Indianapolis Power & Light Company

2014 Integrated Resource Plan

Public Version

Volume 1 of 2

October 31, 2014

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Section 1. EXECUTIVE SUMMARY

As part of IPL's integrated resource planning, the Company participates in an Integrated Resource Planning ("IRP") process as required by the Indiana Administrative Code ("IAC") on a biennial basis to identify a resource plan to reliably serve IPL customers for a forward looking twenty (20) year period. For the first time, the Company also participated in a Public Advisory Process as required by the proposed IAC that yielded meaningful stakeholder feedback in the development of the 2014 IRP. The IRP analyzes a combination of projected customer load, existing resources, projected operating costs, anticipated environmental and other regulatory requirements, and potential supply and demand side resources within the context of risks of uncertain future landscapes to plan to provide electricity service in the most cost-effective way possible.

IPL's mission is "Improving lives by providing safe, reliable, affordable energy solution to the communities we serve." As a result of numerous current and future expected environmental requirements, IPL has developed and is executing plans to significantly change its generation portfolio. The Company's strategy includes a combination of activities in order to continue to reliably and affordably meet the future needs of our customers:

1. Offer cost-effective energy efficiency programs to help customers reduce their energy usage and help the Company reduce its peak system demand.
2. Upgrade its existing generation fleet to reduce air emissions and reduce or treat waste water.
3. Convert some existing coal-fired units to natural gas generation.
4. Retire several units where it is not economic to comply with future environmental requirements.
5. Construct a modern, efficient combined cycle natural gas plant.
6. Enhance the Company's transmission and distribution system.
7. Explore and implement new technologies, such as solar generation through our renewable feed-in tariff, energy storage, electric transportation and smart grid.

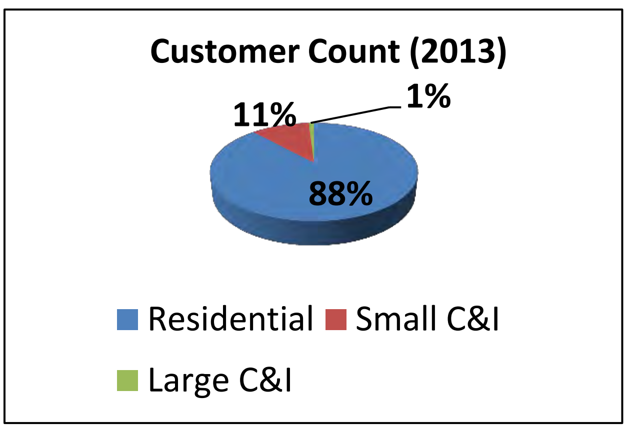
If all components of the strategy are approved, IPL will have a cleaner and more diversified generation portfolio while continuing to provide safe, reliable and affordable energy solutions to the Indianapolis community.

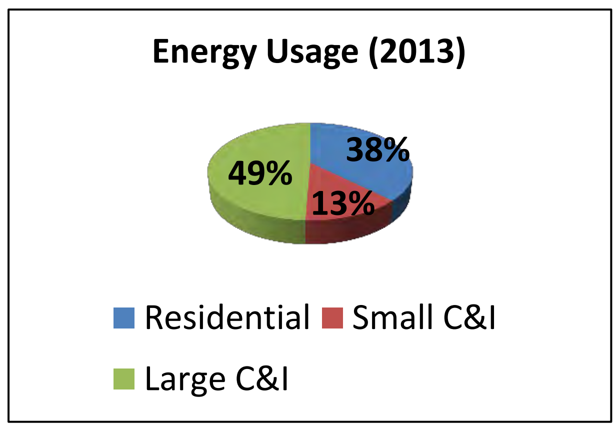
IPL's 2014 IRP modeling results indicate that in the majority of the future scenarios the base case expansion plan yields the lowest present value revenue requirement ("PVRR"). This plan does not add any new generation resources - other than the projects[1] listed above in IPL's strategy - until 2031 to meet the Company's energy and capacity requirements. Because the base case expansion plan serves customers reliably and cost effectively under multiple future scenarios, IPL considers this plan its Preferred Resource Portfolio.

Background

IPL serves approximately 470,000 households and businesses in ten counties in Central Indiana, mainly in Marion County and adjoining counties[2]. The service area is compact measuring 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 Operating ("MISO"). IPL owns and efficiently operates approximately 3,089 MW[3] of generation at four plants, over 800 miles of transmission lines, and over 11,600 miles of distribution lines as a vertically integrated investor owned utility. IPL also has purchase power agreements for approximately 98 MW of solar generation and approximately 300 MW of wind generation. IPL's customer mix and their respective energy usage split between residential and small and large Commercial and Industrial ("C&I") is shown in Figure 1.1. The Large C&I customers class, which is only 1% of the Company's customer count, consumed the largest amount of IPL's 2013 total jurisdictional retail energy.

Figure 1.1 – IPL Customer Mix and Energy Use





Source: IPL

[1] The projects in IPL's strategy represent projects currently approved and pending before the Indiana Utility Regulatory Commission ("IURC").
[2] Although IPL is not the sole service provider in the adjoining counties, IPL does provide service to some customers in Boone, Hamilton, Hancock, Shelby, Johnson, Morgan, Owen, Putnam, and Hendricks counties.
[3] This is based on summer ratings for planning purposes at the time of this filing.

Existing Resources

Thermal Generation

Subsequent to the 2011 IRP, decisions have been made to significantly transform IPL's generating fleet as described below. In 2013, IPL discontinued operation at the following five oil-fired units: HSS Units 3 and 4, HSS Gas Turbine Unit 3, and Eagle Valley Units 1 and 2.

IPL currently owns and operates the following generation:

(1) the four unit, coal-fired Petersburg Generating Station in Petersburg, Indiana. The Petersburg station, located in close proximity to its Indiana fuel supply, provides low cost generation to IPL's customers. This plant is being retrofitted with environmental compliance equipment in accordance with the Commission's order in Cause No. 44242.

(2) the seven unit, Harding Street Generating Station ("HSS") in Indianapolis, IN, including three coal units and four natural gas fired combustion turbines. Because HSS is directly connected to the IPL load zone, it provides an important capacity resource at the center of IPL's service territory, thus reducing transmission costs and interruption risk. In accordance with the Commission's order in Cause No. 44339, IPL is refueling HSS Units 5 and 6 from coal to natural gas in 2016. Pending Commission approval of Cause No. 44540, IPL will also refuel HSS Unit 7 from coal to natural gas, which will eliminate all coal fired units at this plant in 2016.

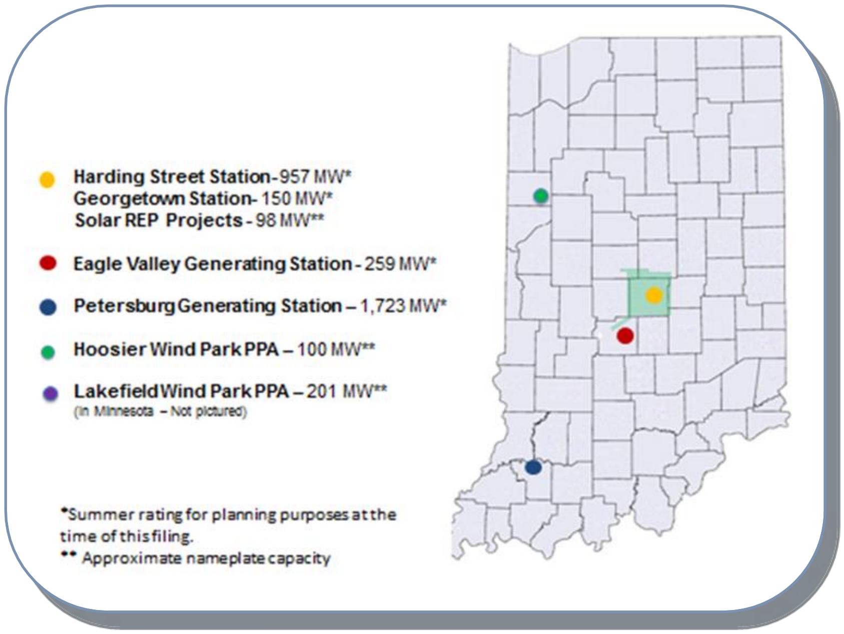
(3) the four unit, coal-fired Eagle Valley Generating Station in Mooresville, IN. Eagle Valley Units 3 through 6 will be retired in 2016 as part of IPL's plan to comply with the EPA's environmental mandates, including the Mercury and Air Toxics Standard ("MATS"). Pursuant to the Order in Cause No. 44339, IPL is adding a 644 to 685 MW[4] natural gas fired combined cycle gas turbine at the Eagle Valley Generating Station in 2017.

(4) the two unit, natural gas fired Georgetown Generating Station in Indianapolis, IN.

Figure 1.2 shows the relative location and nameplate capacity of IPL's generating stations.

[4] IPL is constructing a 671 MW CCGT.

Figure 1.2 – IPL Facilities



Source: IPL

Wind and Solar Generation

While no mandatory federal or state renewable energy standard ("RES") currently exists, IPL's resources include approximately 300 MW of wind generation secured under long term Power Purchase Agreements ("PPAs"), which diversifies IPL's generating portfolio. Under the terms of the PPAs, IPL receives all of the energy and Renewable Energy Credits ("RECs") from the two wind farms[5]. Additionally, as of September 1, 2014, IPL purchases the energy and renewable attributes from approximately 66 MW of solar projects through IPL's Rate REP program. IPL's Rate REP is a three-year pilot renewable energy feed-in tariff offering approved by the IURC that went into effect on March 30, 2010 and concluded in 2013. In total, there are currently 98 MWs of solar PV nameplate capacity under long-term contracts through this program; approximately 66 MWs are in-service and the remaining 32 MWs are expected to be in-service in the first half of 2015. IPL has the 5th largest per capita concentration of solar among U.S. cities to date.[6] See Section 7, Attachment 8.1 and 8.2 for a listing and map of the

[5] The null energy of the Wind PPAs is used to supply the load for IPL customers and, in the absence of any RES mandates, IPL is currently selling the associated RECS, but reserves the right to use RECs from the Wind PPAs to meet any future RES 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."

[6] http://www.environmentcaliforniacenter.org/reports/cae/shining-cities

Rate REP projects. IPL is currently selling the RECs associated with the Wind PPAs to offset the cost of this energy to customers and anticipates doing the same for the RECs from the solar projects. However, IPL reserves the right to use RECs to meet any future environmental requirement such as RES or the EPA' Clean Power Plan ("CPP").

Impact of Environmental Regulations on Generation Resources

As summarized in the Thermal Generation section above, EPA regulations have led to significant generating plant upgrades and generation portfolio changes over the past several years to improve air emissions and water quality as described below.

In response to the Mercury and Air Toxics Standard ("MATS") Rule issued in February 2012, IPL developed a Compliance Plan, which included activated carbon injection and sorbent injection for mercury control and upgraded Flue Gas Desulfurization ("FGD") systems for acid gas control on coal-fired units. The Plan also included upgraded electrostatic precipitators on Petersburg Units 1 and 4 and Harding Street Unit 7, in addition to baghouses on Petersburg Units 2 and 3 for particulate and mercury control. Finally, the Compliance Plan includes continuous emissions monitoring systems ("CEMS") for mercury ("Hg"), hydrochloric acid ("HCl"), and particulate matter ("PM"). The IURC approved IPL's MATS Compliance Plans in August 2013 (Cause No. 44242) and construction of Petersburg controls is currently underway.

IPL's MATS Compliance Plan determined that installation of the compliance controls was not economical for the smaller, less controlled units, Eagle Valley Units 3 through 6 and Harding Street Units 5 and 6. In May 2014, the IURC granted a Certificate of Public Convenience and Necessity ("CPCN") for IPL to construct a new combined cycle natural gas turbine ("CCGT") unit and approved converting Harding Street Units 5 and 6 to natural gas fired units. IPL plans to retire Eagle Valley Units 3 through 6 by the April 2016 MATS compliance deadline. In addition to the MATS Rule, the Indiana Department of Environmental Management ("IDEM") issued National Pollutant Discharge Elimination System ("NPDES") permit renewals to Petersburg and Harding Street in August 2012. The reasonable least cost plan to comply with the estimated costs of NPDES and future environmental regulations is to convert Harding Street Unit 7 to natural gas-fired and to install measures to address wastewater and Stormwater at both Petersburg and Harding Street generation stations. As a result, the MATS controls proposed in Cause No. 44242 were no longer necessary for that unit. IPL is currently proposing to the IURC in Cause No. 44540 to refuel Harding Street Unit 7 to operate on natural gas which reduces cost of compliance with NPDES and the impact on the environment.

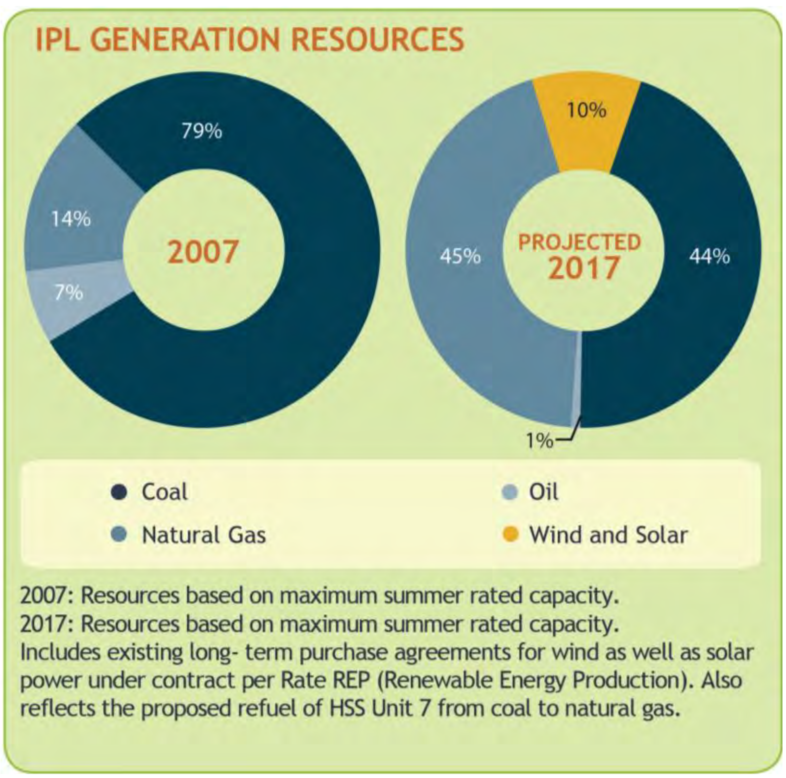
The future impacts on IPL's generation resources continue to be uncertain amidst potential legislation and U.S. Environmental Protection Agency ("EPA") regulations.

New Generation

IPL received approval on May 14, 2014 from the IURC (See IURC Cause No. 44339) to construct a 644 MW to 685 MW[7] natural gas-fired combined-cycle plant. This new CCGT is necessary to replace the generation from the retired Eagle Valley Generating Station, as discussed above, and IPL's previously existing capacity shortage. The approved new construction will furnish IPL with the resources necessary to serve retail load economically and reliably. Additional need for new generation in the short-term has been eliminated due to this recent approval.

