
- ☐ wind ____%
- ☐ other ____%

Discussion

Next Steps

Dr. Marty Rozelle, Facilitator

Written comments and feedback

- Deadline to send written comments and questions regarding this meeting to ipl.irp@aes.com is Tuesday, June 21
- All IPL responses will be posted on the IPL IRP website by Tuesday, July 5
- IPL is considering a webinar to share modeling results in August

Next scheduled meeting

Friday, September 16, 2016

- Resource Portfolio results
- Sensitivities
- Preferred Resource Plan
- Short Term Action Plan

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ipl an AES company

Thank you!

We value your input and appreciate your participation. Please submit your feedback form and recycle your nametag at the registration table as you leave the meeting today.

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June 14 Appendix

Capacity reserves exceed min requirement of ~14% in draft base case

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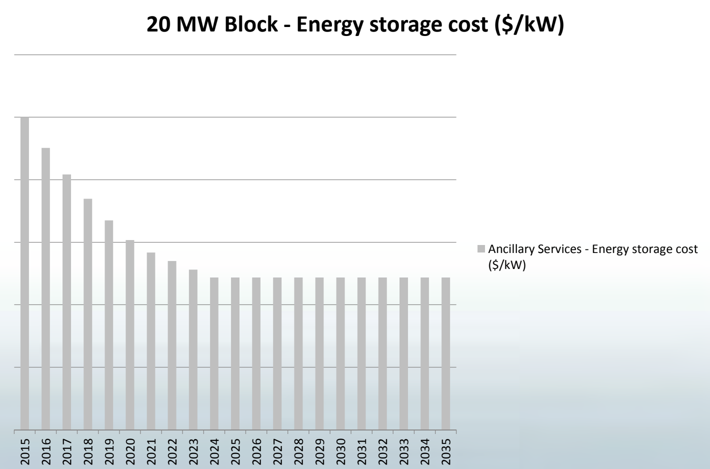
Energy storage cost forecast



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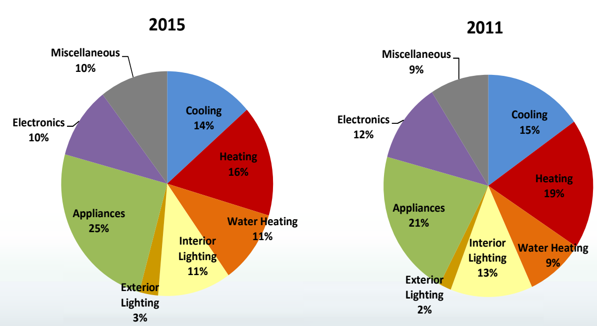
IPL residential market profile



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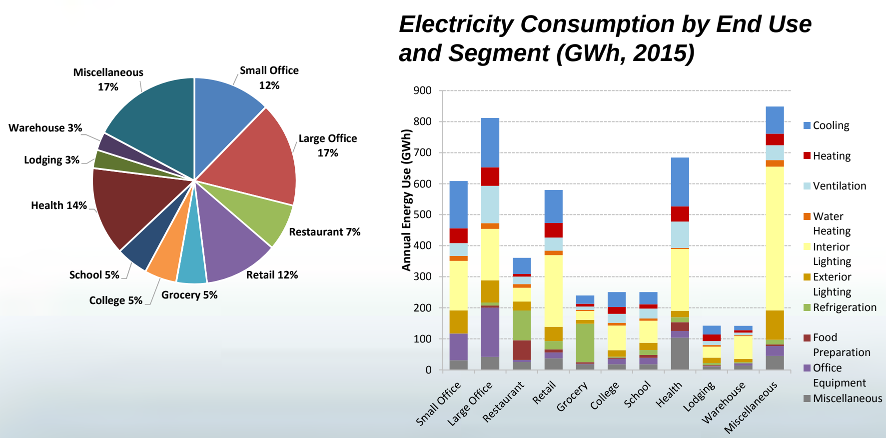
IPL commercial market profile



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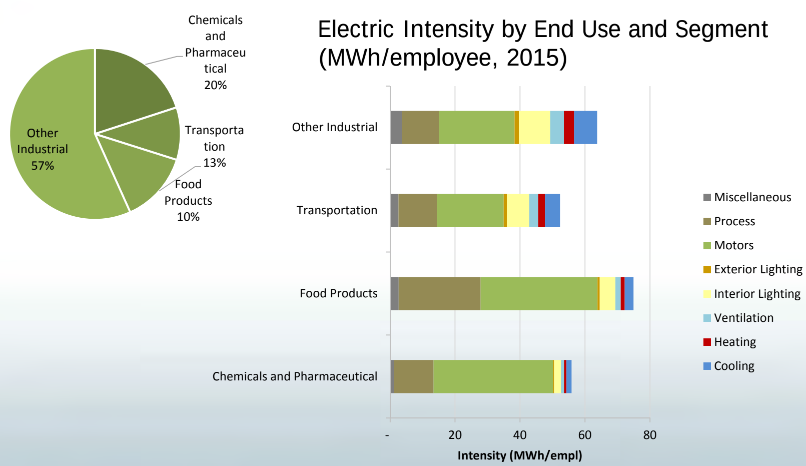
IPL Industrial market profile



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REVISED 9-6-16

- DSM appendix slides - real $ noted
- Added slides 50 - 56

Integrated Resource Plan Public Advisory Meeting #3

August 16, 2016

Welcome & Safety Message

Bill Henley, VP of Regulatory and Government Affairs

Meeting Guidelines

Joan Soller, Director of Resource Planning

Agenda for today

9:30am Welcome
- Meeting Agenda and Guidelines
- Summary & Feedback from IRP Public Advisory Meeting #2

9:45am IRP modeling update
- Updates to modeling
- Draft model results for all scenarios

10:30am Stakeholder Feedback

10:45am Sensitivity analysis setup

11:30am Conclusion

Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions
- Three ways to participate remotely:
  - The phone line will be muted. Press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
  - Use WebEx online tool for questions during meeting
  - Email additional questions or comments to ipl.irp@aes.com
- All may email questions/comments by August 23 for IPL to respond via website by September 6

Active cases before the commission

- Cause No. 42170, ECR-26
- Cause No. 44121, Green Power (GPR 9)
- Cause No. 43623, DSM 13
- Cause No. 44576, Rates (under appeal)
- Cause No. 44792, DSM 2017 Plan
- Cause No. 44794, SO_2 NAAQS and CCR
- Cause No. 44795, Capacity and Off System Sales Riders

Summary & Feedback from IRP Public Advisory Meeting #2

Joan Soller, Director of Resource Planning

Topics covered in Meeting #2

- Stakeholder presentations
- Portfolio Comparison based on Metrics
- Transmission & Distribution
- Load Forecast
- Environmental Risks
- Portfolio and Metrics Exercises
- Draft base case results

- Presentation materials, audio recording, acronym list, and meeting notes are available on IPL's IRP webpage here: https://www.iplpower.com/irp/

Stakeholder interaction continues

- Since the June meeting, IPL has reached out to the following stakeholders:
  - Citizens Energy
  - Hoosier Interfaith Power & Light (HIPL)
  - IPL Advisory Board
  - National Association for the Advancement of Colored People (NAACP)

Stakeholder portfolio exercise feedback

Resource	Potential IPL 2034 Portfolio June 2016	Range of Stakeholder Preferred Capacity Percentage
Coal	32%	0 – 30%
Natural Gas	31%	0 – 35%
Battery	18%	5 – 18%
Wind	9%	9 – 30%
DSM	7%	7 – 20%
Solar	3%	6 – 30%
Oil	0%	0 – 10%

Stakeholder metrics exercise feedback

Metrics	Scores
Air quality*	10
PVRR	10
CO_2 intensity	8
Planning reserves	7
Rate impact in 5 year increment	6
CO_2 emissions over time	5
Cost variance risk ratio	5
Annual average CO_2 emissions	3
Flexibility - Quick start vs. peak load	3
Bill impact / energy burden	2
Flexibility - Portfolio diversity (fuel)	2
Resource mix over time	2
Social Equity	*2*

green = stakeholder proposed

blue= IPL proposed

*other pollutants including PM, NOx, SO2, methane emissions

Questions?

IRP Modeling Update

Joan Soller, Director of Resource Planning

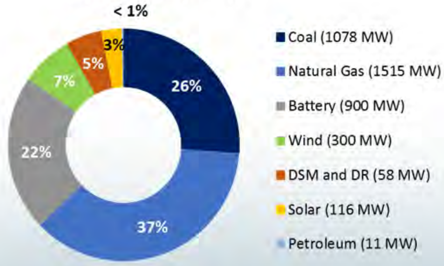
Base case has evolved since last meeting

- Incorporated NERC standards voltage stability requirements
  - Minimum 450 MW baseload on 138 kV in addition to EV CCGT
- Adjusted battery capacity credit to 25% to represent 4 hour energy output durations
- Added wind parameters
  - Capacity credit in 2022 as a proxy for expected transmission expansion
  - Frequency response (via energy storage) per proposed order in FERC docket RM 16-6 and reactive power (via quick capacitors) provisions per recent FERC Order 827
  - Limit 250 MW per year and total of 1000 MW to mirror minimum loads

Base case comparison

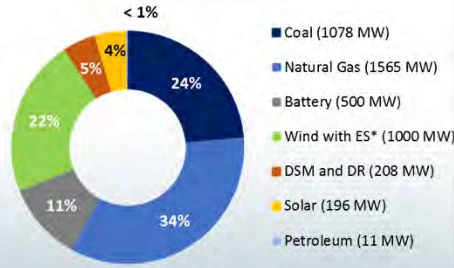
Initial Base Case (June 2016)

Potential IRP 2036 Portfolio
(operating capacity)



Final Base Case (Aug 2016)

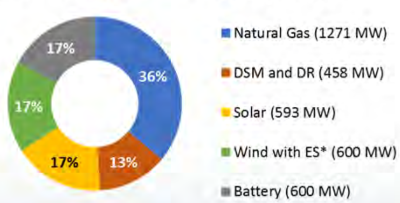
Potential IPL 2036 Portfolio
(operating capacity)



*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

IPL created a Quick Transition Scenario to reflect Stakeholder feedback

Quick Transition Planning Capacity



<u>Inputs:</u>

- All coal units retire by 2030
- Retain minimum NG on local 138 kV system to meet NERC standards
- Adopt maximum achievable DSM
- Balance comprised of solar, wind and storage

*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

Summary of scenarios

1. Base Case
2. Robust Economy
3. Recession Economy
4. Strengthened Environmental Rules
5. High Adoption of Distributed Generation
6. Quick Transition

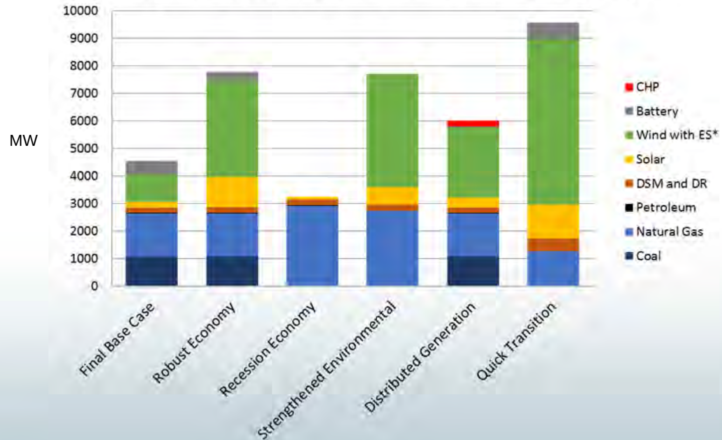
Scenario Characteristics/Variable Drivers

	Scenario Name	Load Forecast	Natural Gas and Market Prices	Clean Power Plan (CPP) and Environment	Distributed Generation (DG)
1	Base Case	Use current load growth methodology	ABB Mass-based CPP Scenario	Mass-based CPP starting in 2022. Low cost environmental regulations: ozone, 316b, NSR, and CCR	Expected moderate decreases in technology costs for wind, storage, and solar
2	Robust Economy	High*	High*	Base Case	Base Case
3	Recession Economy	Low*	Low*	Base Case	Base Case
4	Strengthened Environmental Rules	Base Case	Base Case	20% RPS + high carbon costs. High costs: NAAQS ozone, 316b, OSM, NSR*	Base Case
5	Distributed Generation	Base Case	Base Case	Base Case	Base case with fixed additions of 150 MW in 2022, 2025, and 2032*
6	Quick Transition	Base Case	Base Case	Base Case	Fixed portfolio to retire coal, add max DSM, minimum baseload (NG), plus solar, wind and storage*

*Purple font indicates changes.

Scenarios produce varied expansion plans

Operating Capacity of IPL Resources in 2036 (MW)

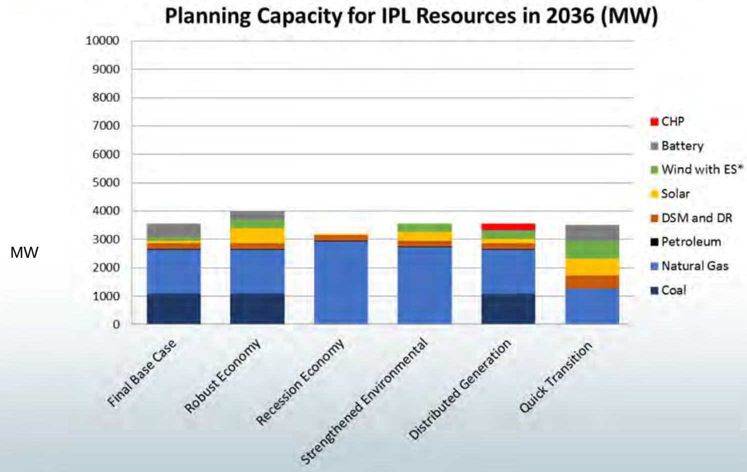


*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

Scenario observations

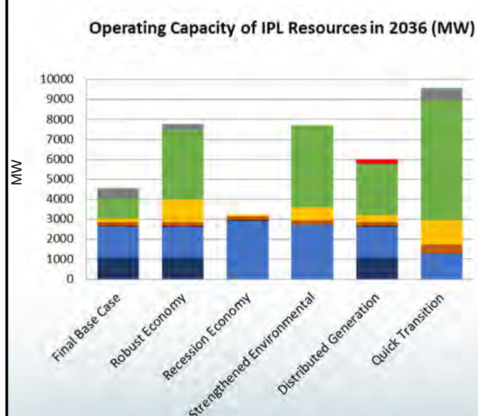
Base Case	Assumes existing units operate through their estimated useful life.
Robust Economy	Load increased by ~370 MW with higher NG prices.
Recession Economy	Load decreased by ~300 MW, lower NG, includes Pete 1-4 refuel early.
Strengthened Environmental	Higher costs for CO_2, 316 b, NAAQS ozone, OSM, and NSR. Includes P1 retirement, P2-4 refuel.
Distributed Generation	Customers choose DG for reasons other than economics totaling ~450 MW or ~15% of IPL load.
Quick Transition	Asset additions are "lumpy" in 2030 when there is an inflection point in Clean Power Plan compliance. The Maximum Achievable Potential DSM was added.

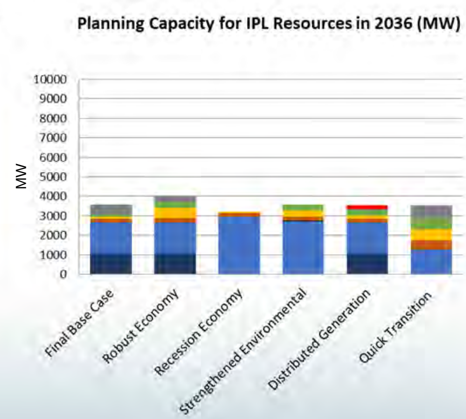
Planning capacity provides resource adequacy in MISO



*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

Planning capacity for renewables is lower than operating capacity

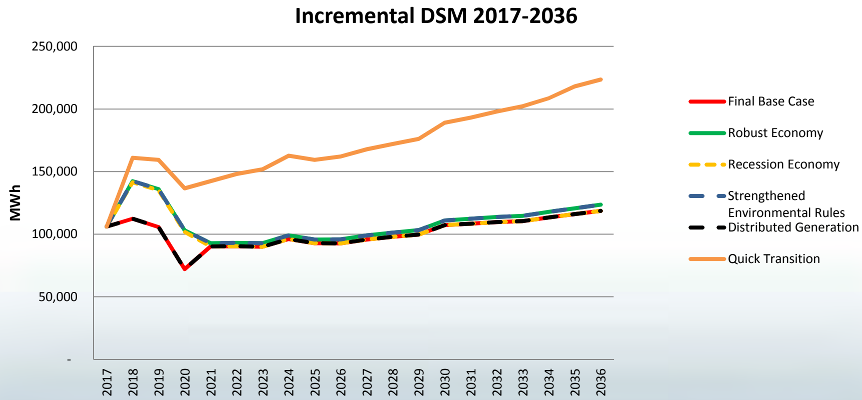




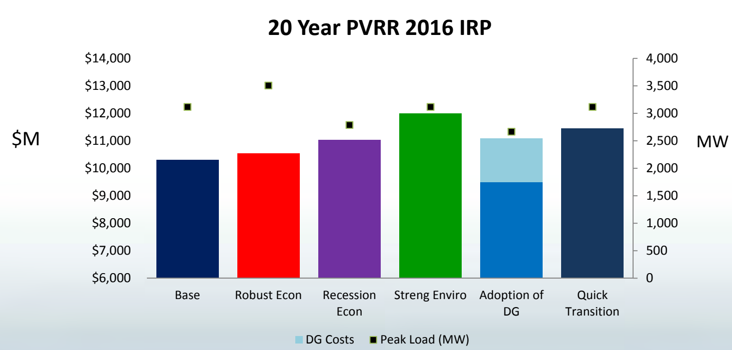
CHP Battery Wind with ES* Solar DSM and DR Petroleum Natural Gas Coal

*Wind resources are paired with Energy Storage (ES) in anticipation of proposed FERC rule for frequency response.

DSM varies by scenario



Costs are shown as Present Value Revenue Requirement (PVRR) 2017 - 2036



*Light blue DG costs are estimated for 450 MW. Customer DG costs will vary.

Questions?

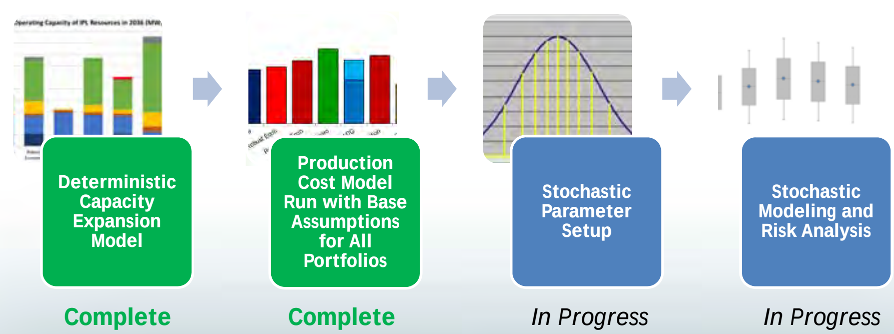
Sensitivity Analysis Setup

Patrick Maguire
Director, Corporate Planning & Analysis

Sensitivity analysis plan

- Two deterministic carbon sensitivities for the base case
  - Delayed CPP from 2022 to 2030
  - High carbon cost for CPP
- Stochastic modeling for all portfolios
  - Multiple inputs varied in each model run
    - Examples: Load (peak and energy), commodity prices, carbon prices, capital costs, forced outage rates

IRP modeling process



Two modeling approaches

Deterministic Model	Stochastic Model

Deterministic Model

Scenario

CapEx Resource Plan

Sensitivity a

e.g. NG ↑
NG ↑+ Load ↑

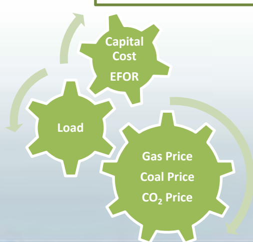
Sensitivity b

e.g. NG ↓
NG ↓+ Load ↓

Stochastic Model

Scenario

CapEx Resource Plan



Example:
10 variables
X 10 draws
100 iterations for each portfolio

Why model stochastically?

Deterministic Model	Stochastic Model

Deterministic Model

Advantages
- Easy to administer with no formal probability calculations
- Can be comprehensive with the right amount and combination of variables

Shortcomings
- More qualitative setup, e.g. variables changed by user-defined known and fixed amounts
- Difficult to capture correlations between variables

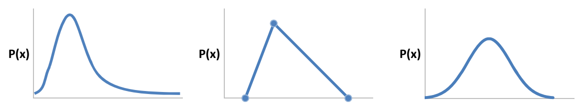
Stochastic Model

Advantages
- More robust accounting for interrelatedness and correlation between variables
- Well-established statistical principles and common use guide the setup

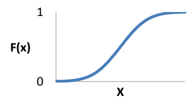
Shortcomings
- Difficult to perform and consolidate statistical probability data and correlations
- All variable iterations fed into Integrated Model to generate power prices => significantly higher amount of model simulation time

Parameter setup

Define the distribution



Determine Cumulative Distribution

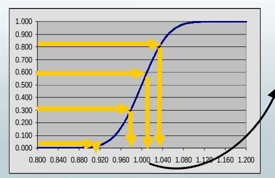


Pick a random number

Use random number to get to multiplier

Account for specific variable characteristics:

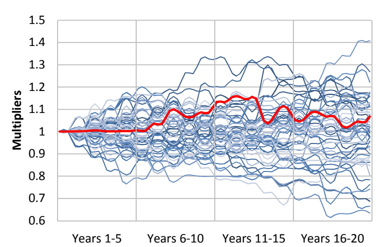
- *Random Walking*
- *Mean Reversion*
- *Seasonality*
- *Skewness*
- *Kurtosis*



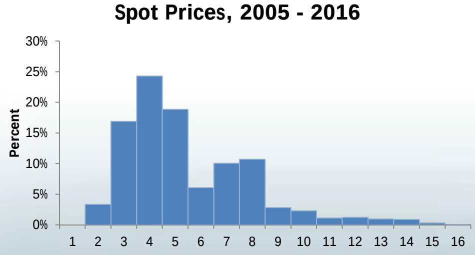
1.037
0.980
0.952
1.005
1.002
1.013
1.003

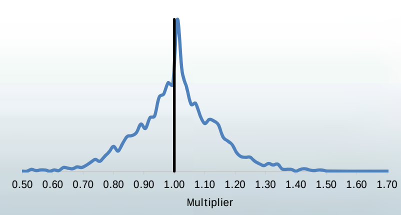
Stochastic Parameter: Gas

Well established market with extensive historical data



Histogram of Historical Henry Hub Spot Prices, 2005 - 2016

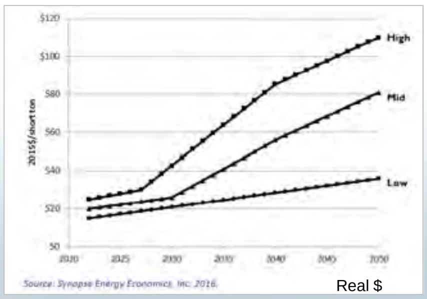


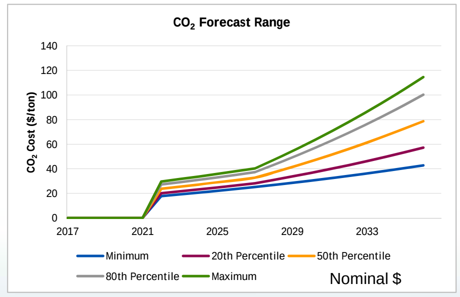


Stochastic Parameter: CO_2

Lack of historical pricing complicates variable setup

Synapse forecasts guided the range of outcomes





Use of Stochastic Parameters

ILLUSTRATIVE PURPOSES ONLY

Variable Multipliers

Draw	Gas Price	Coal Price	Demand	etc.
1	1.10	1.00	1.15	...
2	1.18	1.06	1.01	...
3	1.15	1.08	1.14	...
4	0.97	0.97	1.03	...
5	1.06	1.04	1.08	...
6	1.04	0.98	1.11	...
7	1.07	0.95	1.11	...
8	1.09	1.07	0.95	...
9	1.10	1.00	1.00	...
10	1.06	1.07	0.99	...
11	0.97	1.04	1.15	...
12	1.15	1.08	0.97	...
13	1.15	1.01	1.14	...
14	1.01	1.04	1.10	...
15	1.18	1.03	1.10	...

Fundamental Forecasts

Market Price Model

Draw	Power Price
1	$40.50
2	$37.97
3	$51.53
4	$31.25
5	$37.35
6	$36.09
7	$35.60
8	$34.20
9	$34.09
10	$35.22
11	$36.99
12	$37.36
13	$41.81
14	$36.73
15	$41.87

Strategic Planning Model

PVRR ($ in Billions)

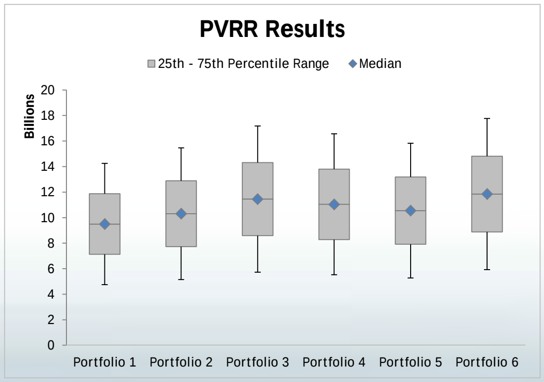
Draw	Portfolio 1	Portfolio 2	Portfolio 3
1	$9.6	$10.8	$10.4
2	$10.1	$10.6	$7.7
3	$10.9	$12.2	$8.6
4	$8.7	$9.4	$10.6
5	$9.2	$12.8	$7.6
6	$8.4	$10.8	$9.7
7	$10.3	$12.4	$10.9
8	$11.2	$11.1	$8.9
9	$7.9	$8.3	$10.0
10	$8.8	$12.5	$8.6
11	$7.9	$9.8	$11.4
12	$11.9	$9.0	$9.1
13	$9.5	$11.9	$9.5
14	$7.5	$8.1	$8.5
15	$11.0	$12.2	$11.4

Model Results and Application

Stochastic results will guide the formation of the metrics

- Provides a range of results (PVRR, carbon emissions, etc.) across all iterations

ILLUSTRATIVE PURPOSES ONLY



Questions?

Next Steps

Joan Soller, Director of Resource Planning

Written comments and feedback

- Deadline to send written comments and questions regarding this meeting to ipl.irp@aes.com is Tuesday, August 23
- All IPL responses will be posted on the IPL IRP website by Tuesday, September 6

Final 2016 IPL IRP Public Advisory Meeting

Friday, September 16, 2016

- Final model results
- Sensitivity analyses results
- Preferred Resource Plan
- Short-term Action Plan

Thank you!

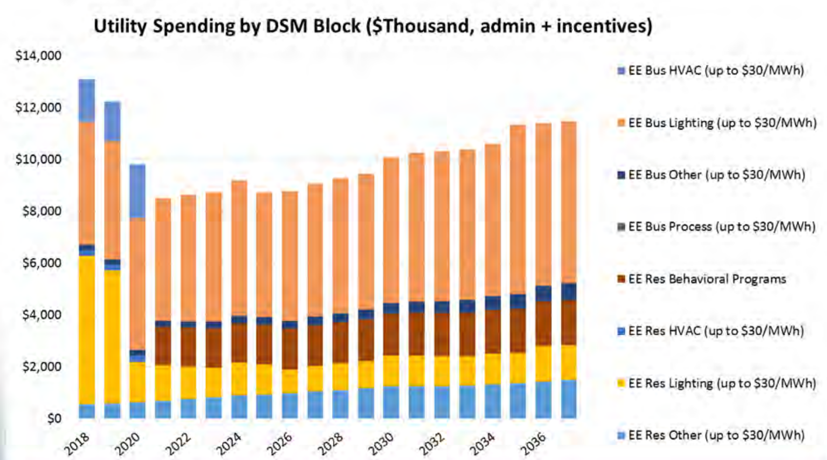
We value your input and appreciate your participation. Please submit your feedback form and recycle your nametag at the registration table as you leave the meeting today.

INDIANAPOLIS POWER & LIGHT COMPANY

APPENDIX – DSM DETAILS

INDIANAPOLIS POWER & LIGHT COMPANY

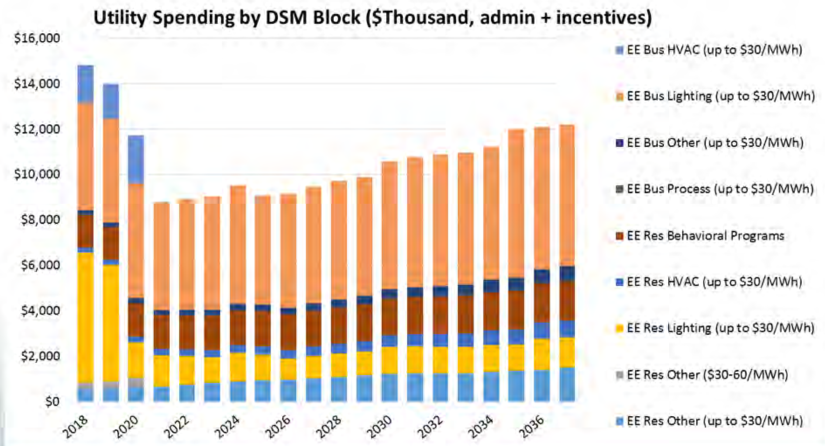
Base case



in real $

INDIANAPOLIS POWER & LIGHT COMPANY

Robust economy



in real $

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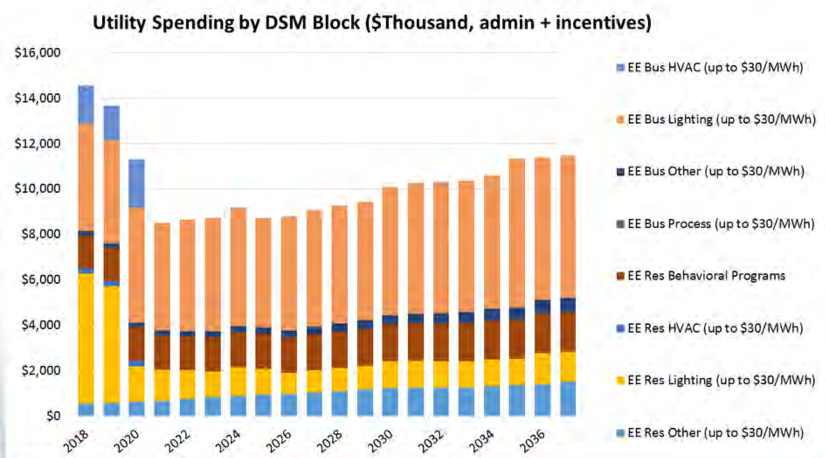
Recession economy



in real $

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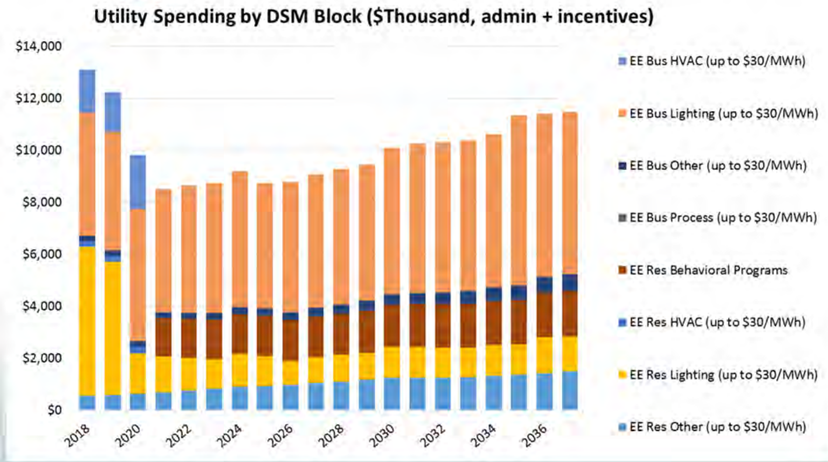
Adoption of distributed generation



in real $

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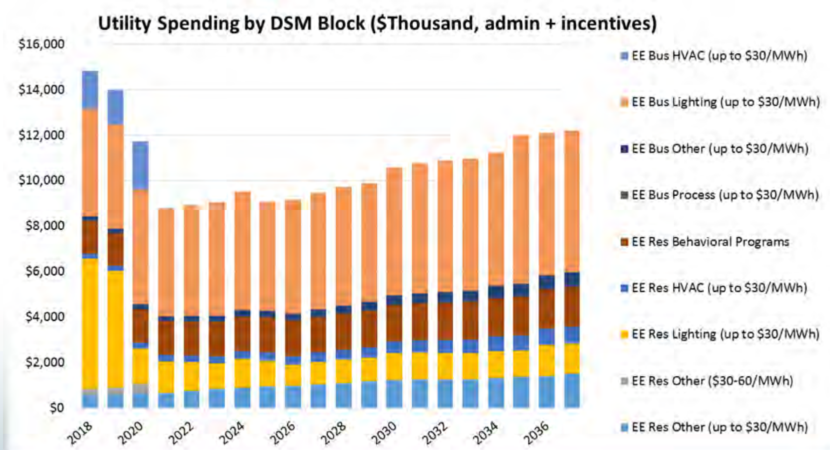
Strengthened environmental



in real $

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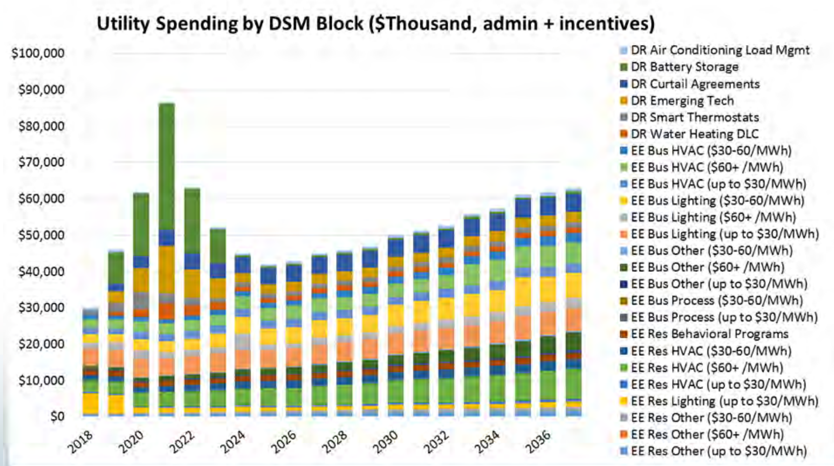
Quick transition



in real $

DSM building blocks selected

(based upon maximum achievable)

DSM Blocks Selected	Final Base Case	Robust Economy	Recession Economy	Strengthened Environmental	Distributed Generation
Res Other up to $30MWh 2018-2020	X	X	X	X	X
Res Other $30-60MWh 2018-2020		X		X	
Res Lighting up to $30MWh 2018-2020	X	X	X	X	X
Res HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Behavioral Program 2018-2020		X	X	X	
Bus Other up to $30MWh 2018-2020	X	X	X	X	X
Bus Lighting up to $30MWh 2018-2020	X	X	X	X	X
Bus HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Other up to $30MWh 2021+	X	X	X	X	X
Res Lighting up to $30MWh 2021+	X	X	X	X	X
Res HVAC up to $30MWh 2021+		X		X	
Res Behavioral Programs 2021+	X	X	X	X	X
Bus Process up to $30MWh 2021+	X	X	X	X	X
Bus Other up to $30MWh 2021+	X	X	X	X	X
Bus Lighting up to $30MWh 2021+	X	X	X	X	X

Quick Transition DSM

DSM Blocks	2018-2020	2021-2037
EE Res Other (up to $30/MWh)	X	X
EE Res Other ($60+ /MWh)	X	X
EE Res Other ($30-60/MWh)	X	X
EE Res Lighting (up to $30/MWh)	X	X
EE Res HVAC (up to $30/MWh)	X	X
EE Res HVAC ($60+ /MWh)	X	X
EE Res HVAC ($30-60/MWh)	X	X
EE Res Behavioral Programs	X	X
EE Bus Process (up to $30/MWh)	X	X
EE Bus Process ($30-60/MWh)	X	X
EE Bus Other (up to $30/MWh)	X	X
EE Bus Other ($60+ /MWh)	X	X
EE Bus Other ($30-60/MWh)	X	X
EE Bus Lighting (up to $30/MWh)	X	X
EE Bus Lighting ($60+ /MWh)	X	X
EE Bus Lighting ($30-60/MWh)	X	X
EE Bus HVAC (up to $30/MWh)	X	X
EE Bus HVAC ($60+ /MWh)	X	X
EE Bus HVAC ($30-60/MWh)	X	X
DR Water Heating DLC	X	X
DR Smart Thermostats	X	X
DR Emerging Tech	X	X
DR Curtail Agreements	X	X
DR Battery Storage	X	X
DR Air Conditioning Load Mgmt	X	X

ADDED 9-6-16

APPENDIX II– ENERGY MIX BY SCENARIO

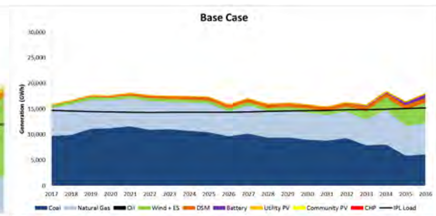
ADDED 9-6-16

Will be discussed at the 9-16-16 meeting

How to Read Energy Mix Slides

- "Long"= more generation in a single hour than load
  "Short"= more load in a single hour than generation
- IPL is long and short throughout the year at different times

These graphs will be shared again and discussed at the final public advisory meeting.