IPL has made great strides to diversify its portfolio by changing the fuel mix from 79% coal and 14% natural gas and no renewables in 2007 to the projected mix of 44% coal and 45% natural gas in 2017, subject to IURC approval. The Company has also added 10% wind and solar resources to its portfolio since 2007. The Company's projected resource portfolio in 2017 is expressed in Figure 1.3.

Figure 1.3 – Projected Generation Resources



Source: IPL

[7] IPL is constructing a 671 MW CCGT.

As a result of HSS refueling to NG, Petersburg MATS Controls, and Eagle Valley CCGT replacement generation, IPL expects to achieve considerable reductions in fleet-wide emission rates by 2017 from current (2013):

- 67% reduction in SO_2 emission rate
- 23% reduction in NO_x emission rate
- 23% reduction in PM emission rate
- 76% reduction in Hg emission rate
- 7% reduction in CO_2 emission rate

Transmission and Distribution Enhancements

IPL's has studied the need for transmission and substation projects for retirement of generation connected to the IPL 138 kV system and designed projects to ensure deliverability of power into the IPL load zone. These projects include the installation of new 345 kV breakers, autotransformers, and 138 kV capacitor banks to improve power import capability from the 345 kV system to load centers on the 138 kV system. Several projects associated with the new CCGT will be completed in 2015 and 2016. In addition, IPL plans to install a Static Volt Ampere Reactive ("VAR") System to provide dynamic voltage and reactive power support.

IPL has enhanced its distribution system to incorporate the Rate REP projects. People in multiple areas of IPL worked closely to develop efficient procedures and successfully interconnect the DG sites. Based on the proposed location and feeder interconnection, specific engineering site studies were performed to determine if the distribution system could reliably support the DG resource without impacting the service reliability of existing customers. Line extension projects were engineered and constructed as needed. To date ten (10) projects with capacity of 500 kW to 10 MW have been connected to IPL's smart grid network to enable remote switching for IPL to safely work on distribution lines without any chance of DG backfeed. See Section 4C for more information on IPL's transmission and distribution system.

IRP Modeling Scenarios

IPL identified three key drivers most likely to impact its preferred resource portfolio: (a) CO_2 prices as a proxy for pending environmental legislation related to greenhouse gas ("GHG") emissions, (b) gas/market prices, and (c) load forecast differences due to economic and DSM impacts. Eight (8) scenarios were identified based on combinations of these drivers as shown in Figure 1.4 below. Instead of assuming the four (4) coal-fired units at Petersburg will remain in service through the projected planning life, the modeling software chose unit retirement dates based upon when they would no longer be economic to run in various scenarios. See Section 4 - Integration for a detailed description of these scenarios.

Figure 1.4 – IPL's 2014 IRP Modeling Scenarios

Scenario No	Scenario Name	Gas/Market Price	CO_2 Price	Load Forecast
1	Base	Ventyx Base	IPL-EPA Shadow price starting 2020	Base
2	High Load	Ventyx Base	IPL-EPA Shadow price starting 2020	High
3	Low Load	Ventyx Base	IPL-EPA Shadow price starting 2020	Low
4	High Gas	Ventyx High	IPL-EPA Shadow price starting 2020	Base
5	Low Gas	Ventyx Low	IPL-EPA Shadow price starting 2020	Base
6	High Environmental	Ventyx Environmental	Waxman-Markey proxy Ventyx Fall 2013 prices starting 2025	Base
7	Environmental	Ventyx Mass Cap	Mass Cap ICF Prices beginning in 2020	Base
8	Low Environmental	Ventyx Base	None	Base

Source: IPL

Key Driver #1 - Future Environmental Regulation

The environmental challenges facing utilities is unprecedented in terms of the number of rules coming due simultaneously, the compressed timeframe for compliance and the wide array of rules covering all environmental media (air, water, and waste). There are a number of environmental initiatives that the EPA is considering at the federal level that will likely impact coal-fired generation. These include, but are not limited to:

- Cross State Air Pollution Rule ("CSAPR")
- National Ambient Air Quality Standards ("NAAQS")
- Greenhouse Gas ("GHG") Regulation
- Cooling Water Intake Structures, Clean Water Act Section 316(b)
- Coal Combustion Residuals ("CCR")

This IRP addresses GHG Regulation through a CO_2 price. See Section 3 of this IRP for more information on Environmental Rules and Regulations.

Key Driver #2 – Natural Gas Prices

As mentioned above in New Generation, IPL expects to increasingly utilize natural gas within its generation fleet. Natural gas ("NG") alternatives are important in the analysis of new supply options for two reasons: First, is the significant pressures felt by U.S. utilities to retire existing coal assets and the difficulty in permitting new coal-fired generation. As important, however, is the emergence of shale gas and the significant increase in available U.S. natural gas resources. Breakthroughs and commercial developments in hydraulic fracturing technologies have economically tapped previously inaccessible reserves and brought huge supplies of shale gas from domestic sources. The advent of shale gas along with increasing levels of storage capacity continues to create an abundant supply of domestic NG, suppressing NG prices.

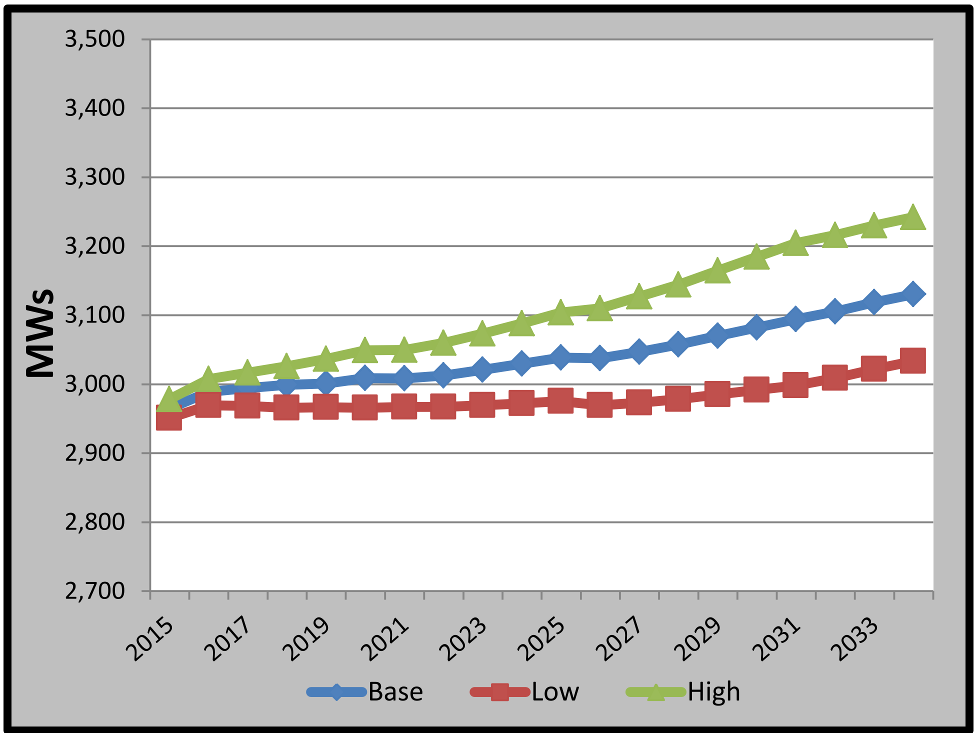
The increase in shale gas offers long-term NG price stability and substantial growth in use of NG for power production. Because market prices correlate with NG prices, the high and low NG scenarios reflect high and low market prices as well. As experienced during the Polar Vortex in the winter of 2013/2014, pipeline transportation constraints can result in a sudden rise in NG prices within the market zones and therefore electricity prices, unlike the historically relatively stable prices of coal. Instability in NG gas prices represents a key area of concern in the IRP planning period. IPL plans to hold firm transportation to liquid market centers and/or production zones to mitigate the price spikes seen during the Polar Vortex. IPL's gas-fired generation facilities are situated in favorable locations near several gas pipelines which provide the opportunity for multiple sources of NG and competitive procurement. See Section 4A for more discussion on natural gas resource options.

Key Driver #3 – Load Variation

To capture forecast uncertainty in Ventyx's IRP modeling, IPL selected three peak forecast scenarios: 1) Base load, 2) Low load, and 3) High load, with the Base load being the most probable. The base load forecast is established through econometric modeling using proprietary Moody's forecast economic parameters, such as Marion County household information and Indianapolis Manufacturing and Non-Manufacturing Employment. This forecast is adjusted by incorporating all forecasted energy efficiency DSM and other direct load impacts, such as appliance efficiencies. IPL then adds cost effective load management resources including demand response DSM, such as Air Conditioning Load Management ("ACLM") and interruptible programs plus any other load modifications, such as distribution automation enabled voltage reductions. This adjusted net load forecast, adjusted for MISO resource adequacy requirements, determines the supply resources needed to reliably serve IPL load and meet MISO resource adequacy requirements.

The High and Low load forecasts were derived by applying the low and high ranges of the State Utility Forecasting Group's (SUFG) 2013 IPL-forecast to IPL's internal forecast. Although this range, as modeled by the SUFG, is primarily driven by economics, we interpret the range to represent uncertainties resulting from: economic activity, DSM program impacts and technological and behavioral changes. For reference, IPL's base case with net DSM impacts represents a peak load forecast growth at 0.3% CAGR with 3131 MW of net internal demand ("NID") by 2034. IPL's forecast range, as modeled by Ventyx in the Capacity Expansion module, ranged from 0.2% CAGR (3,033 MW) for the Low Load forecast to 0.5% CAGR (3,242 MW) for the High Load forecast by 2034. Figure 1.5 below is IPL's Base, High, and Low peak forecast net of DSM.

Figure 1.5 – Peak Forecast (Net of DSM)



Source: IPL

Demand Side Management: Load Variation Impact

IPL's DSM programs are comprised of energy efficiency and load management. Since IPL's 2011 IRP, Senate Enrolled Act 340 ("SEA 340") has been passed resulting in the elimination of IURC established DSM targets and providing the availability for large customers to opt-out of DSM program participation. Hence, the DSM evaluation for this IRP is driven by a traditional analysis that identifies the market potential for cost effective DSM.

Despite the elimination of IURC set DSM targets, IPL filed Cause No. 44497 with the IURC to continue energy efficiency programs that were identified as cost-effective in 2015 and 2016.

Also, to reflect the Company's projected energy efficiency programs and savings, IPL contracted with Applied Energy Group ("AEG") to develop a DSM market potential forecast through 2034 to include in this IRP.

As part of its DSM strategy, IPL offers a number of Demand Response programs. At the end of 2013, IPL accounted for approximately 27 MW of Air Conditioning Load Management, 20 MW of Conservation Voltage Reduction ("CVR") described below, and 36 MW of contracted demand response capability with its C&I customers. In total, that is 83 MW of Demand Response programs. Section 4B fully describes DSM history, current programs and future plans.

Smart Grid: Load Variation Impact

IPL has enhanced service reliability and field asset operations by deploying Smart Grid assets through its Smart Energy Project. From 2009 to 2013, Distribution Automation ("DA") and Advanced Metering Infrastructure ("AMI") initiatives were completed to produce reliability benefits, reduce peak demand and improve operational efficiency.

Reliability improvements driven by adding distribution Supervisory Control and Data Acquisition ("SCADA") software tools and protective distribution devices throughout the system have resulted in 12.1 % SAIFI improvements to treated circuits by reducing the number of customers who experience a service interruption when a fault occurs on the system and restoring power more quickly through remote switching[8].

IPL has implemented a conservation voltage reduction ("CVR") program to reduce system peak demand as mentioned above with other demand response programs. IPL worked with MISO and stakeholder forums to allow this to be considered a Load Modifying Resource ("LMR") and count for capacity. In 2014, IPL registered a conservative target of 20 MW in MISO and has included this capacity in the IRP model. See Section 4C for more details about this and other Smart Grid benefits.

Resource Modeling Results

IPL worked with Ventyx to model and evaluate IPL's portfolio of existing generation and new resource options against forecast load requirements to derive its integrated resource plan. The modeling takes a structured multi-step process from load forecast to resource needs to a resource plan.

IPL uses its forecast of existing generation resources, including the planned unit retirements, to identify the resource gap to be met by additional supply resources. The Ventyx Capacity Expansion and Scenario Evaluation modules were used to identify low cost and low risk resources for IPL's resource portfolio. In addition to IPL's base case, which includes base market and gas prices, a base load forecast, and moderate CO_2 costs, the scenarios include

[8] Based on 2014 experience.

sensitivities related to the three key drivers: potential environmental regulations reflected in CO_2 costs, natural gas price and market price variation, and load variation. In all scenarios, IPL is not expected to build any additional generation until 2031 at the earliest to meet capacity and energy requirements. Additional need for new generation in the short-term has been eliminated due to the recent approval of the new Eagle Valley CCGT and the conversion of HSS Units 5 through 7[9] from coal to natural gas. (See IURC Cause No. 44339.) However, there is still much uncertainty surrounding the EPA Proposed Clean Power Plan. Depending on the construct of the final rule and how Indiana chooses to administer this regulation, additional adjustments to IPL's generation portfolio could be needed to comply with regulations. More information on IPL's load forecast and supply resource planning is available in Section 4D and 4 respectively.

Capacity Purchases

IPL customers have benefited in recent years from IPL's ability to purchase capacity at prices well below the levelized cost of building new generation. However, due to EPA MATS regulation based retirements, the supply-demand balance of capacity and load continues to come more into equilibrium in the MISO footprint, driving an increase in capacity prices. IPL will be retiring Eagle Valley Units 3 through 6 on April 16, 2016, six weeks before the end of the MISO Planning Year ("PY") 2015-2016. MISO's current resource adequacy requirement states a capacity resource that clears a planning reserve auction must be available during the entire commitment period, otherwise replacement capacity from the same zone must be secured to avoid compliance penalties. On June 20, 2014, IPL submitted a request to FERC to waive the replacement requirement needed during the stated 6 week span. This request was granted by FERC on October 15, 2014, eliminating the need to replace capacity during that time span and avoiding unnecessary costs for IPL customers.

To mitigate the MISO Planning Resource Auction price volatility risk, IPL has bilaterally purchased 100 MWs of Zone 6 Zonal Resource Credits at a fixed and known price for the PY 2015-2016 resulting in a minimal net capacity requirement. For PY 2016-2017, IPL has purchased 100 MWs of Zone 6 Zonal Resource Credits at a fixed and known price and nears completion of an agreement for an additional 200 MW. This results in a net capacity requirement ranging from 50 to 100 MW.

IPL will continue to evaluate the purchase of additional capacity to meet the difference between its actual Planning Reserve Margin Requirement and secured resources with bilateral purchases or sales, auction purchases or sales, additional demand response, or other resources. Starting in Planning Year 2017-2018, with the addition of the Eagle Valley CCGT, IPL projects that its resources will exceed its MISO Planning Reserve Margin Requirement for 2017-2018 by 240 MWs which it plans to optimize in the capacity market.

[9] The refuel of HSS Unit 7 from coal to natural gas is pending approval by the IURC in Cause No. 44540.

Preferred Portfolio

Once the new generation construction and unit refuels, as discussed in the New Generation section above, are complete, IPL will meet its peak demand until future unit retirements are necessary. Therefore, IPL's preferred portfolio is the base case expansion plan. This plan includes no additional generation extending out until 2031, at which point the Company anticipates the retirement of Petersburg 1 along with Harding Street Units 5 through 7. The determination and additional details surrounding IPL's preferred portfolio can be found in Section 4 - Integration.

Research & Development/Technology Applications

IPL continually evaluates emerging technologies, new applications of technologies and contemporary methods to improve operational excellence, identify future business opportunities and enhance long-term planning. Specifically, (1) energy storage, (2) enhanced combustion turbine output options, (3) the expansion of electric transportation, and (4) utilizing smart grid assets are included as part of these efforts. Accordingly, IPL is investigating the possibility of installing a Battery Energy Storage System ("BESS") within its grid to provide ancillary services. This could be up to a 20 MW facility located within IPLs 138 kV grid, which will also facilitate local stakeholder education. See Section 2, Changing Business Landscapes, for more information about the potential BESS installation. Turbine enhancements in the form of cooling inlet air to increase output through a process known as "fogging" is under investigation. IPL led transportation electrification efforts through its Electric Vehicle ("EV") program over the past three (3) years. Approximately 160 Electric Vehicle Supply Equipment ("EVSE") units were installed in homes, businesses and public locations to foster support of EV usage. In addition, IPL implemented a time-of-use rate ("EVX") and public EV ("EVP") tariff. This environmentally friendly transportation mode has been well received by its approximate 100 participants[10]; however, EV sales and public EVSE usage is lower than originally forecasted in Indianapolis. Additionally, IPL is working with the City of Indianapolis to implement an electric vehicle supply equipment system throughout its service territory. This would create the first total electric vehicle car sharing system in the United States. The program includes up to 1,000 EVSE at 200 locations to support 500 EVs, as outlined in IPL's proceeding filed with the IURC in Cause No. 44478. If approved, the facilities will be installed by June 2016, to modernize IPL's electric distribution infrastructure and decrease the community's dependence on foreign oil. See Section 4B and 4C for more information on IPL's involvement with EVs. Finally, IPL will continue to optimize smart grid assets. Please see Section 5 for more information about these efforts.

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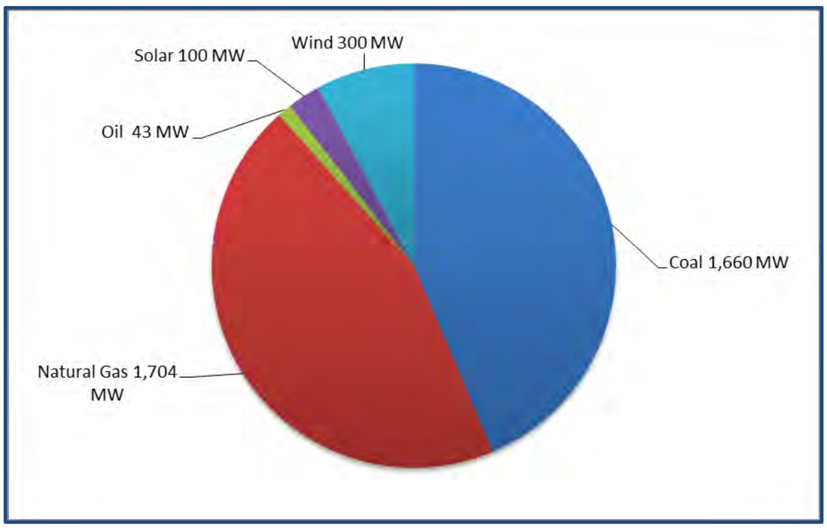
[10] IPL's 2013 Electric Vehicle Program Report can be found under a link located at: https://www.iplpower.com/Business/Programs_and_Services/Electric_Vehicle_Charging_and_Rates/

Portfolio 2024 and 2034

Much of the IRP reporting is appropriately focused on where IPL is, what uncertainties IPL is facing, and how IPL is going to navigate those challenges. The process ultimately results in a preferred resource plan, as identified above, that best serves IPL customers. In addition to defining the preferred resource plan, it is also helpful to focus on what IPL's generation mix consists of after the preferred plan is executed. IPL's selection is based upon a 50 year view to incorporate full plant life and end effects as shown in Section 4. "Portfolio 2024" and "Portfolio 2034" are snapshots of IPL's 10 and 20 year resource mix broken out by base, intermediate, and peaking resources. Of note, the energy efficiency DSM identified is the incremental DSM forecast from 2014 forward, as previous DSM programs are continually incorporated into the net internal demand ("NID") load forecast.

The 10 year look-forward projects about 3,830 MW of base load and intermediate resources, including 1,660 MW of coal-fired generation, 1,704 MW of gas-fired generation, and 43 MW of oil-fired generation. Additionally, IPL's portfolio will include 300 MW of wind generation and 100 MW of solar generation.

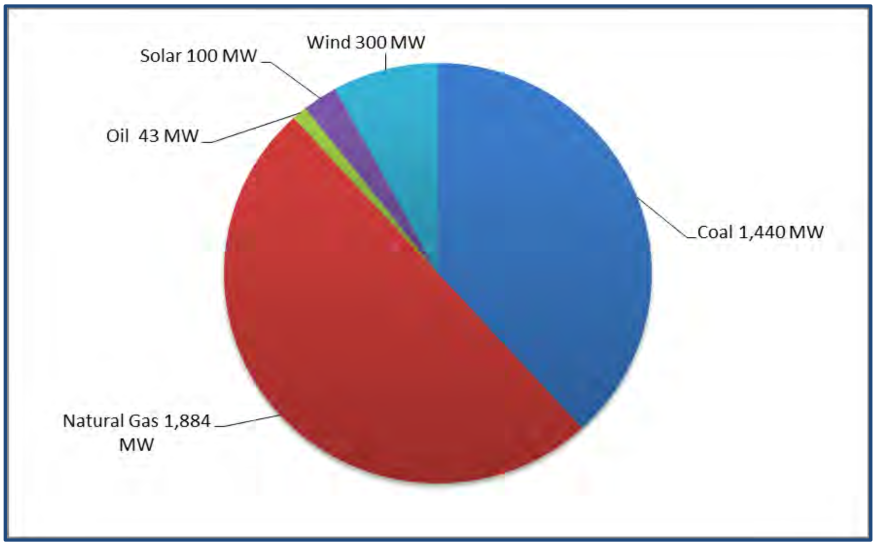
Figure 1.6 – IPL Resources – 2024 (by Operating Capacity)



Source: IPL

The 20 year outlook projects a slightly different outlook, as existing unit retirement dates become a factor. Prior to 2034, it is anticipated that Petersburg Unit 1 along with Harding Street Units 5 through 7 will retire. With CCGT being the least cost option for replacement generation, the shift from a portfolio primarily made up of coal resources to a natural gas intensive mix is expected to continue. The 2034 resource mix includes a total 3,767 MW of base load and intermediate resources, including 1,440 MW of coal-fired generation, 1,884 MW of gas-fired generation, and 43 MW of oil-fired generation. Likewise, the renewable resources are expected to remain at the 2024 levels of 400 MW.

Figure 1.7 – IPL Resources – 2034 (by Operating Capacity)



Source: IPL

Although the model selects new CCGT units in the preferred resource plan based upon current market conditions and what IPL knows today, other 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, and load forecasts.

Section 2. THE CHANGING BUSINESS LANDSCAPE

Since the submission of the IPL 2011 IRP, the business landscape for IPL and the electric utility industry has shifted in a number of key areas. Also, this 2014 IRP is being filed under a proposed rule 170 IAC 4-7, which includes different requirements including more transparent descriptions of risk analysis and mitigation, regional transmission organization membership impacts in the IRP, and reasoning for decision making to identify the preferred resource portfolio. The landscape areas described below are key drivers in the development of this IRP and IPL's future resource strategy.

Changing Regulatory Landscape

[170-IAC 4-7-4(b)(14)]

The most current revision of the proposed rule 170 IAC 4-7, which describes the Indiana IRP process and requirements, was issued on October 4, 2012. While this rule has not yet been finalized, IPL and other Indiana electric utilities are voluntarily working to comply with the new requirements as much as possible. In addition to the amended documentation requirements and methodology and risk descriptions, there are two new items within the proposed rule: (1) a public advisory process, and (2) a non-technical summary to be posted on the utility's website. Both of these new requirements aid in stakeholder education and input.

IPL hosted three public advisory meetings to inform its stakeholders and gather feedback. Stakeholders were notified by email and a newspaper public notice at least 30 days in advance of the meetings. Meeting materials in the form of Microsoft PowerPoint slides were posted on the Company's webpage two weeks prior to each meeting. Stakeholders were invited to attend in person or via the Webex option. A summary of the topics discussed are listed below. In addition, the meeting materials are provided as Section 7, Attachment 9.1 of this IRP.

1st Public Advisory Meeting - May 16, 2014

- Introduction to IPL and Integrated Resource Planning Process
- Energy and Peak Forecasts
- Demand Side Management: Energy Efficiency and Demand Response
- Planning Reserve Margin
- Generation Overview
- Environmental Overview
- Distributed Energy Resources
- Proposed Modeling Assumptions

2nd Public Advisory Meeting - July 18, 2014

- Demand Side Management Update

- Environmental Update
- Incorporating Stakeholder Input
- Presentation of Initial Ventyx Scenario Results

3rd Public Advisory Meeting - October 10, 2014

- Waste Water Analysis Results
- Updated Modeling Inputs and Assumptions
- Presentation of Ventyx Scenario Results
- Short Term Action Plan

Approximately 30 stakeholders were present at each of the three meetings including IPL residential, commercial and industrial customers, the Indiana Utility Regulatory Commission ("IURC"), the Office of Utility Consumer Councilor ("OUCC"), the Citizens Action Coalition ("CAC"), the Sierra Club, and other environmental and interest groups. After the first workshop, the Company responded to 112 comments and questions while an additional 29 comments and questions followed the second meeting. Modifications made as a result of stakeholder participation include: reduced the estimated cost of new wind resources, assigned a cost of carbon to every scenario evaluated, and created eight (8) scenarios versus four (4) scenarios to reflect multiple combinations of possible risks. The public advisory process increased transparency in IRP planning and was a conducive environment for discussion.

On October 31, 2014, IPL posted a non-technical summary on its IRP webpage including an overview of the Company and its existing resources, the public advisory process, the Company's current capacity position, and the Company's IRP scenarios, assumptions, and resulting preferred resource portfolio. A short term action plan and accompanying schedule is also described. The non-technical summary provides a simplified explanation of the Company's IRP.

The public advisory process was a productive way to include a variety of points of view and produce a more robust IRP. Stakeholder input drove changes to expand the number of scenarios IPL analyzed from four to eight, spurred the inclusion of additional wind sensitivity analysis, and helped IPL understand how to more effectively explain decision making processes. IPL welcomed suggested improvements for the 2016 process from participants which will be thoughtfully considered.

Meeting materials, stakeholder comments and questions, and meeting summaries are included in Volume II of this IRP and are available at https://www.iplpower.com/irp/.

Contemporary IRP Inputs and Methodology

[170-IAC 4-7-4(b)(11)]

IPL fully supports and employs a continuous improvement process for service reliability and efficient business management. As part of this process, IPL seeks to implement IRP best practices to improve the accuracy of our data, forecasts, risk mitigation and modeling. Since the 2011 IRP, the Company has completed the following activities:

- Included dynamic forecasted market prices in the model as well as market operations simulation whereby market resources or IPL units may be selected to meet IPL's load requirements
- Included a range of possible greenhouse gas regulatory impacts
- Updated data for weather normalization more frequently than was done in the past
- Described its experience with Distributed Generation ("DG") including impacts to transmission and distribution elements
- Implemented a public advisory process in the development of the IRP as described below
- Reviewed 2013 IRP documents filed by Indiana utilities and participated in 2014 IRP public advisory meetings conducted by NIPSCO and Vectren and applied lessons learned

As part of the Company's efforts to stay abreast of new and efficient methods, IPL employees have attended the Commission's annual IRP contemporary issues technical conferences in 2013 and 2014 as well as various industry conferences. IPL employees have also attended resource planning focus area conferences and trainings, such as:

- Association of Edison Illuminating Companies - Load Research Conference
- Itron, Inc - Forecasting 101Workshop: An Introduction to Forecasting
- Itron, Inc - Fundamentals of Sales and Demand Forecasting Workshop
- Itron, Inc - 11th Annual Energy Forecasting Meeting
- Itron, Inc - 12th Annual Energy Forecasting Meeting
- Edison Electric Institute - Load Forecasting Group Meeting

Risk Mitigation

[170-IAC 4-7-8(b)(7)(A)] [170-IAC 4-7-8(b)(7)(B)]

IPL regularly evaluates risks to its business and identifies means to mitigate these risks. As part of our normal business practices and for the IRP process, the risks and mitigation methods in Figure 2.1 are reviewed. The key risks that affect resource planning, as shown in the left-most column, drove the development of IPL's scenarios to analyze potential future impacts: environmental regulation, load variation, and fuel costs. Section 4 (Integration) describes how IPL's preferred resource plan mitigates these risks as best as possible, specifically the three key risks identified above.