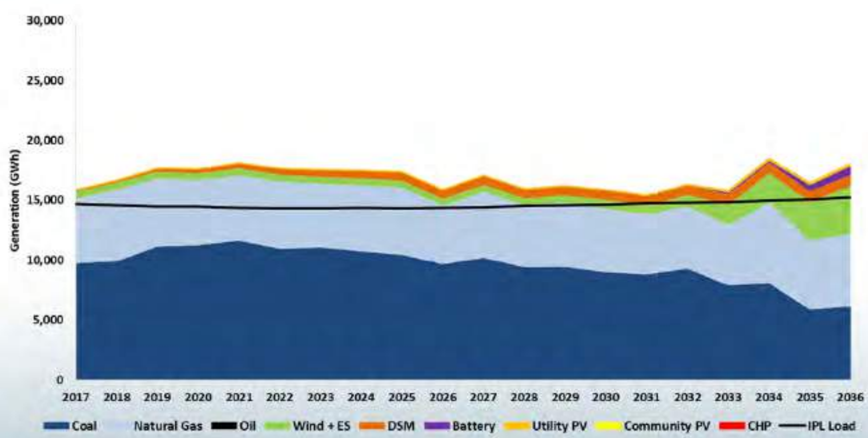


- Based on the nature of dispatching units, IPL will still buy and sell from the market in the base case

ADDED 9-6-16

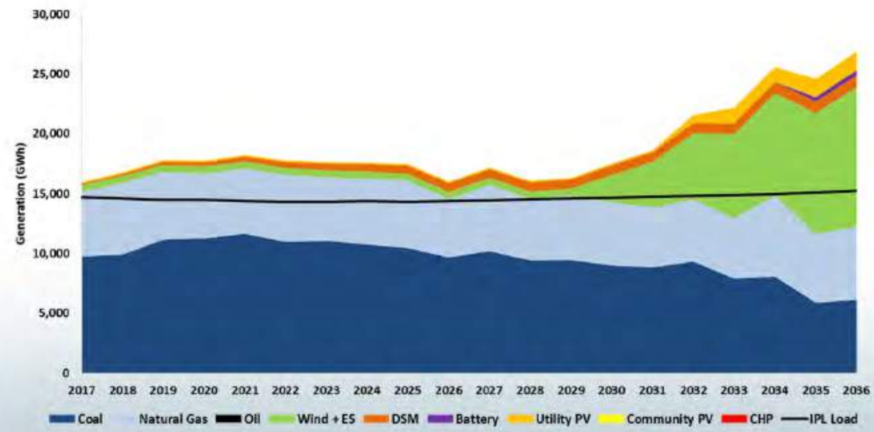
Will be discussed at the 9-16-16 meeting

Base Case Energy



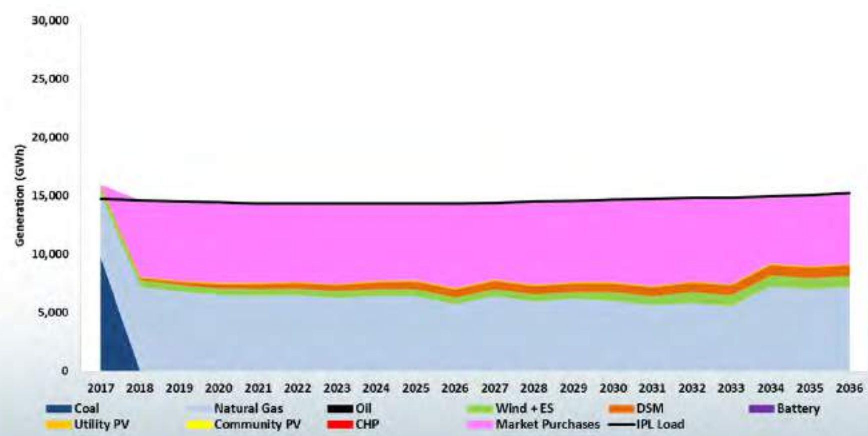
ADDED 9-6-16
Will be discussed at the 9-16-16 meeting

Robust Economy Energy



ADDED 9-6-16
Will be discussed at the 9-16-16 meeting

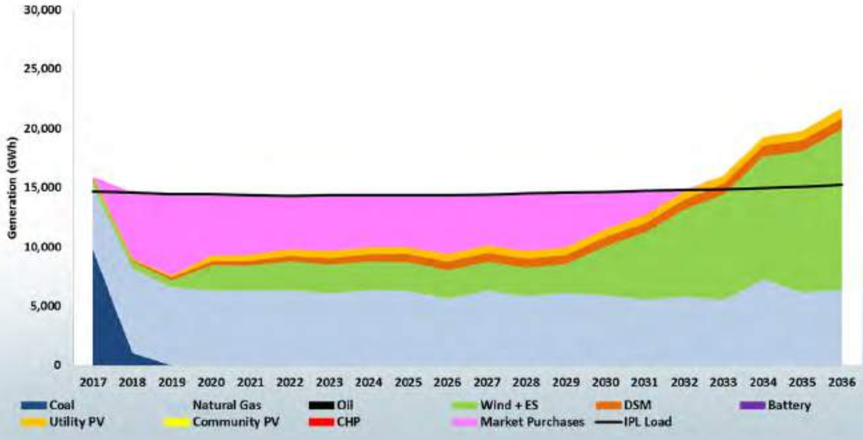
Recession Economy Energy



ADDED 9-6-16

Will be discussed at the 9-16-16 meeting

Strengthened Environmental Energy



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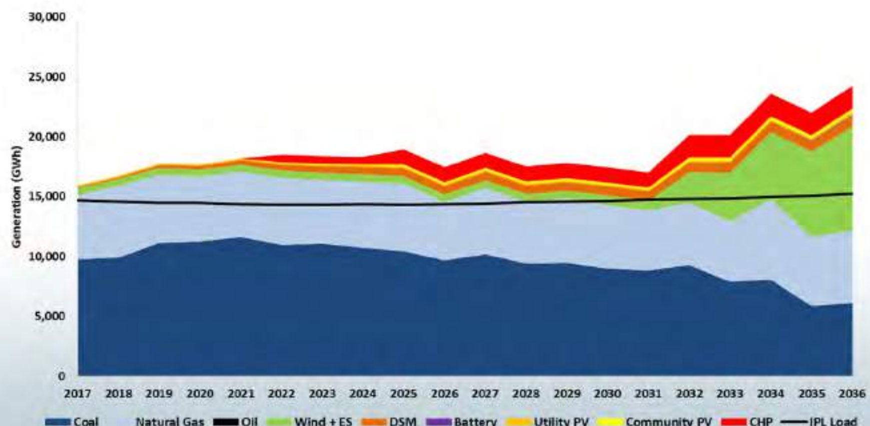
ADDED 9-6-16

Will be discussed at the 9-16-16 meeting

High Customer Adoption of DG Energy



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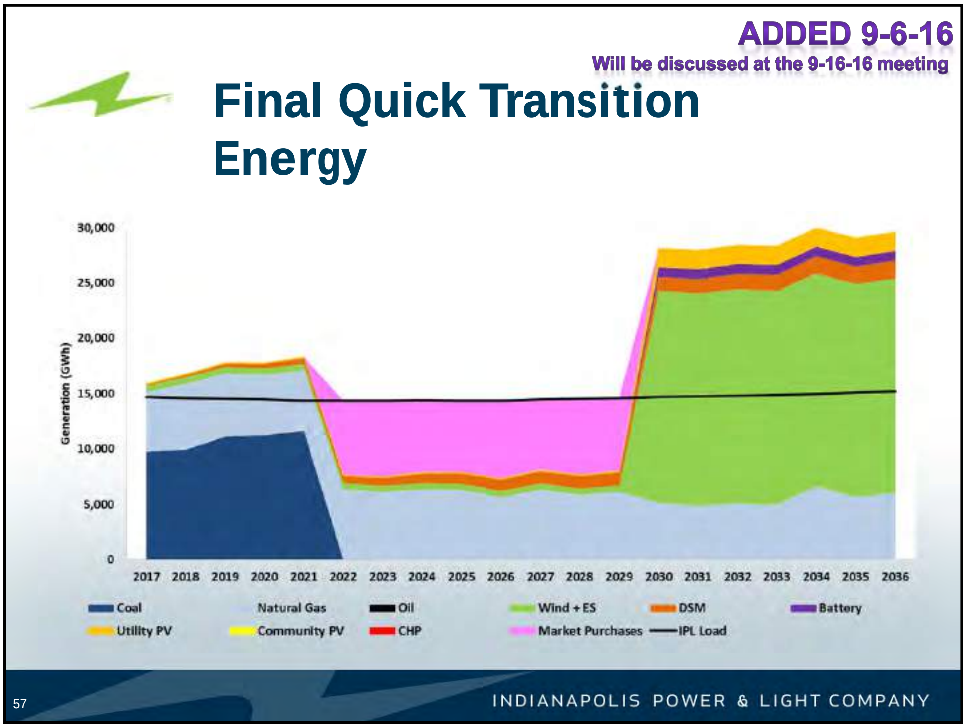
ADDED 9-6-16
Will be discussed at the 9-16-16 meeting
Final Quick Transition Energy
Generation (GWh)
30,000
25,000
20,000
15,000
10,000
5,000
0
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
Coal
Natural Gas
Oil
Wind + ES
DSM
Battery
Utility PV
Community PV
CHP
Market Purchases
IPL Load
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REVISED 10-06-16

Revised Slides 64 & 114

Integrated Resource Plan Public Advisory Meeting #4

September 16, 2016

INDIANAPOLIS POWER & LIGHT COMPANY

Welcome & Safety Message

Bill Henley, VP of Regulatory and Government Affairs

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Meeting Guidelines

Dr. Marty Rozelle, Facilitator

Agenda for today

9:00am Welcome
- Meeting Agenda and Guidelines
- Summary & Feedback from IRP Public Advisory Meeting #3
- Guiding Principles
- Final Model Results
- Preferred Resource Portfolio

10:25am Break
- Metrics & Sensitivity Analysis Results

11:45 – 12:30pm Lunch
- Analysis Observations
- Discussion of Results
- Short Term Action Plan
- IRP Public Advisory Process Feedback
- Concluding Remarks & Next Steps

2:30/3:00pm Meeting Concludes

Meeting Guidelines

- Time for clarifying questions at end of each presentation
- Small group discussions
- The phone line will be muted. During the allotted questions, press *6 to un-mute your line, and please remember to press *6 again to re-mute when you are finished asking your question.
- Use WebEx online tool for questions during meeting
- Email additional questions or comments by September 23
- IPL will respond via website by October 7

Active Cases before the Commission

- Cause No. 38703, FAC 113
- Cause No. 42170, ECR-27
- Cause No. 44576, Rates (under appeal)
- Cause No. 44792, DSM 2017 Plan
- Cause No. 44794, SO_2 NAAQS and CCR
- Cause No. 44808, MISO Rider

Summary & Feedback from IRP Public Advisory Meeting #3

Joan Soller, Director of Resource Planning

Topics covered in Meeting #3

- IRP modeling update
- Draft model results for all scenarios
- Stakeholder feedback
- Sensitivity analysis setup

Presentation materials, audio recording, acronym list, and meeting notes are available on IPL's IRP webpage here: https://www.iplpower.com/irp/

Scenario Characteristics/Variable Drivers

	Scenario Name	Load Forecast	Natural Gas and Market Prices	Clean Power Plan (CPP) and Environment	Distributed Generation (DG)
1	Base Case	Use current load growth methodology	ABB Mass-based CPP Scenario	Mass-based CPP starting in 2022. Low cost environmental regulations: ozone, 316b, and CCR	Expected moderate decreases in technology costs for wind, storage, and solar
2	Robust Economy	High*	High*	Base Case	Base Case
3	Recession Economy	Low*	Low*	Base Case	Base Case
4	Strengthened Environmental Rules	Base Case	Base Case	20% RPS + high carbon costs. High costs: NAAQS ozone, 316b, OSM*	Base Case
5	Distributed Generation	Base Case	Base Case	Base Case	Base case with fixed additions of 150 MW in 2022, 2025, and 2032*
6	Quick Transition	Base Case	Base Case	Base Case	Fixed portfolio to retire coal, add max DSM, minimum baseload (NG), plus solar, wind and storage*

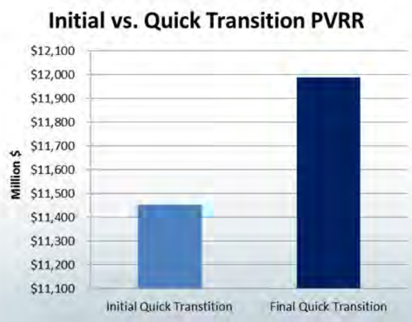
*Purple font indicates changes from the Base Case.

IPL response to feedback

- IPL modified the Quick Transition scenario
  - Pete 1 retirement and Pete 2-4 refuel in 2018
  - Include maximum achievable DSM and balance of resources with solar, wind and batteries in 2030
  - Minimum NG resources stayed the same

Quick Transition results changed

PVRR (2017-2036) varied



Resources varied earlier

Questions?

Guiding Principles and Assumptions

Joan Soller

Guiding principles for IRP

- IPL will comply with IURC rules and orders, IAC requirements, NERC reliability standards and FERC approved MISO tariffs.
- Costs estimates for demand and supply side resources are based upon local economics and recent market experiences.
- IPL is agnostic to the resource mix comprising portfolio plans.
- The model is agnostic to resource ownership; however, IPL's capital structure is modeled to calculate costs.

IAC – Indiana Administrative Code, IURC – Indiana Utility Regulatory Commission, NERC – North American Electric Reliability Corporation, FERC – Federal Energy Regulatory Commission, MISO – Midwest Independent System Operator

DSM guiding principles

- Demand Side Management (DSM) is modeled as a selectable resource in this IRP which represents a change from previous IRPs.
- IPL plans to offer cost effective DSM programs that are inclusive for customers in all customer classes, appropriate for the market and customer base, modify customer behavior and provide continuity from year to year.

These assumptions are consistent in the study period

- IN regulatory framework
- MISO Capacity construct
- IPL engages in MISO stakeholder process
- Natural gas & market price correlation trends
- Distributed Generation (DG) is synchronized with the grid & not curtailed

These potential changes may affect future portfolios

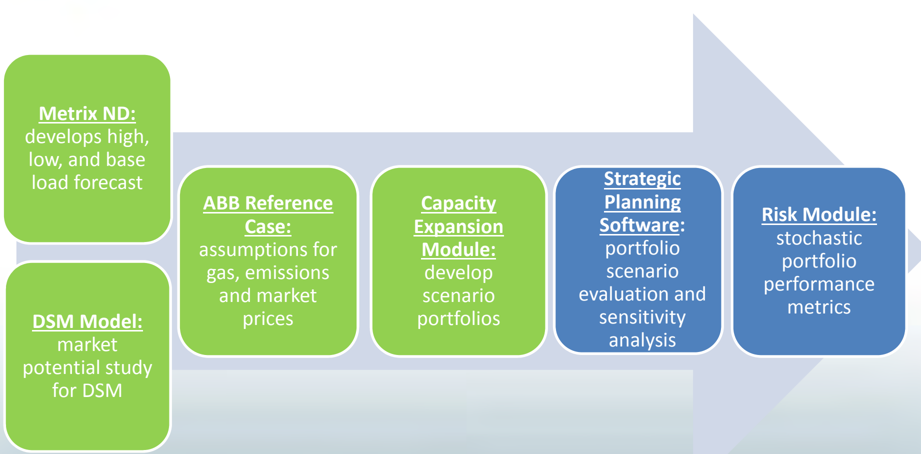
- Technology enhancements
- Pending national election impacts on:
  - Pending environmental regulations
  - Public policy
  - Tax credits
- Stakeholder sustainability interests

Questions?

Final Model Results

Diane Crockett, Principal Consultant ABB

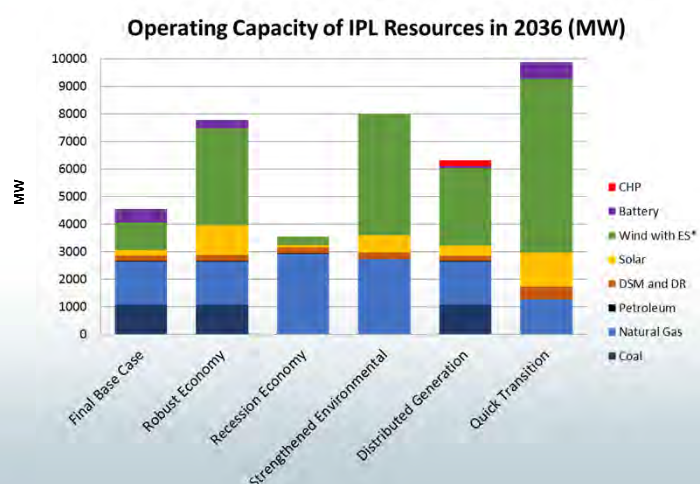
Portfolio Development Process



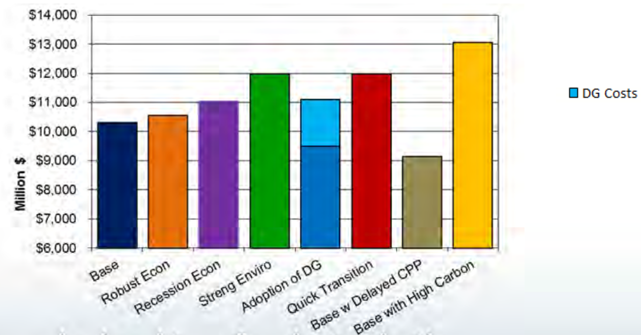
Review of resource alternatives

IRP Resource Technology Options	
	MW Capacity
Simple Cycle Gas Turbine	160
Combined Cycle Gas Turbine - H-Class	200
Nuclear	200
Wind	50
Solar	> 5 MW
Community Solar	1 MW
Energy Storage	20
CHP – industrial site (steam turbine)	10
DSM	Varies
Market purchases	Up to 200 MW

Scenario Capacity Mix in 2036

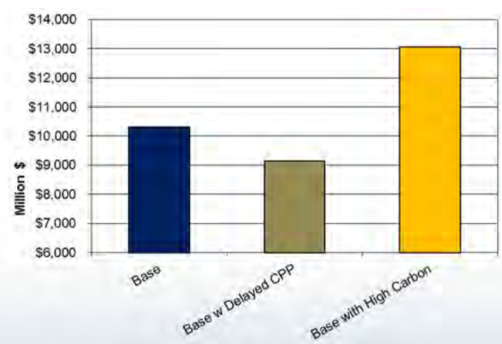


Scenario Present Value of Revenue Requirements (PVRR) 2017-2036



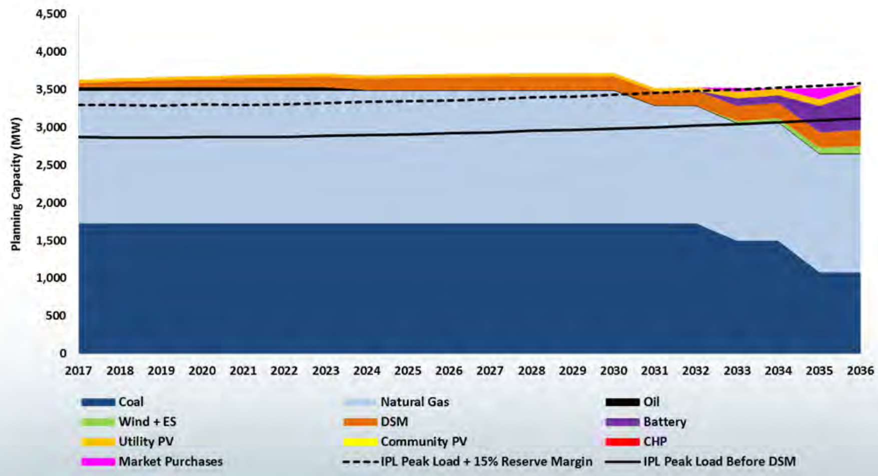
- Each portfolio was developed to perform best under the assumptions for that scenario
- Since assumptions vary between scenarios, not all portfolios are directly comparable
- This graph shows the PVRR of all portfolios *utilizing the base assumptions* prior to introducing stochastic uncertainty

Base Sensitivity PVRRs 2017-2036



- CPP starts in 2030 instead of 2022 for the delayed case
- More stringent CPP is represented by using high carbon cost scenario beginning in 2022

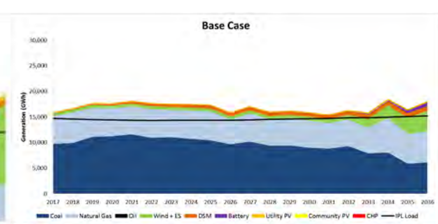
Base Case Capacity



- Includes Petersburg upgrades for NAAQS, SO_2 and CCR

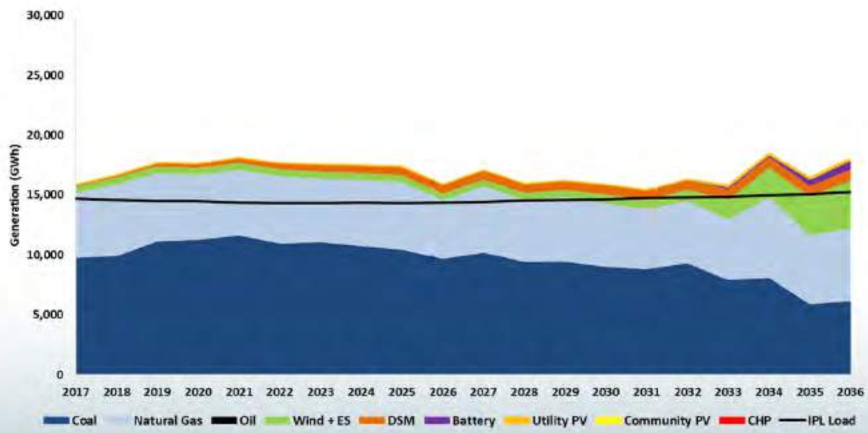
How to Read Energy Mix Slides

- "Long"= more generation in a single hour than load
  "Short"= more load in a single hour than generation
- IPL is long and short throughout the year at different times



- Based on the nature of dispatching units, IPL will still buy and sell from the market in the base case

Base Case Energy



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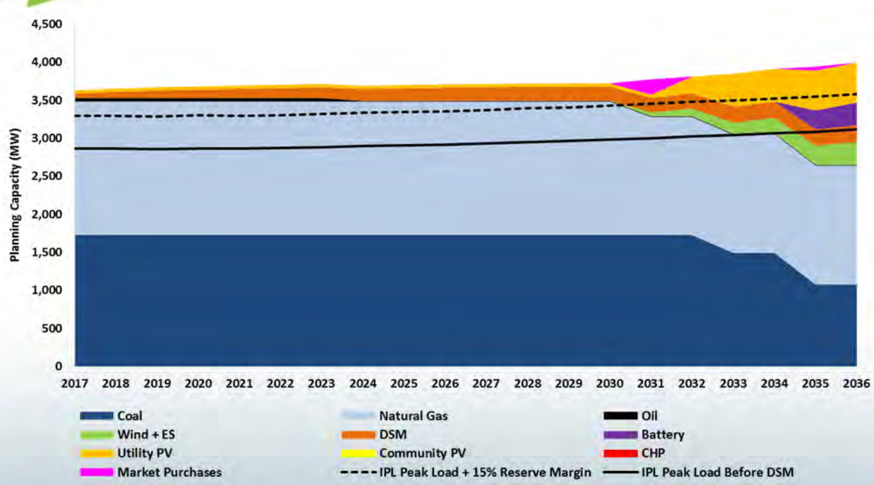
Robust Economy Capacity



- Includes upgrades for NAAQS, SO_2 and CCR
- High load capacity expansion plan under base load assumption

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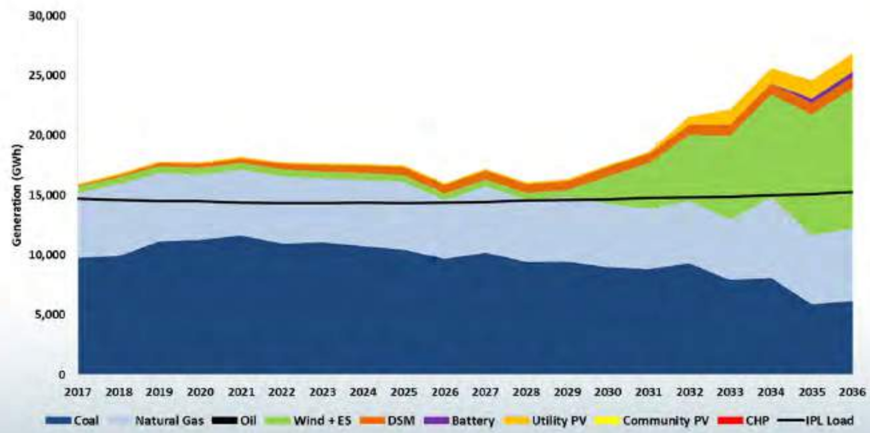
Robust Economy Energy



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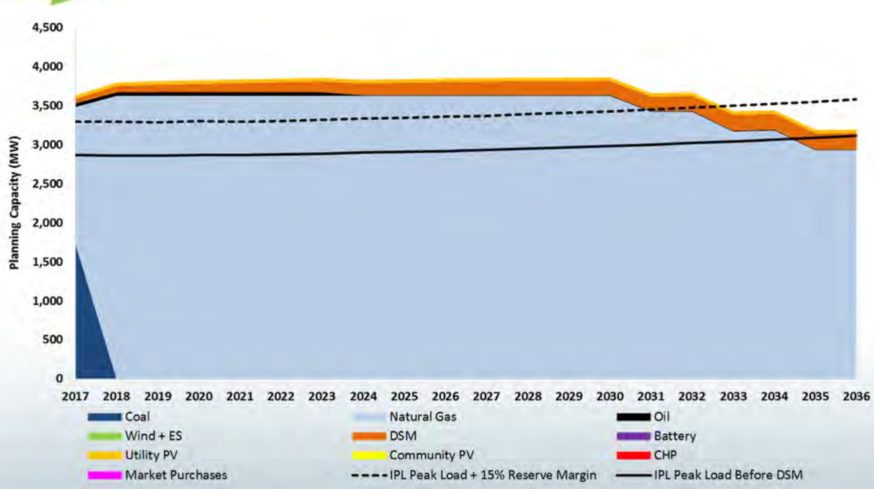
Recession Economy Capacity



- Refuel Pete 1-4
- Low load capacity expansion plan under base load assumption

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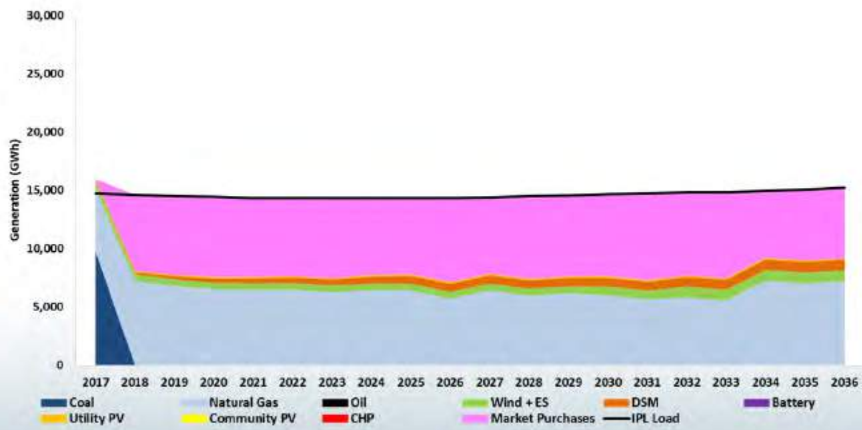
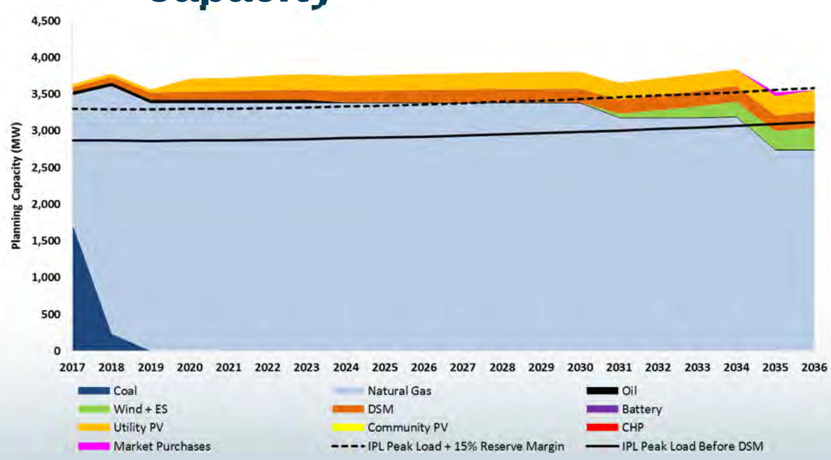
Recession Economy Energy



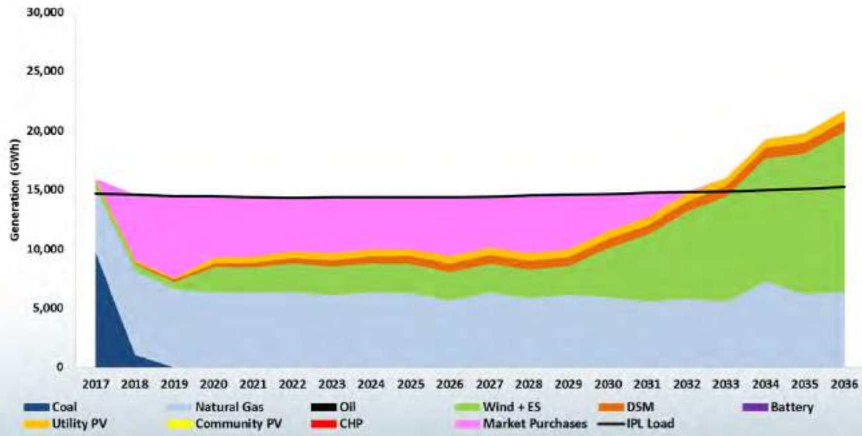
- Refuel Pete 1-4
- Low load capacity expansion plan under base load assumption

Strengthened Environmental Capacity



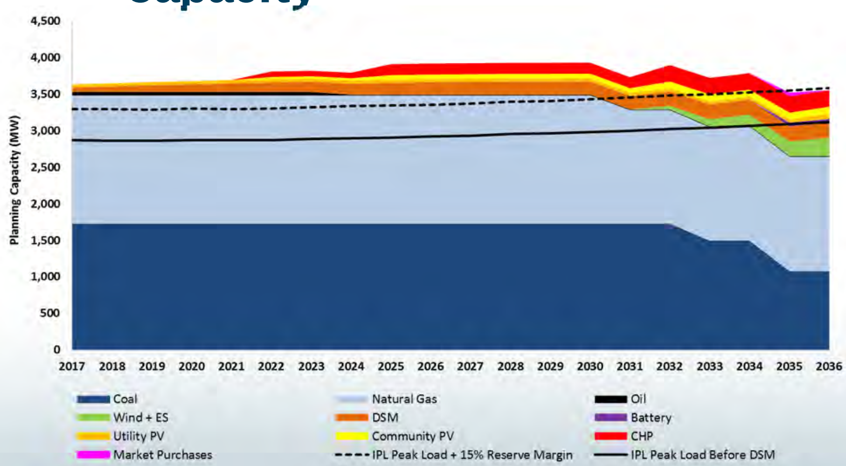
- Retire Pete 1
- Refuel Pete 2-4
- 20% Renewable Portfolio Standard by 2022

Strengthened Environmental Energy



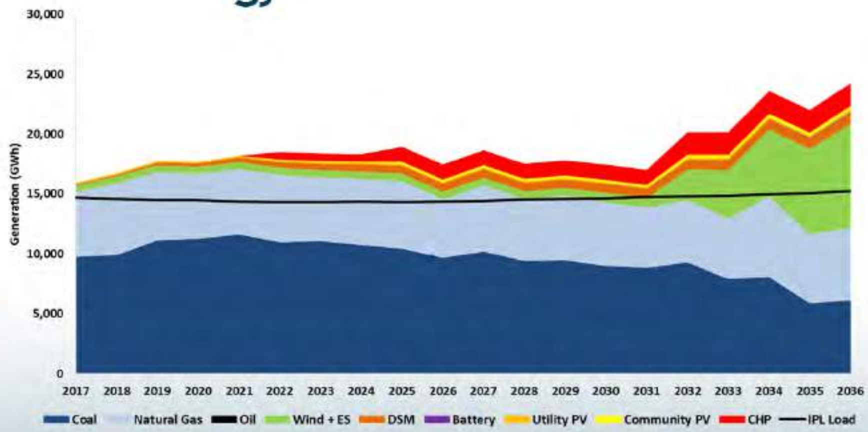
- Retire Pete 1
- Refuel Pete 2-4
- 20% Renewable Portfolio Standard by 2022

High Customer Adoption of DG Capacity



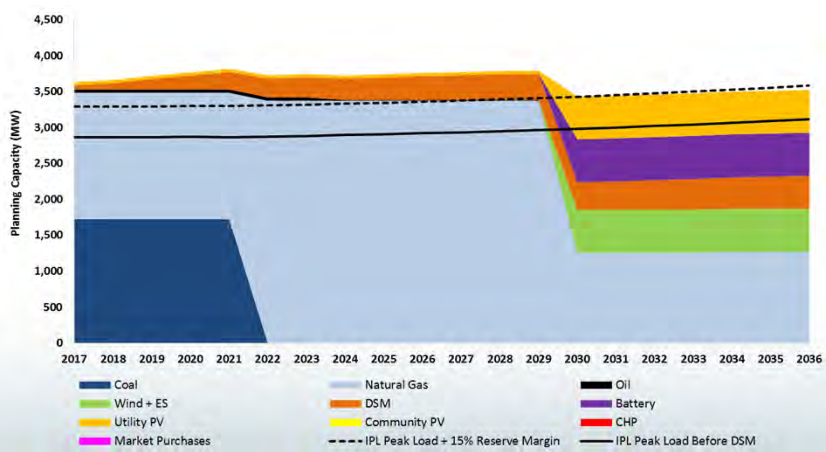
- Includes upgrades for NAAQS, SO_2 and CCR
- 10 MW of Wind, 65 MW of Community Solar and 75 MW of CHP in 2022, 2025 and 2032

High Customer Adoption of DG Energy



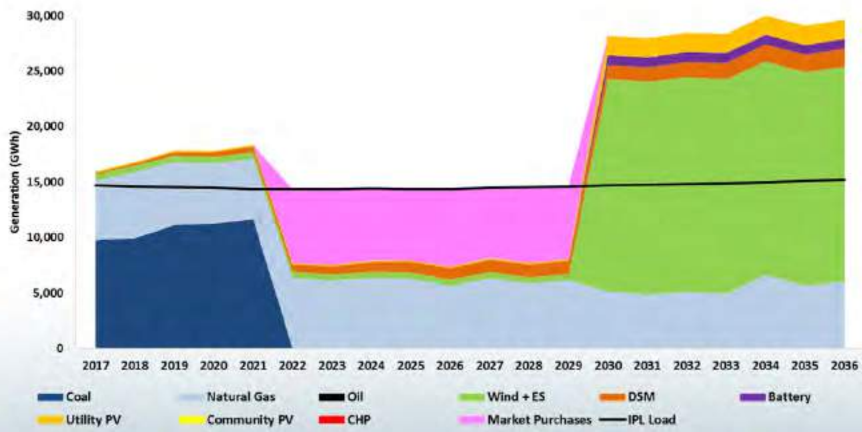
- 10 MW of Wind, 65 MW of Community Solar and 75 MW of CHP in 2022, 2025 and 2032

Quick Transition Capacity



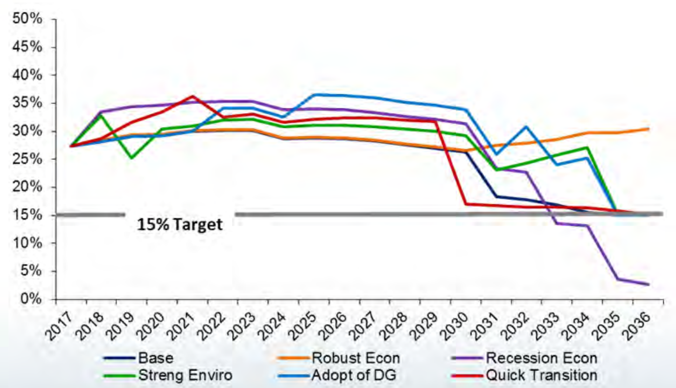
- Includes upgrades for NAAQS, SO_2 and CCR
- Retire Pete 1 and Refuel Pete 2-4 in 2022
- Retire Pete 2-4, HS GT 4-6, HS 5&6, HS IC1, Pete IC1-3 in 2030

Quick Transition Energy



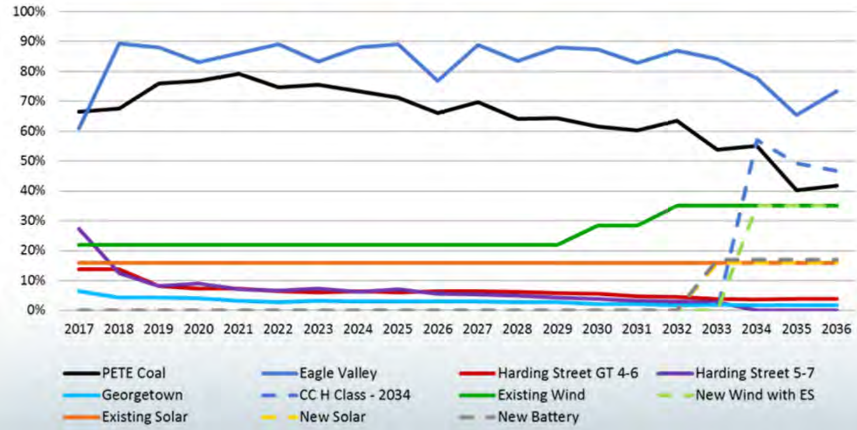
- Retire Pete 1 and Refuel Pete 2-4 in 2022
- Retire Pete 2-4, HS GT 4-6, HS 5&6, HS IC1, Pete IC1-3 in 2030

Reserve Margins



- This graph shows the Reserve Margin for all plans *utilizing the base load assumption*
- All portfolios optimized for the load forecast of the specific scenario
  - Example: Low load forecast was a driver in Recession Economy scenario. This chart shows the reserve margin if IPL planned for a low load forecast and the base load forecast materialized.

Capacity factors for Base Case



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Capacity factors for Strengthened Environmental

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Questions?

Preferred Resource Portfolio

Joan Soller, Director of Resource Planning

Rationale for determining the Preferred Resource Portfolio

- IPL's preferred resource portfolio reflects the most likely inputs and most probable risks known at this point in time.
- The primary selection criteria is the reasonable least cost to customers stated in terms of the Present Value Revenue Requirement (PVRR) metric.
- Other metrics including rate and environmental impacts, market reliance and risk exposure were considered but not equally weighted.

IPL's IRP Preferred Resource Portfolio

- The preferred resource portfolio is the Base Case in the 2016 IRP
- PVRR is the lowest
- Risk tradeoff between probable PVRR costs and variance is most favorable for customers
- Subsequent IRP analyses will consider changes to assumptions and risks
- IPL will continue to monitor risks associated with resource planning

Preferred Resource Portfolio summary

Final Base Case resource changes (2017 to 2036)

- Upgrade Pete units for NAAQS-SO_2 and CCR
- Implement 206 MW DSM
- Retire (32 MW oil) HS GT 1&2
- Retire (628 MW NG) HSS 5, 6, 7
- Retire (651 MW coal) Pete 1 & 2
- Purchase 200 MW capacity
- Add 1000 MW wind, 100 MW Solar, 500 MW Battery
- Add 450 MW CCGT

Questions?