Figure 2.1 – IPL Risks and Mitigation Methods

Risk	Description	Mitigating Measure
Environmental Regulation	As described fully in Section 3 of this IRP, a wide variety of regulations related to water, air, and waste continue to impact the electric utility industry and will do so in the near future.	To mitigate these risks, IPL carefully evaluates potential impacts and actively participates in the rulemaking processes including work with various industry trade groups and government agencies.
Load Variation	Loads may vary based on consumer usage behavior, demand response program participation, weather as described below, public policy and many economic drivers.	Planning reserve margins determined by MISO, above annual load forecasts, serve as mitigating measures to address increased load. IPL proactively manages costs regularly to mitigate the impacts of variable costs and revenues.
Fuel Costs	Commodity pricing varies based on supply, demand, and source.	IPL's contracts include fixed costs and market based commodity prices with variable index-based escalation factors. In addition, increasing generation portfolio fuel diversification will mitigate price increases. (See IHS report. "The Value of US Power Supply Diversity" dated July 2014 for more information.)
Fuel Supply	Commodity availability directly influences IPL's ability to run its generating units efficiently. Shortages may occur during high volume periods including seasonal peaks.	IPL maintains inventory of 35 to 50 days for coal resources. In addition, long-term coal supply contracts that rotate on a three (3) year cycle are negotiated. IPL's existing natural gas units have run intermittently which did not justify the need for contracts with fixed demand charges. For units to be refueled and the new CCGT, IPL contracts for firm delivery and no-notice services for natural gas to mitigate fuel availability risks. IPL maintains firm transportation for the new Eagle Valley CCGT unit which can also serve the Harding Street units. As generating units are refueled to NG, IPL will contract for additional firm transportation as necessary.
MISO Market Changes	As a member of MISO, IPL is subject to changes in FERC approved MISO tariffs and business practices which may impact operations and long-term planning. These may be in the area of capacity credits, transmission expansion policy and costs, or demand response design.	IPL actively participates in MISO stakeholders processes including the Transmission Owners Committee to mitigate risks of changes. If needed, IPL intervenes at FERC to protect the best interests of its customers.
Weather	Variances in weather directly affect IPL's retail load requirements, costs and revenues.	IPL evaluates 30 year weather patterns as part of the IRP process to forecast loads. In addition, high, low and base load forecasts were evaluated within scenarios to determine possible resource requirement outcomes.
Workforce Availability	Labor intensive operations require consistent highly trained staff	IPL regularly negotiates contracts with bargaining unit employees and contractors to ensure qualified staff are available to perform necessary work. In addition, IPL's total rewards compensation is competitive within

		the utility industry to retain employees.
Reliability	Outages to distribution and occasionally transmission equipment due to public vehicular accidents, storms or mechanical failures can impact service reliability. In addition, transmission system design limitations affect the amount of power that can be imported to the IPL 138 kV system.	IPL's plans to site generation close to its load center and connect it to its 138 kV system. This intentionally mitigates risks of limited import capabilities and fluctuations in voltage and reactive power.
Technology Advancements	Over the past several years, resource technologies continue to evolve to decrease costs and improve efficiencies. These may include gas turbines, distributed generation, solar PV, wind turbines, battery storage, electric vehicles, fuel cells, demand response, energy management systems and other applications.	IPL stays abreast of technology cost trends and uses up to date information in the IRP. For example, the CCGT and wind turbine capital costs in this IRP are lower than the 2011 IRP. IPL continues to connect solar DG facilities from 2 kW to 10 MW through net metering and Rate REP programs and learn from its operational experience in this area. For the first time, IPL has included DG capacity in its IRP. IPL continues to research best practices in this area and monitor developments in terms of innovation and adoption rates to plan for future impacts.
Construction Costs	Construction expenses vary based on commodity costs, scope creep, labor and material expenses.	IPL works diligently to schedule and manage its internal and contracted resources. It competitively bids contracts, negotiates fixed fees whenever commercially practical, coordinates changes in scope closely to minimize cost increases, requires transparent regular reporting of progress and costs and open audit rights to verify vendor expenses when negotiating vendor contracts. Cost savings are captured through project management efforts and reflected in fair rates and charges.
Production Cost Risk	Variances in production costs are dependent upon electricity demand, fuel supply, market pricing and other factors.	IPL's diverse portfolio helps to mitigate production cost risks through varying fuels, that is, coal, natural gas, oil, wind and solar, as well as technologies including simple and combined cycle turbines, distributed generation, demand response, etc.
Generation Availability	Generation equipment is subject to electro-mechanical failures which directly impact the availability of the units to produce electricity.	In accordance with asset management best practices, IPL performs planned maintenance on a regular basis and performs root causes analyses when failures occur as means to mitigate these risks.
Access to Capital	Adequate funding to finance large capital projects is essential to long-term business success. Varying interest rates and capital access may affect this.	IPL manages a balanced financial portfolio through a blend of equity, short term and long term debt to mitigate these risks.

Regulatory Risk	There is jurisdictional overlap in several areas where FERC has jurisdiction relative to markets, but the primary responsibility resides with the States. Jurisdiction over Resource Adequacy and Demand Response are two of those overlap areas.	IPL actively engages with MISO, IURC, FERC, and the Organization of MISO States (OMS) to clarify the jurisdiction and maintain appropriate outcomes for its customers. Educating stakeholders and listening to other points of view helps to create collaborative results whenever possible.
Misc. Catastrophic Events	Major events such as weather catastrophes can occur as part of normal business	IPL has concrete plans for business continuity/disaster recovery for each area and the Company as a whole. Annual drills in critical areas such as T&D operations are conducted. Debrief sessions are held to identify lessons learned and identify improvements.

Financing

[170-IAC 4-7-8(b)(6)(D)]

As identified above, access to capital is a critical component of managing the electric utility business. IPL must secure funding to complete capital projects. IPL expects that existing cash balances, cash generated from operating activities and borrowing capacity on our committed credit facility will be adequate for the foreseeable future to meet anticipated operating expenses, interest expense on outstanding indebtedness and recurring capital expenditures, and to pay dividends to the owners of the business. Sources for principal payments on outstanding indebtedness and nonrecurring capital expenditures are expected to be obtained from: (i) existing cash balances; (ii) cash generated from operating activities; (iii) borrowing capacity on our committed credit facility; and (iv) additional debt financing. In addition, due to current and expected future environmental regulations, it is expected that equity capital will continue to be used as a significant funding source. AES has approved significant equity investments in IPL for its proposed nonrecurring capital expenditures from 2013 through 2017; for example, on June 27, 2014, IPALCO received an equity capital contribution of $106.4 million from AES for funding needs related to IPL's environmental and replacement generation projects, which IPALCO then made the same investment in IPL.

All of IPL's long-term borrowings must first be approved by the IURC and the aggregate amount of IPL's short-term indebtedness must be approved by the Federal Energy Regulatory Commission (FERC). IPL has received FERC approval to borrow up to $500 million of short-term indebtedness outstanding at any time through July 28, 2016. In December 2013, IPL received an order from the IURC granting the authority through December 31, 2016 to, among other things, issue up to $425 million in aggregate principal amount of long-term debt (inclusive of $130 million of IPL first mortgage bonds issued in June 2014).

Demand Side Management

IPL has continually offered DSM since 1993. But since the last IPL IRP was completed in 2011, the landscape for DSM in Indiana has changed significantly. Prior DSM efforts were influenced by the significant energy efficiency targets established in the IURC Phase II Generic Order. These targets provided the direction for the amount of DSM efforts in the State of Indiana through the end of 2014. The Generic Order also established five Core DSM Programs and identified the mechanism for these Core programs to be delivered by a state-wide third party administrator.

The 2013-2014 Indiana General Assembly passed Senate Enrolled Act 340 ("SEA 340"), which, among other things, (1) effectively terminated the Generic DSM Order's savings goals and (2) provided the industrial customers with demand at a single site greater than one MW the opportunity to opt-out of participation in utility sponsored energy efficiency programs.

(1) While the IURC's Generic Order was the dominant factor in shaping DSM developments in Indiana, IPL is committed to continue to offer cost effective DSM programs to its customers. A confluence of internal and external influences has prompted IPL, and the electric industry as a whole, to make a concerted effort to increase the levels of DSM offerings to its customers. Increasing fuel costs and volatility, a looming build cycle for new generation and environmental concerns have caused renewed interest in DSM.

(2) While it is still uncertain to what extent customer opt-outs will reduce the DSM market potential in IPL's service territory, there will be some reduction in potential. However, the reduction in DSM opportunities may be mitigated to the extent that large customers create energy efficiency projects on their own. IPL plans to submit comments to the EPA as part of the CPP rule making process and will suggest that opt-out customers report their energy efficiency savings to the appropriate agency. This information will aid in IPL's ability to comply with the CPP.

Forecast

[170-IAC 4-7-5(a)(4)]

Economic conditions have improved at a slower than anticipated recovery rate from the financial crisis in 2008-2009. Although Indiana's Gross State Product ("GSP") and other key economic indicators are back to pre-recession levels, future conditions are viewed to not achieve pre-recession growth rates. According to Moody's Analytics, Indiana's economy is expected to experience an uptick in 2014 and 2015 with GSP growth rates of 3.6% and 3.4% respectively. After this improvement, growth in Indiana's economy is expected to slow down to 1.3% in the following two years. The reduced growth expectations results from negative demographic trends such as an aging workforce, lowering the growth of the labor force, accompanied by political uncertainty surrounding the current Federal Budget Crisis and future inflation rates. Indiana's GSP is forecast to level off at a modest 1.6% for the following 6 years. This growth in economic activity is mainly driven by growth in manufacturing and household income. Sales before any DSM adjustments are expected to grow at a compound annual growth rate of 1.2% over the next three years, and 0.7% over the next 20 years. The growth-rate drops to 0.7% over the next three years after DSM savings are netted out. In other words, DSM is forecasted to address 42% of the estimated load growth.

Fuel Landscape

[170-IAC 4-7-4(b)(7)]

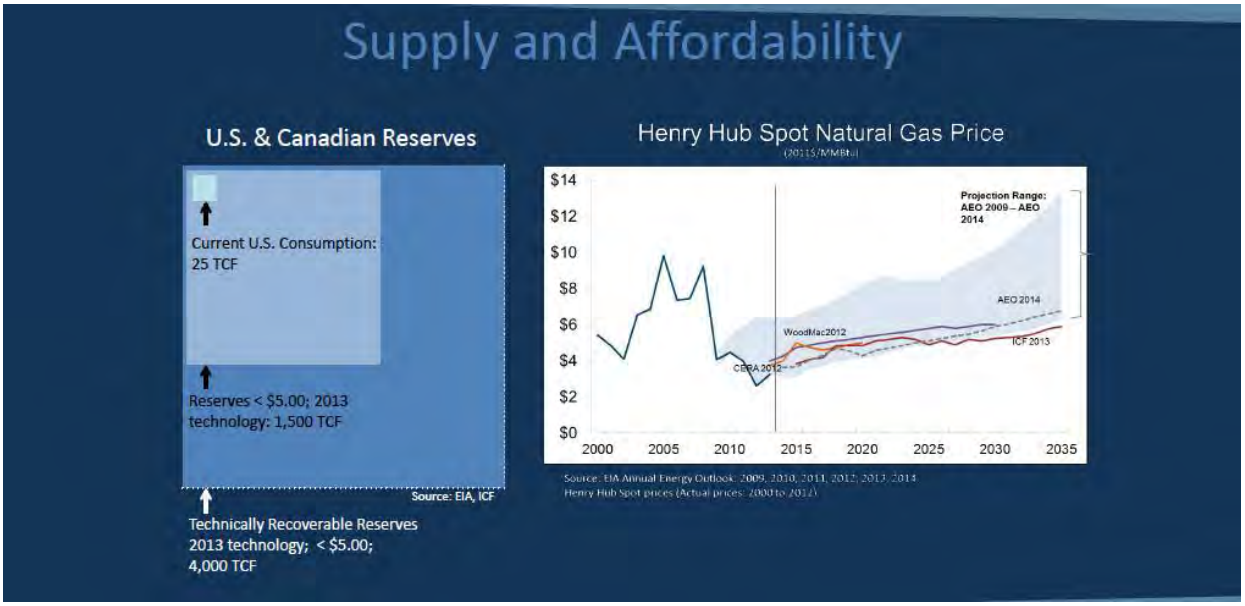
After 2017, IPL expects to increasingly use natural gas within its generation fleet. The emergence of shale gas into the United States ("U.S.") natural gas ("NG") supply has sparked a renaissance in domestic NG markets. As little as a decade ago, the outlook for U.S. NG production was rather bleak. Reserves in conventional wells had peaked and begun to decline in 2001 with little expectation for a reversal. Tight supplies and expensive and unreliable liquefied natural gas imports were the expected new normal of the U.S. natural gas market. However, developments in hydraulic fracturing technologies and directional drilling brought the massive quantities of shale gas from what was one of the most expensive sources in the market to one of the cheapest. In fact, the United States is now the largest producer of natural gas in the world, having surpassed Russia and Iran (Canada is now in fourth place).

Furthermore, shorter drilling times and front-loaded well yields make shale supplies more flexible to swings in demand and less expensive. This is particularly true of "wet gas plays" where the associated oil and natural-gas liquids drive the drilling and natural-gas is a "by-product" of the effort.

Figure 2.2 below, prepared by the America's Natural Gas Alliance, and based upon EIA and ICF consulting data, puts this information into graphic format. On the left are three interweaved boxes. The smallest, in the left-hand corner, shows current U.S. natural gas consumption. The other two boxes show current U.S. reserves of natural-gas and additional reserves which are technically recoverable. Although current consumption of natural gas is huge in the U.S. (25 TCF), reserves and technically-recoverable reserves are much, much higher.

Likewise, on the right side of Figure 2.2, the price forecast for natural gas is flatter and more stable – as opposed to the area in light blue shading which shows the earlier forecasts of much higher natural-gas prices. The historic numbers for pricing shows high volatility with natural-gas prices swinging from low to high. This volatility was caused both by declining supplies of natural gas, and reliance on one primary natural-gas basin (the gulf coast). Storms in the Gulf of Mexico would cause production to be halted which in turn drove up prices. One of the additional benefits of the shale revolution is to open up many different natural-gas basins in the U.S. For example, Indiana will increasing receive natural gas from Pennsylvania and Ohio.

Figure 2.2 – EIA and ICF Natural Gas Supply and Affordability



Source: EIA, ICF

In addition to plentiful supply in the United States, the Indianapolis region is bisected by five major natural-gas pipelines. These allow natural-gas power plants in Central Indiana to source fuel from the Gulf of Mexico, the Rocky Mountain region and the new shale playes in Pennsylvania and Ohio.

It is now widely expected that the electricity generation sector will significantly grow its natural gas generation fleet to be significant consumers of this plentiful resource. In response to these factors, the price, according to Ventyx, stabilizes over the next 20 years as shown in Section 7, Confidential Attachment 5.1, Ventyx IPL IRP Modeling Summary. More discussion and industry commentary on NG markets can be found in Section 4D, Market Trends and Forecasts, Fuel Forecasts.

Although IPL expects to increasingly use natural gas within its generation fleet, the Company values coal as a stable, low cost and reliable fuel source. Coal is a regional strength, especially for IPL's Petersburg units which are located close to coal mines reducing transportation cost and risk. Coal plays an important role in portfolio diversification as described in the July 2014 IHS report "The Value of US Power Supply Diversity."

Environmental Landscape

[170-IAC 4-7-6(a)(4)]   [170-IAC 4-7-7(a)(1)]   [170-IAC 4-7-7(a)(2)]

The Environmental Protection Agency ("EPA") is in the process of developing and implementing various regulations that will especially impact coal-fired fleet generation. The environmental challenges facing utilities is unprecedented in terms of the number of rules coming due simultaneously, the compressed time frame for compliance and the wide array of rules covering all environmental media. There are a number of environmental initiatives that are being considered at the federal level that may impact the cost of electricity derived from the burning of coal. This includes, but is not limited to:

- Cross State Air Pollution Rule ("CSAPR") - While IPL cannot predict the outcome of the final Rule, we expect to comply through the successful operation of our existing pollution control equipment. In addition, IPL may purchase NO_x and/or SO_2 allowances on the open market to supplement our compliance plan.
- National Ambient Air Quality Standards ("NAAQS") - The areas in which IPL operates are all currently designated as nonattainment for SO_2. As a result, IDEM must develop a State Implementation Plan ("SIP") establishing new requirements to ensure that the areas return to attainment. The impact of the SO_2 NAAQS will be dependent upon the final SIP developed by IDEM.
- Greenhouse Gas ("GHG") Regulation - At this time, IPL cannot predict the final outcome of the Clean Power Plan as it is currently a proposed rule and the State will have discretion in its implementation. However, based on the proposed rule, the impacts may include decreased dispatch of coal-fired generation, increased dispatch of natural gas and renewable generation, and increased demand side energy efficiency measures.
- Cooling Water Intake Structures, Clean Water Act Section 316(b) - The rule could require closed cycle cooling systems. Alternatively, utilities could be faced with installing less costly controls, like modified travelling screens and fish handling and return systems. Three of the five IPL coal-fired units are currently equipped with closed cycle cooling systems. Another is equipped with a cooling tower which dissipates approximately one-half of the waste heat generated by that unit. The impact of this rule will be dependent upon Indiana Department of Environmental Management's ("IDEM") determination for Best Technology Available for the IPL generating stations.
- Coal Combustion Residuals ("CCR") - It is currently expected that EPA will issue a final rule in December 2014. The outcome could potentially require closure and capping of existing ponds, additional CCR disposal costs, and the installation of groundwater monitoring.