Short Break

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Metrics & Sensitivity Analysis Results

Patrick Maguire, Director, Corporate Planning & Analysis
Megan Ottesen, Regulatory Analyst, Resource Planning

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Recall stakeholder metrics exercise feedback

Metrics	Scores
Air quality*	10
PVRR	10
CO_2 intensity	8
Planning reserves	7
Rate impact in 5 year increment	6
CO_2 emissions over time	5
Cost variance risk ratio	5
Annual average CO_2 emissions	3
Flexibility - Quick start vs. peak load	3
Bill impact / energy burden	2
Flexibility - Portfolio diversity (fuel)	2
Resource mix over time	2
Social Equity	2

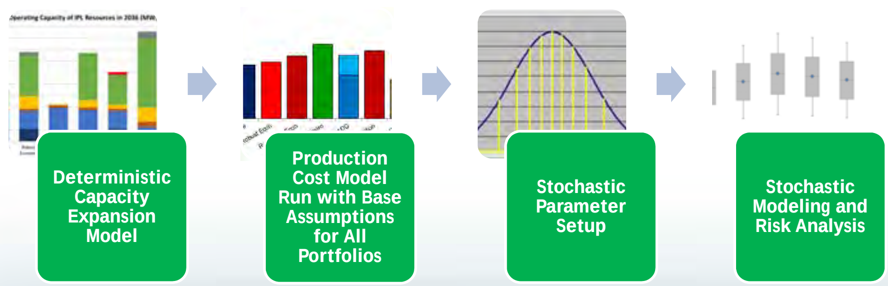
green = stakeholder proposed
blue= IPL proposed

*other pollutants including PM, NOx, SO2, methane emissions

Metrics developed with stakeholder input

Cost	Financial Risk	Environmental Stewardship	Resiliency
• Present Value Revenue Requirement (PVRR) • Rate Impact	• Risk Exposure	• Average annual CO_2 emissions • Average annual NO_x emissions • Average annual SO_2 emissions • CO_2 intensity	• Planning Reserves • Distributed Generation penetration • Market reliance (energy and capacity)

Recall sensitivity analysis setup from Meeting 3…



Complete | Complete | Complete | Complete

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Metrics are based upon a blend of model results

Deterministic Model

- Change selected variables by a fixed and known amount
- Example:
  - Natural gas prices up 10%
  - Load up 10%
- Output
  - PVRR for each sensitivity
  - Change in emissions

Stochastic Model

- Subject multiple variables to randomness
- Ranges are bound by estimated probability distributions and statistical properties
- Output
  - 50 model iterations for each portfolio
  - Risk profiles
  - Financial metrics

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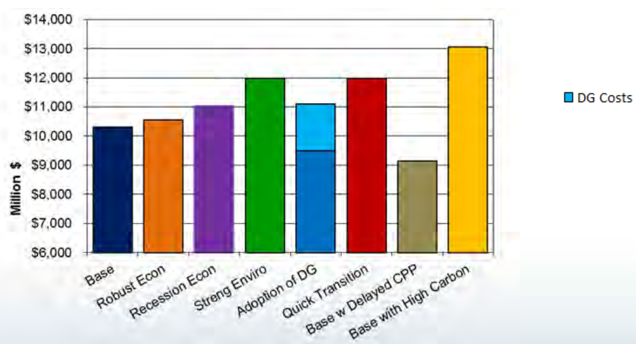
Cost Metric: PVRR

1. Present Value Revenue Requirement (PVRR):

– The total plan cost (capital and operating) expressed as the present value of revenue requirements over the study period

PVRR = Present Value of Revenue Requirements 2017-2036

PVRR for 2017-2036



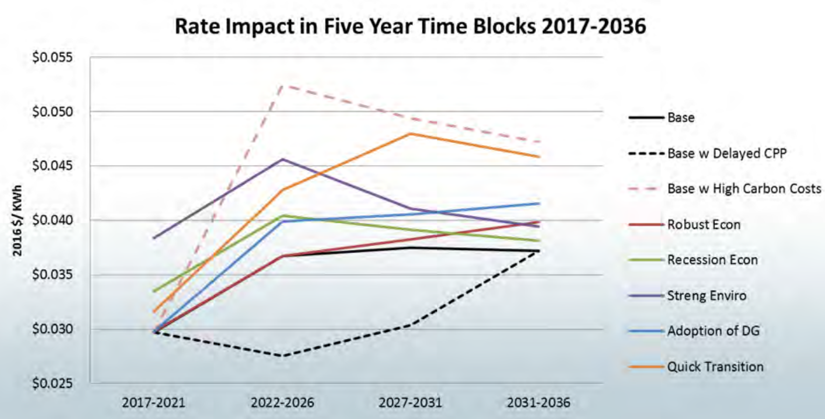
Cost metric: Rate Impact

2. Rate Impact:

- Shows the incremental impact of adding new resources to our rates
- This shows an aggregate rate impact and does not reflect rate design for different customer classes
- Expressed in terms of cents/kWh in five year time blocks
- Levelized average system cost

Rate Impact = Present Value of Revenue Requirements (5 year period) / Total kWh Sales (5 year period)

Incremental rate impact due to resource changes only



Financial Risk: Risk Exposure

3. Risk Exposure:

- The difference between the value at the 95th percentile of probability and the value at 50% percentile probability (expected value)
- In order to reflect risk, this metric utilizes results from stochastic modeling as opposed to deterministic results

Risk Exposure = The PVRR at the 95% probability – expected PVRR

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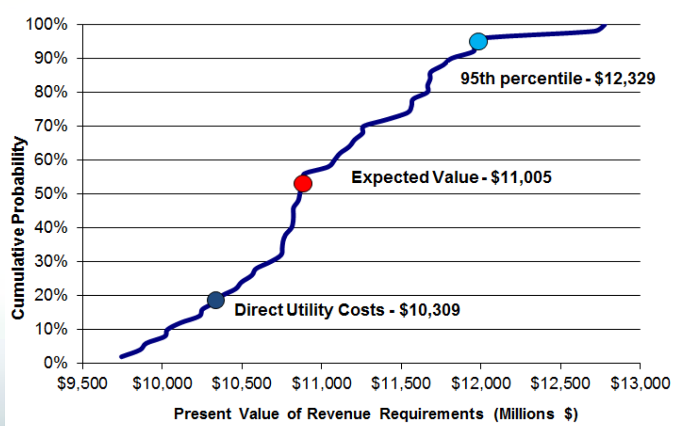
Risk Exposure – risk profile chart



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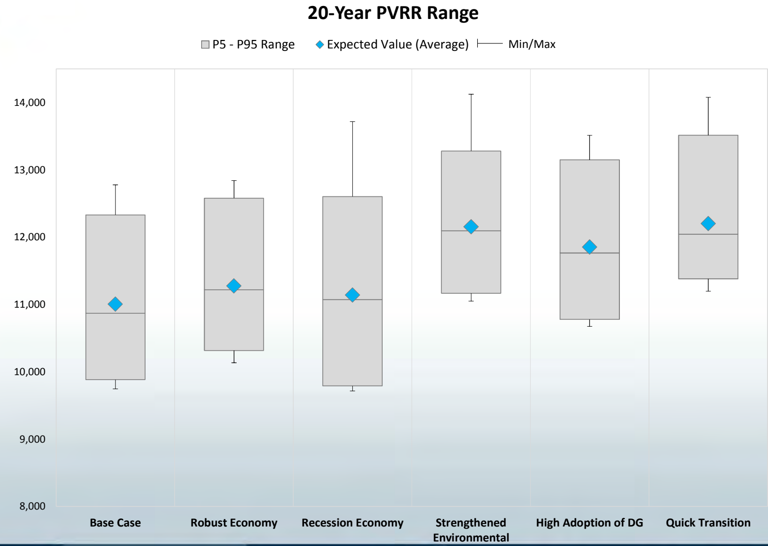
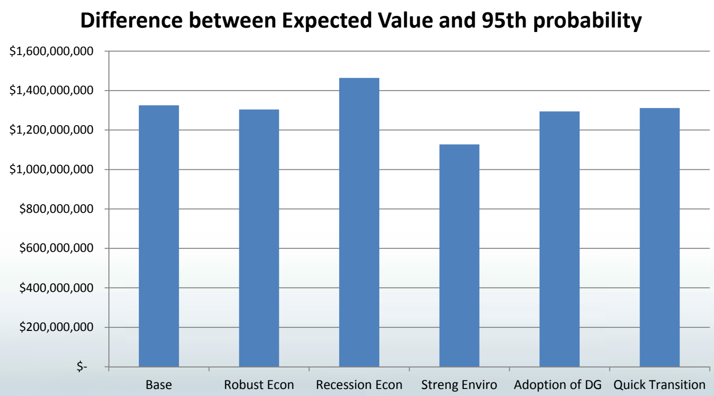
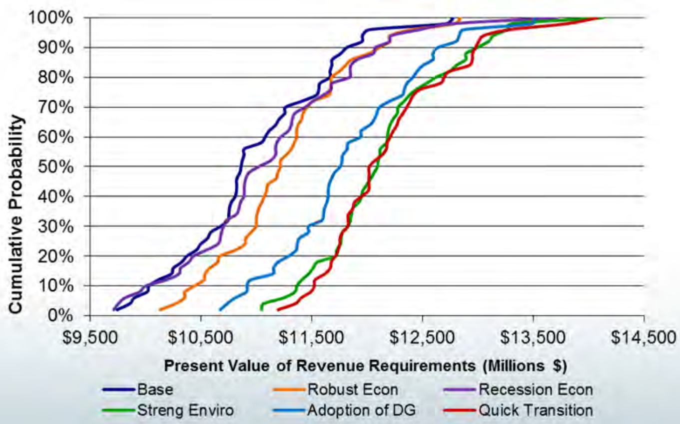
Risk Exposure range



Risk Exposure



Combined Risk Profiles



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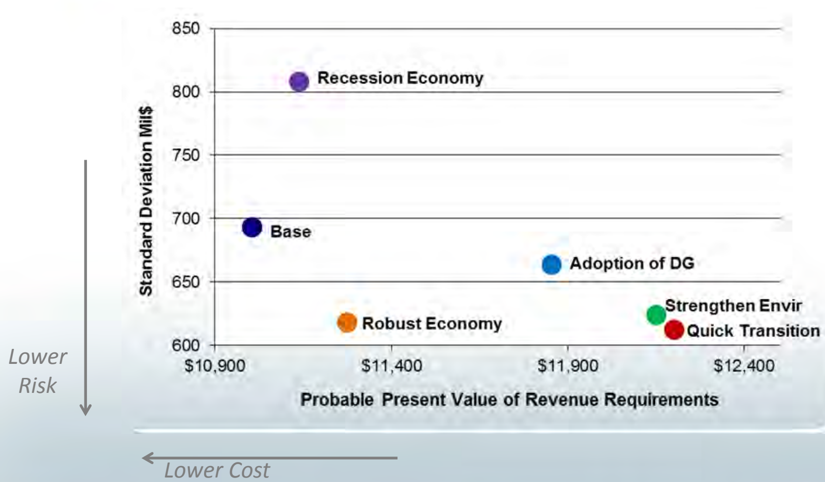
Risk trade off diagram



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Tornado charts show impacts of drivers

- Provide information on the driving factors that influence PVRR based on stochastic modeling
- Provide insights for risk mitigation
- Charts were prepared for each scenario
- 10 year blocks were used
- Total impact is a blended view, not the sum of the ranges

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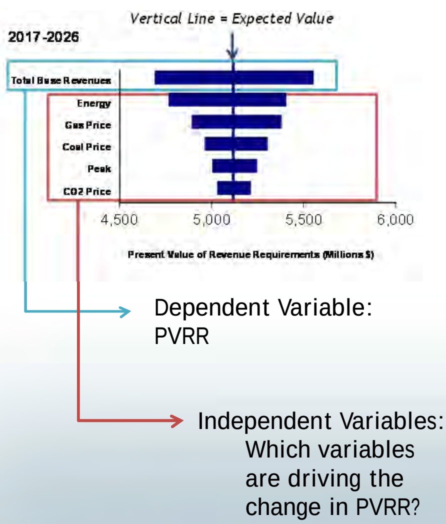
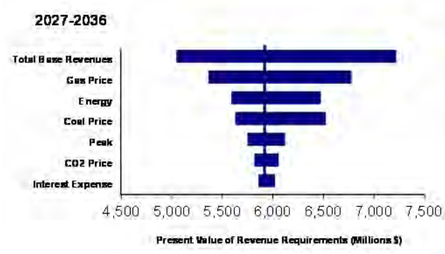
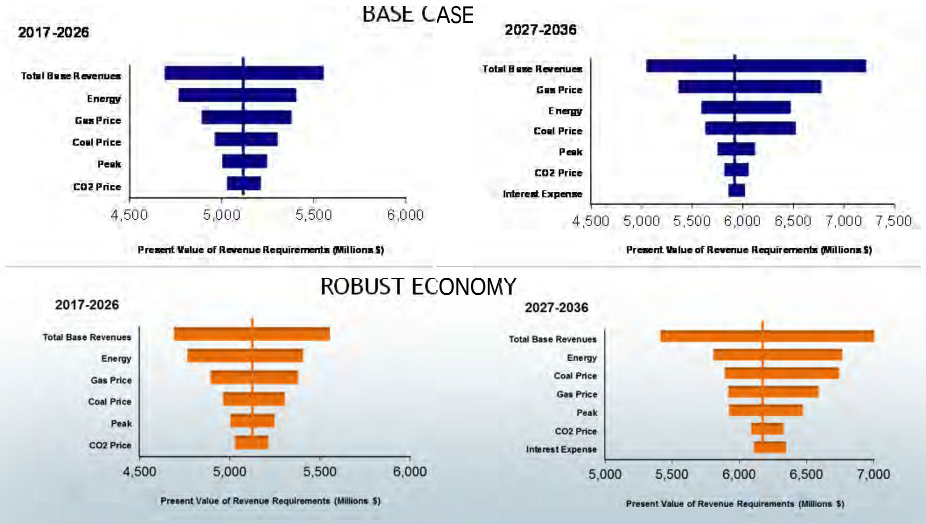
Base Case Tornado Chart





Tornado: Base Case and Robust Economy



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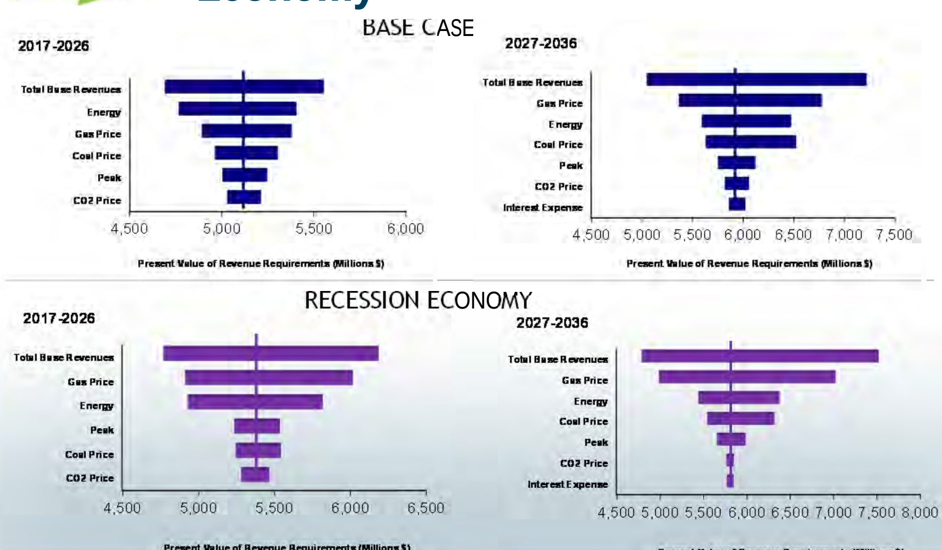
Tornado: Base Case and Recession Economy



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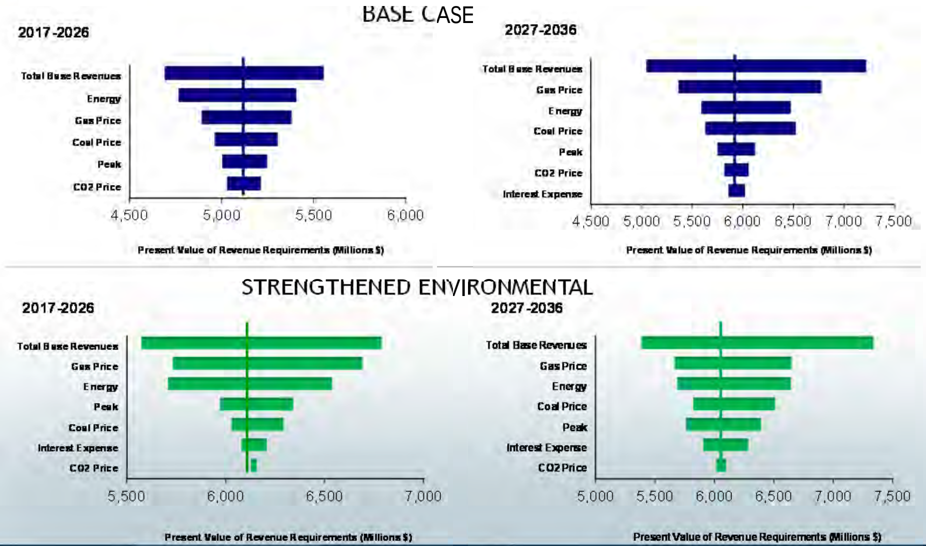
Tornado: Base Case and Strengthened Environmental



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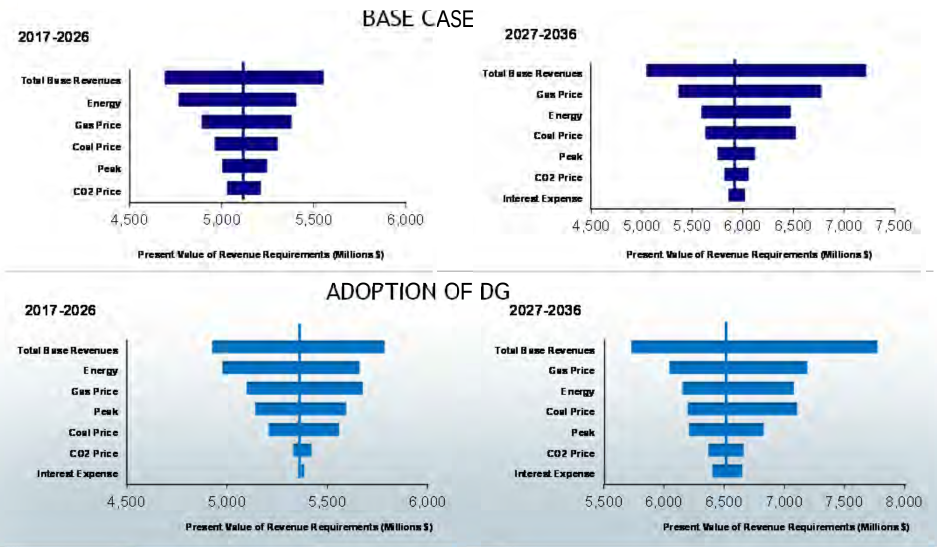
Tornado: Base Case and Adoption of DG



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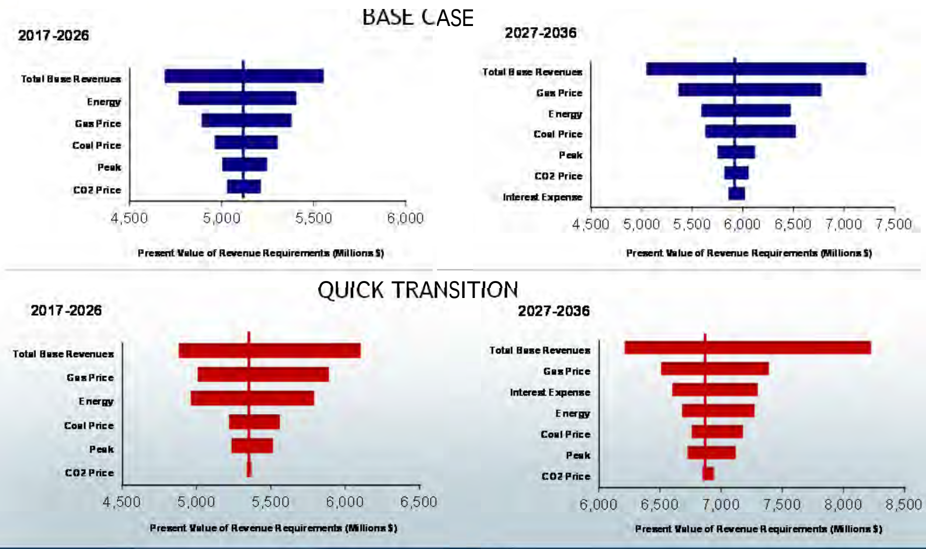
Tornado: Base Case and Quick Transition



Environmental Metrics: CO_2, SO_2, NOx

3. Average annual CO_2 emissions (tons)

Annual Average CO_2 Emissions = $\dfrac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$

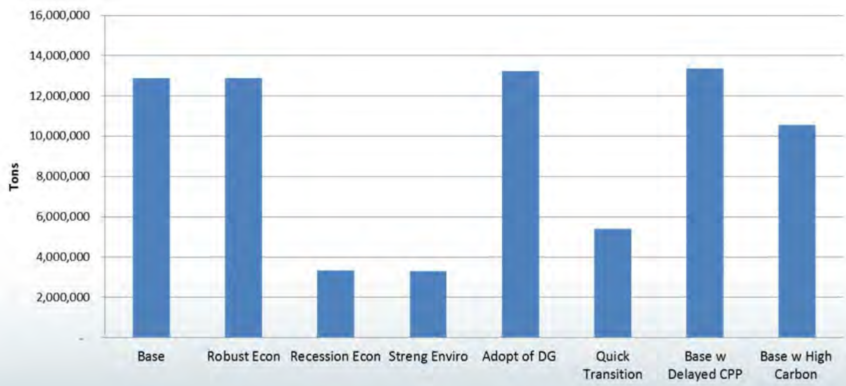
4. Average annual SO_2 emissions (tons)

Annual Average SO_2 Emissions = $\dfrac{\text{Sum of } SO_2 \text{ tons emitted}}{\text{\# of years in the study period}}$

5. Average annual NO_x emissions (tons)

Annual Average NOx Emissions = $\dfrac{\text{Sum of } NO_x \text{ tons emitted}}{\text{\# of years in the study period}}$

Average annual CO_2 emissions (tons)



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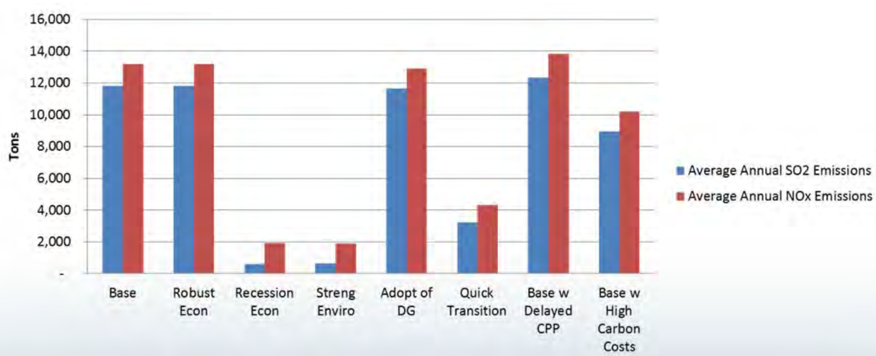
Average annual NO_x and SO_2 emissions



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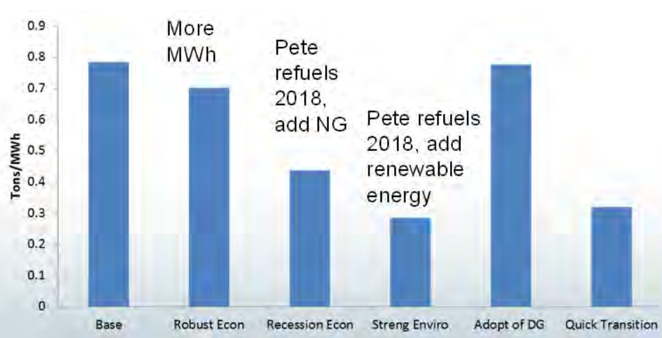
Environmental Metrics: CO_2 intensity

6. CO_2 intensity (tons/MWh)

CO_2 Intensity for study period = $\dfrac{\text{Sum of } CO_2 \text{ tons emitted}}{\text{MWh energy generated}}$

CO_2 intensity for study period



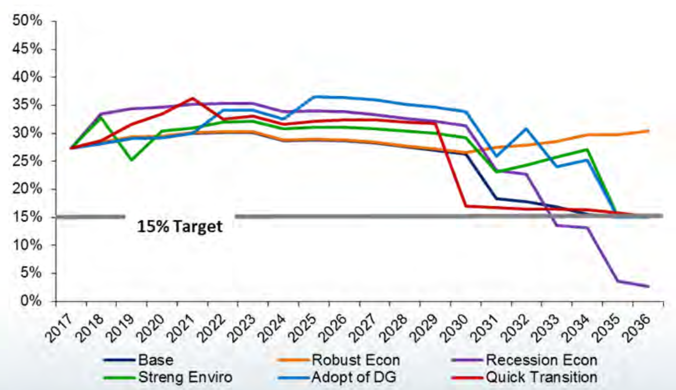
Reliability Metric: Planning Reserves

7. Planning Reserves

- Planning reserves are the MW of supply above peak forecast

Planning Reserves as a percent of load forecast	= IPL's resources (MW) – peak utility load forecast (MW) / utility load forecast

Planning Reserves



- This graph shows the Reserve Margin for all plans *utilizing the base load assumption*
- All portfolios optimized for the load forecast of the specific scenario
  - Example: Low load forecast was a driver in Recession Economy scenario. This chart shows the reserve margin if IPL planned for a low load forecast and the base load forecast materialized.

Reliability metric: DG Penetration

8. DG Penetration

- Percent of IPL's resources that is distributed generation
- Includes IPL's existing 96 MW of solar and all new solar additions
- Shown in 5 year time blocks

$$\text{DG Penetration} = \frac{\text{distributed generation supply (MW)}}{\text{IPL resources (MW)}}$$

Reliability metric: DG penetration

In terms of Capacity

Scenario	2017-2021	2022-2026	2027-2031	2032-2036
Base	2%	2%	2%	4%
Robust Econ	2%	2%	2%	13%
Recession Econ	2%	2%	2%	3%
Strengthened Environmental	5%	9%	9%	8%
Adoption of DG	3%	8%	10%	10%
Quick Transition	2%	2%	6%	17%

Reliability Metric: market reliance

9. & 10. Market reliance – Energy and Capacity

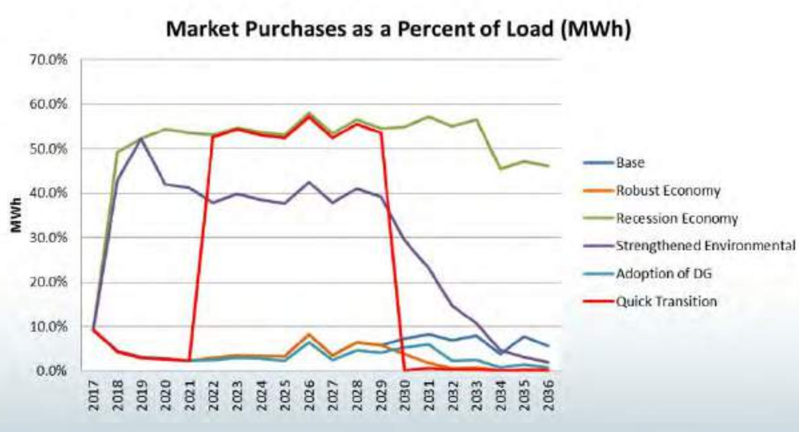
- Market reliance for energy: Percent of load met with market purchases

Market Reliance for energy = $\frac{\text{MWh of market purchases}}{\text{MWh of customer demand}}$

- Market reliance for capacity: Total MW of capacity purchased from MISO capacity auction to meet peak demand plus 15% reserve margin

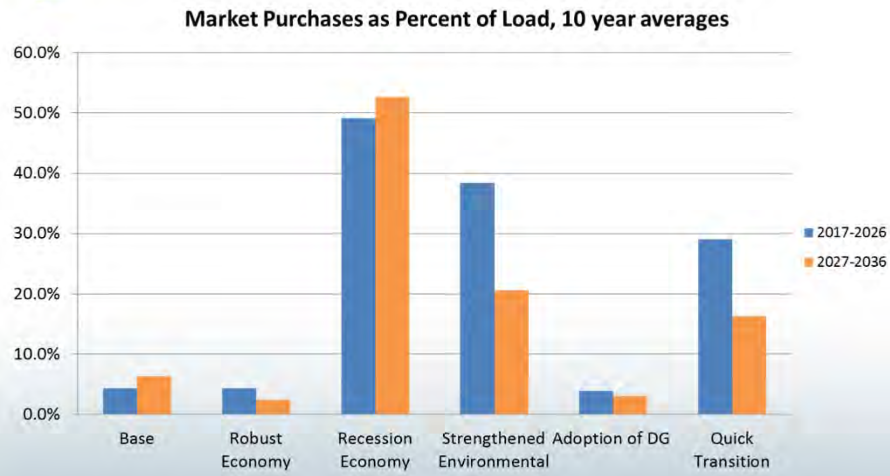
Market Reliance for capacity = total capacity purchases

Market Reliance



* Each scenario's portfolio is modeled with the Base Case load

Market Reliance - Energy



* Each scenario's portfolio is modeled with the Base Case load

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Market Reliance – Capacity

	Base	Robust Economy	Recession Economy	Strengthened Environmental	Adoption of DG	Quick Transition
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031		200 MW				
2032						
2033	50 MW					
2034						
2035	150 MW	50 MW		50 MW	50 MW	
2036						

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Metrics Summary

Scenarios	Cost		Financial Risk	Environmental Stewardship				Resiliency			
	20 yr PVRR ($ MN)	Rate Impact, 20 yr average ($/kWh)	Risk Exposure ($)	Average annual CO2 emissions (tons)	Average annual NOx emissions (tons)	Average annual SOx emissions (tons)	Total CO2 intensity (tons/MWh)	Planning Reserves (lowest amount over 20 yrs)*	Distributed Generation (Max DG as percent of capacity over 20 yr)	Market Reliance for Energy (Max over 20 yrs)	Market Reliance for Capacity (Max MW over 20 yrs)
Base	$ 10,309	$ 0.035	$ 1,461,856,693	12,883,603	13,181	11,808	0.510	15%	2%	9%	150
Robust Econ	$ 10,550	$ 0.036	$ 1,361,308,495	12,883,183	13,181	11,808	0.410	27%	2%	9%	200
Recession Econ	$ 11,042	$ 0.038	$ 1,529,366,806	3,334,067	1,925	593	0.284	3%	3%	58%	0
Streng Enviro	$ 11,990	$ 0.041	$ 1,183,639,662	3,309,326	1,910	629	0.150	15%	2%	52%	50
Adopt of DG	$ 11,092	$ 0.038	$ 1,382,467,346	13,159,800	13,332	11,808	0.459	15%	11%	9%	50
Quick Transition	$ 11,988	$ 0.042	$ 1,469,716,821	5,403,645	4,320	3,243	0.173	15%	3%	57%	0

* this Planning Reserves metric compares each scenario's resources to the Base Case peak load forecast.

Questions?

Lunch Break

Analysis Observations

Joan Soller, Director of Resource Planning

As proposed in meeting #1…

	2014 IRP Feedback	IPL Response/Planned Improvements
1	Constrained Risk Analysis	Stakeholder discussion about risks will occur early in the 2016 IRP process.
2	Load Forecasting Improvements Needed	IPL is reviewing load forecast to enhance data in the 2016 IRP.
3	DSM Modeling not robust enough	IPL has piloted modeling DSM as a selectable resource and will discuss this in public meetings.
4	Customer-Owned and Distributed Generation lacked significant growth	IPL will develop DG growth sensitivities to understand varying adoption rate impacts.
5	Incorporation of Probabilistic Methods	IPL will incorporate probabilistic modeling in 2016 IRP.
6	Enhance Stakeholder Process	IPL participated in joint education session with other utilities to develop foundational reference materials. We will incorporate more interactive exercises in 2016.

Analyses Observations

- Stakeholder input has shaped modeling process
- Metrics have informed discussions
- Scenario development and related economic modeling results produced varying portfolios
- The future may vary from this snapshot
- Transmission voltage stability analyses will continue

Analyses Observations (cont'd)

- The ultimate resource portfolio may differ from model results should assumptions vary from the Base Case (e.g. Strengthened Environmental with ~40% market reliance)
- Resources perform to meet the scenario parameters with varying capacity factors
- Wholesale energy & capacity sales offset revenue requirements
- More analysis of batteries with renewables is expected

Questions?

Discussion of Results

Reference handout for small group questions.

Short Term Action Plan

Joan Soller, Director of Resource Planning

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Short Term Action Plan Criteria Proposed in 170 IAC* 4-7

- Explanation of the previous short term action plan and differences based on what actually transpired
- 3 year view (2017 through 2019)
- Includes resource changes and major projects
- Description of preferred resource portfolio elements
- Implementation schedule

*IAC – Indiana Administrative Code

Status of 2014 IRP Short Term Action Plan (for 2015-2017)

- Completed Items
  - Retired Eagle Valley (EV) coal Units 3-6
  - Refueled Harding Street Station (HSS) units 5, 6 and 7 from coal to natural gas
  - Retrofitted Petersburg units for Mercury and Air Toxics Standards (MATS) regulation
  - Secured market capacity purchases for 2015-2017
  - Built HSS 20 MW Battery Energy Storage System

Status of 2014 Short Term Action Plan (cont'd)

- In progress
  - Implement DSM for 2015-2017
  - Construct EV Combined Cycle Gas Turbine (CCGT)
  - Retrofit Pete and HSS for National Pollutant Discharge Elimination System (NPDES) permit compliance
  - Complete transmission projects for EV CCGT
  - Support Blue Indy electric car sharing program (74 of 200 locations complete)

2016 Short Term Action Plan Items (2017-2019)

Resource Changes	2017	Implement DSM proposed for 2017, draft and seek approval for 2018-2020 DSM action plan
	2017	Complete EV CCGT Construction
	2018	Complete CCR/NAAQS-SO2 Pete upgrades
Transmission	2017	Upgrade (1) 138 kV line, replace (1) auto-transformer
	2018	Upgrade 3 substations, (3) 138 kV lines, and replace breakers at 2 substations
	2019	Implement projects identified in 2017 & 2018

Questions?

IRP Process Feedback

Dr. Marty Rozelle, Facilitator
Joan Soller, Director, Resource Planning

IPL's planned improvements to 2019 IRP process

1. Analyze smart meter data for more granular load forecasting
2. Refine Demand Side Management (DSM) modeling
3. Research MISO transmission congestion forecasts
4. Assess 138 kV voltage stability options
5. Refine frequency & reactive support requirements of new wind assets
6. Study firming benefits of batteries with renewables

Stakeholder process feedback

- Reference handout for large group questions.

Questions?

Concluding Remarks & Next Steps

Marty Rozelle, Meeting Facilitator
Joan Soller, Director of Resource Planning

Next Steps

2016 IPL IRP Schedule	
September 23, 2016	Stakeholder comments due to IPL (ipl.irp@aes.com)
October 7, 2016	IRP Public Advisory Meeting #4 Notes and responses posted to IPL IRP Webpage
November 1, 2016	IPL files 2016 IRP with the IURC
90 days after filing: February 1, 2017	Interested Party Deadline to Submit Comments to the IURC. See 170 IAC 4-7-2* for details
120 days after filing: March 1, 2017	IURC Director's Draft Report publication expected

IAC – Indiana Administrative Code
*The draft proposed rule is available at: http://www.in.gov/iurc/2674.htm

Questions?

Thank you!

We value your input and appreciate your participation. Please submit your feedback form and recycle your nametag at the registration table as you leave the meeting today.

Appendix

Recession Economy summary

Resource changes (2017 to 2036)

- Refuel 1629 MW Pete 1-4 to NG
- Implement 208 MW DSM
- Retire (32 MW) HS GT
- Retire (628 MW) HSS 5, 6, 7
- No capacity purchases
- No wind, solar, or battery additions
- Add 450 MW CCGT

Robust Economy Summary

Resource changes (2017 to 2036)

- Upgrade Pete units for NAAQS-SO_2 and CCR
- Implement 218 MW DSM
- Retire (32) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- Retire (651 MW) Pete 1 & 2
- Purchase 250 MW capacity
- Add 3500 MW wind, 1006 MW Solar, 300 MW Battery
- Add 450 MW CCGT

Strengthened Environmental Summary

Resource changes (2017 to 2036)

- Retire (224 MW) Pete 1
- Refuel 1403 MW Pete 2-4
- Implement 218 MW DSM
- Retire (32 MW) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- Purchase 50 MW capacity
- Add 4100 MW wind, 549 MW Solar
- Add 450 MW CCGT

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High Customer Adoption of DG Summary

Resource changes (2017 to 2036)

- Upgrade Pete units for NAAQS-SO_2 and CCR
- Implement 208 MW DSM
- Retire (32 MW) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- No capacity purchases
- Add 30 MW DG wind, 195 MW DG solar, 225 DG CHP
- Add 2500 MW utility wind, 157 MW utility solar, 50 MW battery
- Add 450 MW CCGT

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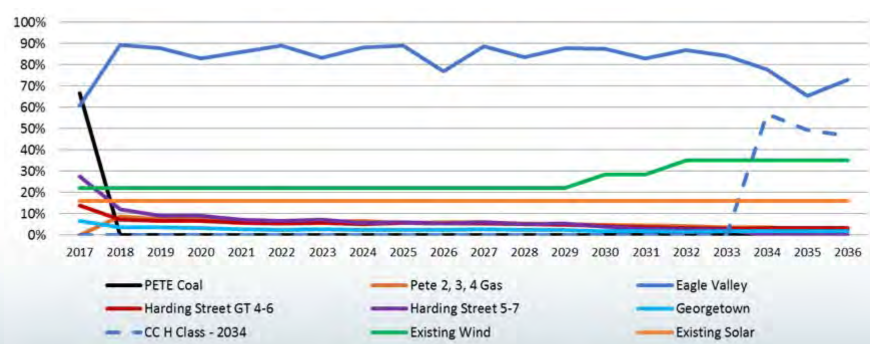
Quick Transition Summary

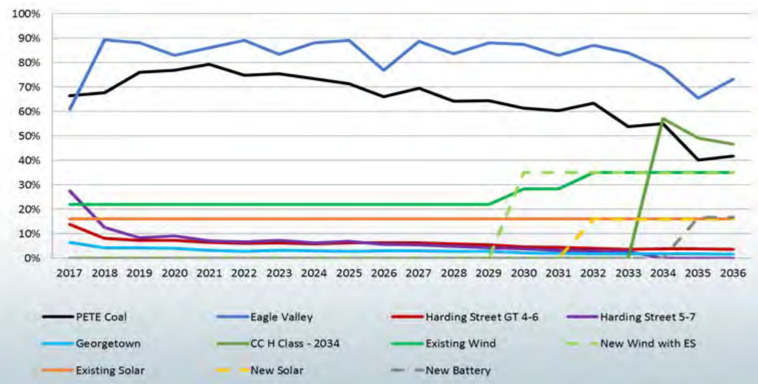
Resource changes (2017 to 2036)

- Retire (224 MW) Pete 1
- Refuel 1403 MW Pete 2-4 to NG
- Implement 458 MW DSM
- Retire (32 MW) HS GT 1&2
- Retire (628 MW) HSS 5, 6, 7
- No capacity purchases
- Add 6000 MW wind, 1146 MW solar, 600 MW battery
- Add 450 MW CCGT

Capacity Factors for Recession Economy



Capacity Factors for Robust Economy



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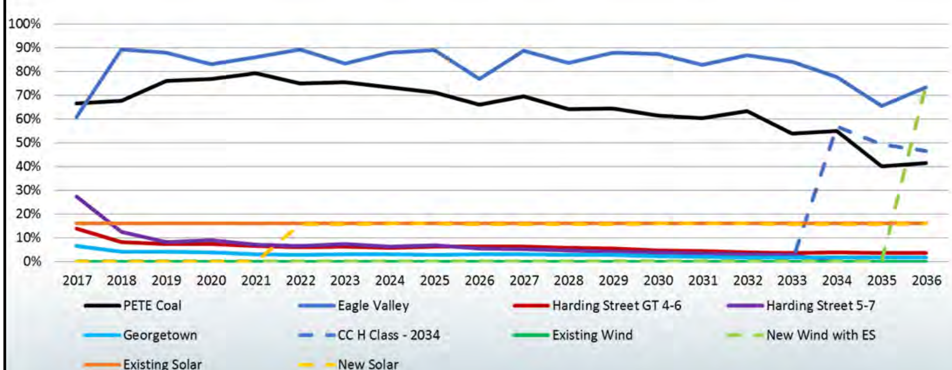
Capacity factors for High Customer Adoption of DG



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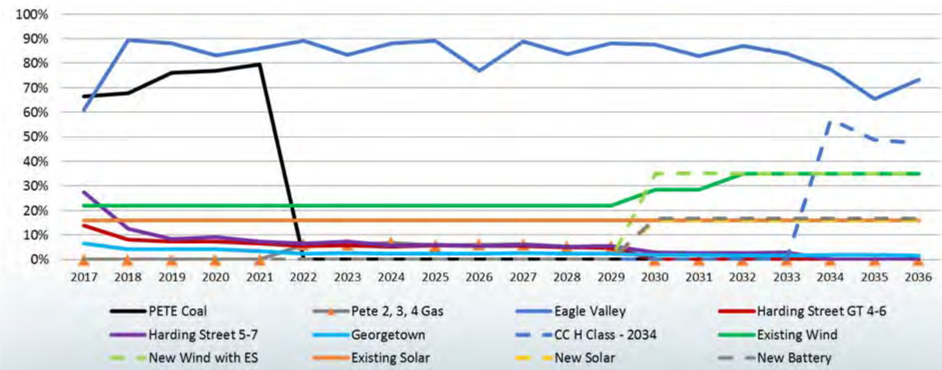
Capacity factors for Quick Transition



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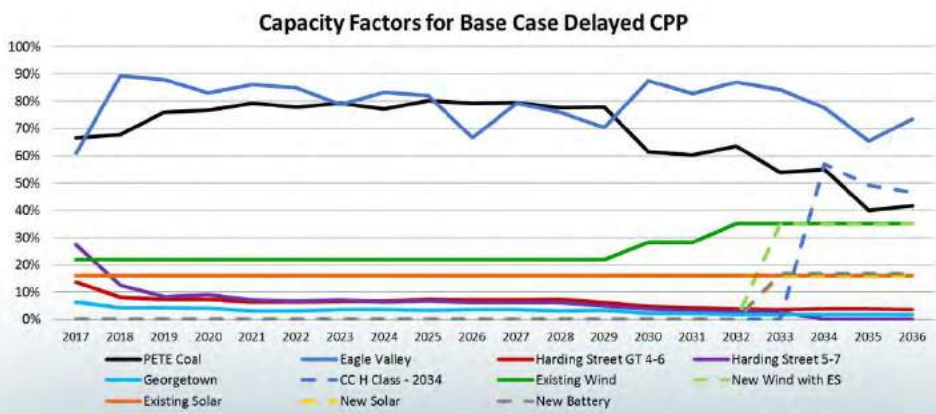
Capacity factors for Base Case Delayed CPP