These Rules may require additional investment for compliance. Planning for compliance is complicated by the significant level of uncertainty surrounding the final outcome of the regulations, including impacts and timing and potential legislative activity. See Section 3 for a more detailed discussion of anticipated environmental impacts.

Transmission Expansion Cost Sharing

[170-IAC 4-7-6(d)(4)]

Since the last IRP, both at the state level and in the MISO tariff, the right of first refusal for transmission projects needed for reliability to be built by the incumbent utility has been preserved. Effective with the 2015 planning cycle, due to the implementation of FERC Order 1000, the right to develop Market Efficiency and Multi-Value transmission projects ("MEPs" and "MVPs") has opened up to third party transmission developers. This event necessitates a process to qualify transmission developers and to select a developer to build the project. This will add up to three years to the process of placing transmission enhancements in service. FERC demands that incumbent utilities who wish to bid on projects not directly connected to their own transmission systems compete with third parties for the right to build and therefore must submit a developer application to MISO for evaluation. If the project is directly connected to the incumbent's transmission system, no application is required; however, the incumbent still must compete for the right to build MEPs or MVPs. To preserve its right to develop transmission projects of all types and locations, IPL has completed the application process dictated by the MISO tariff. As one result of implementation of FERC Order 1000, MISO has proposed numerous changes to the project types that will be vetted through the stakeholder process in the coming months. Additionally, due to the integration of Entergy into the MISO system at the end of 2013, changes to the kV bright lines of MEPs and MVPs are proposed. If those bright lines are lowered as proposed, IPL will be required to pay a greater portion of the shared costs of transmission in the now much larger footprint.

Battery Energy Storage Systems

Ongoing cost reductions and technology improvements driven by consumer electronics (cell phones, laptops) and electric vehicle applications continue to improve opportunities for battery-based energy storage systems ("BESS") as resources on the electricity grid. BESS systems are being installed on power grids around the world in ever larger sizes. Lithium-ion batteries are used in much of recent BESS development, though significant research and development ("R&D") is underway on a wide range of chemistries with the promise of quantum reductions in battery energy density.

Major BESS components are interconnection facilities, power conditioning systems, and batteries. Battery arrays typically operate up to 1000 Volts DC and are connected to Power Conditioning Systems ("PCS") for transformation to AC power. PCSs are most typically bi-directional Insulated-gate bipolar transistor "(IGBT') based inverter systems converting AC power to DC to charge batteries and converting DC to AC power when discharging. PCSs operate typically at 480V on the AC side to 1000V on the DC side. Inverters are bi-directional versions of inverter systems typically used in solar and wind electricity generating applications, and have also been used for many years in motor drives and industrial processes. Interconnection facilities connect PCSs to electricity grid distribution and transmission voltages by way of step-up/step-down transformers – the same common electrical equipment used in all power system generation and load applications. The permitting profile of a BESS is more benign that traditional power resources. There are no air emissions, no water consumption for cooling, and no fuel supply is needed except for a connection to the power grid. A BESS consists of simple structures containing energy storage equipment and electric transformers with switchgear, similar to a data center.

AES (IPL's parent company) is a worldwide leader in energy storage applications. In fact, the first test units ever deployed by AES were at the IPL Glens Valley Substation.

IPL Battery Storage Project- IPL is in the late-stages of analyzing several options, including up to a 20 MW BESS within Indianapolis and MISO regional transmission area which would likely be located within the IPL 138 kV grid. The immediate benefit that the BESS would provide to customers is fast-response frequency regulation for the grid. To maintain grid stability, load (demand for electricity) and generation (supply of electricity) must be in balance on a real time basis. The grid currently sends AGC (automatic generation control) signals to traditional power plants to either increase or decrease their output to keep the system in balance. Although this is an adequate way to provide frequency regulation, it is inferior to fast-response batteries which can instantaneously add or remove power to the grid. This has been proven within the nearby PJM regional transmission system.

Although frequency regulation of a BESS project is the immediate commercial benefit to IPL customers, IPL will also explore and pilot studies on other applications such as renewables integration focusing on solar, ramping, peak shaving, as a capacity resource in lieu of traditional combustion turbines, black start capability, and VAR support ("Volt Ampere Reactive"). IPL has begun the initial process with MISO for the required studies for a BESS system, as well as continuing in-house engineering and regulatory analysis. IPL is also modeling the current ancillary services pricing within the MISO market which will have a significant impact on whether to deploy a system sooner or later. IPL plans to provide additional information on this project to stakeholders as appropriate. While IPL is investigating the feasibility of installing a Battery Energy Storage System ("BESS") to provide ancillary services, capacity and pilot testing for renewable integration, it was not included as a separate new resource in the Ventyx model for this IRP due to MISO tariff conditions, which are not favorable to energy storage.[11]

[11] IPL is working with MISO to adapt its tariff and Business Practice Manuals to treat BESS appropriately.

Section 3. ENVIRONMENTAL RULES and REGULATIONS

[170-IAC 4-7-7(a)(1)] [170-IAC 4-7-7(a)(2)] [170-IAC 4-7-8(b)(7)(A)]

EPA is in the process of developing and implementing a new suite of rules that will impact coal-fired fleet generation. The environmental challenges facing utilities is unprecedented in terms of (1) the number of rules coming due simultaneously; (2) the compressed time frame for compliance; and (3) the wide array of rules covering all environmental media. As it relates to air, EPA is regulating for the first time greenhouse gas ("GHG") emissions. As it relates to water, EPA is regulating cooling water intake structures. Finally, as it relates to solid waste, EPA is proposing further restrictions for ash management. The most recent impending EPA rules include, but are not limited to the following:

- In June 2010, EPA proposed revised regulations for Coal Combustion Residuals ("CCRs") with consideration of two primary options: (a) regulate CCRs as a solid waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"); or (b) regulate ash as a hazardous waste under Subtitle C of RCRA.
- In January 2013, EPA lowered the National Ambient Air Quality Standard ("NAAQS") for particulate matter.
- In June 2013, EPA proposed revisions to the Clean Water Act's effluent limitation guidelines regulations for the steam electric power generating industry.
- In January 2014, EPA re-proposed the New Source Performance Standard ("NSPS") for GHGs for new sources.
- On April 29, 2014, the Supreme Court upheld EPA's July 2011 Cross State Air Pollution Rule ("CSAPR"), which regulates SO_2 and NO_x emissions, remanding the Rule to the D.C. Circuit, which lifted the stay on October 23, 2014.
- In June 2014, EPA proposed the Clean Power Plan which would regulate GHGs from existing sources.
- In August 2014, EPA finalized a revised regulation requiring utilities to reduce the adverse impacts to fish and other aquatic life caused by cooling water intake structures.

These rules may require additional investment for compliance. Planning for compliance with these regulations is complicated by the significant level of uncertainty surrounding the final outcome of the regulations, including impacts, timing and potential legislative activity.

In light of these uncertainties, each of the EPA rules will be discussed in detail later in this section following a review of the existing environmental rules and regulations.

Existing Regulations – Significant Environmental Effects

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

Air Emissions

IPL is subject to regulation on the following air emissions: Sulfur Dioxide, Nitrogen Oxide, Regional Haze, Mercury and Air Toxics Standard ("MATS"), National Ambient Air Quality Standard, and Greenhouse Gas.

Sulfur Dioxide

Title IV of the Clean Air Act Amendments of 1990 ("CAAA") established a two-phase statutory program to reduce SO_2 emissions. The EPA allocated SO_2 emissions allowances based on a formula that uses historical operating data for specified years multiplied by the allowable limit and then converted to tons of emissions allowed. These tons of emissions are called "allowances" that can then be bought, sold or transferred between units for compliance purposes. Phase I of the program became effective on January 1, 1995, for larger, higher emitting units. In Phase I, the EPA allocated SO_2 emissions allowances based on an emission rate of 2.5 lbs. per MMBtu. Phase II of the program became effective on January 1, 2000, and the EPA lowered the emissions rate used to allocate SO_2 allowances from 2.5 to 1.2 lbs. per MMBtu.

In response to this regulatory program, IPL developed an Acid Rain Compliance Plan that was submitted to the IURC on July 1, 1992, (IURC Cause No. 39437) and subsequently approved on August 18, 1993. This plan called for the installation of two SO_2 retrofit Flue Gas Desulfurization ("FGD") units on Pete Unit 1 and Pete Unit 2. These FGD units were placed in-service in 1996. FGD is the technology used for removing SO_2 from the exhaust flue gases in power plants that burn coal or oil to produce steam for the steam turbines that drive their electricity generators.

The SO_2 regulations remained relatively unchanged as did the IPL compliance plan until March 10, 2005, when the EPA issued Clean Air Interstate Rule ("CAIR") which covered the 28 eastern states and the District of Columbia ("D.C."). The federal CAIR established a two-phase regional cap-and-trade program for SO_2 and NO_x. Phase I of CAIR for SO_2 had an effective date of January 1, 2010, and reduced SO_2 emissions by 4.3 million tons; 45% lower than 2003 levels. Phase II of CAIR, was scheduled to become effective on January 1, 2015.

In anticipation of this CAIR regulatory program and to help meet the existing CAAA regulatory requirements, IPL developed a Multi-Pollutant Plan ("MPP") that was submitted to the IURC on July 29, 2004, (IURC Cause No. 42700) requesting approval of certain core elements of the plan which were approved on November 30, 2004. In order to reduce SO_2 emissions, IPL completed the Petersburg Generating Station ("Pete") Unit 3 FGD enhancement (May 2006) and the new Harding Street Generating Station ("HSS") Unit 7 FGD (September 2007). IPL also identified the enhancement of the Pete Unit 4 FGD as a core element of its MPP. IPL also completed a

Pete Unit 4 FGD upgrade project (IURC Cause No. 43403 approved April 2, 2008) in 2011 to help meet the additional SO_2 emission reduction requirements. IPL materially meets the Phase I CAIR requirements for SO_2 upon completion of all of these projects. However, IPL supplements its compliance plan with the purchase of emission allowances on the open market as needed.

As IPL was developing and implementing its MPP, the United States ("U.S.") Court of Appeals for the D.C. Circuit vacated the federal CAIR in July 2008 and remanded it to the EPA. Subsequently, in September 2008, the EPA moved for rehearing to the full bench (en banc). In December 2008, the U.S. Court of Appeals for the D.C. Circuit issued an order requiring the EPA to revise the federal CAIR and reinstate the effectiveness of the existing rule until the EPA revises CAIR. Thus, CAIR has remained in effect and will do so until a replacement rule is in place.

In August 2010, the EPA issued a proposed replacement rule, known as CSAPR, which was subsequently finalized in July 2011. The CSAPR mandated additional cuts in SO_2 and NO_x emissions in two phases: 2012 and 2014. Further, it was a modified cap and trade rule with unlimited trading of allowances within individual states but limited interstate trading. However, prior to CSAPR becoming effective in 2012, several appeals were filed challenging its implementation. On December 31, 2011, the Court granted a request for stay and instructed EPA to implement CAIR during the stay. On August 21, 2012, the Court vacated and remanded back to EPA the CSAPR. As a result, CAIR remains in effect.

On April 29, 2014, the Supreme Court upheld CSAPR, remanding the Rule to the D.C. Circuit Court which lifted the stay on October 23, 2014. Many uncertainties remain related to the potential implementation of CSAPR, including timing, allocation of allowances, and market pricing. As it relates to timing, the D.C. Circuit Court did not specifically address the timeline suggested by EPA, which includes implementation of Phase I in 2015 and implementation of Phase II in 2017. As it relates to allowances, they may be allocated as originally included in the final Rule or EPA may re-evaluate and re-allocate allowances prior to re-instating the Rule. EPA may address new lower standards in the Rule prior to implementation, making the Rule more stringent. As a result of the uncertainty around the timing and allocation of allowances, there is also significant uncertainty around market pricing associated with this final Rule.

While we cannot predict the outcome of the Court decision or the final Rule which will be implemented, we expect that such a Rule would have a similar impact as that of CAIR or the original CSAPR. As such, IPL expects to comply through the successful operation of our existing pollution control equipment. In addition, IPL may be required to purchase NO_x and/or SO_2 allowances on the open market to supplement its compliance plan.

Nitrogen Oxide

On September 24, 1998, the EPA issued a final rule, referred to as the NO_x State Implementation Plan ("SIP") Call. The rule imposed more stringent limits on NO_x emissions from fossil fuel-fired steam electric generators in 21 states in the eastern third of the U.S., including Indiana. In June 2001, the Indiana Air Pollution Control Board adopted the Federal NO_x SIP Call rule requiring IPL and other Indiana utilities to meet a system wide NO_x emissions rate of 0.15 lb. MMBtu during the annual ozone season from May 1 – September 30 each year. In a similar fashion with the CAAA, compliance was demonstrated via an emission allowance trading program. In order to meet these more stringent NO_x emission reduction requirements which became effective in 2004, IPL installed Selective Catalytic Reduction ("SCR") equipment on Pete Unit 2, Pete Unit 3 and HSS Unit 7 along with several low NO_x clean coal technology ("CCT") projects on other units. The Pete SCR units commenced operations in May 2004 whereas the HSS Unit 7 SCR came online in May 2005.

As previously discussed, the EPA issued CAIR in May 2005. The federal CAIR not only required additional SO_2 emission reductions but it also required further NO_x emission reductions. Phase I of CAIR became effective for NO_x on January 1, 2009, and required NO_x emission reductions by 1.7 million tons, 53% from 2003 levels. In addition, for the first time, NO_x compliance was required on a year-round basis in addition to the annual summer ozone requirements. Phase II of CAIR was scheduled to become effective on January 1, 2015.

IPL has already substantially met the Phase I CAIR emission reduction requirements for NO_x as a result of the installation of the SCR equipment on Pete Unit 2, Pete Unit 3 and HSS Unit 7. The only major impact from CAIR Phase I is IPL must now operate its NO_x emission reduction equipment on a year-round basis.

As mentioned earlier, EPA issued replacement rule, known as CSAPR, which has faced legal challenges for which the details of the outcome remain unknown.