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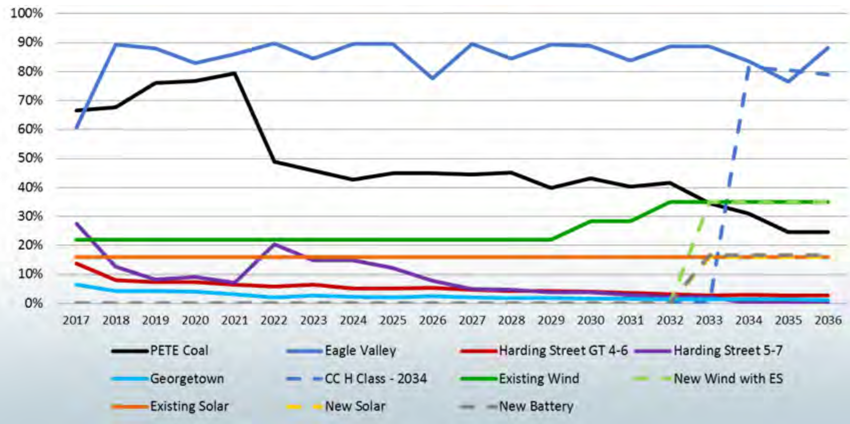
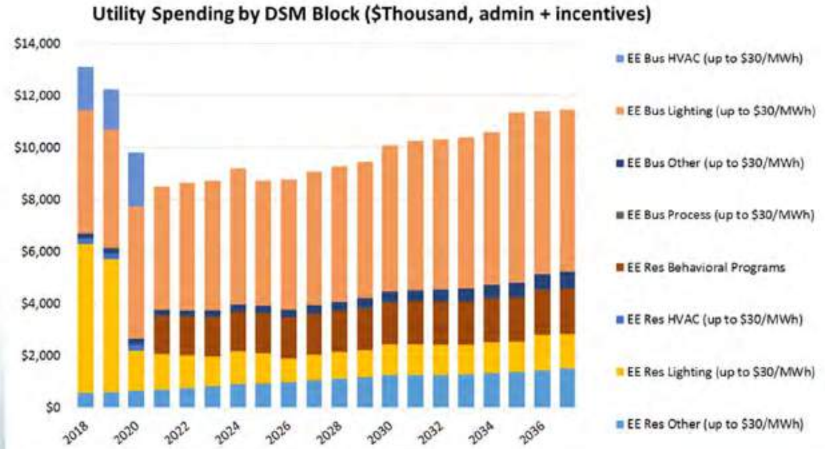
Capacity Factors for Base Case High Costs of Carbon

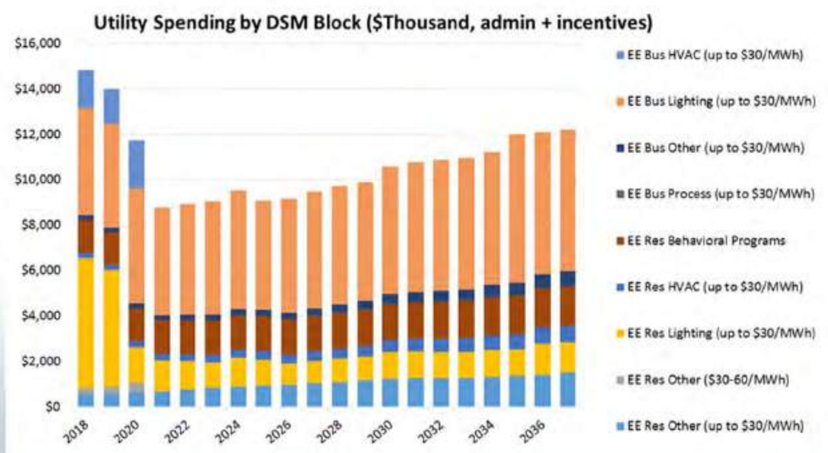


Base case

Utility Spending by DSM Block ($Thousand, admin + incentives)



Robust economy



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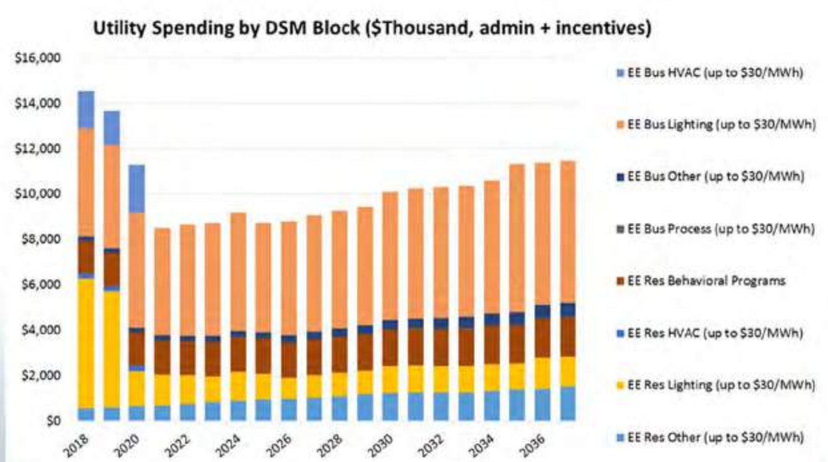
Recession economy



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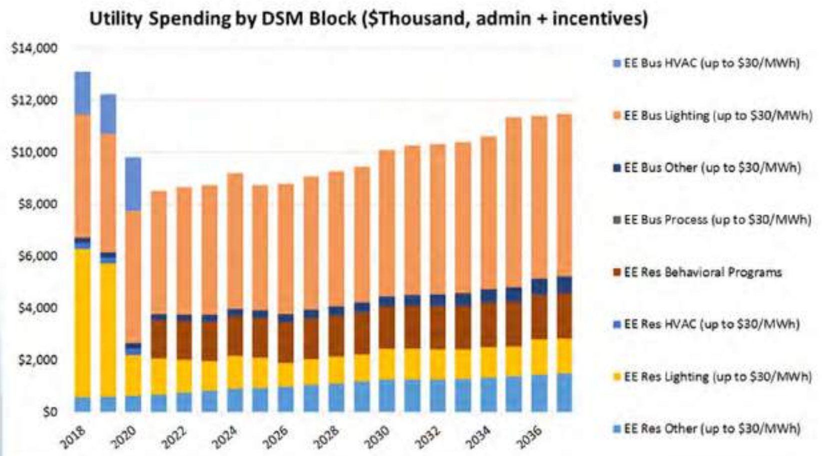
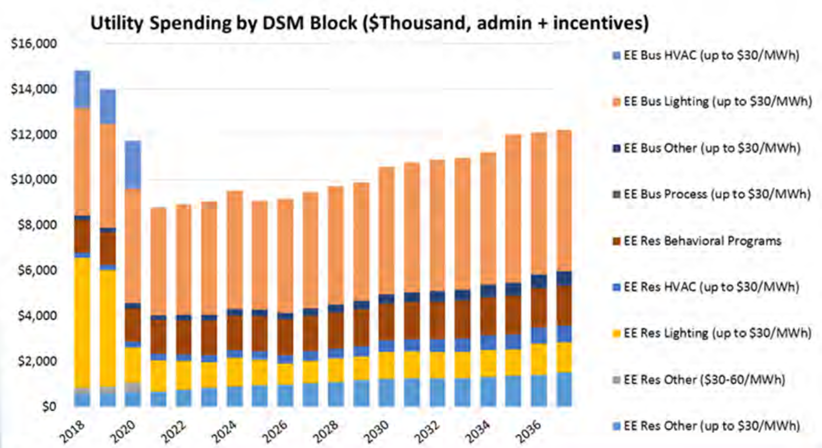
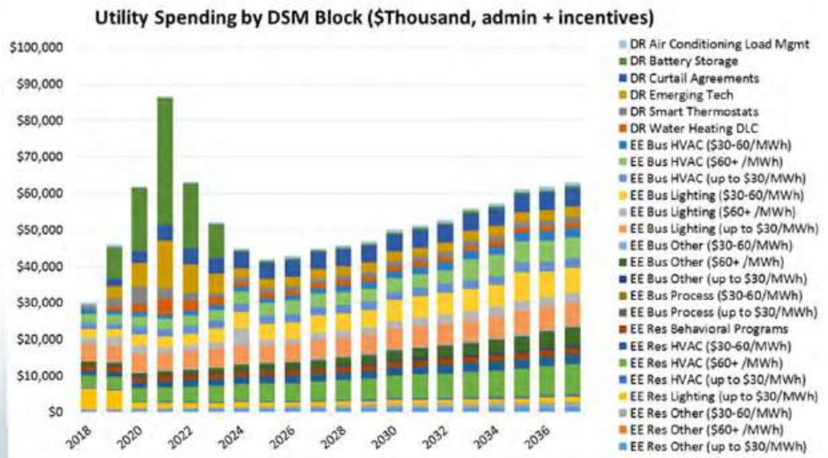
Adoption of distributed generation



Strengthened environmental



Quick transition



DSM building blocks selected

(based upon maximum achievable)

DSM Blocks Selected	Final Base Case	Robust Economy	Recession Economy	Strengthened Environmental	Distributed Generation
Res Other up to $30MWh 2018-2020	X	X	X	X	X
Res Other $30-60MWh 2018-2020		X		X	
Res Lighting up to $30MWh 2018-2020	X	X	X	X	X
Res HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Behavioral Program 2018-2020		X	X	X	
Bus Other up to $30MWh 2018-2020	X	X	X	X	X
Bus Lighting up to $30MWh 2018-2020	X	X	X	X	X
Bus HVAC up to $30MWh 2018-2020	X	X	X	X	X
Res Other up to $30MWh 2021+	X	X	X	X	X
Res Lighting up to $30MWh 2021+	X	X	X	X	X
Res HVAC up to $30MWh 2021+		X		X	
Res Behavioral Programs 2021+	X	X	X	X	X
Bus Process up to $30MWh 2021+	X	X	X	X	X
Bus Other up to $30MWh 2021+	X	X	X	X	X
Bus Lighting up to $30MWh 2021+	X	X	X	X	X

Quick Transition DSM

DSM Blocks	2018-2020	2021-2037
EE Res Other (up to $30/MWh)	X	X
EE Res Other ($60+ /MWh)	X	X
EE Res Other ($30-60/MWh)	X	X
EE Res Lighting (up to $30/MWh)	X	X
EE Res HVAC (up to $30/MWh)	X	X
EE Res HVAC ($60+ /MWh)	X	X
EE Res HVAC ($30-60/MWh)	X	X
EE Res Behavioral Programs	X	X
EE Bus Process (up to $30/MWh)	X	X
EE Bus Process ($30-60/MWh)	X	X
EE Bus Other (up to $30/MWh)	X	X
EE Bus Other ($60+ /MWh)	X	X
EE Bus Other ($30-60/MWh)	X	X
EE Bus Lighting (up to $30/MWh)	X	X
EE Bus Lighting ($60+ /MWh)	X	X
EE Bus Lighting ($30-60/MWh)	X	X
EE Bus HVAC (up to $30/MWh)	X	X
EE Bus HVAC ($60+ /MWh)	X	X
EE Bus HVAC ($30-60/MWh)	X	X
DR Water Heating DLC	X	X
DR Smart Thermostats	X	X
DR Emerging Tech	X	X
DR Curtail Agreements	X	X
DR Battery Storage	X	X
DR Air Conditioning Load Mgmt	X	X

2016 Integrated Resource Plan Modeling Summary

Prepared for:
Indianapolis Power & Light Company

Date Submitted:
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Liability Note

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EXECUTIVE SUMMARY

ABB was retained by Indianapolis Power & Light Company (IPL) to provide analytical services to support its 2016 Integrated Resource Plan (IRP). ABB used the Midwest Fall 2015 Power Reference Case projection of natural gas, emission and energy prices. In addition, ABB forecasted gas and energy prices for the MISO-Indiana Power Market for additional scenarios and stochastic modeling.

Sections, tables and figures identified as “Confidential” are available in Volume 2 of IPL’s full 2016 Integrated Resource Plan as Confidential Attachment 2.2.

ABB performed IPL portfolio expansion simulations using its Capacity Expansion Module to model demand side and supply side alternatives. The module did a complete numerical simulation of all possible combinations using mixed integer linear programming (MILP) while maintaining a minimum 15 percent reserve margin as required by MISO for the current planning year. While this minimum level is reviewed annually, IPL opted to assume a constant value in the study period. The decision criterion or objective function is to minimize the costs to customers presented in terms of present value of revenue requirements (PVRR). Study period was 2017-2036 with end effects through 2046.[1]

In addition, ABB used their Strategic Planning (SP) software to model the portfolio, financial and rate making simulations. ABB calibrated the operating characteristics of the IPL fleet consistent with the National Ambient Air Quality Standard for Sulfur Dioxide Emissions (“NAAQS-SO_2”) and Coal Combustion Residuals (“CCR”) Rule Compliance Project, and performed deterministic and scenario assessments for the plans.

Five sets of CO_2 prices were used for this analysis:

- Deterministic prices were used from ABB’s 2015 Fall Reference Case for the CO_2 Tax Scenario.
- Deterministic prices were developed for the high/low gas scenarios with a CO_2 Tax.
- Deterministic prices were developed for IPL’s high carbon cost forecast which was based on the data provided by its vendor ICF Federal Legislation data starting in 2022. A set of 50 stochastic prices for MISO-IN were developed using ABB’s Integrated Model and its Smart Monte Carlo sampling program.

The six scenarios of the energy industry’s future were modeled. Highlights for each scenario were:

Base: Base load forecast with CO_2 Tax reference case assumptions with implementation of national greenhouse gas legislation starting in 2022. A carbon tax serves as a proxy for future carbon regulation which may be allowance or tax based.

Robust Economy: High load forecast with high gas and market prices correlated with base CO_2 Tax.

[1] The process within SP to capture end effects consists of running the simulation beyond the study period. When conducting integrated resource planning and active evaluation of constructing base load generating facilities, it is critical to properly evaluate the cost effectiveness of resource additions by extending the planning horizon

Recession Economy: Low load forecast with low gas and market prices correlated with base CO_2 Tax.

Strengthened Environmental Rules: Base load forecast with high carbon cost assumptions starting in 2022 with correlated gas and market prices. A Renewable Portfolio Standard of 20% was added in by 2022.

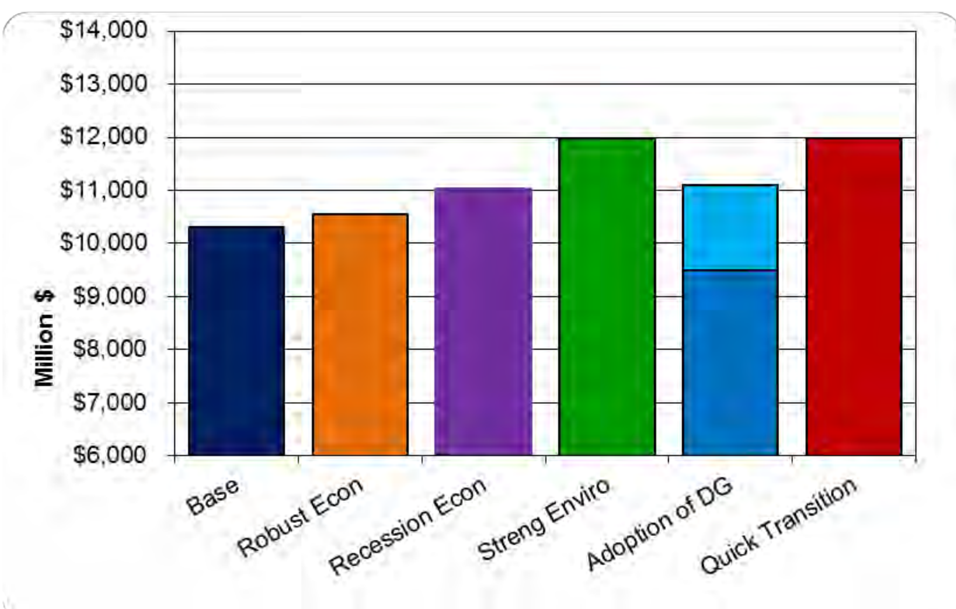
High Customer Adoption of Distributed Generation (DG): Same as Base Case with 150 MW of DG added in each of the three years: 2022, 2025 and 2032 to reflect potential customer choices.

Quick Transition: Same as base case with Pete 1 retirement and refueling Pete 2-4 in 2022 and maximum achievable Demand Side Management (DSM), and the balance of resources comprised of solar, wind and battery storage in 2030 based on stakeholder feedback.

ABB performed deterministic and risk analyses to evaluate IPL's scenarios under varying conditions, identifying a wide range of possible portfolios. . Figure 1-1 shows the 20 Year PVRR for the six scenarios. For the High Customer Adoption of DG Scenario, the light blue DG costs are estimated for 450 MW.

Figure 1-2 through Figure 1-4 illustrate the resource additions, reserve margin and annual aggregate incremental rate increases due to resource changes only for the six scenarios.

Figure 1-1
Scenario - PVRR Rankings (2017-2036)



(Source: ABB Advisors.)

Figure 1-2
Base Scenario Resource Plan Additions

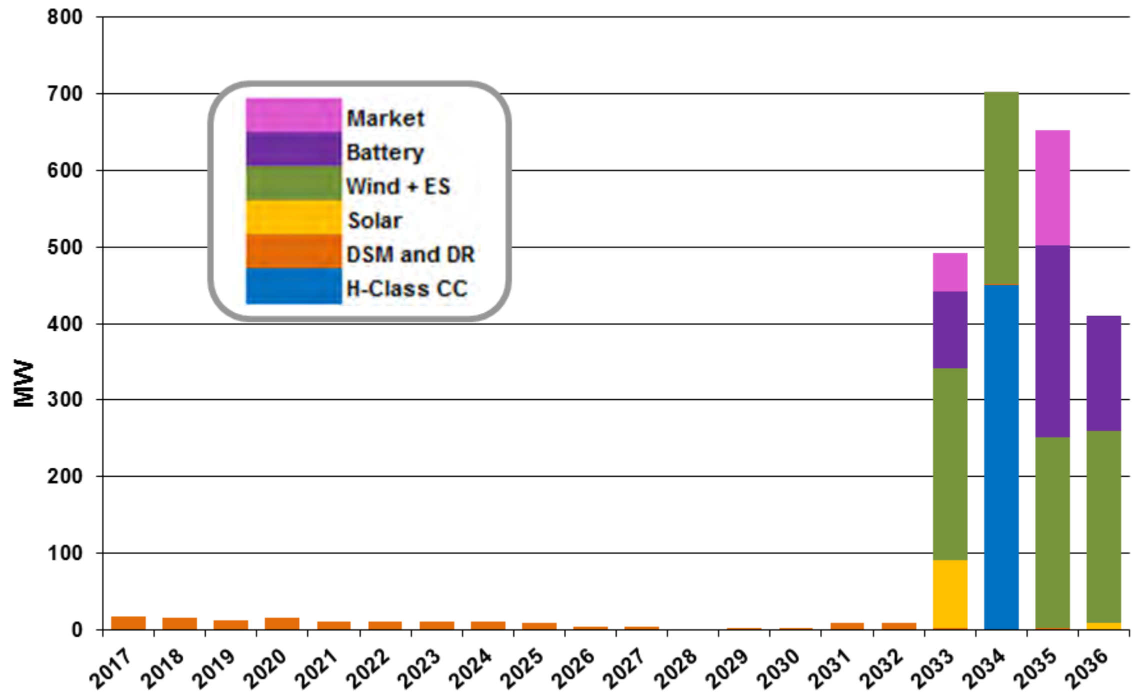
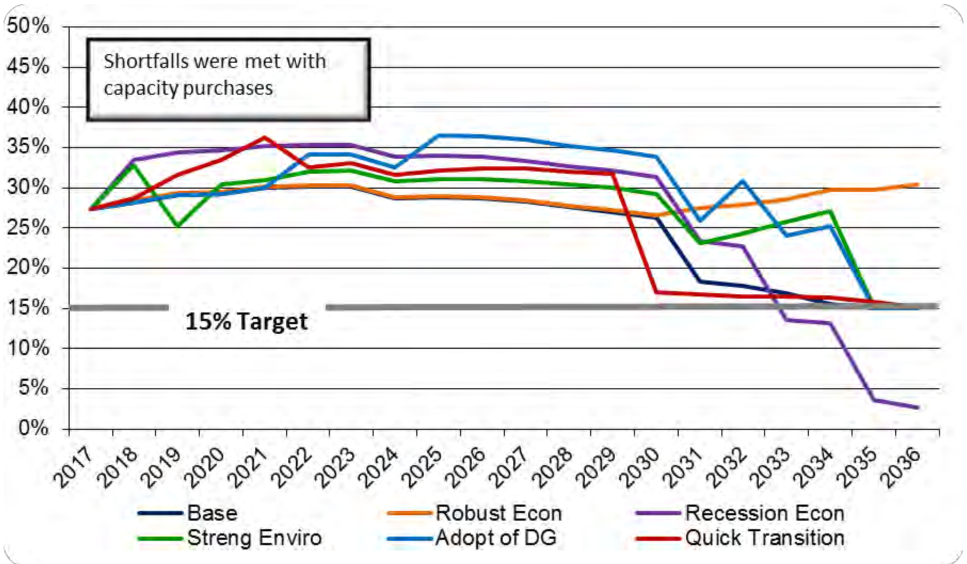
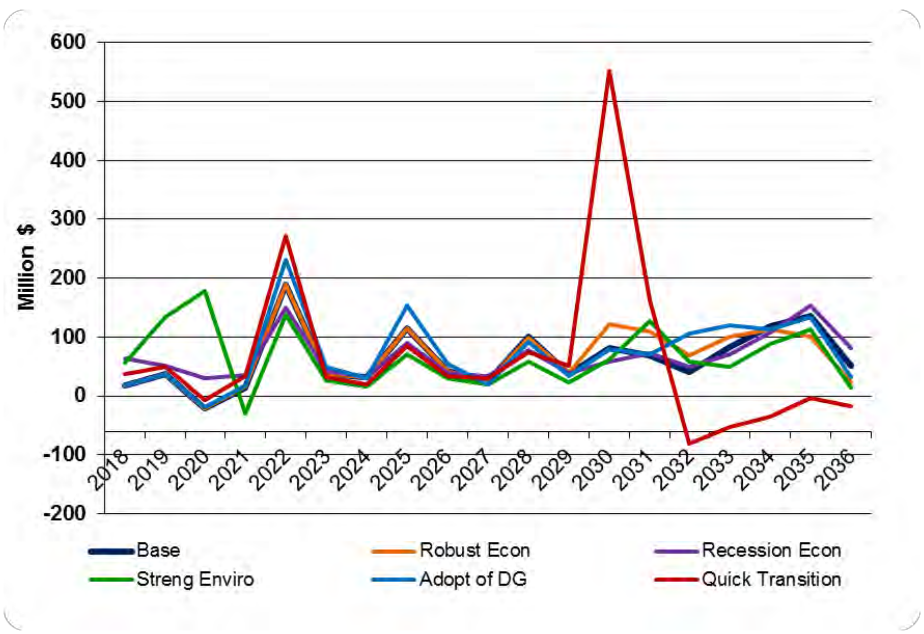


Figure 1-3
Resource Portfolios- Reserve Margin (IPL Installed Capacity). All plans utilize the base load assumption.



(Source: ABB Advisors.)

Figure 1-4
Scenario Annual Rate Increases[2]



(Source: ABB Advisors.)

[2] The Quick Transition portfolio was crafted from stakeholder input. The 2022, 2025 and 2030 asset additions align with CPP compliance periods. The lumpy additions in 2030 would likely be smoothed.

1 SCOPE OF PROJECT

ABB believes that the Resource Planning process and results need to be fully "owned" by the client. ABB provided consulting advice, oversight and analytics of IPL's current and projected resources. IPL provided portfolio information and approval of key assumptions. As such, the approach involved a combined ABB and IPL team as it relates to aspects of the engagement.

ABB utilized Strategic Planning (SP) *powered by MIDAS Gold™* in conjunction with the Capacity Expansion Module (CEM) to meet the needs of the resource planning study. SP and CEM allowed our consultants to quickly screen and optimize resource options and feedback the information to the client's portfolio. SP also allowed the capture of financial information that was not related to production results including, but not limited to, the financial aspects of a construction program, timing of cash and creation of rate base items. SP captured revenue requirements based on return on rate base.

IPL's expectations were the development of a detailed resource plan evaluation process which captures and quantifies the risk of certain events. To accomplish this, ABB performed the following scope of work:

MISO-Indiana Market Simulation

1. Forecasted Hourly Energy Prices. Five sets of prices were used for this analysis:

- Deterministic prices were used from ABB's 2015 Fall Reference Case for the Clean Power Plan (CPP) Carbon Tax Scenario.
- Deterministic prices were developed for the high/low gas scenarios with a CO_2 Tax.
- Deterministic prices were developed for ICFs Federal Legislation Scenario starting in 2022.
- A set of 50 stochastic prices for MISO-IN were developed using ABB's Integrated Model and its Smart Monte Carlo sampling program.

2. Forecasted Annual Capacity Prices. Provided a deterministic projection of MISO-Indiana 2017-2036 capacity prices from ABB's Fall Reference Case.

IPL Portfolio (Capacity Expansion Module or CEM) Simulation

1. Modeled supply-side alternatives including combustion gas turbines, combined cycles, nuclear, wind, battery storage and photovoltaic ownership options.
2. Modeled demand-side alternatives identified in IPL's 2016 DSM Market Potential Study (MPS) as selectable resources based on similar measure load shapes by rate class and cost. (e.g. Residential lighting under $30/MWh as a bundle.)
3. Allowed the model to retrofit/refuel or retire the Pete units in 2018.
4. Performed a complete numerical simulation of all possible combinations using mixed integer linear programming (MILP) while maintaining a minimum 15 percent reserve margin with a decision criterion of minimizing the present value of revenue requirements (PVRR). The results of the CEM screenings were passed to the Strategic Planning model as part of the portfolio, financial, and rate making simulations.

IPL Portfolio Simulation

1. Calibrated the operating characteristics of the IPL fleet (fuel type, variable cost, fixed cost, heat rate, minimum capacity, must run status, spinning reserve, maximum capacity, emission rates, starts). Calibration was based on National Ambient Air Quality Standard for Sulfur

Dioxide Emissions (“NAAQS-SO_2”) and Coal Combustion Residuals (“CCR”) Rule Compliance Project work recently completed. Modifications to the Pete Unit retrofit costs and unit capacity ratings were then adjusted. Base year was updated to 2016 dollars.

2. The IPL assets and load are dispatched competitively against the electricity market prices. This modeling more accurately mimics the implementation of the Midcontinent Independent Transmission System Operator (MISO) market, where IPL sells its generation into the MISO market and purchases its retail load requirements from the MISO market.
3. Performed deterministic and scenario simulations to assess the performance and risk associated with each resource plan.

Scenario Based Market Price Simulation

ABB utilized the CPP Carbon Tax market price scenario developed in our 2015 Fall Power Reference Case in addition to forecasting energy prices for the MISO-Indiana Power Market for the following additional scenarios.

1. The four scenarios are as follows:

    Base (CPP Carbon Tax): The focus of the CPP Carbon Tax Scenario was to meet the national target reduction of 32 percent using a mass-based approach. ABB utilized its proprietary Integrated Model to determine a CO_2 tax that would be required to meet the 32 percent reduction by 2030. In addition, it was further refined to reflect the CO_2 tax that would be required to meet the interim targets. This scenario also included an uplift in the natural gas prices and reduced coal prices due to increased/reduced demand respectively.

    Low Gas Price with CPP Carbon Tax: For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes (base), but also of probabilities around the projection. Accordingly, ABB developed upper and lower 10 percent confidence bands around the gas forecast. This means that there is a long-run 80 percent probability that future gas prices will occur within these bands and that 10% of the time gas prices can be lower than the projected low gas price. Market prices developed for this scenario are consistent with the low gas prices and a CO_2 tax.

    High Gas Price: Again, this means that there is a long run 80 percent probability that future gas prices will occur within the upper and lower 10 percent confidence band and that 10% of the time gas prices can be higher than the projected high gas price. Market prices developed for this scenario are consistent with the high gas prices and a CO_2 tax.

    High carbon costs: ABB developed gas and market prices that were correlated with the high carbon cost assumptions in $/ton starting in 2022.

2 REGIONAL MODELING ASSUMPTIONS

Introduction

ABB created a forward view of the MISO-Indiana regional electricity market, which includes IPL's portfolio. The database uses publicly available information through 2024 and is further extrapolated to 2036 using general trends for prices, demand growth and resource expansion.

The Forward View is a proprietary perspective of the future based on public or commercial information and experience in working in electricity markets. This fundamental approach relies on first identifying the basic components of electricity price: supply, transmission and demand, and using best available sources, project the components over time and geography.

Supply is disaggregated into types of generation, and further disaggregated into fuels (or drivers), operations of the resources (capacity, heat rates, planned outages, and forced outages), the amount of additions (and retirements) over time and other factors such as emissions from power generation.

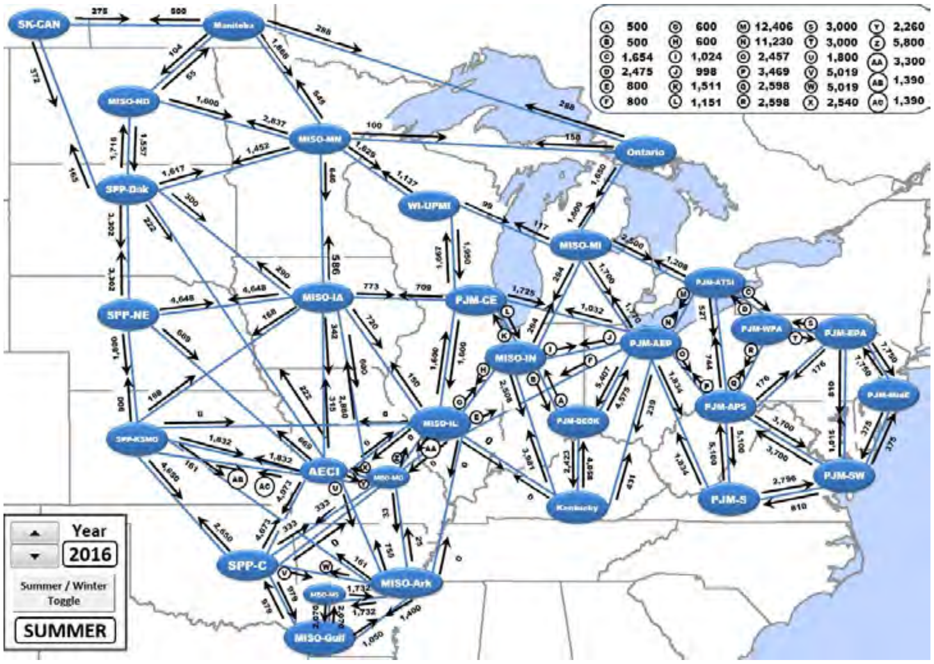
Demand is the demand for electricity by zone (191 zones in North America). Monthly peak and energy demand is forecast over a ten year period. Then, reference hourly demand of electricity is applied to forecasts to produce forecasts of hourly demand by region.

Mid-Continent Market Topology

The Midwest region covers nearly 2.3 million square miles and includes all or portions of 26 U.S states and the Canadian provinces of Saskatchewan and Manitoba. Almost 40% of the US and Canadian population live in this area, and approximately 470,000 MW of generating resources supply 1,796 TWh of energy annually. The Midwest is highly interconnected, and, with some limitation, generation from any area with in the Midwest can be used to meet load in any other area. These interconnections results in a highly interdependent Midwest electricity market.

To develop hourly energy prices for MISO-IN, ABB modeled the entire Eastern Interconnection with transmission interties and zonal price points. Figure 2-1 displays the transmission system with a focus on the mid-continent market.

Figure 2-1
Mid-Continent Market Configuration (MW Transfer Limit)



(Source: ABB Advisors.)

Market Price Formation

ABB used a fundamentals-based approach to calibrate unit performance, market prices, and power flows. ABB simulated the operation of each generating unit of the Eastern Interconnection. For each region, ABB's software models considered:

- Individual generating unit characteristics including heat rates, variable O&M, fixed O&M, and other technical characteristics;
- Transmission line interconnections, ratings, and wheeling rates;
- Resource additions and retirements;
- Nuclear unit outages and refuelings;
- Hourly loads for each utility or load serving entity in the region; and
- The cost of fuels that supply the plants.

ABB's models simulated the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The models are based on a zonal approach where market areas (zones) are delineated by critical transmission constraints. The simulation is based on a mathematical function that performs economic power exchanges across zones until all eligible economic exchanges have been made.

ABB's calibration methodology was to benchmark the models against observed:

- prime mover output within the market zones;
- market prices; and
- power flows.

Market Price Results

ABB created a forward view of the MISO-Indiana regional electricity market, which includes the IPL portfolio. The highly interconnected regions of the Eastern Interconnect (NPCC, SERC, FRCC, SPP, PJM, MISO and MRO)[3] required the demand, supply and transmission to be considered for the entire region. The database uses publicly available information through 2024 and is further extrapolated to 2036 using general trends for prices, demand growth and resource expansion.

Four sets of deterministic prices were used for this analysis:

- Prices from ABB's 2015 Fall Reference Case for the CO_2 Tax Scenario.
- Prices were developed for the high/low gas scenarios with a CO_2 Tax.
- Prices were developed for ICFs Federal Legislation Scenario.

The following describes the market prices used in each scenario.

Base: 2015 Fall Reference Case CO_2 Tax assumptions with implementation of national greenhouse gas legislation starting in 2022.

Robust Economy: High Gas: ABB's subjective view of 90th percentile of probability distribution that corresponds to limited shale supply scenario. Market prices developed for this scenario are consistent with the high gas prices and the Base CO_2 tax.

Recession Economy: Low Gas: ABB's subjective view of 10th percentile of probability distribution that corresponds to production costs for best shale plays. Base scenario CO_2 Tax. Market prices developed for this scenario are consistent with the low gas prices and the Base CO_2 tax.

Strengthened Environmental: Market and gas prices developed for ICF's assumption of implementation of national greenhouse gas legislation (Federal Legislation) starting in 2022.

High Customer Adoption of DG: Same as Base Case

Deterministic Results

Table 2-1 summarizes the base (CPP Carbon Tax) annual 5x16 (On-Peak), Wrap (Off-Peak) and 7x24 (Average) electricity prices for the MISO-Indiana region.

Table 2-1 – Confidential Table
Base (CO_2 Tax) Prices for the MISO-Indiana Region (Nominal $/MWh)

[3] Northeast Power Coordinating Council, SERC Reliability Corporation, Florida Reliability Coordinating Council, Southwest Power Pool, Pennsylvania-New Jersey-Maryland Interconnection, Midwest Independent System Operator and Midwest Reliability Organization

Base (CO_2 Tax) electricity prices for MISO-Indiana are summarized in Figure 2-2.

Figure 2-2 – Confidential Figure
Base (CO_2 Tax) Prices for MISO-Indiana Region (Nominal $/MWh)

Table 2-2 and Figure 2-3 summarize the average (7x24) electricity prices that were specifically developed for the IRP scenarios along with the Base (CO_2 Tax) market prices.

Table 2-2 – Confidential Table
7x24 Scenario Prices for the MISO-Indiana Region (Nominal $/MWh)

Figure 2-3 – Confidential Figure
7x24 Scenario Prices for MISO-Indiana (Nominal $/MWh)

Natural Gas, Oil Price, Coal Price and Emissions Write up – Confidential

Figure 2-4 – Confidential Figure
Fall 2015 Henry Hub Forecast Comparison (2015 $/MMBtu)

Table 2-3 – Confidential Table
CPP Carbon Tax Scenario Monthly Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)

Figure 2-5 – Confidential Figure
CPP Carbon Tax Scenario Henry Hub Natural Gas Forecast (Nominal $/MMBtu)

Table 2-4 summarizes the three approaches incorporated by ABB to produce the Reference Case natural gas price forecast.

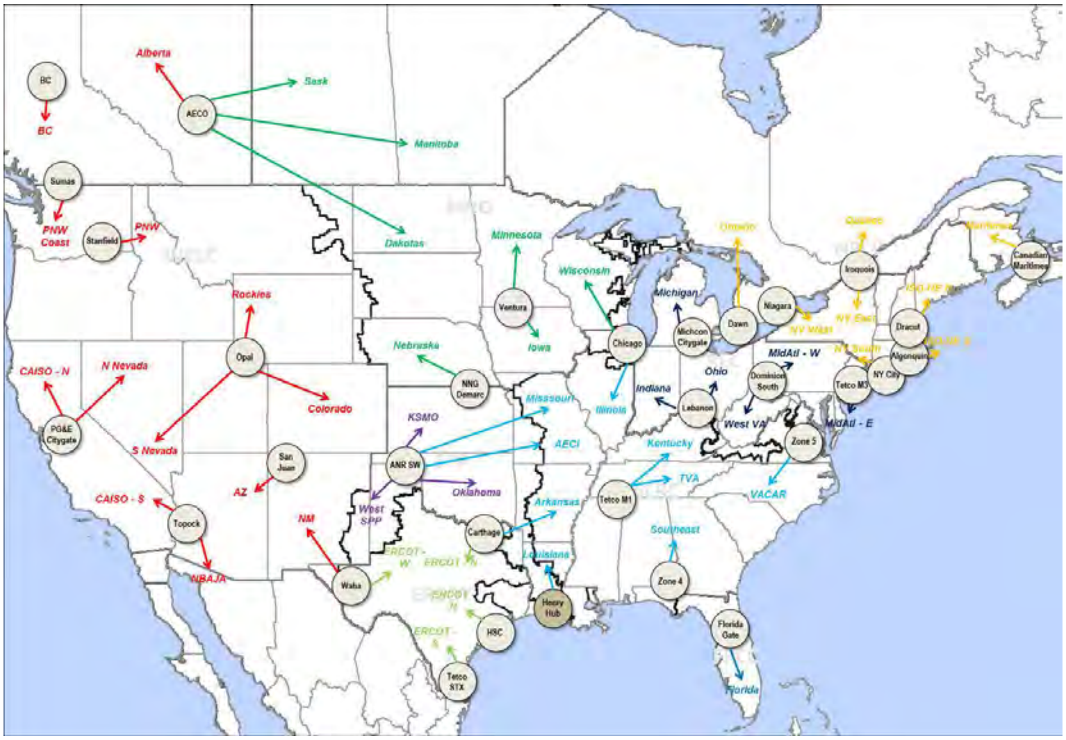
Table 2-4
Reference Case Gas Price Forecasting Phases

Forecast Phase	Period Length	Data Source	Forecast Technique
Futures Driven	First 24 Months	NYMEX Henry Hub futures and market differentials	Calculated Henry Hub and liquid market center differentials
Blend	Months 25-48	ABB Advisors and NYMEX/Velocity Suite	Linear process to gradually equate near-term to long-term fundamentals
Long-term Fundamentals	Remaining forecast period (to 2040)	ABB Advisors	Fundamental supply and demand analysis modeling

(Source: ABB Advisors.)

Figure 2-6 illustrates the liquid market centers that are used in the Fall 2015 Reference Case forecast.

Figure 2-6
Natural Gas Liquid Market Centers



(Source: ABB Advisors.)

Table 2-5 shows ABB's annual coal basin price forecast for US Basin Coal.

Table 2-5 - Confidential
ABB US Basin Coal Price Forecast (Nominal $MMBtu)

Table 2-6 contains the Reference Case emission prices for the MISO-Indiana transaction group in addition to the high carbon cost assumptions.

Figure 2-7 illustrates the CO_2 emissions cost for the two environmental scenarios.

Table 2-6 – Confidential
Emission Costs (Nominal $/Ton)

Figure 2-7 - Confidential
CO_2 Emission Costs (Nominal $/Ton)

3 PORTFOLIO MODELING ASSUMPTIONS

Natural Gas

The natural gas prices used for IPL's system include the forecast for the Henry Hub price plus $0.05/MMBtu delivery to Eagle Valley and $0.20/MMBtu delivery to Harding Street and Georgetown. **Table 3-1** summarizes the annual Henry Hub plus basis differential for all scenarios.

Table 3-1 - Confidential
Annual Natural Gas Prices for all Scenarios (Nominal $/MMBtu)

Inflation

A 2.5 percent escalation rate was used for the forecast period.

Discount Rate

Per IPL's direction, ABB assumed a 5.61 percent discount rate based on IPL's most recent rate case and all PVRR dollars amounts presented have been discounted back to 2016 dollars.

IPL Coal Price Forecast

IPL provided a Petersburg coal price forecast based upon local contract negotiation pricing for the first three years, followed by local projections for the next seven years, and then a fixed escalation rate for the remainder of the study period.

Table 3-2 - Confidential
IPL Coal Price Forecast (Nominal $/MMBtu)

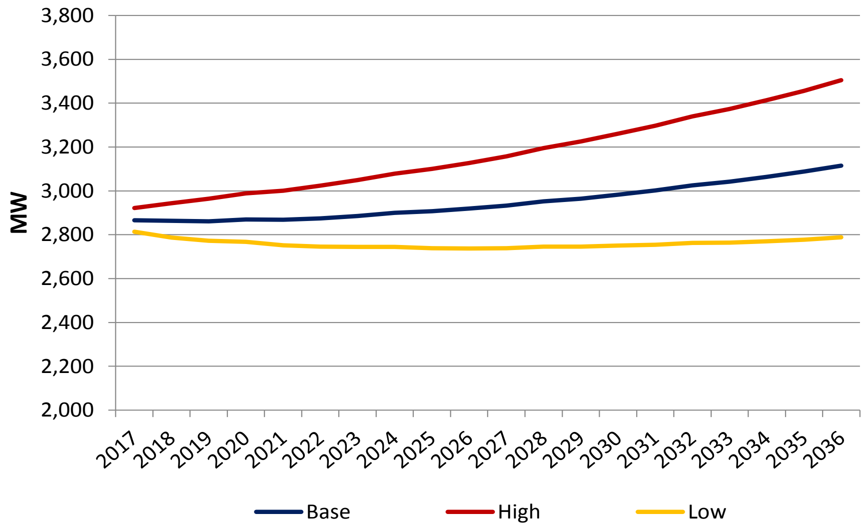
Unit Operating Characteristics

Operating characteristics of the IPL portfolio units were obtained from IPL-based on National Ambient Air Quality Standard for Sulfur Dioxide Emissions ("NAAQS-SO_2") and Coal Combustion Residuals ("CCR") Rule Compliance Project work that was completed in Q4 2015. Modifications to the Pete Unit retrofit costs and unit capacity ratings were then adjusted. Base year was updated to 2016.

IPL Load Forecast

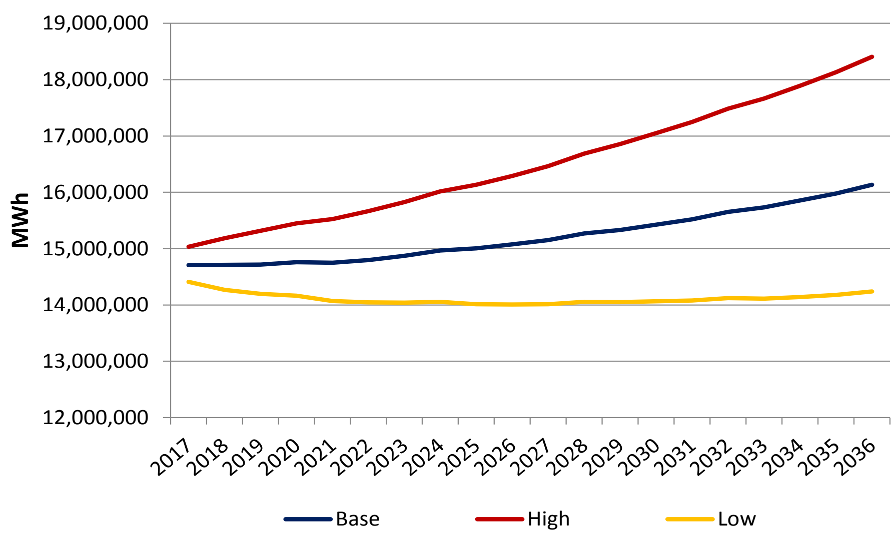
High, medium and low load forecast was supplied by IPL. Figure 3-1 & Figure 3-2 show the load forecast for both peak and energy for base, low and high ranges.

Figure 3-1
IPL Peak Forecast (2017-2036)



Source: IPL

Figure 3-2
IPL Energy Forecast (2017-2036)



Source: IPL

IPL Load and Resource Balance Report

Figure 3-3 contains IPL's Load and Resource Balance report for the period of 2017-2036 for the base plan. The capacity ratings are for planning based on MISO rules. Existing wind receives no planning capacity credit since the PPAs do not include firm transmission services. A 10% planning capacity was used for wind units starting in 2031 to reflect expected transmission system enhancements. A 45% planning factor was used for existing solar based on IPL's actual PPA data and a 48% planning factor was used for all new solar additions as allowable by MISO to reflect possible technology improvements or be located outside the IPL service territory with improved insolation performance.

Figure 3-3
Base Plan Load and Resource Balance Report

Indianapolis Power & Light
Load and Resource Balance Report

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PETE ST1	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	0	0	0	0
PETE ST2	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0
PETE ST3	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
PETE ST4	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531	531
HS GT4	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
HS GT5	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS GT6	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
GTOWN GT1	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HS ST5 Gas	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0
HS ST6 Gas	102	102	102	102	102	102	102	102	102	102	102	102	102	102	0	0	0	0	0	0
HS ST7 Gas	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	0	0	0
Eagle Valley	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
HS GT1	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS GT2	19	19	19	19	19	19	19	0	0	0	0	0	0	0	0	0	0	0	0	0
HS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PETE IC3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CC H Class	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	450	450
Hoosier Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakefield Wind Park	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	50	75	100
Solar Existing	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43	43	43	48
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	350	500
Market	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	150	0
Total Resources	3575	3575	3575	3575	3575	3575	3575	3537	3537	3537	3537	3537	3537	3537	3335	3335	3320	3306	3315	3345
Original Peak Load	2866	2864	2862	2870	2868	2875	2885	2900	2907	2920	2933	2952	2965	2983	3002	3026	3042	3065	3088	3116
DR & Coincident Peak DSM Total	58	75	92	104	119	129	140	151	161	170	175	179	180	182	185	194	202	204	206	208
Peak Load - DSM Removed	2808	2789	2770	2766	2749	2746	2746	2749	2746	2750	2758	2773	2785	2801	2817	2832	2840	2861	2882	2908
Reserve Margin	27.3%	28.2%	29.0%	29.2%	30.0%	30.2%	30.2%	28.7%	28.8%	28.6%	28.2%	27.6%	27.0%	26.3%	18.4%	17.8%	16.9%	15.6%	15.0%	15.0%

4 STOCHASTIC ASSUMPTIONS

Introduction

ABB's Integrated Model uses a structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission, and provides a solid basis for decision-making. Using a stratified Monte Carlo sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, unit availability, capital expansion cost, and emission price) and take into account statistical distributions, correlations, and volatilities.

Stratified sampling can be thought of as "smart" Monte Carlo sampling. Instead of drawing each sample from the entire distribution – as in Monte Carlo sampling – the sample space is divided into equal probability ranges and then a sample is taken from each range. By allowing these uncertainties to vary over a range of possible values, Strategic Planning develops a range or distribution of forecasted price.

Prices are derived using a rigorous probabilistic approach that does the following:

1. Quantifies the uncertainties that drive market price through a Stratified Monte Carlo sampling model;
2. Puts the uncertainties into a decision tree;
3. Evaluates multi-region, hourly market price for a set of consistently derived futures using Strategic Planning; and
4. Accumulates the information into expected forward price and volatility of the marketplace.

The uncertainty drivers developed for the specific MISO-IN market prices are also used when evaluating the portfolio. During the portfolio evaluation, the prices and the associated uncertainties provide sufficient information about the market to allow for proper evaluation of alternatives. For example, high gas prices would generally result in high on-peak prices. If the high gas prices were not used in conjunction with the high electric prices, resource evaluation would be biased.

Uncertainty Variables

For the regional price trajectories, ABB examines the impact of demand, fuel price, and supply on regional spot market prices. Additionally, for the portfolio analysis, we examine the uncertainty of resource capital cost provided by IP&L. Specifically, the following uncertainties are evaluated:

Demand

- Mid-Term Peak Demand by region
- Mid-Term Energy by region
- Long-Term Electric Demand Growth

Fuel Prices

- Mid-Term Gas Price
- Long-Term Gas Price
- Long-Term Coal Price
- Long-Term Oil Price

Emission Cost

- Long-Term CO_2 Price

Supply

- Mid-Term Coal Unit Availability by region
- Long-Term Combined Cycle Capital Cost
- Long-Term Wind and Solar Capital Cost
- Long-Term Utility Scale and Community Solar Cost
- Long-Term Battery Storage Cost

Stochastic Draws

Using Strategic Planning's Stratified Monte Carlo sampling program, ABB created 50 future scenarios for price development and portfolio evaluation. ABB has performed extensive market price trajectory simulations and has determined that 50 trajectories provide a reasonable balance between the number of scenarios to achieve a convergent solution and a manageable number of stochastic scenarios to be applied to many resource plan alternatives. Uncertainty draws were made for the capital cost of the resource additions in the portfolio evaluation. These capital cost draws are combined with the uncertainty draws from the price development runs.

Mid-Term Peak and Energy by Region

Monthly peak and monthly energy are constant variance variables (i.e. the variance remains constant over time) with normal probability distributions. For constant variance variables, monthly variability is expressed in terms of the normalized standard deviation (Std Dev/Mean) for the month. To derive the regional values for peak, ABB calculated the average standard deviation of the regional, growth-adjusted historical peaks by month. A parallel methodology is used to derive the standard deviations for monthly energy. Unique standard deviations are developed for all of the regions in the database. The correlation between the regional historical monthly peak and energy values are incorporated into the uncertainty analysis. The monthly correlations are calculated using the standard Excel correlation function.

Table 4-1 shows typical monthly normalized standard deviations for monthly peak and energy uncertainty variables for the MISO-IN transaction group. The correlation coefficients are also included.

Table 4-1
Peak and Energy Standard Deviations

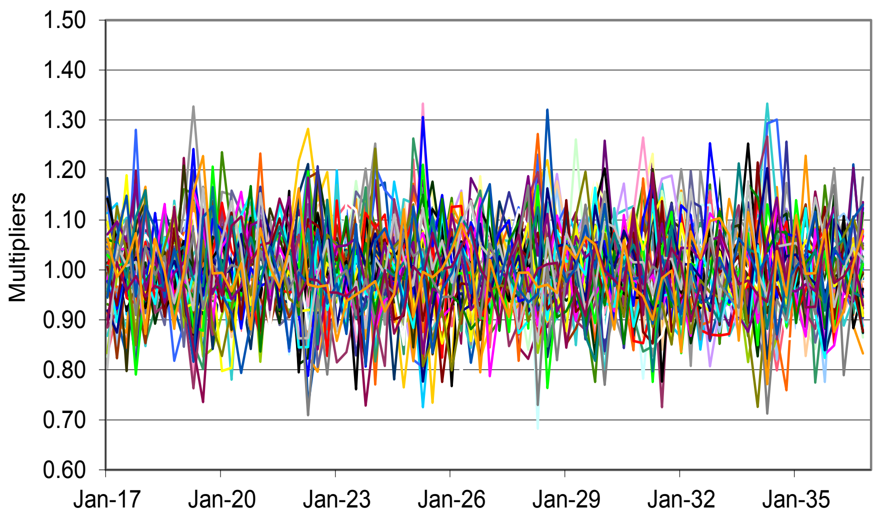
	Peak Standard Deviation	Energy Standard Deviation	Peak - Energy Correlation
Jan	0.082	0.071	0.897
Feb	0.073	0.073	0.964
Mar	0.079	0.082	0.940
Apr	0.096	0.081	0.916
May	0.094	0.081	0.851

Jun	0.060	0.069	0.764
Jul	0.067	0.068	0.899
Aug	0.079	0.084	0.924
Sep	0.092	0.096	0.897
Oct	0.130	0.098	0.759
Nov	0.095	0.088	0.980
Dec	0.083	0.087	0.902

(Source: ABB Advisors)

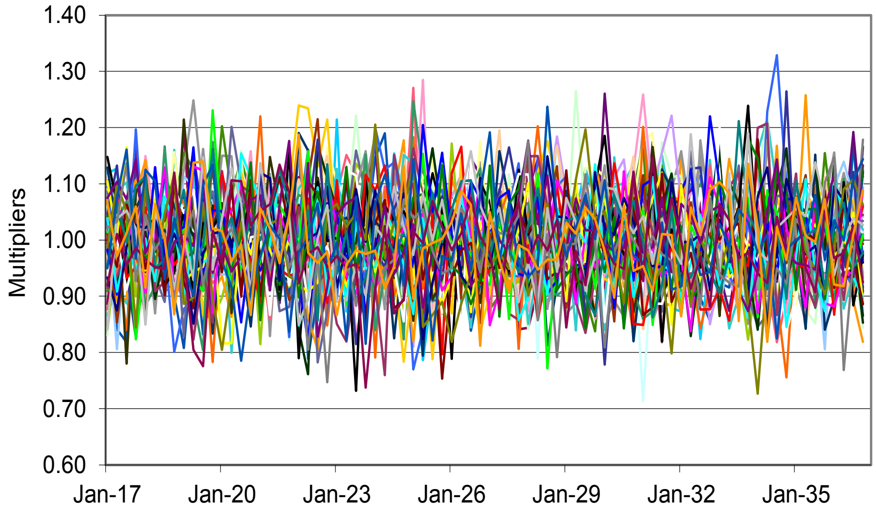
These parameters are used by ABB's Stratified Monte Carlo sampling program to develop a statistically consistent set of uncertainty multipliers. The resulting monthly peak and energy multipliers are then used to modify the input market area forecasts. MISO-IN peak and energy multipliers are shown in Figure 4-1 and Figure 4-2 The figures illustrate 50 draws per month. Alternatively, Figure 4-3 and Figure 4-4 show the peak and energy probability distribution of the multipliers. For each month, the correlated peak and energy draws are applied to the normalized peak and energy forecast by customer class.

Figure 4-1
MISO-IN Peak Multipliers



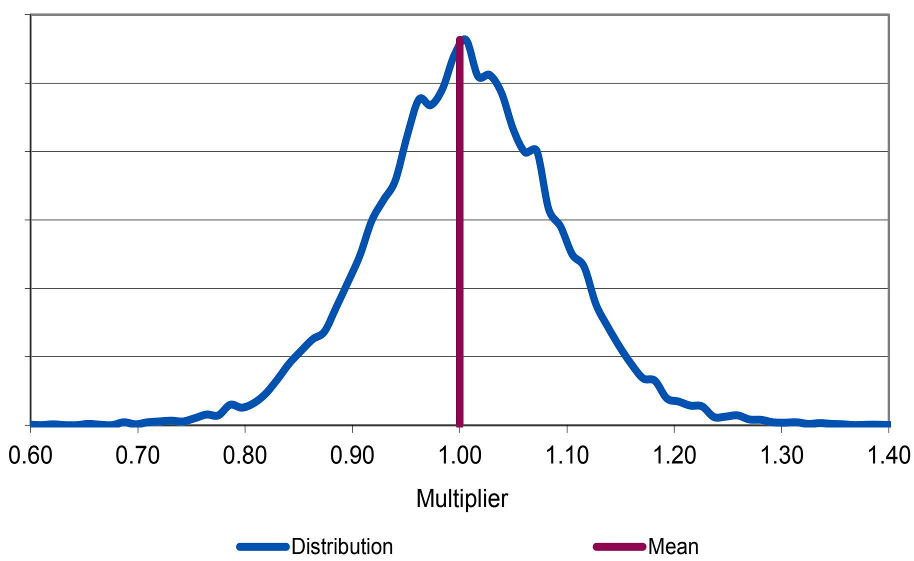
(Source: ABB Advisors)

Figure 4-2
MISO-IN Energy Multipliers



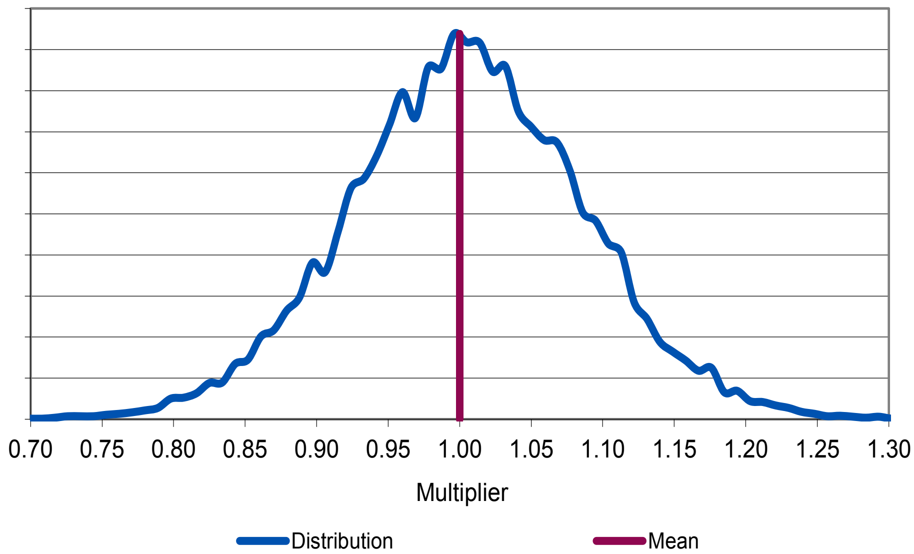
(Source: ABB Advisors)

Figure 4-3
MISO-IN Peak Distribution



(Source: ABB Advisors)

Figure 4-4
MISO-IN Energy Distribution

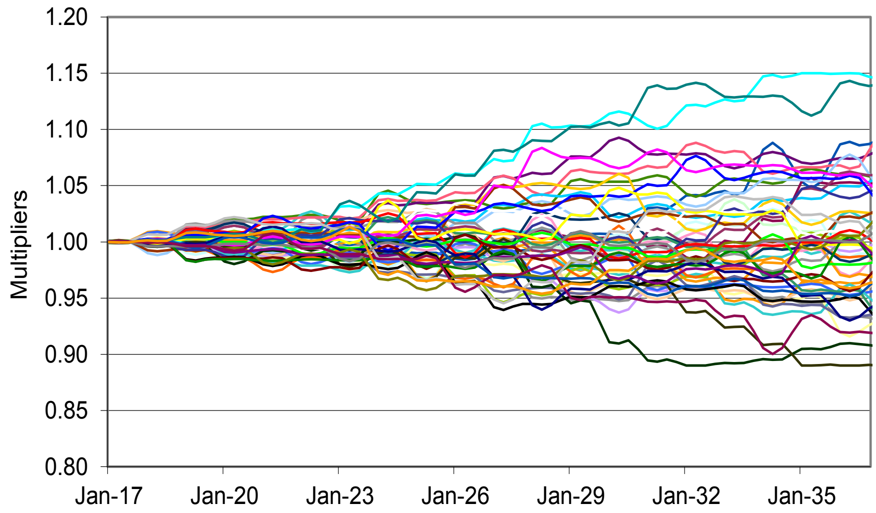


(Source: ABB Advisors)

Long-term Demand (to consider uncertainty in the rate of long-term load growth)

In order to consider the uncertainty in the rate of long-term load growth, demand multipliers are created to modify both peak and energy. The base assumption for the overall long-term growth rate is 0.55%, which is based on the Fall Reference case Midwest Peak and Energy Load Forecast in the MISO NERC Assessment Area. In the example below, volatility parameters are adjusted to consider a range of growth rates between -0.05% and 0.96% over the planning horizon. Figure 4-5 shows the demand multipliers.

Figure 4-5
Long-Term Demand Multipliers



(Source: ABB Advisors)

Mid-term Gas Price

Gas price is a random-walking variable; that is, its variance grows linearly with time. Based on an examination of gas price behavior, the prices tend to mean-revert. That is, over some definable period of time, the price of the commodity tends to move back toward the mean value. For Stratified Monte Carlo sampling, monthly variability for mean-reverting, random-walking variables is expressed in terms of the normalized standard deviation of the error for the month. The variability is further defined by specifying the time period over which the price mean-reverts. This value is expressed in terms of months.

For price development, ABB uses the monthly normalized standard deviation of error terms and the mean reversion time detailed in Table 4-2. Additionally, the multipliers are limited on the low side to 0.7 thru 2021 and 0.6 from 2022-2036.

Table 4-2
Gas Random-Walking Parameters

	Gas Standard Deviation
Jan	0.094
Feb	0.093
Mar	0.087
Apr	0.092
May	0.083
Jun	0.087
Jul	0.088
Aug	0.103
Sep	0.09

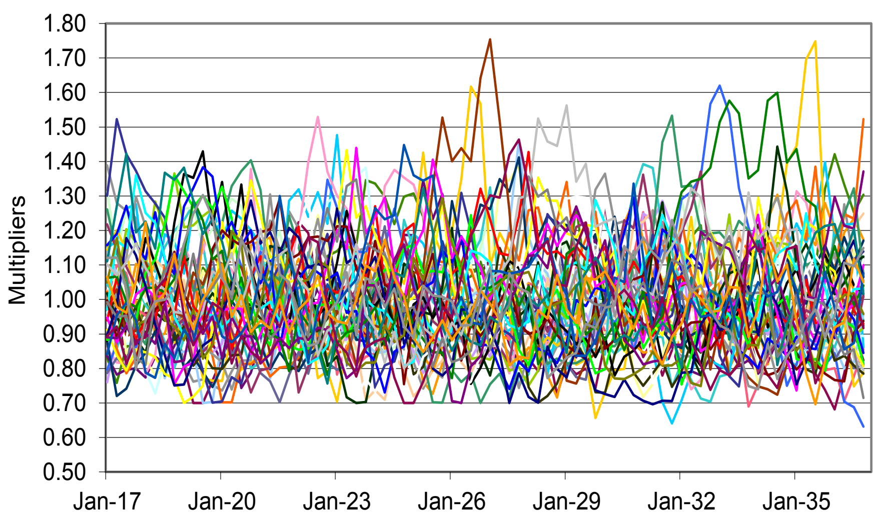
Oct	0.093
Nov	0.099
Dec	0.087
Reversion Time	4.682

(Source: ABB Advisors)

To develop monthly variability values for gas price, ABB began with a database of daily Henry Hub-delivered gas prices for the period 2001-2015. From the daily data, ABB calculated the average gas price by month and year. These averages are adjusted to remove outliers and underlying trends such as seasonal variation and growth rates. Using the resulting average monthly prices, ABB calculated the standard deviation of error terms.

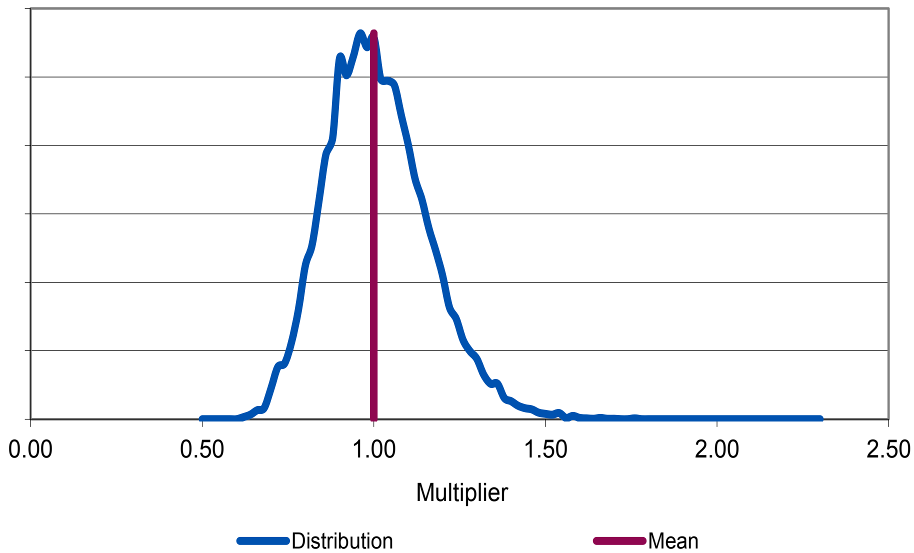
The multipliers resulting from the gas parameters in Table 4-2 are shown in Figure 4-6 and the probability distribution for gas is in Figure 4-7

Figure 4-6
Henry Hub Gas Price Multiplier



(Source: ABB Advisors)

Figure 4-7
Gas Price Distribution

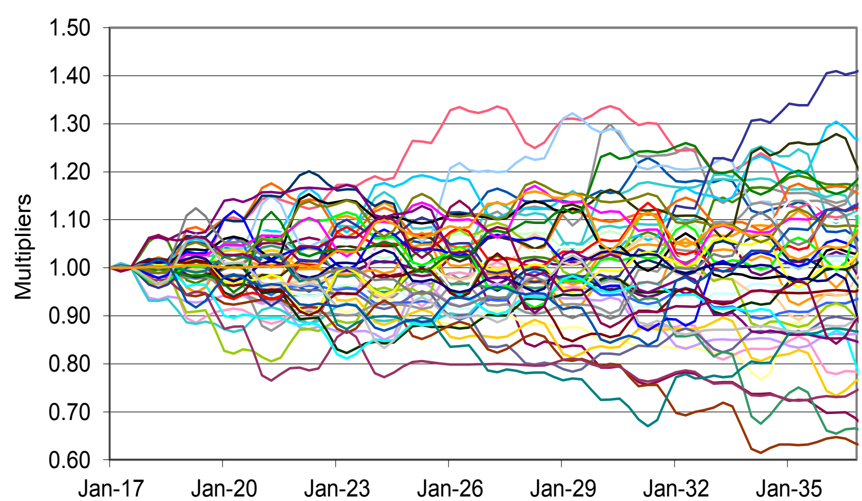


(Source: ABB Advisors)

Long-term Gas, Coal and Oil Price

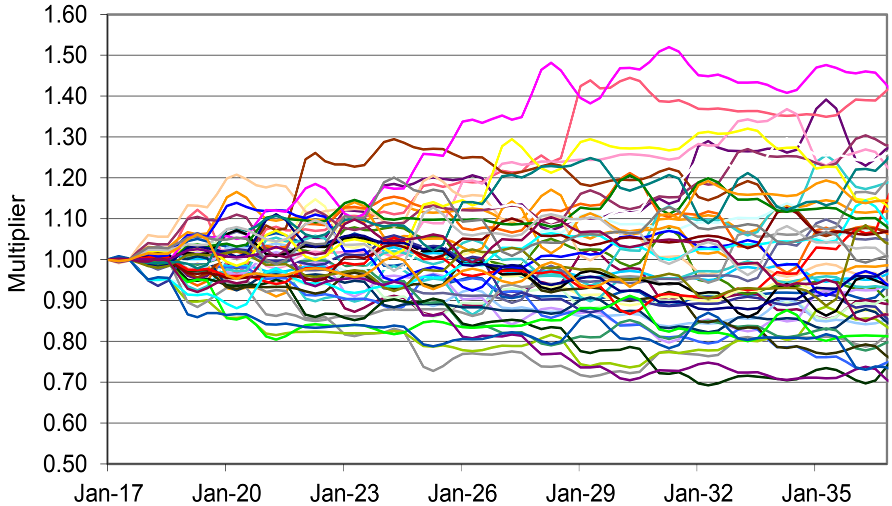
In order to consider the uncertainty in the long-term gas, coal and oil forecast, multipliers are created to modify the gas, coal and oil prices. The base assumption for the escalation of gas, coal and oil prices was 2.5%. Volatility parameters are adjusted to reflect a range of prices bounded by the minimum and maximum values of our fundamental forecast. Figure 4-8, Figure 4-9 and Figure 4-10 show the long-term gas, coal and oil multipliers, respectively.

Figure 4-8
Long-term Gas Multipliers



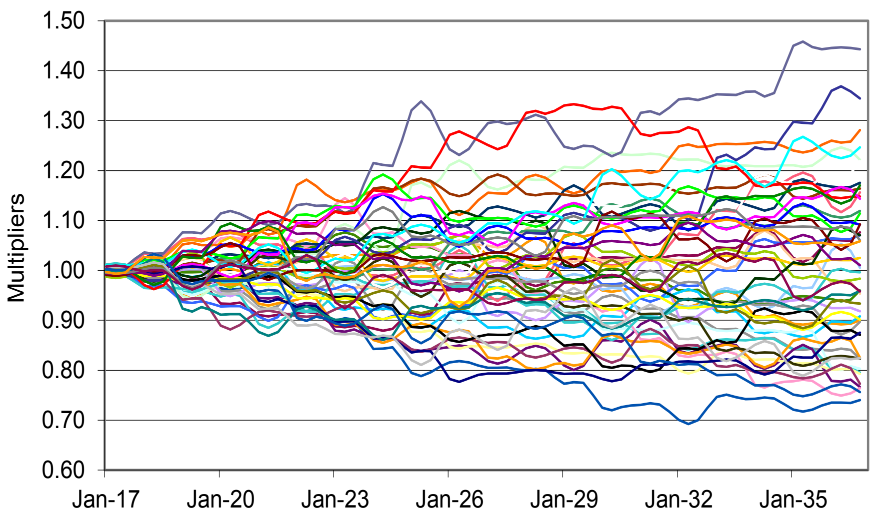
(Source: ABB Advisors)

Figure 4-9
Long-term Coal Multipliers



(Source: ABB Advisors)

Figure 4-10
Long-term Oil Multipliers



(Source: ABB Advisors)

Mid-term Coal Unit Availability by Region

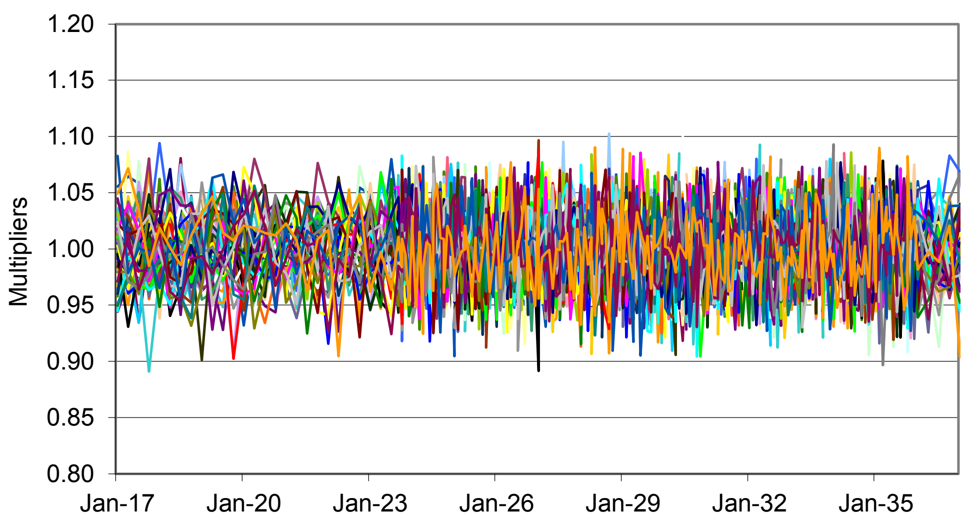
Given the stair-step behavior of the supply curve as it transitions from nuclear to coal to gas and oil, ABB has found that the availability of units within a zone by prime mover-fuel type can have a pronounced impact on market prices and congestion. Simply put, coal availability in a zone may have an impact on prices, flows, and congestion. To capture the stochastic uncertainty of unit availability, ABB makes draws to mimic the impact of availability.

Coal unit availability is a constant variance variable with a normal distribution. For coal availability, no monthly variation is defined. Draws are made using only the annual normalized standard deviation of the probability distribution (where the mean is assumed to be 1).

The coal availability multiplier varies the forced outage rate of coal units. It was assumed that there would be a 65% chance that 500 MW of capacity (out of 152,000 MW) would be unavailable for five days out of a month. Also, since the distribution of the coal availability is normal, there would be a 95% chance that 500 MW of capacity would be unavailable for ten days out of the month. These assumptions result in an annualized standard deviation of 0.03. Random draws using this standard deviation are made for each region for each endpoint.

Figure 4-11 shows the coal unit availability multiplier for a typical region for the 50 endpoints used to determine market prices.

Figure 4-11
Coal Unit Availability Multipliers



(Source: ABB Advisors)

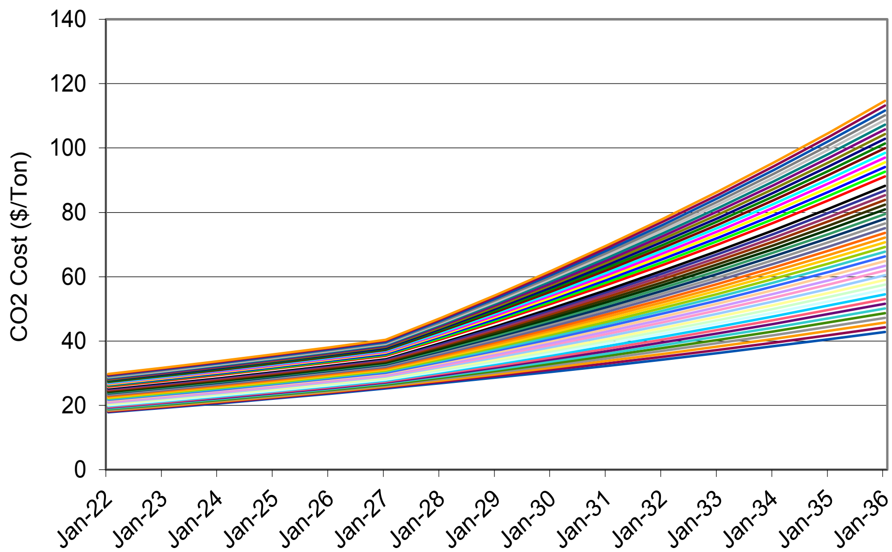
Long-Term Uncertainty CO_2 Price

Unlike the previous uncertainty variables, the lack of historical pricing for CO2 complicates its setup. For this reason, to create uncertainty for carbon pricing the Synapse Spring 2016 National Carbon Dioxide Price Forecast (Updated March 16, 2016) was used.

The Synapse CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility integrated resource planning (IRP) and other electricity resource planning analyses. The report includes updated information on federal regulations, state and regional climate policies, and utility CO_2 price forecasts, as well as Synapse's analysis of the final Clean Power Plan. Synapse's CO_2 price forecast reflects their expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term legislation passed by Congress to reach science-based emissions targets, will result in significant pressure to decarbonize the electric power sector. [4]

The following CO_2 prices in Figure 4-12 are bounded by the Synapse's high and low projections. The prices were not correlated to any of the other stochastic input variables, however the CO_2 prices were used in the stochastic market price development.

Figure 4-12
CO_2 Price Forecast Range

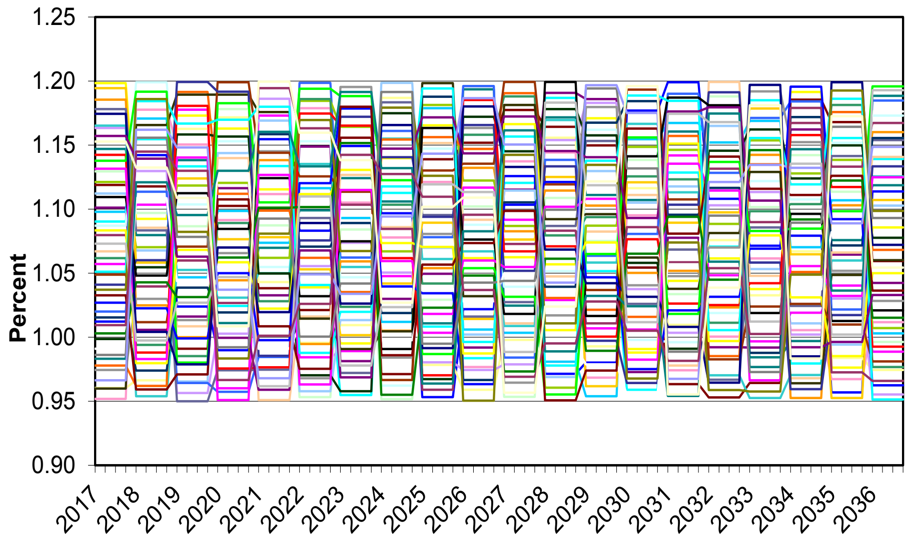


Long-Term Combined Cycle Plant Capital Cost

Combined Cycle (CC) plant capital cost is a constant variance variable with a uniform distribution. Due to site specific construction issues, capital costs are expected to be both higher and lower than the base estimate. It was assumed that the multipliers for capital cost will range from .95 to 1.20 with an expected value of 1.075. Figure 4-13 shows the multipliers used in the analysis.

Figure 4-13
Combined Cycle Plant Capital Cost Multiplier

[4] Spring 2016 National Carbon Dioxide Price Forecast, Synapse Energy Economics, Inc.

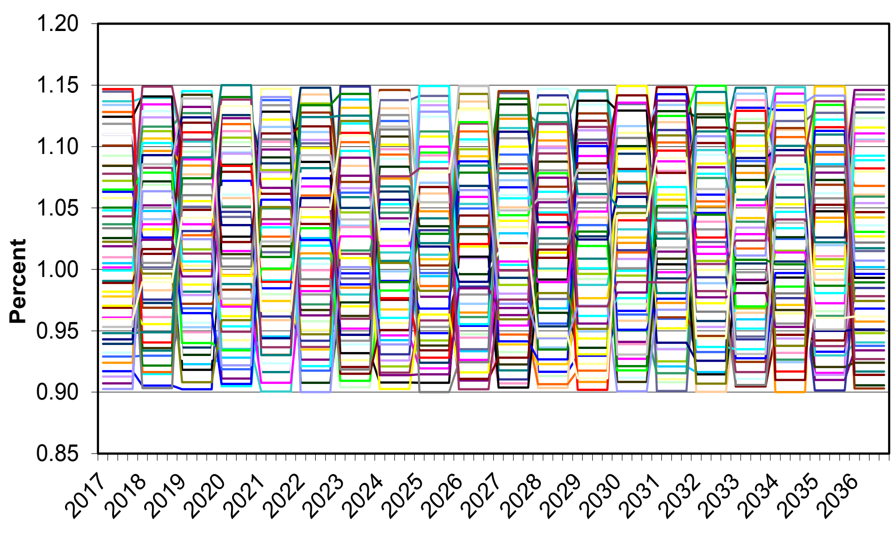


(Source: ABB Advisors)

Wind Capital Cost

Wind plant capital cost is a constant variance variable with a uniform distribution. Technology advances, tax breaks and subsidies have allowed the cost of production to vary in cycles; therefore, capital costs are expected to be higher and lower than the base estimate. It was assumed that the multipliers for capital cost will range from .90 to 1.15 with an expected value of 1.025. Figure 4-14 shows the multipliers used in the analysis.

Figure 4-14
Wind Plant Capital Cost Multiplier

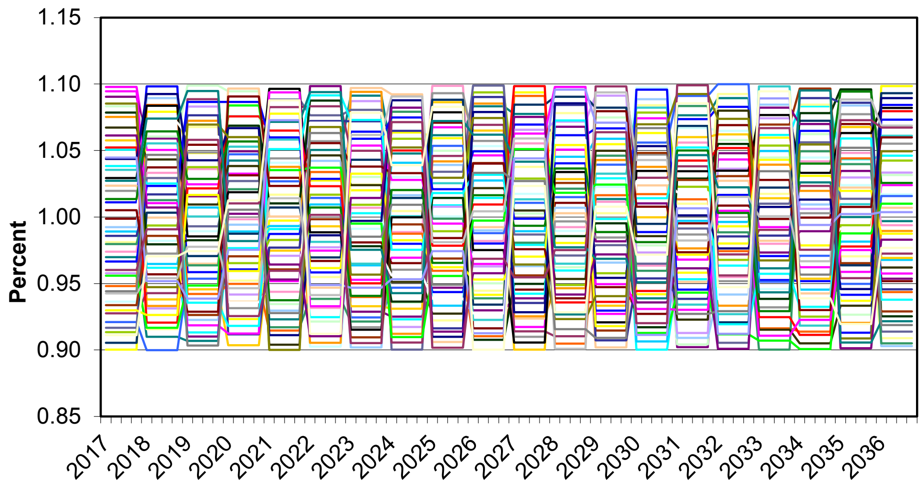


(Source: ABB Advisors)

Energy Storage (Battery) Capital Cost

Peaker Replacement Battery capital cost is a constant variance variable with a uniform distribution. Technology advances are projected to reduce capital costs over time. It was assumed that the multipliers for capital cost will range from .90 to 1.1 with an expected value of 1.0. Figure 4-15 shows the multipliers used in the analysis.