Regional Haze

A Regional Haze rule established planning and emissions reduction timelines for states to use to improve visibility in national parks throughout the U.S. The rule sets guidelines for states in setting Best Available Retrofit Technology ("BART") at older power plants. The EPA determined that states, such as Indiana, which adopt the federal CAIR cap-and-trade program for SO_2 and NO_x will be allowed to apply federal CAIR controls to satisfy BART requirements. The Indiana Air Pollution Control Board also approved a final rule implementing BART which provides that sources in compliance with federal CAIR controls are also in compliance with BART requirements for SO_2 and NO_x. It is anticipated the CSAPR will also meet the BART requirements.

Mercury and Air Toxics Standard ("MATS")

In February 2012, EPA issued the final MATS Rule. MATS places strict emission standards equivalent to the top twelve percent in the industry for each of the four groups of Hazardous Air Pollutants ("HAPs"), as defined in Section 112 of the Clean Air Act ("CAA"): (1) mercury ("Hg"); (2) non-mercury metal HAPs (e.g., barium, beryllium, cadmium, and chromium, among others); (3) acid gas HAPs (e.g., hydrochloric acid ("HCl"); and (4) organic HAPs (e.g., dioxins and furans).

First, the MATS rule establishes a mercury limit of 1.2 lbs/TBtu on a 30-day rolling average on a single unit basis. The rule also allows for emissions averaging on multiple units. In the case of averaging multiple units, the rule establishes a mercury limit of 1.0 lb/TBtu on a 90-day rolling average. EPA allows emissions to be monitored using either Hg continuous emissions monitoring system ("CEMS") or sorbent trap monitoring. Second, the MATS rule limits acid gas emissions by establishing an emissions limit on HCl of 0.0020 1b/MMBtu with compliance demonstrated by frequent stack testing or HCl CEMS. Third, the MATS rule limits non-mercury metal HAPs. The rule allows compliance to be demonstrated with a filterable particulate matter limit of 0.030 lb/MMBtu, based on PM continuous parametric monitoring system ("CPMS"), PM CEMS, or frequent stack testing.

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

IPL received IURC approval in Cause No. 44242 to proceed with its MATS Compliance Plans and construction of Petersburg controls is currently underway. However, it was later determined that when considering the cost of complying with National Pollutant Discharge Elimination System ("NPDES") requirements and other potential future environmental regulations for HSS Unit 7 that the MATS controls were no longer economical and are no longer being installed for HSS Unit 7. IPL has proposed in Cause No. 44540 to refuel HSS Unit 7 from coal to natural gas. The costs, if approved, are listed in Section 5, Short Term Action Plan, Figure 5.5. See the Water section below for more detail on NPDES requirements.

National Ambient Air Quality Standards

EPA is required under the CAA to set NAAQS for air pollutants that endanger public health or welfare. There are several NAAQS but only three directly impacting coal-fired power plants: SO_2, ozone, and particulate. NAAQS do not directly limit emissions from utilities, but states must develop State Implementation Plans ("SIPs") to achieve emissions reductions to address each NAAQS when an area is designated as nonattainment.

Currently, the counties in which IPL operates (Marion, Morgan, and Pike) are designated as attainment or unclassifiable for all pollutants, except SO_2. The areas in which IPL operates are all currently designated as nonattainment for SO_2. As a result, IDEM must develop a SIP establishing new requirements to ensure that the areas return to attainment. This is discussed in greater detail in the next section.

Greenhouse Gas

The only current national regulation for GHG is for existing sources with significant increases in emissions and for new sources. Congress has been unable to implement a national GHG program due to the potential impacts on a struggling economy. Potential future regulation in this area is discussed in the Impending and Future Regulations later in this section.

Existing Controls to Reduce Air Emissions

As shown in Figure 3.1 below, IPL has already installed a myriad of environmental pollution control equipment. IPL has invested over $600 million in the last ten years which has significantly reduced IPL's NO_x, SO_2, and particulate matter emissions as outlined below.

- Pete Unit 2 and Pete Unit 3 SCR in 2004
- HSS Unit 7 SCR in 2005
- Pete Unit 3 FGD upgrade in 2006
- HSS Unit 7 FGD in 2007
- Pete Unit 4 FGD upgrade 2011

Figure 3.1 – IPL Generating Units: Environmental Controls

Unit	Fuel	ICAP Rating (MW)	Environmental Controls
Pete Unit 1	Coal	230	FGD, NN, LNB/OFA
Pete Unit 2	Coal	415	FGD, SCR, LNB/OFA
Pete Unit 3	Coal	540	FGD, SCR
Pete Unit 4	Coal	530	FGD, NN, LNB
Pete DG	Diesel	8	
	Subtotal	1,723	
HSS Unit 5	Coal	100	SNCR, NN, LNB/OFA
HSS Unit 6	Coal	100	SNCR, NN, LNB/OFA
HSS Unit 7	Coal	410	SCR, FGD, NN, LNB/OFA
HSS CTs 1-2	Oil	32	
HSS CT 4	Oil/Gas	79	Water Injection
HSS CT 5	Oil/Gas	79	Water Injection
HSS CT 6	Gas	154	LNB
HSS DG	Diesel	3	
	Subtotal	957	
Eagle Valley Unit 3	Coal	40	
Eagle Valley Unit 4	Coal	55	LNB/OFA
Eagle Valley Unit 5	Coal	61	LNB/OFA
Eagle Valley Unit 6	Coal	100	NN, LNB/OFA
Eagle Valley DG	Diesel	3	
	Subtotal	259	
Georgetown GT 1	Gas	75	LNB
Georgetown GT 4	Gas	75	LNB
	Subtotal	150	
	Total	3,089	

Source: IPL

Note: Acronyms used in Figure 3.1 – CCOFA (Closed-Coupled Overfire Air), FGD (Flue Gas Desulfurization), LNB (Low NOx Burner), NN (Neural Net), SCR (Selective Catalytic Reduction), SNCR (Selective Non-Catalytic Reduction), SOFA (Separated Overfire Air)

As a result of HSS refueling to NG, Petersburg MATS Controls, and Eagle Valley CCGT replacement generation, IPL expects to achieve considerable reductions in fleet-wide emission rates by 2017 from current (2013):

- 67% reduction in SO_2 emission rate
- 23% reduction in NO_x emission rate
- 23% reduction in PM emission rate
- 76% reduction in Hg emission rate
- 7% reduction in CO_2 emission rate

Water

The National Pollution Discharge Elimination System ("NPDES") permit system obtains its authority from Clean Water Act ("CWA"). Section 402 requires permits for the direct discharge of pollutants to the waters of the U.S. These permits, which IPL maintains for each of its power plants, have three main components: technology based and water quality based effluent limitations; monitoring requirements; and reporting requirements.

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

On August 28, 2012, the IDEM issued NPDES permit renewals to Petersburg and Harding Street. These permits contain new Water Quality Based Effluent Limits ("WQBELs") and Technology-Based Effluent Limits ("TBELs") for the regulated facility NPDES discharges with a compliance date of October 1, 2015 for the new WQBELs. IPL sought and received approval to extend this compliant date to September 29, 2017, through Agreed Orders from IDEM. The NPDES permits limit several pollutants, but the new mercury and selenium limits drive the need for additional wastewater treatment technologies at Petersburg and Harding Street. IPL determined that installation of the necessary wastewater treatment technologies and other potential future environmental requirements in addition to the necessary Mercury and Air Toxic Standard (MATS) controls described in IPL's case-in-chief Cause No. 44242 were no longer the reasonable least cost plan for HSS. Instead, IPL is currently proposing to refuel HSS Unit 7 to operate on natural gas which reduces the cost to comply with environmental regulations and reduces the impact on the environment.

In addition to establishing effluent limits, the NPDES permit also includes compliance requirements with Section 316(a) and Section 316(b) of CWA. Section 316(a) provides thermal effluent limitations for certain facility outfall discharges which IPL must meet. These limits ensure the facility does not harm the fish, shellfish, and wildlife of the receiving waterbody. Section 316(b) provides regulations requiring that facility cooling water intake structures demonstrate the best technology available to minimize adverse environmental impact. In addition, EPA has recently modified its cooling water intake regulations under Section 316(b) of CWA.

Solid Waste (Solid Waste, Hazardous Waste and Disposal)

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

Hazardous Waste

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

The three categories of hazardous waste are: 1) large quantity generator ("LQG"); 2) small quantity generator ("SQG"); and 3) conditionally exempt small quantity generator ("CESQG"). IPL plants are historically categorized as SQG and CESQG. As such, IPL faces minimal regulations and risk in this area.

Non-Hazardous Waste

Solid waste is regulated under Subtitle D of RCRA. IPL generates a large amount of solid waste every year that must be handled in accordance with this regulation. The primary sources of non-hazardous waste in the steam electric industry are fly ash, bottom ash, and scrubber sludge resulting from the FGD process. The fly ash and bottom ash are generated from the combustion of coal. Generally, IPL generates about 10% ash from the burning of coal or approximately 800,000 tons of ash per year, based on a typical coal burn of about 8,000,000 tons of Indiana coal per year. All ash is managed in accordance with federal, state and local laws and permits.

Ash is normally placed in ponds for treatment via sedimentation, to which the effluent is regulated pursuant to NPDES, shipped back to mines, and/or reused in an environmentally sound manner. In addition, fly ash is mixed with dewatered scrubber sludge and lime to make a stabilized product which is disposed of in a permitted, on-site landfill. Further, the Pete Units 1, 2, and 4 and HSS Unit 7 FGD, produce commercial grade gypsum from FGD operations that can be beneficially used for wallboard manufacturing, cement manufacturing, and agricultural use. In general, ash management activities have not changed for several years. However, more stringent ash management rules are anticipated, as discussed in the next section.

Pending and Future Regulations – Significant Environmental Effects

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

There are a number of environmental initiatives that are being considered at the federal level that may impact the cost of electricity derived from the burning of coal. This includes, but is not limited to more stringent regulations requiring:

- Additional SO_2 emission reductions
- Additional NO_x emissions reductions
- More stringent water management including 316(a) and 316(b)
- Metal and other various pollutant reductions associated with wastewater effluents
- More stringent ash management handling requirements for both wet and dry ash

Cross State Air Pollution Rule

The CAIR was promulgated in 2005, but was vacated by the D.C. Circuit Court. On appeal, the Court ruled that CAIR would remain in effect until such time as EPA promulgated a replacement rule. In August 2010, the EPA issued a proposed replacement rule, known as CSAPR, which was subsequently finalized in July 2011. The CSAPR mandated additional cuts in SO_2 and NO_x emissions in two phases: 2012 and 2014. Further, it was a modified cap and trade rule with unlimited trading of allowances within individual states but limited interstate trading. However, prior to CSAPR becoming effective in 2012, several appeals were filed challenging its implementation. On December 31, 2011, the Court granted a request for stay and instructed EPA to implement CAIR during the stay. On August 21, 2012, the Court vacated and remanded back to EPA the CSAPR. As a result, CAIR remains in effect.

On April 29, 2014, the Supreme Court upheld CSAPR, remanding the Rule to the D.C. Circuit Court which lifted the stay on October 23, 2014. Many uncertainties remain related to the potential implementation of CSAPR, including timing, allocation of allowances, and market pricing. As it relates to timing, the D.C. Circuit Court did not specifically address the timeline suggested by EPA, which includes implementation of Phase I in 2015 nd implementation of Phase II in 2017. As it relates to allowances, they may be allocated as originally included in the final Rule or EPA may re-evaluate and re-allocate allowances prior to re-instating the Rule. EPA may address new lower standards in the Rule prior to implementation, making the Rule more stringent. As a result of the uncertainty around the timing and allocation of allowances, there is also significant uncertainty around market pricing associated with this final Rule.

While we cannot predict the outcome of the Court decision or the final Rule which will be implemented, we expect that such a Rule would have a similar impact as that of CAIR or the original CSAPR. As such, IPL expects to comply through the successful operation of our existing pollution control equipment. In addition, IPL may be required to purchase NO_x and/or SO_2 allowances on the open market to supplement our compliance plan.

National Ambient Air Quality Standards

EPA is required under the CAA to set NAAQS for air pollutants that endanger public health or welfare. There are several NAAQS but only three directly impacting coal-fired power plants: SO_2, ozone, and particulate. NAAQS do not directly limit emissions from utilities, but states must develop State Implementation Plans ("SIPs") to achieve emissions reductions to address each NAAQS.

First, as it relates to SO_2, EPA added a new one hour standard for SO_2 of 75 ppb in June 2010. This short-term standard is more stringent than in prior standards and may require additional SO_2 reductions in any area that is designated as not meeting the standard (known as a non-attainment area). On July 25, 2013, the areas in which IPL's Harding Street, Eagle Valley, and Petersburg Generating Stations operate were designated as non-attainment for this standard. SO_2 reductions for coal-fired units may be required by a SIP developed to meet new SO_2 NAAQS as early as 2017. On September 10, 2014, IDEM published proposed SO_2 SIP limits for IPL facilities. IPL Petersburg will likely require enhanced operation of the existing FGDs to further reduce SO_2 emissions. IPL is currently evaluating the impact of the proposed limits on the Petersburg facility. IPL's Harding Street and Eagle Valley generating stations are expected to comply with the proposed limits because coal-fired operation will cease (pending IURC approval of conversion of HSS 7 to natural gas) prior to the compliance date of the SO_2 SIP, January 2017.

Second, in January 2010, EPA proposed a revision to the NAAQS for ozone. EPA subsequently indicated that it would not propose revisions to the ozone standard until 2013 or later. It is expected that EPA may propose a revision to the NAAQS for ozone in 2014. Although ozone is not directly emitted by power plants, it forms in the atmosphere as a result of chemical reactions involving NO_x and volatile organic compounds in the presence of sunlight. As such, utilities may be required to reduce emissions of NO_x as a result of the revised ozone NAAQS and associated SIP. It is expected that NAAQS attainment under a revised standard and compliance with associated SIP would be required by around 2020.

Third, on January 15, 2013, EPA issued a final rule, which lowered the NAAQS for fine particulate matter ("$PM_{2.5}$"). While designations are not yet final and IDEM has not developed a SIP, EPA has indicated that they expect 99% of counties (including all of Indiana) to meet the standard by 2020, when attainment is required, without any additional controls. In addition, the baghouses currently planned for installation on Petersburg Units 2 and 3 will further reduce $PM_{2.5}$ emissions.

Greenhouse Gas Regulation

On June 18, 2014, EPA published its proposed Clean Power Plan, which establishes the proposed Best System of Emissions Reductions available for existing sources in accordance with Section 111(d) of the Clean Air Act. The President has set a target date of June 1, 2015 for a final rule. States will then be expected to submit their implementation plans to EPA by June 30, 2016, with potential for a one to two year extension.

The proposed Clean Power Plan establishes state-specific rate-based (lbs CO_2/MWh) goals for carbon intensity for which States must develop plans in order to achieve by 2030. States may adopt the rate-based form of the goal of an equivalent mass-based form. EPA based these reductions on "building blocks," or measures of reduction, which include heat rate improvements for existing coal-fired EGUs, substituting generation from carbon-intensive affected EGUs with generation from existing (construction began prior to January 8, 2014) natural gas combined cycle units and renewables, and demand side energy efficiency. States may include some or all of these measures to varying degrees in their State regulations or they may use other measures.

For Indiana, the EPA proposal establishes an interim goal of 1,607 lbs CO_2/MWh, which must be achieved by the State of Indiana on average over the years 2020-2029, in addition to a final goal of 1,531 lbs CO_2/MWh which must be achieved by the State of Indiana in 2030. EPA based these standards on the "building blocks" previously mentioned. Specifically, EPA first used a basis of a six percent heat rate improvement of the coal-fired units in Indiana, which would result in a reduction from 2,158 to 2,029 lbs CO_2/MWh. Second, EPA based the standards on an increase in dispatch of existing natural gas combined cycle units from 53% capacity factor in 2012 to 70% capacity factor in 2020. Third, EPA based the standards on re-dispatch to renewables from a 2012 value of 3% of Indiana's total generation to a value of 6.6% by 2029. Lastly, EPA based the standards on Indiana achieving a 1.5% annual incremental savings as a percentage of retail sales by 2025 and cumulative savings as a percentage of retail sales of 11.66% by 2029.

At this time, we cannot predict the final outcome of the Clean Power Plan as it is currently a proposed rule and the State will have discretion in its implementation. However, based on the proposed rule, the impacts may include decreased dispatch of coal-fired generation, increased dispatch of natural gas and renewable generation, and increase demand side energy efficiency measures.

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

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. Specifically, the 316(b) Rule is intended to reduce the impacts to aquatic organisms through impingement and entrainment due to the withdrawal of cooling water by facilities. In April 2011, EPA published a proposed rule which would set requirements that establish the "Best Technology Available" to minimize such impact. EPA released a final rule on May 19, 2014.

The rule could require closed cycle cooling systems. Alternatively, utilities could be faced with installing less costly controls, like modified travelling screens and fish handling and return systems. Three of the five IPL coal-fired units are currently equipped with closed cycle cooling systems. Another is equipped with a cooling tower which dissipates approximately one-half of the waste heat generated by that unit. The impact of this rule will be dependent upon IDEM's determination for Best Technology Available for the IPL generating stations.

Coal Combustion Residuals (CCR)

Utilities generate ash and other CCRs from the burning of coal and associated activities. Some of the CCRs are beneficially used in products such as concrete and wallboard while some are generally treated in on-site ash ponds or disposed in on-site landfills.

On three separate occasions over the last 20 years, EPA has conducted extensive research on what impacts CCRs have on land and water. Each time, EPA has ruled that CCRs were not hazardous waste. Now, EPA is once again determining how and at what level to regulate CCRs. On June 21, 2010, EPA published regulations for CCRs. EPA indicated that it is considering two primary options: (a) regulate CCRs as a solid waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"); or (b) regulate ash as a hazardous waste under Subtitle C of RCRA. It is currently expected that EPA will issue a final rule in December 2014. The outcome could potentially require closure and capping of existing ponds, additional CCR disposal costs, and the installation of groundwater monitoring.

Summary of Potential Impacts

These regulations would potentially require IPL to incur additional expenses for compliance in the future. Figure 3.2 below provides a summary of these potential regulations including potential timing and preliminary cost estimates.

Figure 3.2 – Estimated Cost of Potential Environmental Regulations

Rule	Earliest Expected Compliance Date	Preliminary Estimated Capital	Preliminary Estimated Annual O&M
CSAPR	January 2015	$0	$0
CCR*	Late 2019	$21M-$30M	$3M-$35M
CWA 316(b)	2020	$6M-$154M	$0M-$6M
ELG	2018	$0M-$43M	$0M-$1M
GHG	2020	TBD	TBD
NAAQS	2017	$27M-$174M	$13M-$15M

*Includes estimated pond closure costs for the Petersburg Generating Station. It does not include the Eagle Valley Generating Station and HSS pond closure costs because IPL will incur those costs at the time they cease burning coal regardless of CCR outcome.

Source: IPL

Section 4. INTEGRATION

Resource Evaluation Process

[170-IAC 4-7-4(b) (1)] [170-IAC 4-7-8(a)]

The goal of IPL's integrated resource planning effort is to identify a resource plan that reliably serves IPL customers while meeting all federal, state, and IURC requirements, maintains rates at the reasonable least cost, and remains robust against the risks of uncertain future landscapes. This section describes the process to utilize modeling data inputs, define scenarios, assess capacity expansion plans, identify potential resource plans, analyze modeling results and select IPL's preferred resource portfolio. Subsections 4A through 4D contain detailed information to support the narrative as shown below.

Subsection	Topic
4A	Resource Options
4B	Demand Side Management
4C	Transmission and Distribution
4D	Markets Trends and Forecasts

To achieve this, IPL selects and tests resource plans against future landscapes that target the key drivers that may significantly impact the electric industry and IPL customers. IPL combines the outcome of the future landscape analyses with other resource selection requirements and targets to select a robust plan which meets IPL's resource goals and represents IPL's preferred resource portfolio strategy.

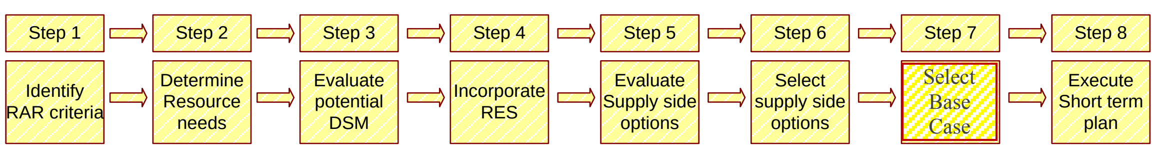
As discussed in detail in the Changing Business Landscape and Environmental Rules and Regulations (Sections 2 and 3), the electric industry faces a multitude of environmental challenges and landscape uncertainties, but also some opportunities for change. EPA's existing, pending, and future regulations governing air, water, and solid waste targeting coal-fired generation clearly challenges existing and future generation resources. Significant among the challenges are the recent and pending EPA rules governing mercury ("Hg") and hazardous air pollutants, and new rules and requirements pending around water and solid waste management. Additionally, Greenhouse gas ("GHG") regulation has recently been proposed by EPA through the Clean Power Plan increasing the challenges faced by existing and new generating units' owners and operators.

In addition, the Indiana General Assembly passed legislation eliminating the previously established IURC target levels of energy efficiency DSM. Regardless, future cost-effective DSM will continue to be a resource used by IPL, which will reduce IPL's future load growth and future supply needs. IPL has included significant DSM savings in this IRP as described in Section 4B.

The outlook for natural gas ("NG") supply and prices remains a positive note for utilities. The continued commercial use of hydraulic fracturing ("fracking") technology has opened up abundant reserves of shale gas supplies, driving NG supplies higher and prices lower. Forecasts reflect prolonged low NG prices throughout the 20 year forecasted period. NG supplies have historically been more risky relative to coal, but access to abundant gas created by fracking technology has reduced the volatility in gas markets, pricing, and sourcing reliability. Gas-fired generation remains a more viable resource consideration, especially in light of the proposed EPA Clean Power Plan since gas-fired generation emits significantly less GHG emissions than coal-fired generation.

To assist in modeling these drivers and conducting IPL's resource planning evaluation, IPL engaged Ventyx in a consulting and modeling role for its integrated resource planning. Ventyx's extensive modeling capability with the scenario analyses of future landscapes provides valuable insights into how specific resource plans perform against a range of possible outcomes. This cost-based evaluation is supplemented by additional decision criteria important to the planning process and ultimate resource selection. Inclusion of criteria, such as fuel source reliability and diversity, new technology reliability, demand side resources, and the timing of likely Greenhouse gas ("GHG") regulation, present planning challenges. IPL employs additional consultants with specific expertise in demand side management ("DSM") with multiple test criteria for DSM selection as described in Section 4B. The resource evaluation and planning at IPL follows a robust multi-step process, as shown below in Figure 4.1, which incorporates refining long-term plans based on dynamic challenges in business and regulatory environments. The goal of this process is to propose a preferred resource portfolio to provide IPL customers with long-term low cost, low risk and reliable electricity service.

Figure 4.1 – IPL's Resource Evaluation Process



Step 1. Identify resource planning criteria including the target reserve margin consistent with MISO resource adequacy requirements ("RAR").

Step 2. Determine resource needs to meet that criteria based on a gross internal demand ("GID") load forecast.

Step 3. Evaluate and model potential DSM programs and incorporate cost-effective DSM into the plan and also into a netted load forecast, to determine net internal demand ("NID"). Add demand response resources including Air

Conditioning Load Management ("ACLM"), interruptible rider programs, and smart grid enabled Conservation Voltage Reduction ("CVR") as resources. [12]

Step 4. Incorporate required supply resources, such as renewable generation, as appropriate and prudent as projected to be required by state or federal law. Currently, Indiana does not have a mandatory Renewable Energy Standard ("RES").

Step 5. Determine remaining resource requirements and evaluate needs against an array of viable supply-side generation options based on minimum revenue requirements criteria and the future volatility/risk around those generation options in future scenarios.

Step 6. Assess supply options against all resource selection objectives, including minimum revenue requirements, risk planning, fuel source reliability, possible future legislation and other pertinent planning criteria.

Step 7. Select a base case expansion plan that incorporates all the DSM, renewable and supply resources that best meet IPL's long term planning objectives.

Step 8. Identify and execute the short-term resource plan as appropriate, while continuing to refine, challenge, and update its longer-term resource plan as new information becomes available.

Source: IPL

Resource Planning Criteria

[170-IAC 4-7-4(b)(9)] [170-IAC 4-7-6(c)(2)] [170-IAC 4-7-6(d)(4)]

As a member of the Midcontinent Independent System Operator ("MISO"), IPL is subject to the planning reserve margin requirement calculated by MISO. MISO determines the level of Planning Reserve Margin Requirement ("PRMR") necessary for the footprint and each Local Resource Zone to meet the 1 day in 10 years Loss of Load Expectation ("LOLE") standard. LOLE calculations take into account factors that determine the required level of Planning Reserve Margin necessary to meet the 1 day in 10 years standard required by FERC jurisdictional Reliability Entities. These factors include but are not limited to load shapes, load forecast uncertainty, regional load diversity, existing and planned capacity resources, and planned transmission facilities. IPL participates in MISO's regional, sub-regional and technical planning processes. The MISO methodology for determining the PRMR and specific results are identified below.

In order to determine generator capability, all units are required to annually demonstrate their maximum available capacity, by performing tests conducted in conformance with tariff terms and conditions. These tests establish the unit's MISO Installed Capacity ("ICAP") rating. The ICAP rating for each unit is then adjusted by its specific three (3) year average Equivalent Forced Outage Rate Demand excluding outside management control events ('XEFORd").

[12] ACLM is described in Section 4B and CVR is described in Section 4C.

XEFORd is a forced outage rate that includes derate and outage information and is measured only during periods when the resource is in demand. This adjusted value establishes the Unforced Capacity ('UCAP") for the unit. Resources with higher availability contribute more toward resource adequacy. The Unforced Capacity ("UCAP") methodology recognizes the relative contribution toward the MISO-wide resource adequacy goal of each generating unit.

The Zonal Resource Credit ("ZRC") requirements based upon one MW unit of Planning Resource converted from one MW of UCAP, can vary by zone. Figure 4.2 below illustrates the FERC approved zonal boundaries IPL is in Zone 6.

Figure 4.2 – MISO Zones

Source: MISO

Resource Adequacy Requirements

MISO requires market participants to identify capacity resources to meet the PRMR based upon specific load requirements on a planning year basis. Planning years are defined as June 1 of the current year through May 31 of the subsequent year. For the 2014-2015 planning year, LOLE results yielded a Planning Reserve Margin ICAP ("PRMICAP") of 14.8 % and a Planning Reserve Margin UCAP ("PRMUCAP) reserve margin of 7.3 %. The PRMUCAP for the 2015-2016 planning year will be published in November of 2014 and preliminary results show a decrease in the PRMUCAP of 0.2%.

Since MISO began calculating the PRMR for its LSEs, it has made annual adjustments to that calculation as well as to the Resource Adequacy construct. The current annual MISO resource adequacy construct may be modified by the next planning year to either replace the annual construct with a seasonal construct or to add seasonal capacity products. A Seasonal Construct is favored by utilities with an obligation to serve as aligns better with its obligations to customers, allows utilities to better adapt changing market, business, and regulatory landscapes, and addresses the winter peaking issues of natural gas. IPL is a leader in the resource adequacy related stakeholder process and actively provides substantive comments to MISO to influence change in the best interests of our customers.

Planning Reserve Margin Modeling

IPL's minimum PRMR established by MISO for 2014 equates to an effective 14.8% reserve margin, representing an increase from 2012 (13.1%) and 2013 (14.2%). As identified above, many factors are used by MISO to establish an LSE's resource adequacy requirement. The LSE's planning reserve margin changes annually as MISO modifies its LOLE analysis and as a result of changes in its EFORd and diversity. IPL's ICAP ratings can also change annually due to the results of unit testing. For Ventyx's long term modeling purposes in this IRP, IPL identified a 14% planning reserve margin to be used consistent with IPL's summer-rated capacity. This long-term modeling number provides for targeted reserves in the range of future expected MISO-determined resource needs and is consistent with the MISO specific calculations shown in Figure 4.3.

Planning Year beginning June 1, 2015 and ending May 31, 2016

IPL is retiring its Eagle Valley units 3 through 6 by April 16, 2016 to comply with its MATS deadline. However, this retirement date is 6.5 weeks before the end of the 2015-2016 MISO Planning Year. MISO's current resource adequacy requirement states a capacity resource that clears a planning reserve auction must be available during the entire commitment period otherwise replacement capacity from the same zone must be secured to avoid tariff compliance penalties levied by FERC. During this 6.5 week low load period IPL has capacity in excess of its requirement to reliably serve its load. The requirement to buy additional capacity is unjust and unreasonable and would be merely a transfer of wealth with no impact on resource adequacy for IPL or Zone 6. In order to avoid the excess costs associated with this provision, on June 20, 2014, IPL submitted a request to FERC to waive the replacement requirement needed during the stated 6.5 week timeframe. With the support of the IURC comments filed with FERC, this request was granted by FERC on October 15, 2014. As a result of FERC granting the Waiver Request, IPL and its customers will not be forced to bear the costs of unneeded capacity.

Determine Resource Needs

[170-IAC 4-7-4(b)(6)] [170-IAC 4-7-5(b)] [170-IAC 4-7-6(b)(8)] [170-IAC 4-7-8(b)(3)]

Load Forecast, Incorporation of Demand Side Management, and Application of Planning Criteria

IPL's load history and forecast of economic drivers are used to derive a base econometric forecast. IPL then overlays any non-economic drivers that are in the landscape, but not in the economic drivers, such as appliance efficiencies, to derive the gross internal demand ("GID"). The GID load forecast includes historical conservation or energy efficiency DSM, but excludes any new energy efficiency DSM initiatives or load management programs.