Figure 4-15
Energy Storage (Battery) Capital Cost Multiplier

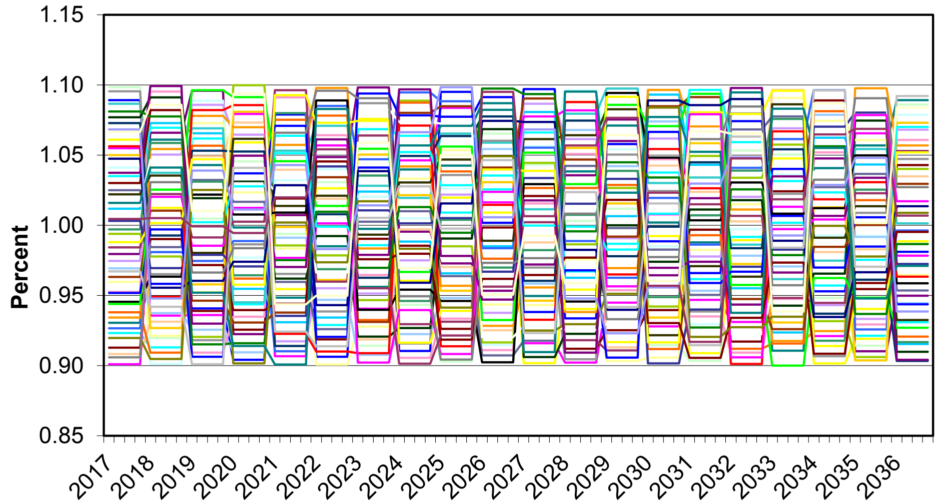


(Source: ABB Advisors)

Utility Solar Capital Cost (>5MW)

Utility Scale Solar plant capital cost is a constant variance variable with a uniform distribution. Like wind, technology advances, tax breaks and subsidies have allowed the cost of production to vary in cycles. In addition, these advances are projected to reduce capital costs over time. It was assumed that the multipliers for capital cost will range from 0.90 to 1.1 with an expected value of 1.0. Figure 4-16 shows the multipliers used in the analysis.

Figure 4-16
Utility Solar Plant Capital Cost Multiplier

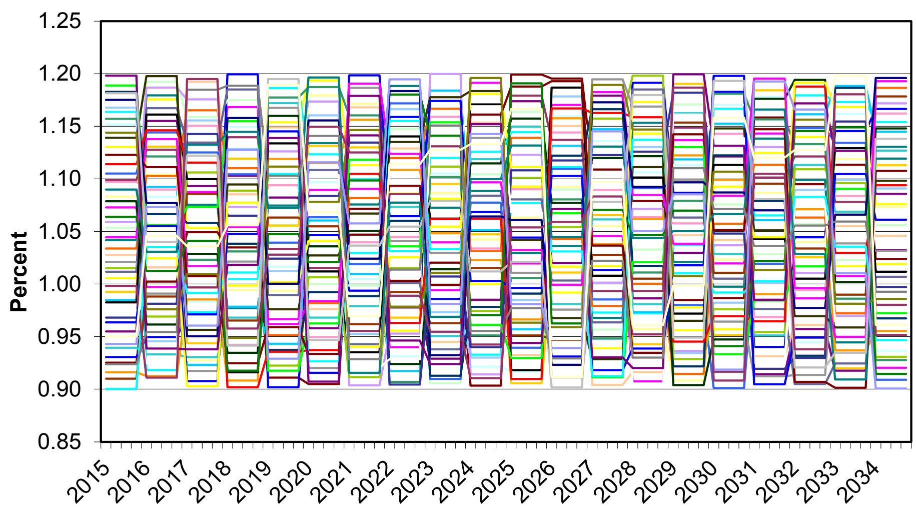


(Source: ABB Advisors)

Community Solar Capital Cost

Like Utility Scale Solar, Community Solar plant capital cost is a constant variance variable with a uniform distribution. Also like wind, technology advances, tax breaks and subsidies have allowed the cost of production to vary in cycles. In addition, these advances are projected to reduce capital costs over time. It was assumed that the multipliers for capital cost will range from .90 to 1.2 with an expected value of 1.05. Figure 4-17 shows the multipliers used in the analysis.

Figure 4-17
Community Solar Plant Capital Cost Multiplier (1MW)



(Source: ABB Advisors)

Summary for Uncertainty Variables

The following chart is a summary of the uncertainty variables and their range multipliers. IPL developed the multipliers for the capital cost uncertainties.

Table 4-3
Uncertainty Variable Range Multipliers

Uncertainty	Uncertainty Range Multiplier
Long-term Demand	.89 - 1.15
Long-term Oil	.69 - 1.46
Long-term Gas	.61 - 1.41
Long-term Coal	.69 - 1.52
Mid-term Peak	.6 - 1.39
Mid-term Energy	.67 - 1.33
Mid-term Gas	.60 - 1.75
Coal Unit Availability	.89 - 1.11
CO2 Price	1.05 - 3.4
Combined Cycle Capital Costs	.95 - 1.2
Wind Capital Costs	.9 - 1.15
Solar Capital Costs	.9 - 1.1
Community Solar Capital Costs	.9- 1.2
Battery Capital Costs	.9- 1.1

5 MARKET PRICE RESULTS

Stochastic Market Price Formation

ABB used a fundamentals-based approach to calibrate unit performance, market prices, and power flows. Based on its proprietary Integrated Model, ABB simulated the operation of each generating unit in Eastern Interconnect. The Integrated Model is a sophisticated state-of-the-art, multi-area, chronological production/market simulation model. Each Integrated Model simulation includes pro forma financials, providing users with a complete enterprise-wide solution.

For each region, the Integrated Model considered:

- Individual generating unit characteristics including heat rates, variable O&M, fixed O&M, and other technical characteristics;
- Transmission line interconnections, ratings, and wheeling rates;
- Resource additions and retirements;
- Nuclear unit outages and refuelings;
- Hourly loads for each utility or load serving entity in the region; and
- The cost of fuels that supply the plants.

The Integrated Model simulated the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The model is based on a zonal approach where market areas (zones) are delineated by critical transmission constraints. The simulation is based on a mathematical function that performs economic power exchanges across zones until all eligible economic exchanges have been made.

ABB's calibration methodology was to:

- Benchmark the model against observed prime mover output within the market zones;
- Benchmark the model against observed market prices; and
- Benchmark the model against observed power flows.

Bidding Behavior

To capture the unique bidding behavior of the energy market, the Integrated Model utilizes a dynamic bid adder algorithm that considers supply/demand conditions and technology type when submitting a bid. In replicating the actual bidding behavior, ABB captured three key elements:

- **Incremental Cost.** Includes fuel price, heat rate, and variable O&M. Under rational bidding, the incremental cost serves as a generator's minimum bid

- **Quasi-Rents Component.** Rent component added to the incremental cost to recover start-up costs, minimum-run costs, and a portion of fixed operating costs and financial expense.

- **Scarcity-Rents Component.** Rent component added to the incremental cost and quasi-rent. As demand increases, there are fewer alternative sources of generation, providing the higher cost generators an opportunity to bid above their variable cost.

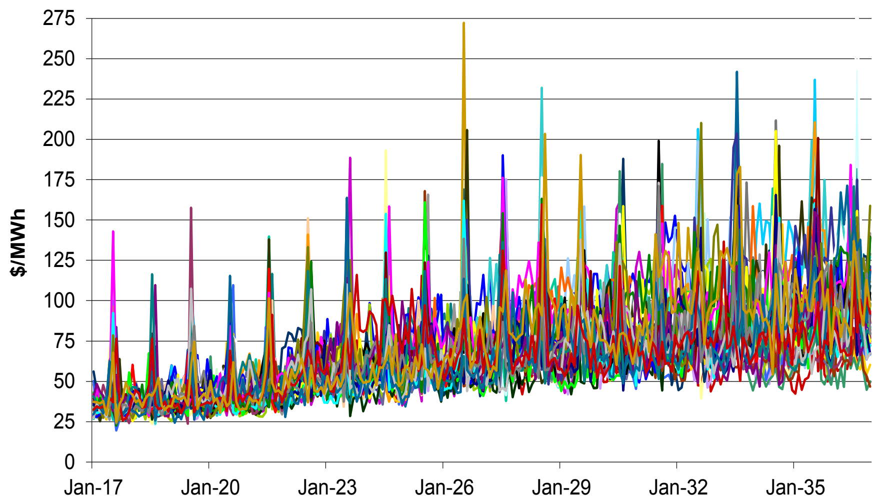
Stochastic Results

ABB's reference case database was combined with a set of 50 uncertainties that explicitly consider uncertainty in demand, fuel prices, supply, and emissions. These uncertainties were created with ABB's Smart Monte Carlo sampling program. The resulting fifty future scenarios were used by the Integrated Model to derive the multi-region, hourly market prices.

Monthly Results

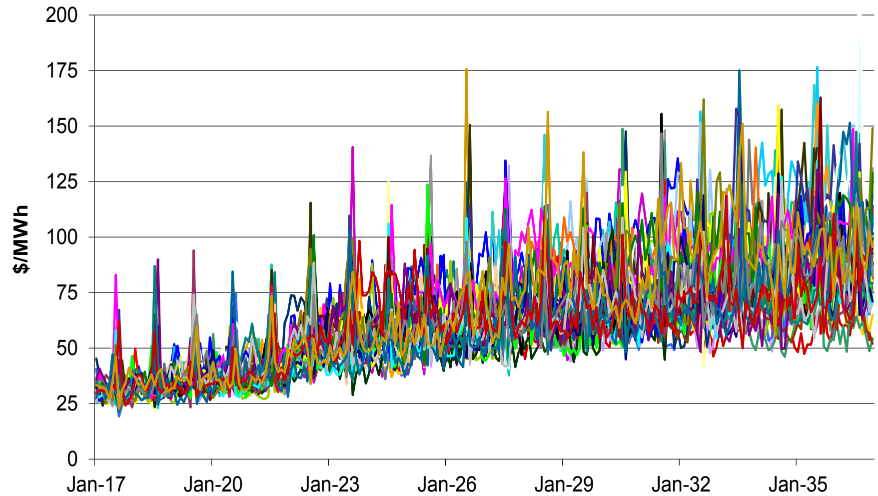
On-Peak and Average prices for the MISO-IN region are shown in Confidential Figure 5- and Confidential Figure 5-. These figures show the results for the 50 sets of stochastic draws.

Figure 5-4
MISO-IN On-Peak Stochastic Results



(Source: ABB Advisors)

Figure 5-5
MISO-IN Monthly Average Stochastic Results (7X24))



(Source: ABB Advisors)

6 SCENARIOS

The following resources were used in the Capacity Expansion Modeling. Unit characteristics were a combination of the Fall 2015 Reference Case and IPL sources. Capacities were modified for the combined cycle, nuclear unit and wind to represent partial unit ownership or a PPA option.

Table 6-1 - Confidential
Resources for Capacity Expansion Modeling (2015$)

To produce optimal resource plans, ABB and IPL identified six future scenarios which were built in the Capacity Expansion module to develop a portfolio for each scenario. The Initial Base Scenario had 2,500 MW of Wind without any constraints. IPL consulted its transmission planners to discuss potential issues with meeting voltage stability requirements to comply with NERC reliability standards. The planners recommended a minimum level of ~1200 MW natural gas fired generation on the IPL 138 kV transmission system to meet these requirements. The IRP team reviewed its minimum loading and developed a 1000 MW wind limit to align with min loads. In addition, the team suggested a limit of 250 MW per year based on procurement and construction constraints. The seven future scenarios screened by capacity expansion include the following:

1. Initial Base Scenario
   - Reference Case Gas, Market and Emission Prices for CO_2 Tax scenario
   - Base load forecast
   - Environmental Upgrade Pete 1-4 for NAAQS-SO_2 and CCR by 2018
   - Low cost of future environmental regulations for Pete 1-4
   - Retire HS GT 1&2 12/2023 and replace with small batteries to be used for blackstart
   - Retire HS 5&6 in 3/2031
   - Retire Pete 1 in 12/2032
   - Retire HS7 in 12/2033
   - Retire Pete 2 12/2034

2. Final Base Scenario
   - Same assumptions as Initial Base Scenario
   - Limit of 1000 MW of Wind for study period and 250 MW Year
   - Minimum ~1200 MW level of natural gas fired generation

3. Robust Economy Scenario
   - Reference Case High Gas Prices correlated with Market Prices and CO_2 Tax
   - High Load Forecast
   - Same retirements as in Initial Base Scenario

4. Recession Economy Scenario
   - Reference Case Low Gas Prices correlated with Market Prices and CO_2 Tax
   - Low Load Forecast
   -
   - Same retirements as in Initial Base Scenario

5. Strengthened Environmental Rules Scenario
   - Gas and Market Prices correlated with ICF Federal Legislation CO_2 Tax
   - Base Load Forecast
   -
   - High cost of future environmental regulations for Pete 1-4

6. High Customer Adoption of Distributed Generation Scenario

- Same assumptions as Initial Base Scenario
- Added 10 MW of Wind, 65 MW Community Solar and 75 MW CHP in each of the three years: 2022, 2025 & 2032

7. Quick Transition Scenario

- Reference Case Gas, Market and Emission Prices for CO_2 Tax scenario
- Base load forecast
- Upgrade Pete 1-4 in 2018
- Retire Pete 1 and Refuel Pete 2-4 in 2022
- Low cost of future environmental regulations for Pete 1-4
- Retire HS GT 1&2 12/2023
- Retire Pete 2-4, HS GT 4&5, HS 5&6, HS IC1, Pete IC 1-3 12/2029
- Adopt Maximum Achievable DSM

Table 6-2 below summarizes the optimal resource expansion plans developed by the Capacity Expansion module when simulated in Mixed Integer Linear Programming mode (MILP).

Table 6-2
Capacity Expansion Results

YEAR	Base Case	Robust Economy	Recession Economy	Strengthened Environmental Rules	High Customer Adoption of Distributed Generation	Quick Transition
2017	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW	DSM*- 58 MW
2018	DSM - 17 MW	DSM - 22 MW	**Refuel Pete 1 - 4** DSM - 22 MW	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG** DSM - 22 MW	DSM - 17 MW	DSM - 28 MW
2019	DSM - 16 MW	DSM - 17 MW	DSM - 17 MW	DSM - 17 MW	DSM - 16 MW	DSM - 59 MW
2020	DSM - 12 MW	DSM - 12 MW	DSM - 12 MW	DSM - 12 MW Wind 500 MW PV 280 MW	DSM - 12 MW	DSM - 47 MW
2021	DSM - 15 MW	DSM - 10 MW	DSM - 10 MW	DSM - 10 MW	DSM - 15 MW	DSM - 52 MW
2022	DSM - 10 MW	DSM - 11 MW	DSM - 10 MW	DSM - 11 MW Wind 100 MW PV 50 MW	DSM - 10 MW PV 65 MW Wind 10 MW CHP 75 MW	**Retire Pete 1 (-234 MW) Coal, Refuel Pete 2-3&4 (1495 MW) to NG** DSM - 19 MW
2023	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 11 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 11 MW PV 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 10 MW	**Retire HS GT 1&2 (-32 MW) Oil** DSM - 18 MW
2024	DSM -11 MW	DSM -12 MW	DSM -11 MW	DSM -12 MW PV 10 MW	DSM -11 MW	DSM -16 MW
2025	DSM - 10 MW	DSM - 11 MW	DSM - 10 MW	DSM - 11 MW	DSM - 10 MW PV 65 MW Wind 10 MW CHP 75 MW	DSM - 18 MW
2026	DSM - 9 MW	DSM - 10 MW	DSM - 9 MW	DSM - 10 MW PV 10 MW	DSM - 9 MW	DSM - 18 MW

2027	DSM - 4 MW	DSM - 5 MW	DSM - 4 MW	DSM - 5 MW PV 10 MW	DSM - 4 MW	DSM - 13 MW
2028	DSM - 4 MW	DSM - 5 MW	DSM - 4 MW	DSM - 5 MW PV 10 MW	DSM - 4 MW	DSM - 13 MW
2029	DSM - 1 MW	DSM - 1 MW	DSM - 1 MW	DSM - 1 MW PV 10 MW	DSM - 1 MW	DSM - 10 MW
2030	**Retire HS 5&6 (-200MW) NG** DSM - 2 MW	**Retire HS 5&6 (-200MW) NG** DSM - 3 MW Wind 500 MW	**Retire HS 5&6 (-200MW) NG** DSM - 2 MW	**Retire HS 5&6 (-200MW) NG** DSM - 3 MW Wind 500 MW	**Retire HS 5&6 (-200MW) NG** DSM - 2 MW	**Retire Pete 2-4 (-1495 MW) NG, HS GT4-6 (294 MW) NG, HS 5&6 (-200 MW) NG, HS IC1 (3 MW) Oil, Pete IC1-3 (8 MW) Oil** DSM - 12 MW Wind - 6000 MW Solar - 1146 MW Battery - 600 MW
2031	DSM - 3 MW	DSM - 3 MW Wind 500 MW Market 200 MW	DSM - 3 MW	DSM - 3 MW Wind 500 MW	DSM - 3 MW	DSM - 13 MW
2032	**Retire Pete 1 (-234 MW) Coal** DSM - 9 MW	**Retire Pete 1 (-234 MW) Coal** DSM - 10 MW Wind 500 MW PV 370 MW	**Retire Pete 1 (-234 MW) Coal** DSM - 9 MW	DSM - 10 MW Wind 500 MW	**Retire Pete 1 (-234 MW) Coal** DSM - 9 MW PV 65 MW Wind 510 MW CHP 75 MW	DSM - 18 MW
2033	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 250 MW Market 50 MW PV 90 MW Battery 100 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 500 MW PV 440 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 500 MW	**Retire HS7 (-428 MW) NG** DSM - 9 MW Wind 500 MW	**Retire HS7 (-428 MW) NG** DSM - 16 MW
2034	**Retire Pete 2 (-417 MW) Coal** DSM - 2 MW H-Class CC 450 MW Wind 250 MW	**Retire Pete 2 (-417 MW) Coal** DSM - 3 MW H-Class CC 450 MW Wind 500 MW	**Retire Pete 2 (-417 MW) NG** DSM - 2 MW H-Class CC 450 MW	**Retire Pete 2 (-417 MW) NG** DSM - 3 MW H-Class CC 450 MW Wind 500 MW	**Retire Pete 2 (-417 MW) Coal** DSM - 2 MW H-Class CC 450 MW Wind 500 MW	DSM - 9 MW H-Class CC 450 MW
2035	DSM - 2 MW Wind 250 MW Battery 250 MW Market 150 MW	DSM - 3 MW Wind 500 MW PV 190 MW Battery 250 MW Market 50 MW Comm Solar 1 MW	DSM - 2 MW H Class CC 200 MW	DSM - 3 MW Wind 500 MW PV 70 MW Market 50 MW	DSM - 2 MW Wind 500 MW Battery 50 MW Market 50 MW	DSM - 11 MW
2036	DSM - 2 MW Wind 250 MW Battery 150 MW PV 10 MW	DSM - 3 MW Wind 500 MW Battery 50 MW Comm Solar 5 MW	DSM - 2 MW	DSM - 3 MW Wind 500 MW PV 60 MW	DSM - 2 MW Wind 500 MW PV 60 MW Comm Solar 1 MW	DSM - 12 MW
	*DSM includes 58.1 MW of existing Demand Response					

(Source: ABB Advisors.)

The Final Base Plan and other scenarios were evaluated further using the production cost model
Strategic Planning.

7 DSM MODELING IN CAPACITY EXPANSION

Avoided Energy Costs

IPL's primary objective in performing its integrated resource plan is to find a mix of supply-side resources and demand-side management (DSM) programs that minimize the costs to customers presented in terms of the present value of revenue requirements (PVRR). The screening of DSM measures was performed by Applied Energy Group, Inc. (AEG) using avoided energy costs developed by ABB. The DSM measures that passed the AEG screening tests were input into the CEM as similar bundles of demand-side resources. CEM optimized both supply-side and demand-side resource completely enumerating all possible combinations and developing least cost integrated resource plans. This technique was used to develop the resource plans under the conditions described earlier in the Scenarios section of this report.

AEG used ABB's forward view of the demand and energy costs in the MISO-IN regional electricity market for screening. The following figure show the avoided energy costs for the CO_2 Tax Scenario. For more information on how the avoided costs were developed, please see section 2, Market Price Process.

Figure 7-1 - Confidential
Monthly On-Peak, Off-Peak and Average Avoided Energy Cost (Nominal $/MWh)

DSM Alternatives after Avoided Cost Screening

The DSM bundles that passed AEG's screening tests and were then passed on to ABB's CEM as a selectable resource are listed in Table 7-1. Some bundles were available for selection in the 2018-2020 time frame and some were available for selection in the 2021 and beyond time frame:

Table 7-1
DSM Bundles

Residential	Commercial	Direct Response
Res Other up to 30MWh 2018-2020	Bus Process up to 30MWh 2018-2020	DR Water Heating DLC
Res Other 30-60MWh 2018-2020	Bus Process 30-60MWh 2018-2020	DR Smart Thermostats
Res Lighting up to 30MWh 2018-2020	Bus Other up to 30MWh 2018-2020	DR Emerging Tech
Res HVAC up to 30MWh 2018-2020	Bus Other 60+ MWh 2018-2020	DR Curtail Agreements
Res HVAC 60+ MWh 2018-2020	Bus Other 30-60MWh 2018-2020	DR Battery Storage
Res HVAC 30-60MWh 2018-2020	Bus Lighting up to 30MWh 2018-2020	DR Air Conditioning Load Mgmt
Res Behavioral Program 2018-2020	Bus Lighting 60+ MWh 2018-2020	
Res Other up to 30MWh 2021+	Bus Lighting 30-60MWh 2018-2020	
Res Other 30-60MWh 2021+	Bus HVAC up to 30MWh 2018-2020	
Res Lighting up to 30MWh 2021+	Bus HVAC 60+ MWh 2018-2020	
Res HVAC up to 30MWh 2021+	Bus HVAC 30-60MWh 2018-20	
Res HVAC 60+ MWh 2021+	Bus Process up to 30MWh 2021+	
Res HVAC 30-60MWh 2021+	Bus Process 30-60MWh 2021+	
Res Behavioral Programs 2021+	Bus Other up to 30MWh 2021+	
	Bus Other 60+ MWh 2021+	
	Bus Other 30-60MWh 2021+	
	Bus Lighting up to 30MWh 2021+	
	Bus Lighting 60+ MWh 2021+	
	Bus Lighting 30-60MWh 2021+	
	Bus HVAC up to 30MWh 2021+	

	Bus HVAC 60+ MWh 2021+	
	Bus HVAC 30-60MWh 2021+	

The DSM bundles that were selected by the Capacity Expansion model and passed on to the portfolio evaluation for each scenario are in the following table. Note that the Quick Transition Scenario did not exclude any of the DSM bundles identified in Table 7-1 above.

Table 7-2
DSM Program by Scenario

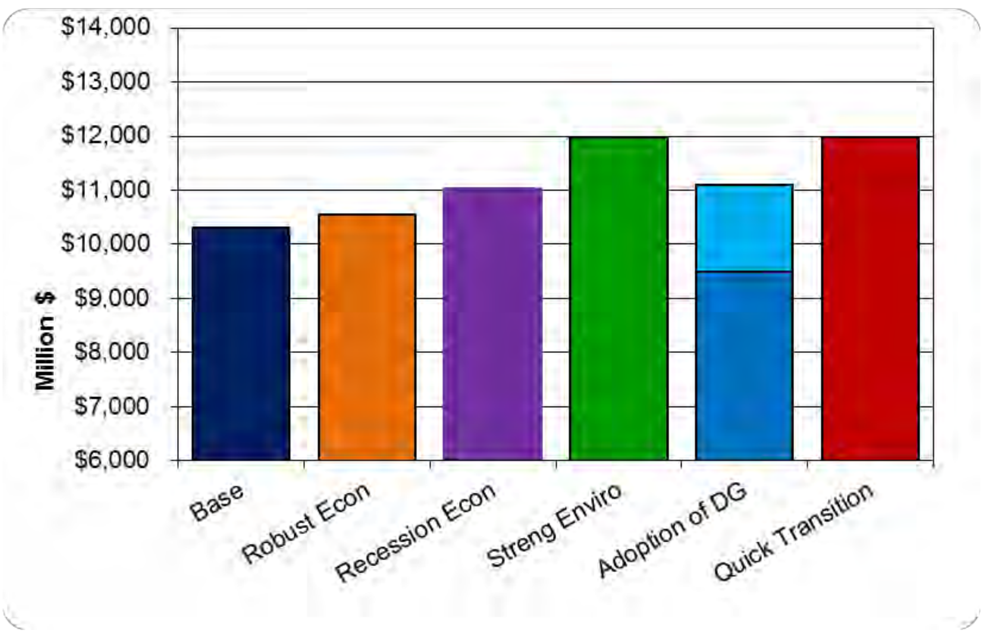
	Final Base	Robust Economy	Recession Economy	Strengthened Environmental Rules	Adoption of DG	Quick Transition
Res Other (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res Other ($30-60/MWh) - 2018-2020		✓		✓		✓
Res Lighting (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res HVAC (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res Behavioral Programs - 2018-2020		✓	✓	✓		✓
Bus Other (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Bus Lighting (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Bus HVAC (up to $30/MWh) - 2018-2020	✓	✓	✓	✓	✓	✓
Res Other (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Res Lighting (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Res HVAC (up to $30/MWh) - 2021-2036		✓		✓		✓
Res Behavioral Programs - 2021-2036	✓	✓	✓	✓	✓	✓
Bus Process (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Bus Other (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓
Bus Lighting (up to $30/MWh) - 2021-2036	✓	✓	✓	✓	✓	✓

8 DETERMINISTIC PORTFOLIO RESULTS

The following series of graphs compares the deterministic results for the six scenario, which were modeled with the Production Cost Model. IPL used several metrics to compare the portfolios, including PVRR, rate impact, and planning reserve margins. Figure 8-1 shows the PVRR for each scenario under base case assumptions. These values are in millions $: Final Base Plan $10,309.02, Robust Economy $10,549.54, Recession Economy $11,042.06, Strengthened Environmental Rules $11,989.88, Adoption of DG $11,092.05, Quick Transition $11,988.14. The Adoption of DG scenario includes estimated DG costs for 450 MW. These costs are represented in the light blue block. Customer DG costs will vary.

Table 8-1 contains the incremental average annual revenue requirements in cents/kWh for the six scenarios. These prices are for resource plan comparative purposes and do not reflect the total revenue requirements of the IPL business. These prices include the costs of all fuel, variable O&M, and emission expenses, capacity and energy purchases for retail load (net of capacity and energy sales), property taxes, state and federal income taxes, and annual some generating unit fixed costs.

Figure 8-1
Scenario PVRR (2017-2036)



(Source: ABB Advisors.)

Table 8-1
Comparative Annual Costs by Scenario

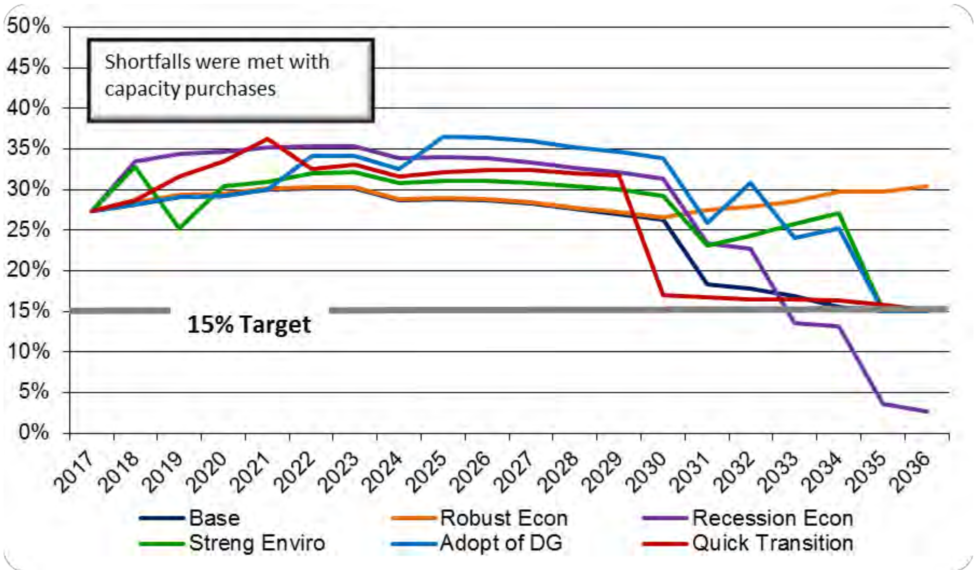
Incremental Average Annual Revenue Requirements (cents/kWh, in nominal $

Year	Final Base Plan	Robust Economy	Recession Economy	Strengthened Environmental Rules	Adoption of DG	Quick Transition
2017	0.032	0.032	0.032	0.032	0.032	0.032
2018	0.034	0.034	0.037	0.036	0.034	0.035
2019	0.036	0.036	0.040	0.045	0.036	0.038
2020	0.035	0.035	0.042	0.057	0.035	0.038
2021	0.036	0.036	0.044	0.055	0.036	0.040
2022	0.048	0.048	0.054	0.064	0.051	0.058
2023	0.051	0.051	0.057	0.066	0.055	0.060
2024	0.052	0.052	0.059	0.066	0.056	0.061
2025	0.060	0.060	0.065	0.071	0.066	0.066
2026	0.063	0.062	0.067	0.072	0.070	0.068
2027	0.064	0.064	0.069	0.073	0.070	0.070
2028	0.070	0.070	0.073	0.076	0.076	0.074
2029	0.072	0.072	0.076	0.078	0.078	0.077
2030	0.077	0.079	0.079	0.081	0.082	0.113
2031	0.081	0.086	0.083	0.089	0.086	0.122
2032	0.083	0.090	0.085	0.092	0.092	0.116
2033	0.088	0.096	0.089	0.095	0.100	0.112
2034	0.094	0.102	0.096	0.099	0.106	0.109
2035	0.102	0.107	0.104	0.106	0.113	0.108
2036	0.104	0.108	0.108	0.105	0.114	0.106

(Source: ABB Advisors.)

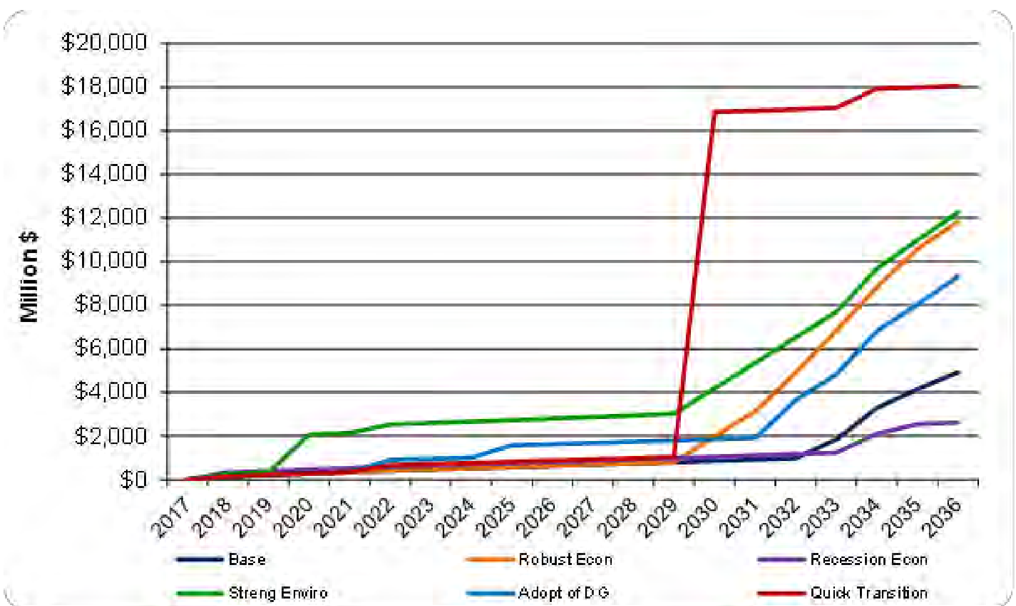
The following graphs compare the reserve margins and cumulative capital expenditures (plant in service) for all portfolios. For the reserve margin calculations, all portfolios utilize the base load assumption. Incremental plant in service includes annual capital expenditures and AFUDC closed to plant.

Figure 8-2
Reserve Margin (IPL Installed Planning Capacity)



(Source: ABB Advisors.)

Figure 8-3
Incremental Plant In-Service (in nominal $, includes DG costs, no depreciation



(Source: ABB Advisors.)

9 DETERMINISTIC PORTFOLIO RESULTS WITH END EFFECTS

End Effects

Strategic Planning (SP) is able to capture end effects. The process within SP to capture end effects consists of running the simulation beyond the study period. When conducting integrated resource planning and active evaluation of constructing base load generating facilities, it is critical to properly evaluate the cost effectiveness of resource additions by extending the planning horizon.

ABB developed a methodology that allows users to reflect an extension period where operational variables are constant and financial calculations continue.

Terms:

- Study Period: the time period over which all simulation features including resource expansion, changes in demand and retirements are measured.
- Extension Period: the time period directly after the study period over which resource expansion, changes to demand and other factors are held constant, while costs, revenues and financial treatments may change.
- End Effects: the impact on decisions made during the study period based upon the presence of costs, revenues and financial treatments occurring in the extension period.

For IPL, ABB utilized a study period of 2017-2036. To capture additional economic life of new resources added, SP simulations were for the period 2017-2046.

The end effects methodology may be explained by disaggregating the total study horizon into the study and extension period. In the study period, the model performs a full simulation of all key elements of the utility portfolio. Resource expansion (and retirement) decisions are made either explicitly or implicitly; demand may vary from year-to-year; the production system performs commitment and dispatch of resources is modeled against load, and so on.

In the extension period, SP continues with a “static” resource expansion scenario over the extension period. Costs are permitted to escalate either according to user-defined assumptions or according to “last year escalation changes” as defined below. Full commitment and dispatch of the model occurs, permitting dispatch that reflects long-run technology changes, as well as a full treatment of the financial assets. Thus, a capital project added in the last year of the simulation will receive a full treatment of capital, taxes and depreciation as well as the costs and revenues (and dispatch/commitment impact on the existing system).

The SP extension period methodology provides a strong representation of the year-to-year elements of the system to properly capture the relative benefits of resources added during the forecast horizon.

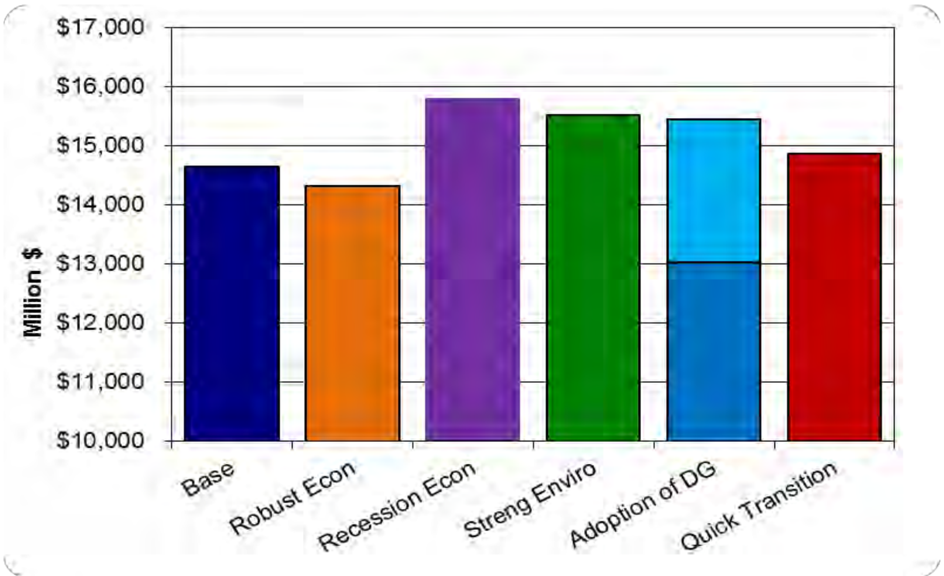
Table 9-1
Extension Period Treatment

	Study Period				Extension Period		
	Year 1	**Year 2**	**Year …**	**Year T**	**Year T+ 1**	**Year T + …**	**Year T + n**
Revenue	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Fuel Expense	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Variable O&M	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Emissions	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Total Expenses	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Capital Treatment	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Tax and Interest	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic	Dynamic
Commitment	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Dispatch	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Resource Expansion	Yes	Yes	Yes	Yes	Static	Static	Static
Retirements	Yes	Yes	Yes	Yes	Static	Static	Static
Demand Growth	Yes	Yes	Yes	Yes	Static	Static	Static
Purchases & Sales	Yes	Yes	Yes	Yes	Yes	Yes	Yes

(Source: ABB Advisors.)

Figure 9-1 shows the PVRRs for the six scenarios with end effects. Again, the Adoption of DG scenario includes estimated DG costs for 450 MW. These costs are represented in the light blue block. Customer DG costs will vary.

Figure 9-1
Scenario PVRRs with End Effects (2017-2046)



(Source: ABB Advisors.)

10 RISK ANALYSIS

Introduction

ABB utilized the Strategic Planning Risk Module to develop cumulative probability distributions which are also known as Risk Profiles.

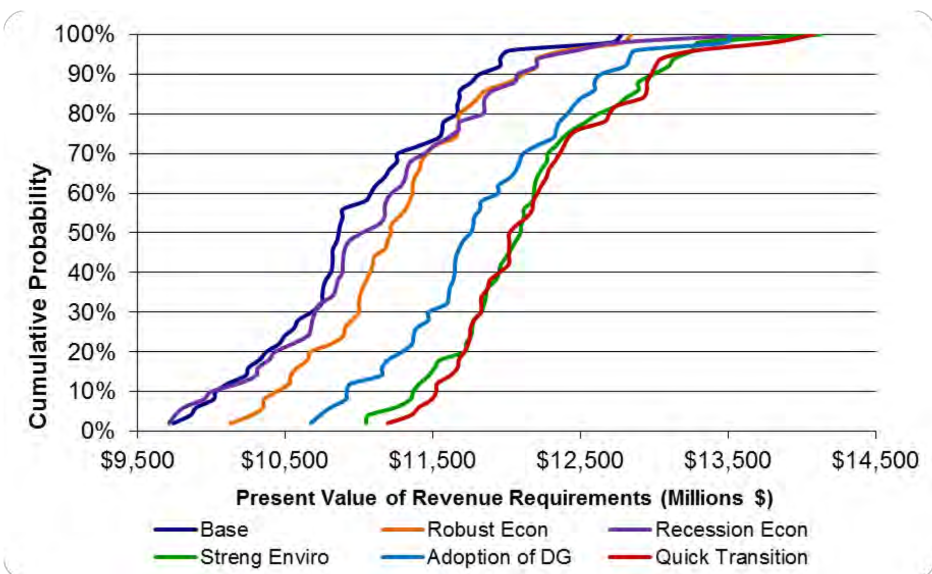
Risk Profiles

Risk Profiles provide the ability to visually assess the risks associated with a decision under uncertainty. The x-axis (Present Value of Revenue Requirements in millions $) shows the range of possible outcomes from the fifty stochastic draws. The y-axis is the cumulative probability of the occurrence of each outcome between 0% and 100%. For example, if the far left point is $9,745 mil and the far right point is $12,777 mil, then there is 100% confidence that the PVRR will be between those two points. The more narrow the range, the less the risk. For this study, ABB used its Integrated Model to develop a set of 50 stochastic prices using ABB's Smart Monte Carlo sampling program. These prices explicitly consider uncertainty in demand, fuel prices, supply, and emissions.

One can view the risk profile to determine the probability that the PVRR will be a particular value. Using the Final Base Plan as an example in the figure below, there is an 80% probability that PVRR could be as much as $11,682 million with an expected value of $11,005 million. From the prior deterministic simulation, the PVRR value was $10,309 million under "base case" conditions. The $696 million difference between the expected value and the deterministic value is "real option value" or extrinsic value. This reflects the risk of the Preferred Plan with future uncertainty.

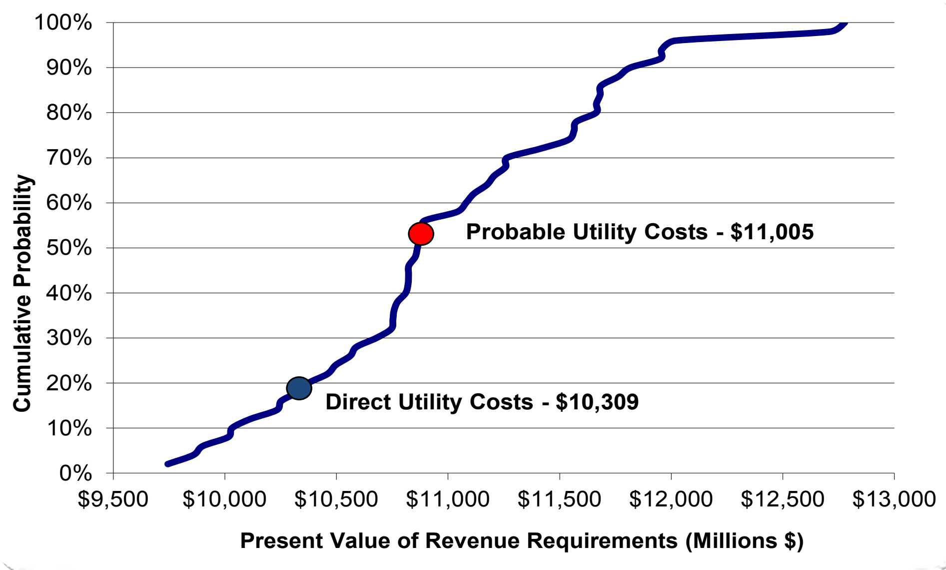
The risk profiles are labeled with two points. The "Direct Utility Cost" (Deterministic) point is the base case, and the "Probable Utility Cost" (Stochastic or Expected Value) point is the average of all 50 uncertain outcomes.

Figure 10-1
All Scenarios - Risk Profiles (2017-2036)



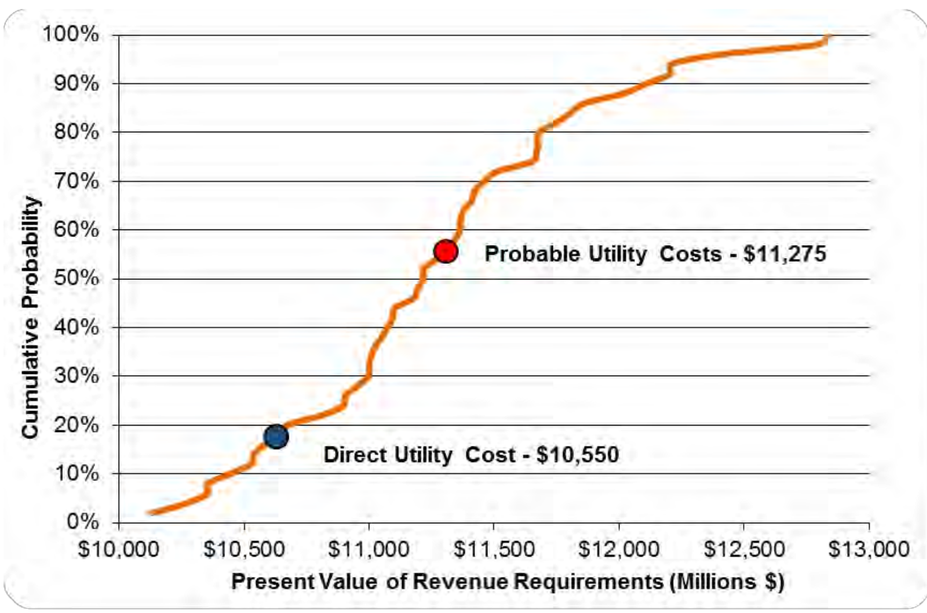
(Source: ABB Advisors.)

Figure 10-2
Base Plan - Risk Profile (2017-2036)



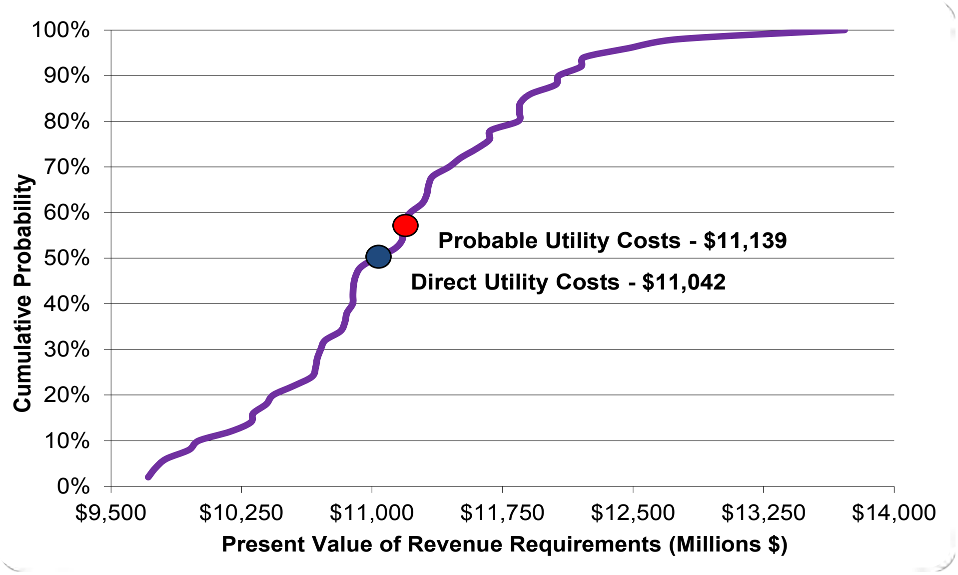
(Source: ABB Advisors.)

Figure 10-3
Robust Economy - Risk Profile (2017-2036)



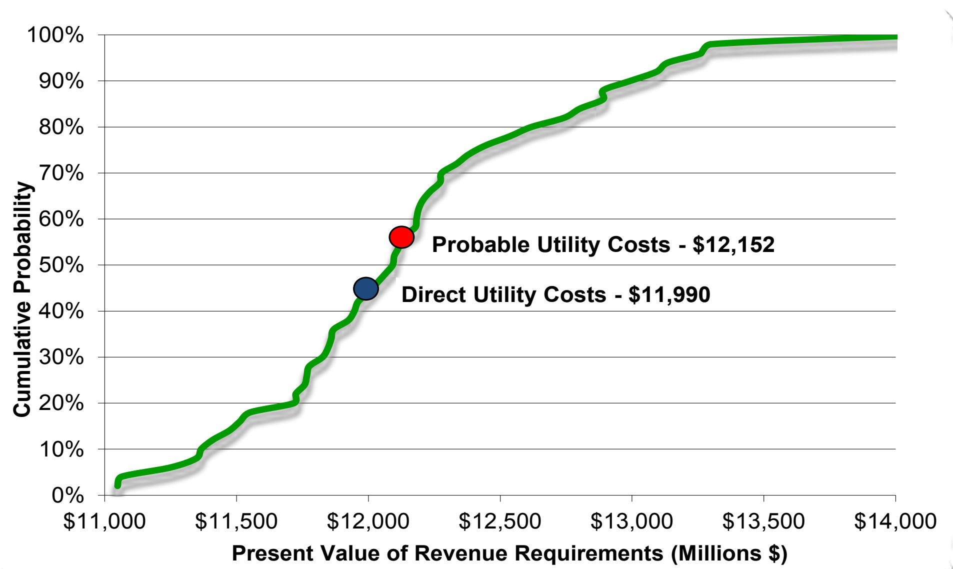
(Source: ABB Advisors.)

Figure 10-4
Recession Economy - Risk Profile (2017-2036)



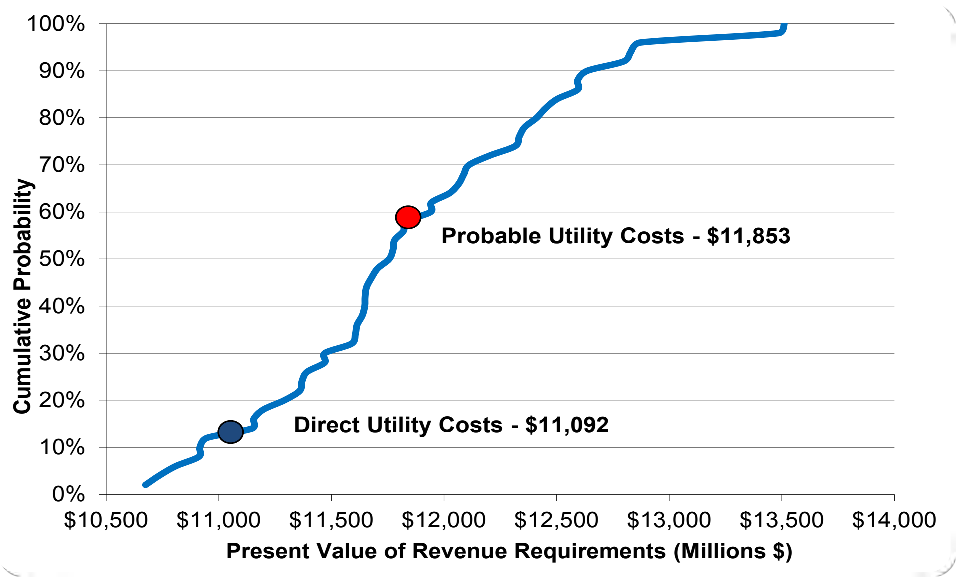
(Source: ABB Advisors.)

Figure 10-5
Strengthened Environmental - Risk Profile (2017-2036)



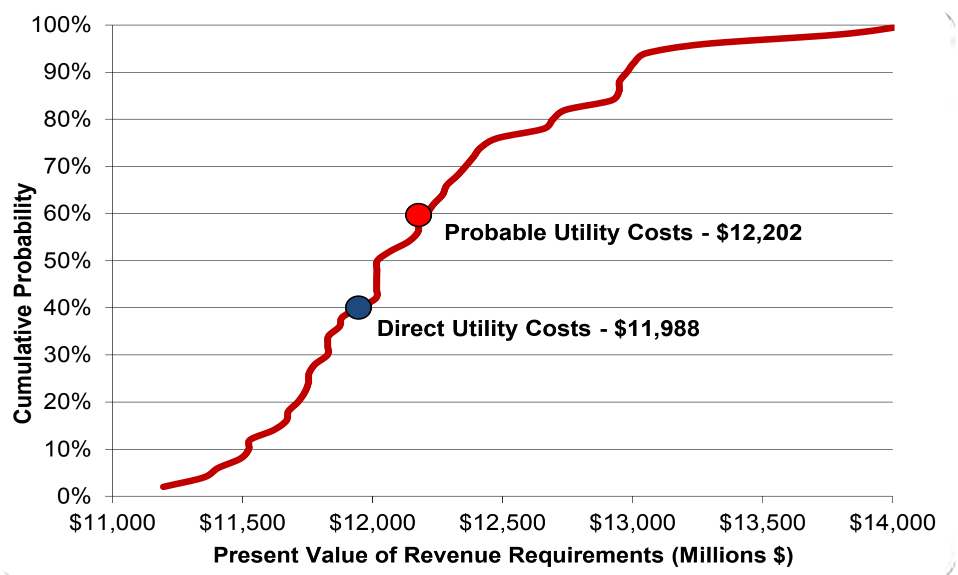
(Source: ABB Advisors.)

Figure 10-6
Adoption of DG - Risk Profile (2017-2036)



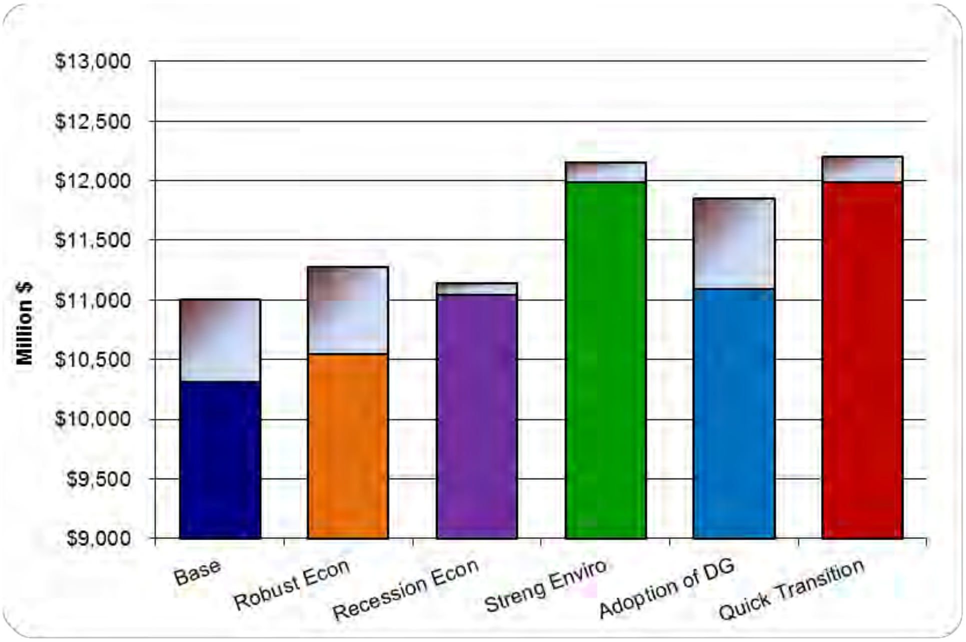
(Source: ABB Advisors.)

Figure 10-7
Quick Transition - Risk Profile (2017-2036)



(Source: ABB Advisors.)

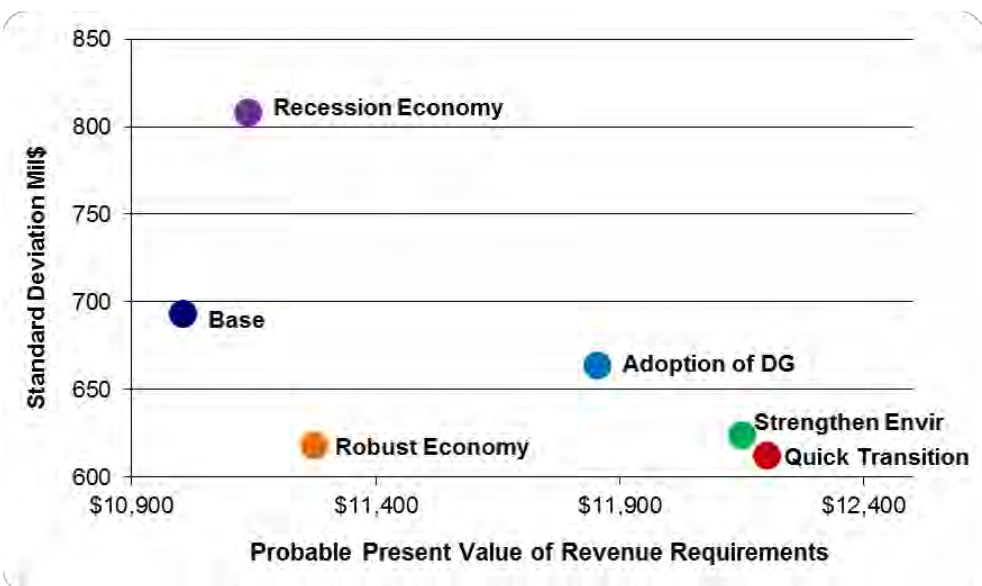
Figure 10-8
All Scenarios - PVRR with Risk Value (2017-2036)



(Source: ABB Advisors.)

The following trade-off diagram is another way to compare the six plans. The trade-off diagram plots the PVRRs on the x-axis and the standard deviation on the y-axis. The plan closest to the lower left quadrant would be the preferred plan because both PVRR and the standard deviation are both minimized.

Figure 10-9
All Scenarios - Trade-Off Diagram



(Source: ABB Advisors.)

11 BASE SENSITIVITY ANALYSIS

CO_2 Sensitivities

Two carbon sensitivities were modeled around the base case.

Case 1 – "Delayed CPP" - Timing of Clean Power Plan

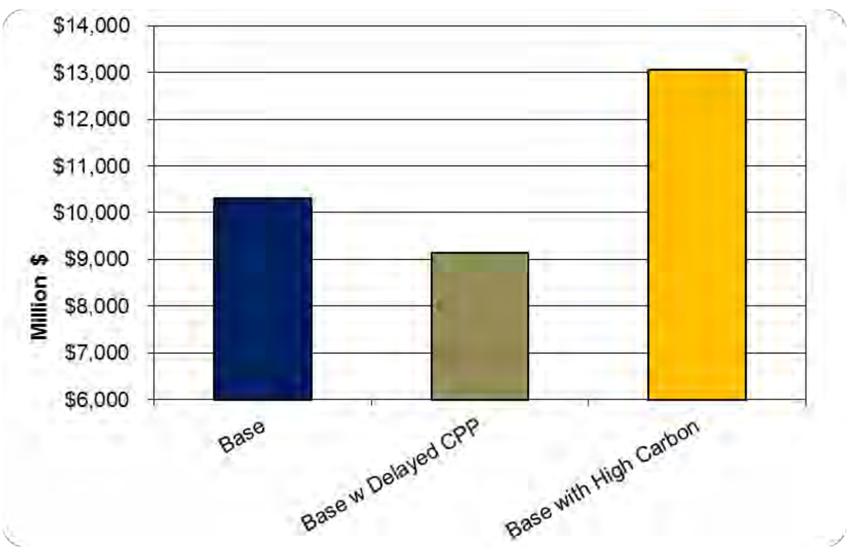
- Same modeling assumption as base plan with CPP starting in 2030 instead of 2022

Case 2 –"ICF Carbon" - More Stringent Clean Power Plan

- Same modeling assumption as base plan except used ICF's Federal Legislation carbon price and market prices.

The following graph compares the results for the 2 cases against the Final Base Plan. Figure 11-1 shows the PVRR for each plan for the base scenario. These values are in millions $: Final Base Plan $10,309.02, Case 1 $9,129.93, Case 2 $13,054.86.

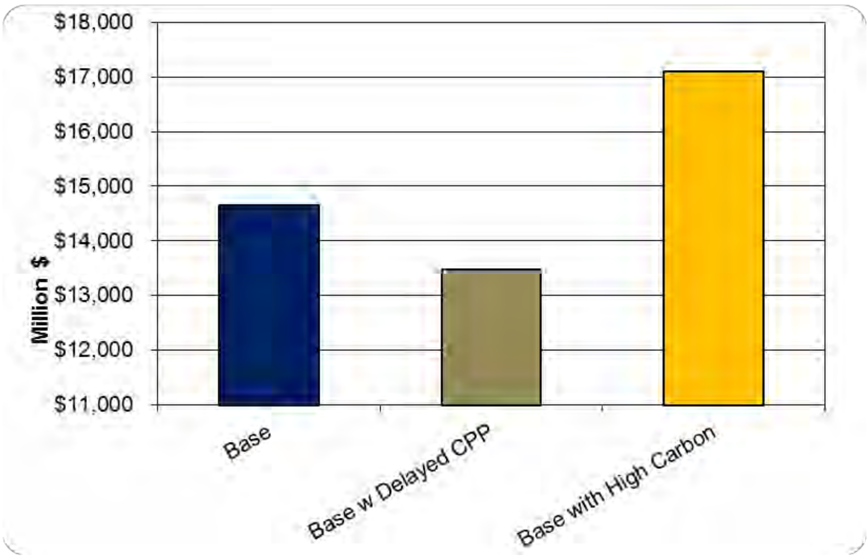
Figure 11-1
PVRR Case Ranking for the Base Case Scenario (2017-2036)



(Source: ABB Advisors.)

Figure 12-2 contains the PVRR for each plan for the base scenario with end effects. These values are in millions $: Final Base Plan $14,651.63, Case 1 $13,472.54, Case 2 $17,089.33.

Figure 11-2
PVRR Case Ranking for the Base Case Scenario (2017-2046)



(Source: ABB Advisors.)

12 SENSITIVITY

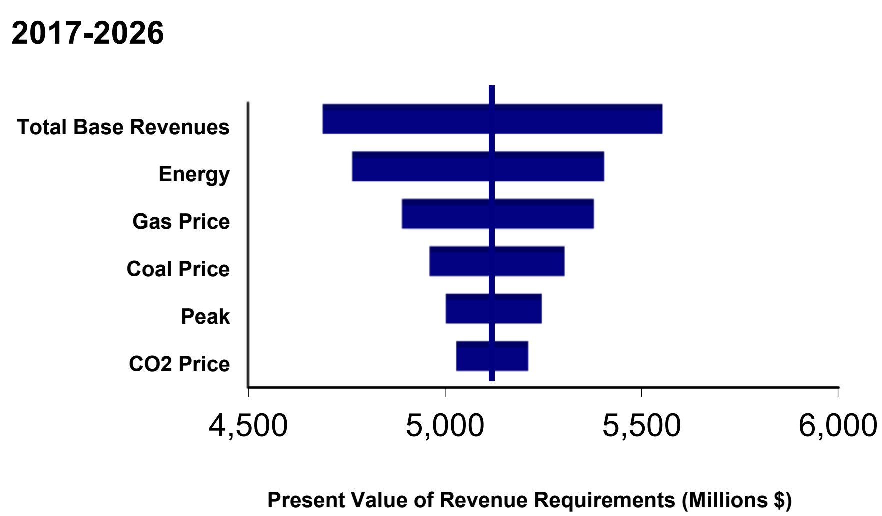
Tornado Charts

Tornado Charts provide information on the driving factors that influence PVRR and can also provide insight into where a risk aversion strategy could be focused to drive PVRR to lower levels or mitigate risk. The Total Base Revenue bar is the dependent variable and the remaining drivers are independent variables. The expected value is represented by the vertical line. When the independent bars are off-set to the left it means that the variable puts downward pressure on the PVRR (lower revenue requirements). If the independent bars are off-set to the right, then the variables put upward pressure on the PVRR (higher revenue requirements).

The tornado charts were developed in 10-year blocks for the stochastic results. There are not any substantial changes for the system in the first ten years. In the last ten years, the CO2 tax begins to have a larger impact on the unit dispatch and there are multiple unit additions and retirements.

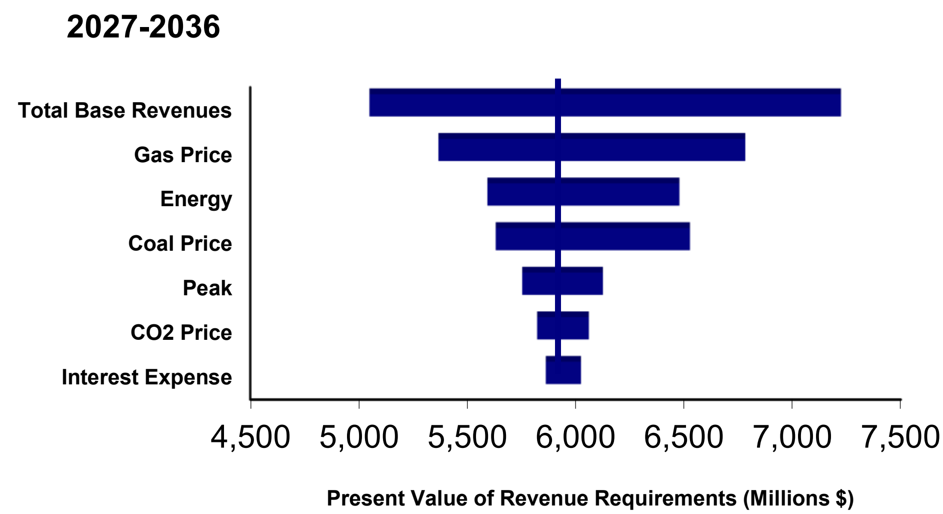
For all of the scenarios in the first ten years, their Tornado Charts indicate that the major driver of PVRR uncertainty is either gas price or energy. Again, for all the scenarios in the last ten years, their Tornado Charts indicate the major driver of PVRR uncertainty is either gas price or energy. The second major driver varies by scenario. For example, for the Quick Transition scenario, interest expense is the second major driver because of the very large capital expenditures in 2030.

Figure 12-1
Final Base Plan - Tornado Chart (2017-2026)



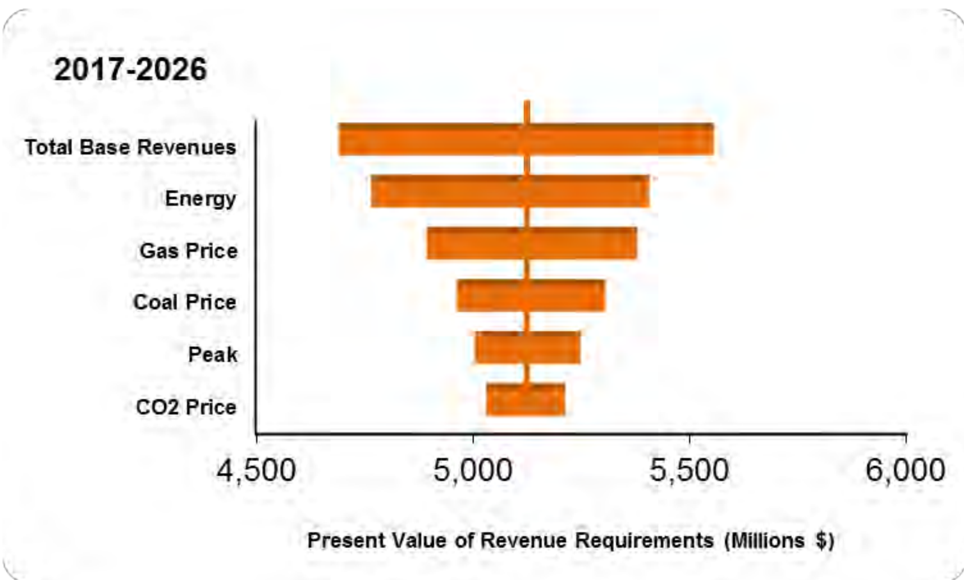
(Source: ABB Advisors.)

Figure 12-2
Final Base Plan - Tornado Chart (2027-2036)



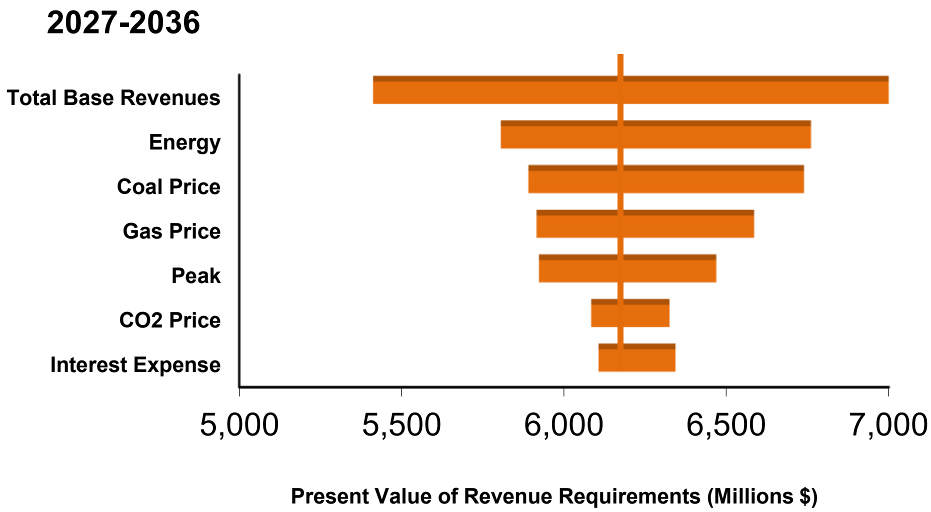
(Source: ABB Advisors.)

Figure 12-3
Robust Economy - Tornado Chart (2017-2026)



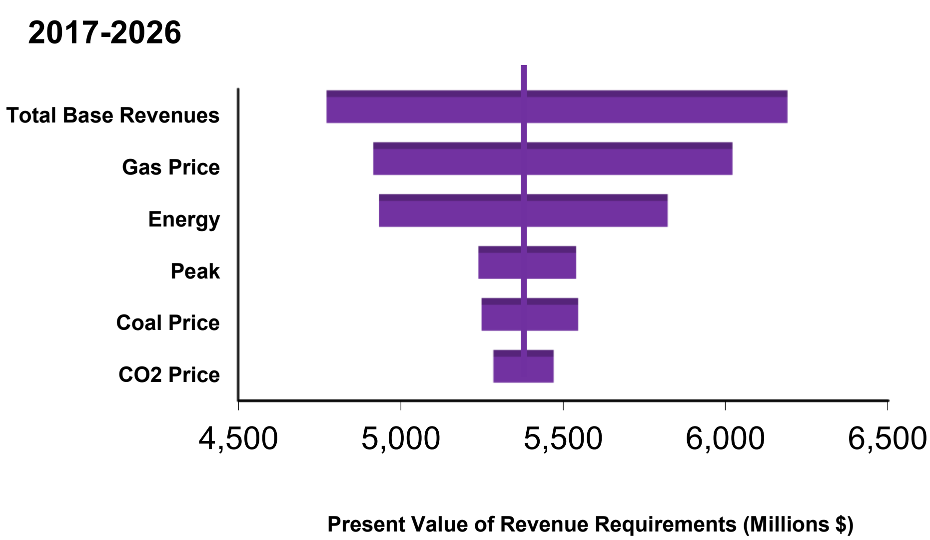
(Source: ABB Advisors.)

Figure 12-4
Robust Economy - Tornado Chart (2027-2036)



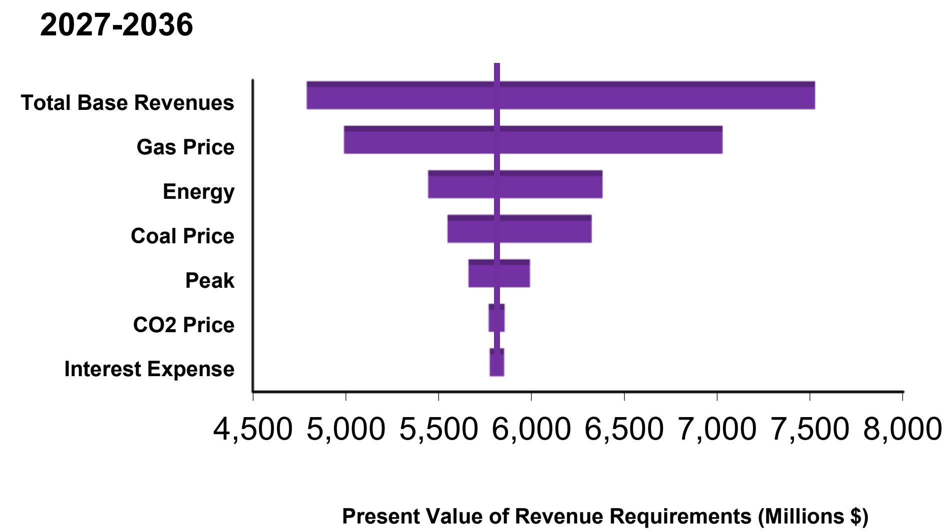
(Source: ABB Advisors.)

Figure 12-5
Recession Economy - Tornado Chart (2017-2026)



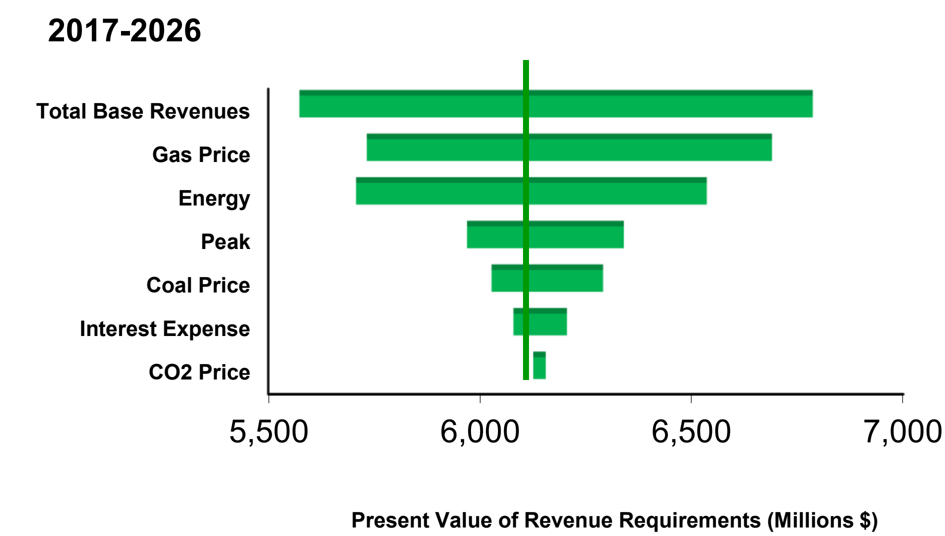
(Source: ABB Advisors.)

Figure 12-6
Recession Economy - Tornado Chart (2027-2036)



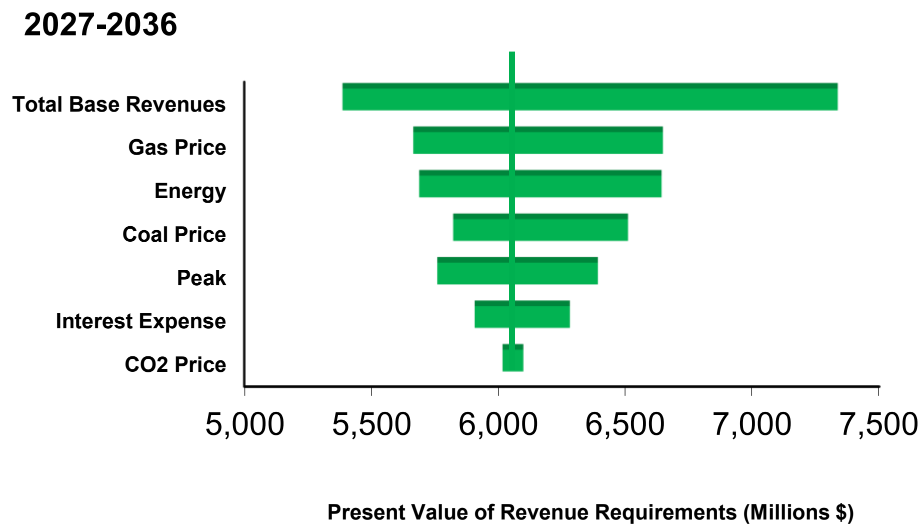
(Source: ABB Advisors.)

Figure 12-7
Strengthened Environmental - Tornado Chart (2017-2026)



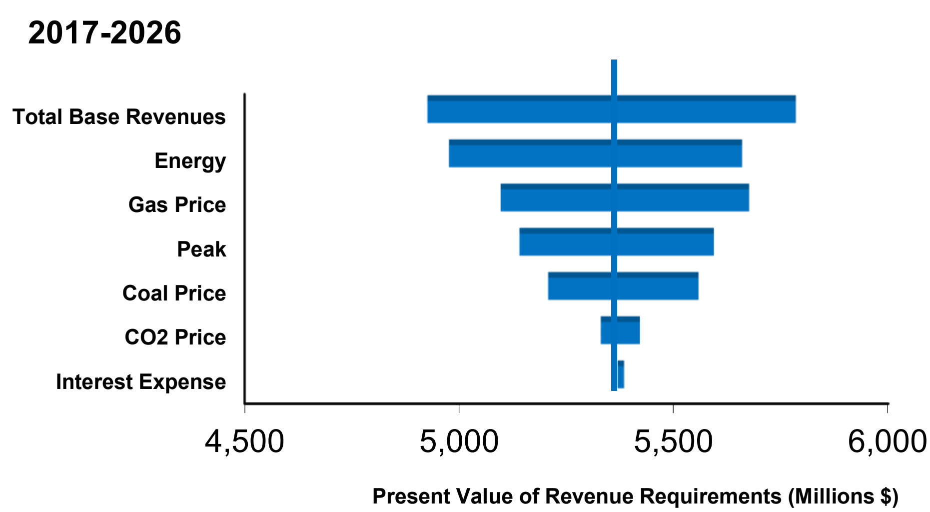
(Source: ABB Advisors.)

Figure 12-8
Strengthened Environmental - Tornado Chart (2027-2036)



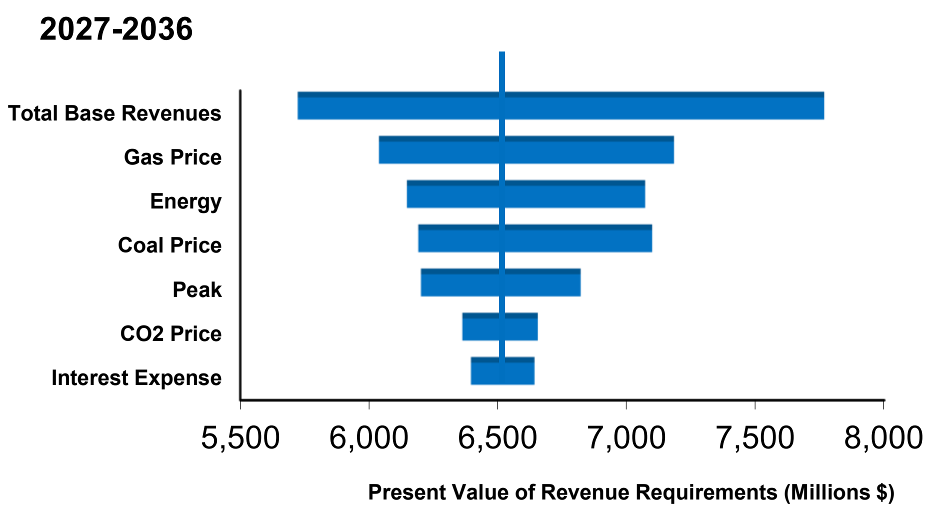
(Source: ABB Advisors.)

Figure 12-9
Adoption of DG - Tornado Chart (2017-2026)



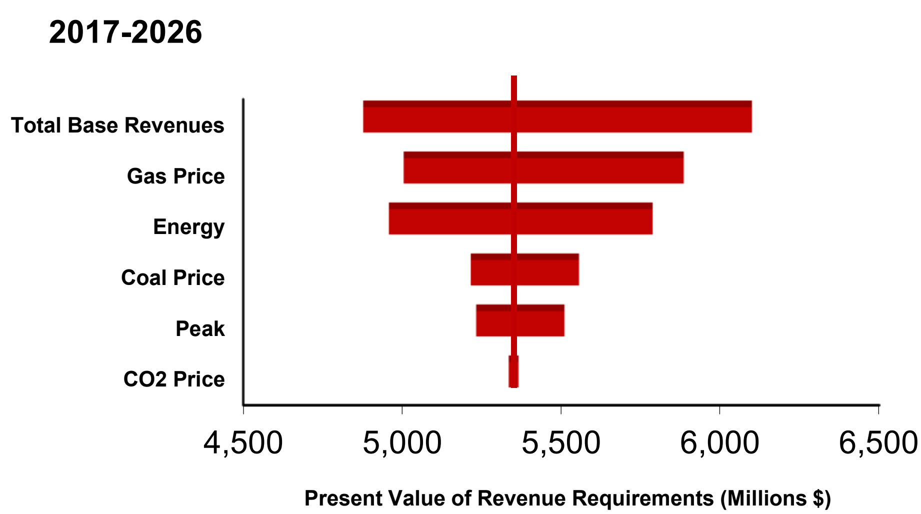
(Source: ABB Advisors.)

Figure 12-10
Adoption of DG - Tornado Chart (2027-2036)



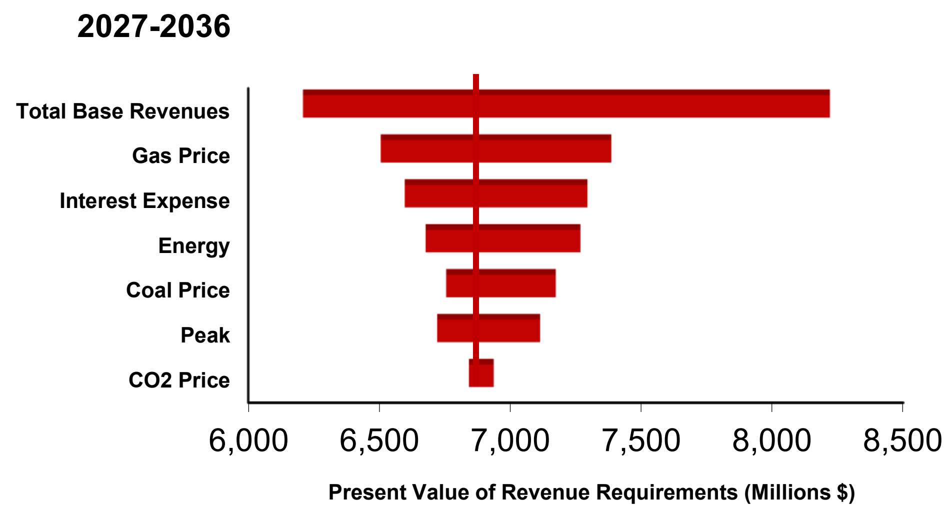
(Source: ABB Advisors.)

Figure 12-11
Quick Transition - Tornado Chart (2017-2026)



(Source: ABB Advisors.)

Figure 12-12
Quick Transition - Tornado Chart (2027-2036)



(Source: ABB Advisors.)

13 SOFTWARE USED FOR ABB REFERENCE CASE

Forecasting Methodology

The ABB Reference Case includes market-based forecasts of North American power, fuel, emission allowance, and renewable energy credit prices that are internally consistent with one another; that is:

- Natural gas and coal prices that are internally consistent with the associated power sector consumption of each fuel;
- Capacity additions, retirements, and retrofits that are internally consistent with the allowance and fuel prices;
- Electric energy and capacity prices that are internally consistent with the capacity additions, etc., and allowance and fuel prices; and
- Renewable energy credit prices that are internally consistent with state renewable portfolio standards and electric energy and capacity prices.

Module Descriptions

The following paragraphs describe the key aspects of each of the five modules of the Integrated Model comprising the forecasting process.

Power Module

The Power Module is a zonal model of the North American interconnected power system spanning 70 zones. The Module simulates separate hourly energy and annual capacity markets in all zones. The Module simulates the operations of individual generating units, i.e., not aggregations of units. The Power Module comprises two components, which simulate 1) operations; and 2) conventional power plant capacity additions.

Operations Component

For given assumptions such as generating unit characteristics described below, the Operations Component simulates a constrained least-cost dispatch of all of the power plants in the system, taking into account hourly loads, operating parameters and constraints of the units, and transmission constraints.

Investment Component

For a given set of the values of variables from the Operations Component, such as hourly electric energy prices, the Investment Component simulates the conventional power plant capacity additions likely to occur in the market:

- For capacity additions, the Investment Component identifies the additions that would be profitable in each zone based solely on first-year economics; i.e., without taking into account reserve margins and the associated capacity payments. The test for such additions is that energy market revenues are greater than the sum of 1) expenses for fuel, emission allowances, variable Operations and Maintenance (O&M), and fixed O&M; and 2) amortized capital costs. Once all such economic capacity additions have been made, the Investment Component identifies zones and groups of zones for which reserve margins are not satisfied. For each such deficiency, the Investment Component then identifies the set of capacity additions that 1) together satisfy the reserve margin requirement, and 2) require the lowest first-year capacity payment, as discussed below. Capacity additions can result in actual reserve margins above target reserve margins.

- The annual capacity price in each zone is calculated as the amount, measured in dollars per kW-year that the marginal unit in the zone required to satisfy the reserve margin would need over and above energy market revenues to break even financially, including the amortized capital cost of the unit.

Fuels Module

The Fuels Module comprises three sub-modules, one each for oil, natural gas, and coal.

Oil Sub-Module

U.S. crude oil prices are based on conditions in the world oil market. Based on extensive prior analysis, ABB Advisors believes that the feedback to the world oil market from the markets represented in the North American forecast, i.e., power, natural gas, coal, and emissions, is extremely weak. Moreover, the effects on the world oil market of the types of policies or exogenous events that might be modeled, such as a CO_2 cap-and-trade program, are also very weak. As a result, ABB Advisors believes it is appropriate to treat the world oil market—and more specifically U.S. crude oil prices—as an exogenous input, as opposed to modeling it explicitly. ABB Advisors currently use the forecast of West Texas Intermediate (WTI) price from the U.S. Energy Information Administration's (EIA) most recent Annual Energy Outlook. We generate forecasts of region-specific prices for refined oil products burned in power plants, e.g., diesel and residual, based on an analysis of historical relationships between these prices and the WTI price.

Natural Gas Sub-Module

The Natural Gas Sub-Module produces forecasts of monthly natural gas prices at individual pricing hubs. The Operations Component consists of a model of the aggregate U.S. natural gas sector. For each month and iteration, it executes in the following manner:

- The Operations Component includes an econometric model of Lower 48 demand in each of the sectors other than power, relating monthly consumption to the Henry Hub price.

- For each iteration of the Operations Module, natural gas demand by the power sector is taken from the prior iteration of the Power Module.

- LNG supply is forecast using proprietary global LNG model and Henry Hub prices from the previous iteration. This model utilizes forecasts of global LNG demand and supply.

- Domestic supply is represented in the Operations Components by exogenous Lower 48 production declines and exogenous assumptions about deliveries from Alaska; a pair of econometric equations relating Lower 48 productive capacity additions to Henry Hub prices in previous months and Lower 48 capacity utilization to the current Henry Hub/WTI price; and net storage withdrawals to balance supply and demand to the extent available storage capacity will permit.

- The Henry Hub price is simulated as the price that balances demand and supply, including net storage withdrawals.

Coal Sub-Module

The Coal Sub-Module utilizes a network LP that satisfies, at least possible cost, the demand for coal at individual power plants with supply from existing mines using the available modes of transportation. For each year and iteration, the Sub-Module executes in the following manner:

- For each iteration, demand by each power generating plant is taken from the prior iteration of the Power Module. The Sub-Module takes into account the potential to switch or blend coals at each plant, where and to the extent such potential exists.

- Supply is represented by mine-level short- and long-run marginal cost curves, maximum output, and developable reserves.

- Transportation is represented as the minimum cost rate for each mine-plant pairing, taking into account the modes of transportation that are possible, e.g., rail, truck, barge.

- The network LP generates forecasts of annual FOB prices by mine, delivered prices by plant, and the characteristics of the coal delivered to each plant, e.g., sulfur and heat content.

- Known contracts between specific mines and power plants are represented. These contracts influence the forecast of spot coal produced at each mine.

Renewables Module

The Renewables Module simulates the market reaction to the imposition of state renewable portfolio standards (RPS). The Module simulates annual additions of renewable capacity that will be made in each zone, by technology type, given 1) the total potential capacity for each technology for each area, and 2) the relevant RPS. The Module also simulates the annual renewable energy certificate (REC) prices for each jurisdiction that imposes an RPS.

The Module considers zone-specific supply curves for renewable additions. Each supply curve is expressed in terms of the amount of capacity that would be constructed, measured in MWh of renewable energy generated, at various REC prices. These supply curves are adjusted to take into account zonal energy and capacity prices. The Module then identifies the renewable capacity additions that 1) together satisfy the RPS, and 2) require the lowest first-year REC price. In such instances, the REC price is set as the additional payment, measured in dollars per MWh, that the marginal capacity addition requires to break even financially, taking into account the energy market revenues, variable and fixed O&M expenses, and amortized capital costs.

14 SOFTWARE USED FOR IRP ANALYSIS

Reference Case Power Price Formation Process

Market prices were used from the Fall 2015 Midwest Reference Case. ABB uses a fundamentals-based methodology to forecast power prices in each region of North America. Based on its proprietary PROMOD IV® software—a proven data management and production simulation model—ABB simulates the operation of each region of North America. PROMOD IV is recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive details in generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations.

For each region, PROMOD IV considers:

- Individual power plant characteristics including heat rates, start-up costs, ramp rates, and other technical characteristics of plants;
- Transmission line interconnections, ratings, losses, and wheeling rates;
- Forecasts of resource additions and fuel costs over time;
- Forecasts of loads for each utility or load serving entity in the region; and
- The cost and availability of fuels that supply the plants.

PROMOD IV provides valuable information on the dynamics of the marketplace through its ability to determine the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. PROMOD IV performs an 8760-hour commitment and dispatch recognizing both generation and transmission impacts. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, and transmission flows.

The heart of PROMOD IV is an hourly chronological dispatch algorithm that minimizes costs (or bids) while simultaneously adhering to a wide variety of operating constraints, including generating unit characteristics, transmission limits, and customer demand.

Strategic Planning Software

Strategic Planning *powered by MIDAS Gold* was utilized to measure and analyze the consumer value of competition.

Strategic Planning (SP) includes multiple modules for an enterprise-wide strategic solution. The modules used for this IRP were:

- Portfolio
- Capacity Expansion
- Financial/Risk

Strategic Planning is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation, asset and customer value. The markets and portfolio modules are hourly, multi-market, chronologically correct market production modules used to derive market prices, evaluate power contracts, and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision making tools necessary to value customers, portfolios and business unit profitability.

Portfolio Module

Once the price trajectories have been completed, the portfolio module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against presolved market prices from the markets module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve. SP operates generation fleet based on unit commitment logic, which allows for plant specific parameters of:

- Ramp rates;
- Minimum/maximum run times; and
- Startup costs.

The decision to commit a unit may be based on one day, three day, seven day and month criteria. Forced outages may be based on Monte Carlo or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints.

Portfolio module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies, or load following for full requirement contracts are active.

Capacity Expansion Module

Capacity Expansion automates screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement, and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market transactions. With Capacity Expansion, the optimal resource expansion strategy is determined based on an objective function subject to a set of constraints. The typical criterion for evaluation is the expected present value of revenue requirements (PVRR) subject to meeting load plus reserves, and various resource planning constraints.

Decisions to build generating units or expand transmission capacity, purchase or sell contracts, or retire generating units are made based on the expected market value (revenue) less costs including both variable and fixed cost components. The model is a mixed integer linear program (MILP) in which the objective is minimization of the sum of the discounted costs of supplying customer loads in each area with load obligations. The model can be used to also represent areas that provide energy and capacity from power stations or contracts, but have no load obligations. The model includes all existing and proposed plants and transmission lines in a utility system.

Financial Module

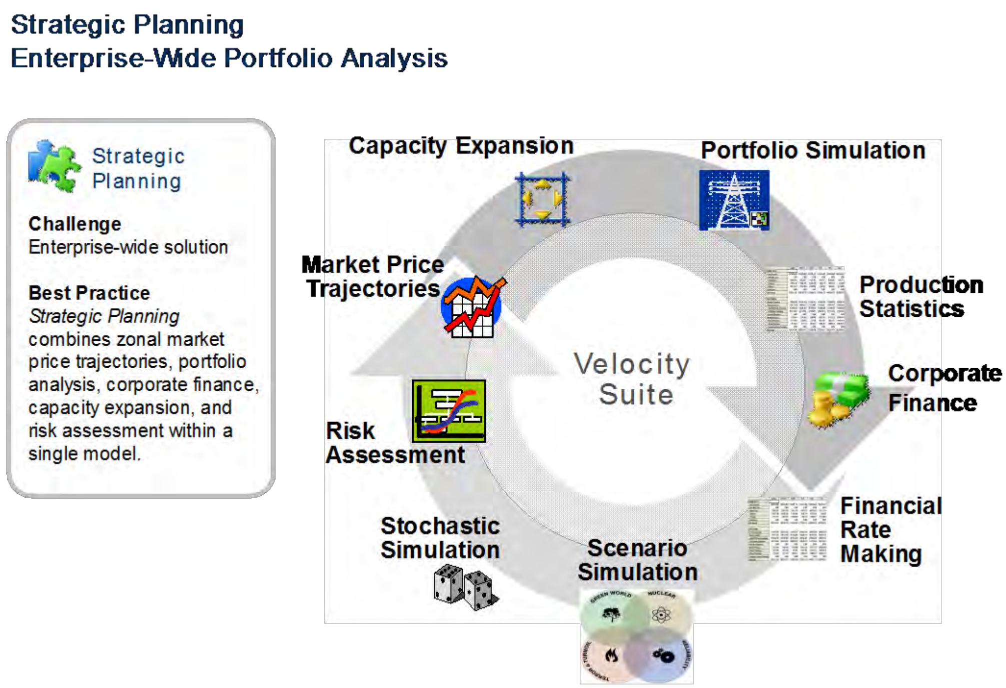
The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

Risk Module

Risk module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based stratified sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price “drivers” (e.g. demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e. Short-Term hourly, Mid-Term monthly, and Long-Term annual) for each transact group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

Figure 14-1
Overview of Process



(Source: ABB Advisors.)

IPL 2016 IRP

Confidential Attachment 2.2 (ABB Modeling Summary – Confidential Version) is only available in the Confidential IRP.

Short Term Action Plan Transmission Expansion Projects

	Project	Description	Construction Period
1	Guion to Westlane Line - 132-40	Upgrade of the IPL Guion to Westlane 138 kV line to at least 298 MVA. The upgrade is needed to increase the line during contingency loading conditions and meet NERC reliability standards.	2017
2	Stout 345-138 kV Auto Transformer	The replacement is needed to due to transformer health.	2017
3	Rockville Substation	The upgrade of the Rockville substation include two new 345 kV breakers and one 138 kV breaker. The project increases imports capability into the IPL 138 kV transmission system, improves reliability, and allows for better operational flexibility.	2018
4	Stout CT to Southwest Line - 132-02	Upgrade of the IPL Stout CT to Southwest 138 kV line to at least 345 MVA. The upgrade is needed to increase the line during contingency loading conditions to meet NERC reliability standards.	2018
5	Stout CT to Stout North Line - 138-98	Upgrade of the IPL Stout CT to Stout North 138 kV line to at least 345 MVA. The upgrade is needed to increase the line during contingency loading conditions to meet NERC reliability standards.	2018
6	Georgetown to Westlane Line - 132-41	The upgrade of the IPL Georgetown to Westlane 138 kV line to at least 333 MVA. The upgrade is needed to increase the line during contingency loading conditions and meet NERC reliability standards.	2018
7	Guion Substation	The upgrade of the Guion Substation include two new 345 kV breakers. The project increase imports capability into the IPL 138 kV transmission system, improves reliability, and allows for better operational flexibility.	2018
8	Parker Substation	The Parker Substation project includes replacement of three 138 kV breakers. The replacement is needed to increase interrupting capability and meet NERC reliability standards.	2018
9	River Road Substation	The River Road Substation project includes replacement of one 138 kV breaker. The replacement is needed to increase interrupting capability and meet NERC reliability standards	2018
10	Center Substation	The Center Substation project includes new 138 kV breakers, disconnects, and relay equipment.	2018
		Estimated Total Cost of all Projects:	**$26.2M**

Note: This does not include any costs for projects completed by other MISO members that will be allocated to IPL.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

SUBMISSION OF COMPLIANCE FILING

Petitioner, Indianapolis Power & Light (IPL), in accordance with the Commission's February 11, 2015 Order in this Cause, files the attached annual report. It recently came to IPL's attention that the annual report was inadvertently not filed by December 31, 2015. IPL acknowledges that this report is late-filed and respectfully requests the Commission accept the late filing. The annual report provides a general update on the BlueIndy project including (1) any profit share received and (2) data gathered at each charging site for purposes of observing, on a generic basis, consumer behavior and the grid in terms of operational effects and costs. In accordance with the Order in this Cause, IPL will file a report by September 2, 2016 (which is within one year of the public opening) on its efforts with respect to a vehicle-to-grid pilot. IPL will file its next annual report on or before December 31, 2016.

Respectfully submitted,

By: ______________________

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Attorneys for INDIANAPOLIS POWER & LIGHT COMPANY

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served this 30th day of June 2016, via electronic mail, on the following:

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THE CITY OF INDIANAPOLIS

INDIANAPOLIS POWER & LIGHT COMPANY

IURC CAUSE NO. 44478

BLUEINDY ELECTRIC CAR SHARE PROGRAM ANNUAL REPORT

JUNE 30, 2016

GENERAL UPDATE

As of June 30, 2016, BlueIndy has deployed 74 electric car sharing charging stations, which includes approximately 369 electric vehicle chargers and 234 vehicles. BlueIndy has over 2,000 registered members and has logged over 20,000 rides. There are currently 18 sites under construction which are focused at local universities, grocery stores, neighborhoods, healthcare, retail, and the outer ring of the IPL service territory.

The line extension costs incurred as of the most recent reporting cycle (June 1, 2016) approximates $919,000.

PROFIT SHARE RECEIVED

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

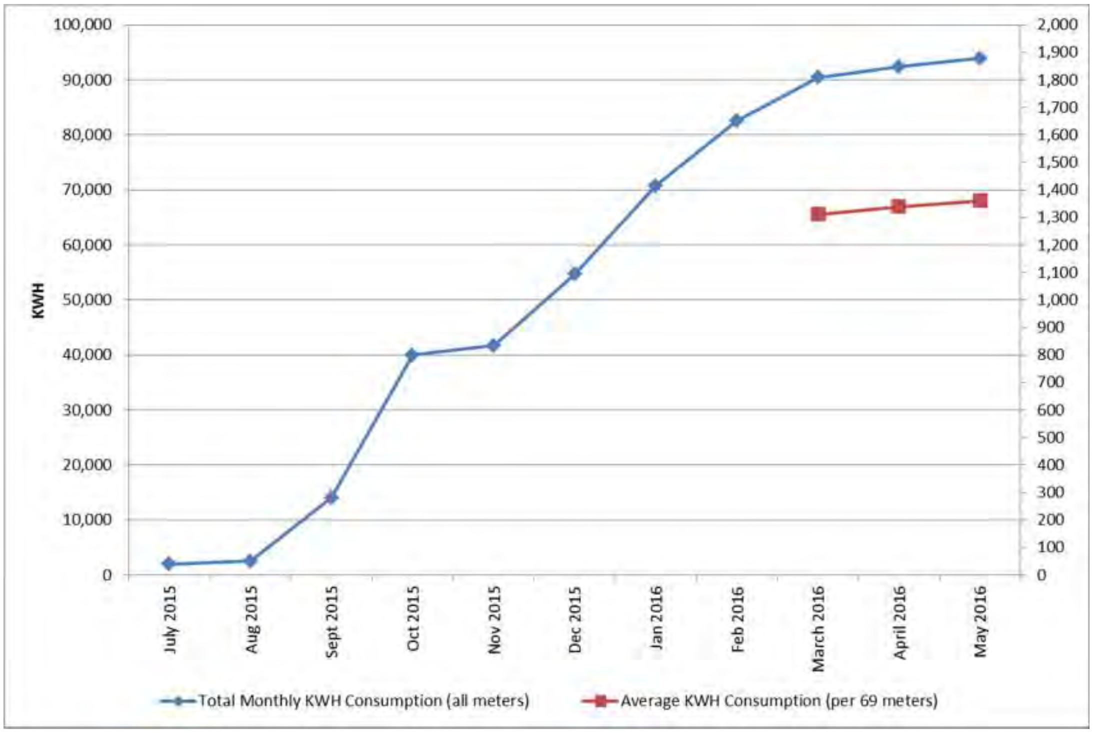
DATA GATHERED AT EACH CHARGING SITE

BlueIndy launched an initial Demo Station downtown at 2 E. Washington in early 2015 to demonstrate the service months ahead of the public opening. BlueIndy's service formally launched to the public on September 9, 2015 with an initial network of 25 Stations and 50 Bluecars in the fleet.

Generally, each BlueIndy Station consists of five (5) parking spots (each spot with a Charging Point Station Kiosk for powering Bluecars or members' personal EVs), 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 steadily added Bluecars and Stations to the service since September 9, 2015 and they are planning to meet the original goal of 500 Bluecars and up to 200 Stations in 2017.

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 Accounting reports that as of May 31, 2016, there has been a total of 597,923 kWh used by 69 of the 74 Stations since the demo site was launched. (BlueIndy will include energy consumption data for the recently launched 5 private Stations including the 4 Stations at the Indianapolis Airport and the 1 Station at the Marriott East in future reports.) There were a total of 544 total months of service across these 69 Stations, which translated to an overall average use of ~1100 kWh per month, per BlueIndy's calculations. In addition, BlueIndy has 80 "EV Charging Members" who use the Stations to charge their personal EVs. BlueIndy will be able to provide segregated personal EV energy consumption data in future reports.

IPL's data analysis as of May 9, 2016 depicted that the 69 meters in service during the most recent 3 month period revealed an average meter consumption of ~1,300 KWhrs/month. This monthly level of consumption is only slightly above a typical residential average energy consumption of 1,100 kWhrs. 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 comparable to the addition of less than 100 residential homes.

Photos of BlueIndy Local Use

BlueIndy Station downtown Indianapolis showing Bluecars and Personal EV charging, Charging Points, Reservation Kiosk and Meter Pedestal.

BlueIndy at the Indianapolis Airport 5th Floor Parking Garage (4 Stations).

STATE OF INDIANA

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SUBMISSION OF COMPLIANCE FILING

Petitioner, Indianapolis Power & Light Company ("IPL"), in accordance with the Commission's February 11, 2015 Order in this Cause, files the attached report on its efforts with respect to a vehicle-to-grid ("V2G") pilot.

Respectfully submitted,

By: ________________________

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The undersigned certifies that a copy of the foregoing was served this 31st day of August 2016, via electronic mail, on the following:

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Vehicle to Grid Report – Cause No. 44478

City of Indianapolis and Indianapolis Power & Light Company

Background

In Cause No. 44478, IPL received approvals to install and defer the costs related to the line extensions necessary to provide electric service to the Blue Indy charging stations. This Order included a provision of a settlement agreement, wherein IPL and the City of Indianapolis (City) agreed to collaborate with BlueIndy to determine the potential feasibility of using the BlueIndy electric vehicles ("EVs") as providers of energy back to the IPL grid as a demand response resource and whether a Vehicle to Grid ("V2G") pilot would be viable. 44478 Settlement Agreement, at 4 (Paragraph 2k).

In accordance with the Settlement Agreement, in the February 11, 2015 Order in Cause No. 44478 (at 21), the Commission directed IPL to provide a report on the V2G pilot efforts within one year of the public opening of the BlueIndy project, which is September 2, 2016.

As stated in the BlueIndy status report filed in this Cause on June 30, 2016, BlueIndy has deployed approximately 74 of 200 planned electric car sharing charging stations. They continue to deploy sites with their original goal still intact.

V2G is a broad term which describes a system in which plug-in electric vehicles communicate with the power grid to provide demand response services (sometimes referred to as a Distributed Energy Resources ("DERs")) by either returning electricity to the grid, charging during off-peak periods or by reducing their charging rate. Some industry experts have introduced the term Vehicle to Grid Integration "(VGI") as a more inclusive description for V2G.

The possibilities for EVs to serve as a DER are intriguing. For example, an EV with an average sized 30 kWh battery has approximately the amount of energy storage as the typical IPL residential customer uses in day.

Report Approach

This report summarizes discussions with BlueIndy, IPL's V2G efforts, lists potential V2G benefits, challenges identified and conclusions.

Discussions with BlueIndy

The fact that BlueIndy has selected Indianapolis as one of the initial communities to deploy an EV ridesharing service makes the City of Indianapolis and IPL uniquely situated to explore and evaluate the possibility of using fleet vehicles in a V2G study/pilot. In particular, the fact that Indianapolis is home to a fleet of identically prepared EVs that have a significant amount of distributed energy storage capacity makes the possibility of grid provided services interesting. Having BlueIndy as a willing partner in this study provides expertise and data not available in other V2G research. The last year has been focused on the rollout of the BlueIndy infrastructure. The cooperation between IPL and BlueIndy during this time has been very collaborative and continues to be so. While BlueIndy is open to future coordinated V2G efforts, their preference is to focus on the initial deployment of project infrastructure in the short-term. Furthermore, many details would need to be worked out before a pilot could begin.

IPL Efforts

IPL has conducted research related to V2G efforts around the United States. The current pilots seem to concentrate on using second life batteries as stationary sources to provide grid services as a predecessor to actual mobile batteries in EVs. While multiple pilots are in progress, commercialization is not yet viable. Please see Appendices 1 and 2 for more detail.

Load Modifying Resource Demonstration Project

As a complement to the evaluation of V2G, IPL contracted with a local electrical contractor to complete a Distributed Energy Storage ("DES") demonstration pilot showcasing home energy storage system technology in a laboratory setting. This demonstration project employs battery energy storage packs from two vendors (Tesla Powerwall and LG Chem) that will provide back-up power and demand response in the form of a Load Modifying Resource ("LMR"). For capacity planning purposes, IPL may eventually aggregate multiple customer systems into a resource that can supply at least 100 kW in order for home energy storage units to qualify as a MISO LMR.

IPL invited BlueIndy and Landis+Gyr (IPL's Advanced Metering Infrastructure (AMI) provider), to a demonstration of the DES pilot. Initial favorable results indicate the DES has the ability to monitor and control individual home circuit breaker loads and call upon the battery to discharge to reduce grid demand. Essentially, the batteries used in the lab replicate vehicle battery technology on a smaller scale.

The control system software under development for the LMR may be used to demonstrate V2G grid capability in a lab setting. Essentially, the batteries used in the lab (approximately 7 kWh battery packs) can replicate some of the functionality of the vehicle battery technology as a grid resource. This work can be considered as an incremental step to prove the technical feasibility of controlling a battery source.

Potential benefits of V2G/VGI

- Demand Response ("DR") resource which results in peak load reduction on the electric grid.
- Provider of ancillary services (frequency response).
- Integration with renewables for reliability, economic and sustainability benefits.
- Support sustainability through repurposing of used of EV batteries.
- Collaboration with local stakeholders including Energy Systems Networks, IUPUI Renewable Energy Center , the City of Indianapolis and others.

Challenges/Opportunities to Consider

The adoption of electric vehicles as a grid resource comes with many challenges:

- Lack of standard protocols for proprietary battery management system.
- Uncertainty about utility communication protocols with battery management systems.
- Battery Original Equipment Manufacturers ("OEMS") unwillingness to warranty batteries used for V2G purposes.
- Warranty concerns among vehicle owners.
- Uncertainty about more frequent charging/discharging cycling on battery life.
- The battery packs in each vehicle will have a unique set of characteristics based on their age and prior charging histories.
- Range and vehicle availability anxiety that results from electric vehicles being used for something other than their primary purpose.
- The need to develop a value proposition for all stakeholders: vehicle owners, manufacturers, dealerships, utilities, system operators.
- Economies of scale: The market for small scale battery energy storage itself will also dictate how soon V2G makes sense to pursue. Due to economic considerations, the market today favors large battery energy storage resource (i.e. one (1) plus MWh size per site). Since a car battery may provide about 20 kWh of capacity, it would be necessary to combine 50 to 100 vehicle battery pacts to get a similar amount of energy as a larger scale stationary system.

Conclusion

At this time, the parties do not believe a full V2G pilot is appropriate given the current status of the BlueIndy build system build out and the challenges cited above.

IPL will continue to stay abreast of V2G utility pilot developments nationally and gain insights related to its LMR pilot. In addition, IPL and BlueIndy will monitor pertinent battery management system standards and communication protocol developments. Following full deployment of its local infrastructure, BlueIndy expects to understand charging data to further explore the magnitude and variability of controllable EV charging over a wide range of factors, including location, vehicle type, charging time of day, charging location, and distances driven.

The parties expect to continue to discuss V2G options and will inform the Commission if a V2G pilot is undertaken.

<u>Appendix 1 – IPL Research related to V2G and VGI</u>

IPL reviewed industry reports[1] and met with vehicle Original Equipment Manufacturers (OEMS) to derive the following observations:

The current research and pilots seem to concentrate on using second life batteries (stationary sources) as a device for the provision of grid services rather than using electric vehicles that are in still in active service.

However, a Demand Response project being run by BMW and Pacific Gas & Electric does combine active EVs with a stationary source. High level details of the current BMW effort and earlier efforts are as follows:

- BMW iChargeForward program
    - 18-month pilot, July 2015 through end of this year.
    - 100 BMW i3 vehicle customers enrolled, get up to $1,540 for participating http://www.bmwusa.com/bmw/bmwi.

    - How it works:
        - PG&E sends DR signal to BMW server for 100 kW reduction.
        - BMW decides how to respond to signal from pool of 100 i3 drivers and/or stationary storage at its Mountain View office.
        - Stationary storage available is a 240 kWh system using eight battery packs pulled from BMW's MINI E project.
        - Project has been successful; PG&E has called many DR events at different times to test the capability; learning a lot about value of EVs as a grid resource.

    - Early BMW EV deployment pilots
            - Mini E program (2009)
                - Converted Mini Cooper.
                - 450 vehicles in the U.S. (CA, NY, NJ).
                - 35 kWh battery pack.
            - ActiveE program (2012)
                - Converted 1 Series Coupe.
                - Deployed 700 in the U.S.; 2 year lease for $499 per month.
                - 32 kWh battery pack.
                - 150 put into service in BMW's DriveNow car sharing. program, which has since become the ReachNow program.
        - UC San Diego demonstrations
            - Testing second-life battery applications by integrating into solar, using batteries from the Mini E program.

[1] These reports are referenced in Appendix 2.

- Florida Power & Light project announced on June 16 will repurpose 200 second life batteries from more than 200 electric vehicles test "peak shaving" for better grid management during periods of high demand via a storage system to be installed in a densely populated residential area in southwestern Miami.

- This project is one of the private sector commitments made during the June 16 White House announcement on Scaling Renewable Energy and Storage with Smart Markets

- In 2015, NextEra, signed a contract for the delivery of 20 MWh of Battery 2nd Life automotive batteries. These batteries were sourced from the BMW ActiveE test fleet in the US and from early BMW i3 vehicles. NextEra will operate them in various industrial sized stationary electricity storage systems.

- BMW Home energy storage with 2nd life batteries
    - Announced on June 21. 2016 http://www.autoblog.com/2016/06/21/bmw-i3-battery-home-energy-storage
        - Initially uses 2nd life batteries from the i3.
    - “The battery storage system electrified by BMW i, enables customers to more fully realize their commitment to sustainability – and to take the next step towards energy independence. With this system, which integrates seamlessly with charging stations and solar panels, customers can offset peak energy costs and also enjoy the added security of an available backup energy supply during power outages.”
    - For commercial and home.
    - Can accommodate new and used batteries.
    - 22 kWh or 33 kWh capacity, “ideally suited to operate a variety of appliances and entertainment devices for up to 24 hours on its own”.
    - “Because the electric draw is much less at home when compared to automotive usage, this storage system is an ideal application for a retired BMW i3 battery and ensures that the repurposed battery will offer many additional years of service”.
    - “The battery storage system also includes a voltage converter and power electronics to manage the energy flow between renewable energy sources, the house interface, and the Li-Ion high-voltage battery from the BMW i3.”

        - "The battery storage system electrified by BMW i is ideally sized so it can be conveniently placed in the basement or the garage of a detached house, where the stored energy can either be used for electrically-operated devices in the home or for charging the battery of an electric car."
        - For reference, BMW i3 has a 22 kWh pack; BMW has delivered 20,000 in the U.S. since sales began in May 2014; that is 440,000 kWh or 440 MWh of energy storage in the field; some of the early ones will be coming off of lease soon.
- Mercedes-Benz
    - Daimler subsidiary ACCUmotive.
    - Commercial and residential applications.
    - Modules come in 2.5 kWh (residential), which can be scaled up to 20 kWh; or 5.9 kWh (commercial), which can be scaled up to whatever size is needed.
    - 500 kW deployed in Germany; went on market in Germany in April 2016.
- Volkswagen
    - Renewed "interest" in electrification following emissions scandal settlement.
    - Intent is to "rectify shortcomings and establish a corporate culture that is open, value-driven and rooted in integrity."
    - 30 new electric models on the road by 2025.
    - Possible gigafactory of its own.
- Tesla
    - Powerwall consumer product.
    - Green Mountain Power (GMP) deployment of Powerwall.
        - "GMP has worked closely with customers to help make the Powerwall an affordable option. Customers can lease one for about $37.50 a month or about $1.25 a day, with no upfront cost. Customers can also choose to partner with GMP to purchase the Powerwall, and with shared access will receive a monthly bill credit of $31.76. Both options represent the value of leveraging the battery to help lower peak energy costs."
- Some of the above projects and additional initiatives are outlined and included in a White House Press Release from June 21, 2016. https://www.whitehouse.gov/the-press-office/2016/06/16/fact-sheet-obama-administration-announces-federal-and-private-sector.

Appendix 2 Literature Review

A summary of research and other utility initiatives. The recent June 2016 publication by Rocky Mountain Institute is particularly comprehensive and useful:

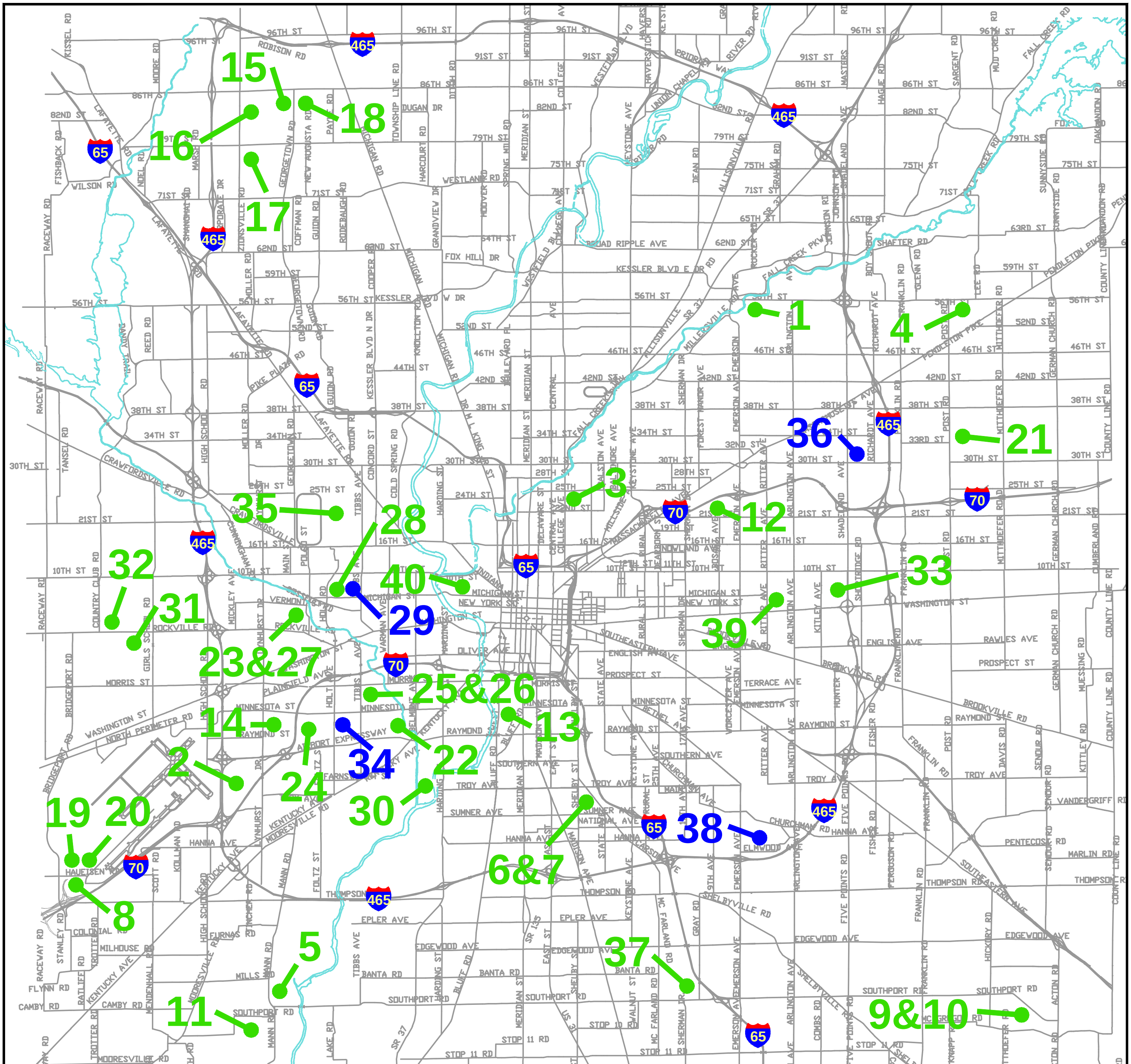
- National Renewable Energy Laboratory: Multi-Lab EV Smart Grid Integration Requirements Study http://www.nrel.gov/docs/fy15osti/63963.pdf
- Electricity Innovation Lab: Electric Vehicles as Distributed Energy Resources http://www.rmi.org/Content/Files/RMI_Electric_Vehicles_as_DERs_Final_V2.pdf
- AC Propulsion, Inc.: Electric Drive Vehicles: A Huge New Distributed Energy Resource http://www1.udel.edu/V2G/resources/A-Brooks-ETI-conf.pdf
- Impact of Electric Vehicles as Distributed Energy Storage in Isolated Systems: the Case of Tenerife http://www.mdpi.com/2071-1050/7/11/15152
- Distributed energy resources management using plug-in hybrid electric vehicles as a fuel shifting demand response resource. http://www.sciencedirect.com/science/article/pii/S0196890415002289
- Rocky Mountain Institute "Electric Vehicles as DERs V2 Final, June 2016 http://www.rmi.org/Content/Files/RMI_Electric_Vehicles_as_DERs_Final_V2.pdf
- Rocky Mountain Institute _ Blog _ EVs "Time to Plan on EVs on the Grid" http://blog.rmi.org/blog_2016_06_15_its_time_to_plan_for_evs_on_the_grid

FINAL RATE REP PARTICIPANTS

Count	Customer	Address	Nameplate Capacity (kW, AC)	Ground / Roof
1	Cathedral High School	5525 E. 56th St.	50	R
2	ES by JMS	5925 Stockberger Place	90	R
3	Indiana Veneers	1121 E. 24th Street	85	R
4	GSA Bean Finance Center	8899 E. 56th Street	1,800	R
5	Melloh Enterprises	6627 Mann Road	39	G
6	L&R #1 (Laurelwood Apts.)	Building #6, 3340 Teakwood Dr	30	R
7	L&R #2 (Laurelwood Apts.)	Building #16, 3340 Teakwood Dr	28	R
8	Airport I	7800 Col. H. Weir Cook Memorial Drive	9,800	G
9	Indy Solar I	10321 East Southport Road	10,000	G
10	Indy Solar II	10321 East Southport Road	10,000	G
11	Indy Solar III	5800 West Southport Road	8,640	G
12	Indy DPW	3915 E 21st Street	95	R
13	Indy DPW	1737 S. West St	95	R
14	Schaefer Technologies	4901 W. Raymond St, 46241	500	G
15	Citizens Energy (LNG North)	4650 W. 86th	1,500	G
16	Duke Realty #98	8258 Zionsville Rd, 46278	2,720 *	R
17	Duke Realty #87	5355 W. 76th St., Indpls., 46268	2,720 *	R
18	Duke Realty #129	4925 W. 86th St. Indianapolis, IN 46268	3,400 *	R
19	Airport Phase IIB	Intersection of Brushwood Rd & Hoffman I	2,500	G
20	Airport Phase IIA	4250 W Perimeter Rd	7,500	G
21	Celadon Trucking Services	9503 E. 33rd Street, 46235	82	R
22	Vertellus	1500 S. Tibbs Ave, 46241	8,000 *	G
23	Merrell Brothers	4251 W. Vermont ST	96	R
24	Grocers' Supply Co.	4310 Stout Field Dr. North	1,000	R
25	A-Pallet Co.	1225 S. Bedford St.	48	G
26	A-Pallet Co.	1305 S. Bedford St.	96	R
27	Town of Speedway, IN	4251 W. Vermont ST	750	G
28	GenNx Properties VI, LLC (Maple Creek Apts)	3800 W. Michigan Street (Bldg 17)	20	R
29	GenNx Properties VI, LLC (Maple Creek Apts)	3800 W. Michigan Street (Bldg 1)	20	R
30	CWA Authority	2700 S. Belmont (WWTF)	3,830	G
31	Rexnord Industries	7601 Rockville Road	2,800	G
32	Equity Industrial A-Rockville LLC	7900 Rockville Road	2,725	R
33	Lifeline Data Centers	401 N. Shadeland Ave	4,000	Carports
34	Omnisource	2205 S. Holt	1,000	G
35	Indianapolis Motor Speedway	3702 W 21st Street	9,000 *	G
36	DEEM	6900 E. 30th Street	500	R
37	Indy Southside Sports Academy	4150 Kildeer Dr	200	R
38	Marine Center of Indiana	5701 Elmwood Ave	500	R
39	5855 LP	5855 E. Washington St.	78	R
40	IUPUI	801 W. Michigan Rd	48	R
		Total	96,384	

Count	Date	Status	Capacity
0	10/1/2016	Under Construction	0
36		Operating	94,392
4		In Development	1,993

* Reduced from approved capacity



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

INDIANAPOLIS POWER & LIGHT CO.

SOLAR FACILITIES

DRAWN BY: RLW

5-18-15

solar-REP-GIS-map

REV. 11-12-15 WJK