IPL determines the cost-effective energy efficiency DSM levels to be included in the resource planning throughout the 20 year planning period based on its forecast described in Section 4B. The cost-effectiveness tests of the DSM programs incorporate the avoided supply capacity and energy costs used in the IRP model. The same capacity and energy costs are used to determine the cost-effectiveness of a new generating unit for production cost modeling to evaluate demand-side resources on a consistent and comparable basis with supply side resources. DSM resources include energy efficiency and demand response programs dependent upon customer participation. The demand response programs, including ACLM and loads associated with IPL interruptible tariffs, are included as a "first resource" option in the capacity expansion plan. Since energy efficiency programs do not have significant capacity attributes and are not dispatchable, they are built in next as reductions to load requirements followed by solar DG energy secured through Rate REP.

IPL recognizes the challenge of DSM program benefit cost test evaluation results not directly aligning with PVRR analysis of the production cost model. Using the same cost inputs for both models aligns outcomes. IPL's short term needs to mitigate environmental regulatory risks through generation additions and retrofits results in excess energy production capability in the IRP planning period. Theoretically, a model including DSM as an optional choice would likely not choose DSM in this situation. IPL recognizes the importance of consistency in DSM programs to focus on changing customer behavior though a multi-year approach; therefore, DSM continues to be included as described above.

As further described in Section 4B, IPL's DSM evaluation process includes estimates of future DSM profiles, program measure duration, program free riders, and coincident peak impacts to identify the expected load impacts. Since these long-term DSM programs will be more clearly defined in future filings with the IURC, estimates of their load impacts are used. The GID forecast is then adjusted to incorporate all cost effective energy efficiency and demand response to derive the net internal demand ("NID"). These load forecasts are shown in the supply-demand balance report in Figure 4.3.

IPL's resource planning reserve margin is applied to the NID forecast to determine the additional IPL resource needs, and used by Ventyx in resource scenario modeling. Note, the current MISO resource adequacy methodology is based on short-term targeted IPL resource requirements rather than a long-term targeted IPL reserve margin, which is influenced by both IPL and regional MISO conditions and correlations as discussed previously.

Figure 4.3 - IPL's Load and Resource Balance Report

PEAK	**15-16**	**16-17**	**17-18**	**18-19**	**19-20**	**20-21**	**21-22**	**22-23**	**23-24**	**24-25**
IPL's Non-Coincident Peak Forecast	2,965	2,989	2,995	2,999	3,001	3,009	3,008	3,013	3,021	3,030
Demand Reduction Programs (MW)	**15-16**	**16-17**	**17-18**	**18-19**	**19-20**	**20-21**	**21-22**	**22-23**	**23-24**	**24-25**
Demand Response	63	63	63	63	63	63	63	63	63	63
Conservation Voltage Reduction (CVR)	20	20	20	20	20	20	20	20	20	20
Total	83	83	83	83	83	83	83	83	83	83
Effective Capacity Reserve Margin										
Net Internal Demand	2,882	2,906	2,912	2,916	2,918	2,926	2,925	2,930	2,938	2,947
PRM_{ICAP}	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
IPL ICAP Requirement	3,285	3,313	3,319	3,324	3,327	3,336	3,335	3,340	3,349	3,359
MISO Installed Capacity (ICAP)	3,119	2,861	3,532	3,532	3,532	3,532	3,532	3,532	3,532	3,532
Effective Reserve Margin using MISO ICAP	8%	-2%	21%	21%	21%	21%	21%	21%	20%	20%

Source: IPL

Supply Resource Modeling

After inclusion of all DSM, IPL plans to satisfy the balance of its resource needs through existing and new supply-side generation and/or capacity purchases. Existing IPL generation resources are undergoing changes as described above. In addition, recent changes in wastewater permit requirements dictated extensive analysis of remaining coal-fired units as described below.

National Pollutant Discharge Elimination System ("NPDES") Analysis

Concurrent with the 2014 IRP process, IPL conducted an extensive evaluation of IPL's two coal-fired generating plants, surrounding the upcoming costs of NPDES compliance along with other potential environmental regulations. As discussed in Section 3, Environmental, NPDES permit requirements regulate and authorize specific industrial wastewater and Stormwater. On August 28, 2012, the IDEM issued NPDES permit renewals to Petersburg and Harding Street, which contain new Water Quality Based Effluent Limits and Technology-Based Effluent Limits, with a compliance date of September 29, 2017, resulting from an IDEM approved extension as described in Section 3 Environmental Rules and Regulations.

The NPDES wastewater compliance projects are centrally designed systems to treat the wastewater and Stormwater from each generating plant, not unit-specific controls, and are primarily driven by the presence of coal-fired generation. Harding Street Unit 7 will be the sole coal-fired unit at Harding Street following the pending refuel of units 5 and 6, and contribute the majority of the costs associated with NPDES compliance. Contrarily, at Petersburg, all generating units are coal-fired, minimizing the incremental impact that any one unit has on NPDES compliance costs.

Using the unit-specific NPDES compliance costs, IPL estimated the full life cycle cost profile of the Big Five coal units (Petersburg Units 1 through 4 and Harding Street Unit 7) and compared those costs to replacement of the coal units with alternative resource options over the estimated remaining life of the units. In order to assess various risks and uncertainties, this analysis included stress testing resource options by considering future unknown environmental regulations including Greenhouse Gas Regulation, National Ambient Air Quality Standards, Coal Combustion Residuals, and cooling tower water impacts called 316(b), but plausible risks by way of discrete scenario analysis and probabilistic decision tree scenario analysis.

The analysis identified the Petersburg NPDES retrofit, inclusive of all four Petersburg units, as the reasonable least cost plan. Furthermore, the NPDES costs at Petersburg are relatively low on a per-unit basis. A simple payback analysis supported the scenario analysis showing all the Petersburg units as having the low cost PVRR under all future scenarios (except for a low gas price scenario where Pete 1 was near breakeven) through 2019. Conversely, high incremental NPDES capital costs associated with Harding Street 7 along with avoidable MATS costs and potential future environmental regulations do not justify continuing Harding Street 7 on coal. The results identified the conversion of Harding Street Station ("HSS") Unit 7 to gas-fired generation as the reasonable least cost plan. Therefore, in the IRP, HSS Unit 7 is modeled under the assumption that the unit will be refueled in 2016.

The NPDES analysis was a detailed analysis specific to NPDES compliance costs and other pending and future regulations costs on IPL's existing generation. Its primary focus was on the economics of the NPDES retrofit decision. The IRP analysis, discussed below, is a much broader resource planning evaluation focused on future resources needs. Using both scenario analysis and a probabilistic decision tree analysis, the NPDES analysis considered a wide range of scenarios surrounding Greenhouse Gas Regulation, National Ambient Air Quality Standards, Coal Combustion Residuals, and 316(b). Whereas, in the IRP modeling, the more known/probabilistic cost estimates of these regulations discerned from the NPDES analysis were used, with the exception of Greenhouse Gas Regulation where three scenarios were used. Both sets of modeling included high, low, and base natural gas forecasts.

On October 16, 2014, IPL filed its NPDES compliance strategy with the IURC, comprising of retrofitting Petersburg and refueling HSS Unit 7. Additional details on IPL's compliance plan as well as the analysis performed can be found under IURC Cause No. 44540.

Existing Generation

[170-IAC 4-7-6(a)(1)] [170-IAC 4-7-6(a)(2)]

In addition to current wind and solar Power Purchase Agreements ("PPAs") described later in this section, Figure 4.4 shows IPL's current generation resources with projected summer installed capacity ratings used in the model for the next 20 years. These numbers reflect all known and/or planned unit derates, life extensions and retirements. This table includes the identified planned retirements of Eagle Valley Units 3 through 6 by April 16, 2016. Likewise, the replacement generation for the mentioned retirements, the Eagle Valley CCGT, has been integrated with an expected in-service date of spring 2017. Fuel changes have also been identified and incorporated into this table showing the approved refueling of Harding Street Steam Turbine Units 5 and 6 and the anticipated refueling of Harding Street Steam Turbine Unit 7.

Figure 4.4 – IPL's Current Generation Resources with Summer Capacity Ratings (MW)

Generating Resource Report																				
MISO Installed Capacity (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
HS ST5	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS ST6	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HS ST7	410	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EV ST3	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EV ST4	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EV ST5	61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EV ST6	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PETE ST1	230	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227	0	0
PETE ST2	415	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410
PETE ST3	540	534	534	534	534	534	534	534	534	534	534	534	534	534	534	534	534	534	534	534
PETE ST4	530	526	526	526	526	526	526	526	526	526	526	526	526	526	526	526	526	526	526	526
HS GT4	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
HS GT5	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
HS GT6	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
GTOWN GT1	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
GTOWN GT4	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
HSS GT1 & GT2	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
PETE IC 1-3	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
EV IC1	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HSS IC1	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
HS ST5 Gas	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0
HS ST6 Gas	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0
HS ST7 Gas	0	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430	0
EV CCGT*	0	0	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671	671
Solar	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Total Resources	3119	2861	3532	3532	3532	3532	3532	3532	3532	3532	3532	3532	3532	3532	3532	3532	3532	3332	3105	2675

*Updated Ratings reflect 671 MW of ICAP Capacity resulting from Duct Firing Technology, however 644 MW was used in modeling.

Source: IPL Installed Capacity (Equivalent of MISO ICAP)

New Generation Resource Modeling

Currently, Indiana's voluntary 10% renewable energy standards ("RES") is included in the resource modeling. IPL is well positioned for the future with about 300 MW of associated energy secured under long-term Wind PPAs and an additional 98 MW of solar energy acquired through our Rate REP program. Therefore, absent any pending RES bills, and a solid renewable energy foundation, no specific renewables requirements were used to constrain the generation resource modeling. The supply resource selection process includes consideration of a range of generation resource options, including H-Class CCGT, CT, Nuclear, Wind and Solar. In the IPL 2011 IRP, the Company determined hydroelectric power was not a viable resource. Inputs from this analysis have maintained constant over the last three years; hence, hydroelectric power has not been included in this IRP. While IPL is investigating the feasibility of installing a Battery Energy Storage System ("BESS") to provide ancillary services, capacity and pilot testing for renewable integration, it was not included as a separate new resource in the Ventyx model for this IRP due to MISO tariff conditions, which are not favorable to energy storage.[13] These technologies are identified in detail in Section 4A. IPL would need to incorporate renewable resources to satisfy any RES during this step.

Once the existing resources were profiled and potential new resources were identified, IPL worked with Ventyx to define and model these new generation resources including IPL's cost definitions and operating profiles. The generation profiles are described in Section 4A and include heat rates, Operation and Maintenance ("O&M") costs, capital costs, and emission rates for each technology.

Capacity Purchase Modeling

IPL customers have benefited in recent years from IPL's ability to purchase capacity at prices below the levelized cost of building new capacity. Although bilateral market capacity prices have remained depressed historically, they are not expected to remain at the current level as the supply-demand balance of capacity comes more into equilibrium in the MISO footprint over the next few years. In 2014, MISO Zone 6 Capacity Auction Clearing Price rose sharply to $16.75 /MW-Day compared to the previously established clearing price in the 2013-14 Planning Year of $1.05/MW-Day. Excess capacity supply will likely continue to diminish in the near term as generators are retired in response to EPA rules set to take effect over the next few years, resulting in a continued rise in MISO capacity auction prices. Stemming from the retirements of Eagle Valley Units 3 through 6 in spring 2016, IPL will need to purchase capacity to bridge the gap between the mentioned forced small unit retirements and in-service date of the CCGT. IPL used forecasted rising capacity market prices for IRP modeling Resources are compared to these market prices which influence the timing and/or need of new generation additions.

IRP Modeling Scenarios

[170-IAC 4-7-8(b)(2)] [170-IAC 4-7-8(b)(7)(A)] [170-IAC 4-7-8(b)(7)(B)] [170-IAC 4-7-8(b)(7)(E)] [170-IAC 4-7-4(b)(6)]

With the resource options identified and profiled, IPL worked with Ventyx to help define possible future power industry landscapes. With the assistance from stakeholders in the public meeting process, IPL identified the three drivers that were viewed to have the largest impact on future plans, along with having a great deal of uncertainty linked to them: environmental regulation, natural gas prices, and load variation.

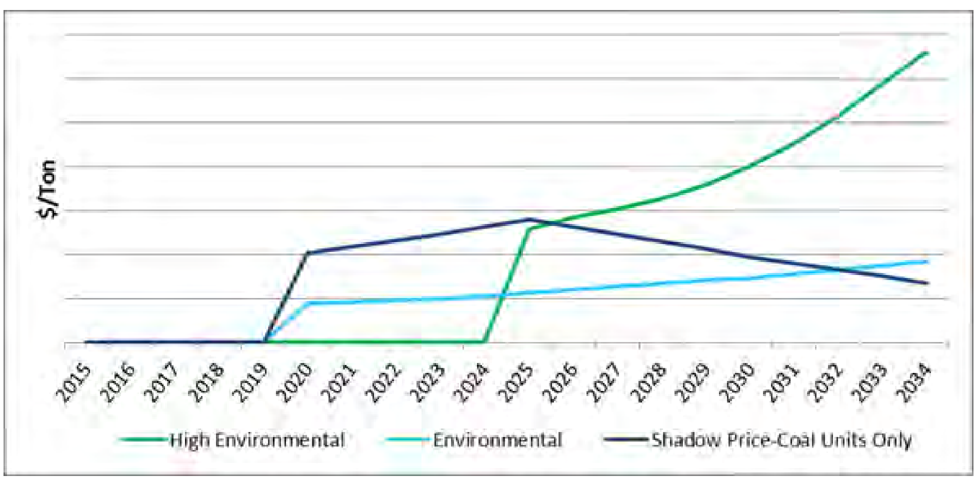
[13] IPL is working with MISO to adapt its tariff and Business Practice Manuals to treat BESS appropriately.

Key Driver #1 – Future Environmental Regulation

IPL considered four environmental landscapes around costs and timing of effective dates for proposed CO_2 regulation. The description associated with each landscape is described below.

- EPA Shadow Price (Base) - The prices are representative of marginal compliance with the EPA's proposed CPP. The modeling for this case applied EPA's shadow prices to IPL's coal unit emissions above the Indiana target emission rate commencing in 2020 using a fixed ($/kW) cost based on the CO_2 building block shadow prices.
- ICF Mass Cap (Environmental) - IPL engaged the consulting firm ICF to provide its CO_2 projections.[14] The prices are representative of ICF's view of the EPA's proposed CPP with the application of aggregate treatment of a cap on CO_2 emissions ("Mass Cap"). This case assumed a market clearing price and was applied in the modeling as an equivalent CO_2 tax to existing fossil generation. The modeling assumes the EPA rules start in 2020 as proposed in the rule making, although ICF's probabilities suggest a reasonable chance of deferred, post 2020, implementation.
- Waxman-Markey (High Environmental) - These prices, developed by Ventyx as part of their 2013 Fall Reference case, are representative of previously proposed federal legislation known as the Waxman-Markey Bill. These prices represent the high range of our CO_2 sensitivities.
- No CO_2 (Low Environmental) - A no CO_2 case that could either reflect no near term regulation or no or very low additional costs needed beyond IPL's current projected resource plan. This shows incremental effects of CO_2 compared to the base case.

Figure 4.5- CO2 Sensitivities



Source: Ventyx

See Section 7, Confidential Attachment 5.1, Ventyx IPL IRP Modeling Summary for pricing.

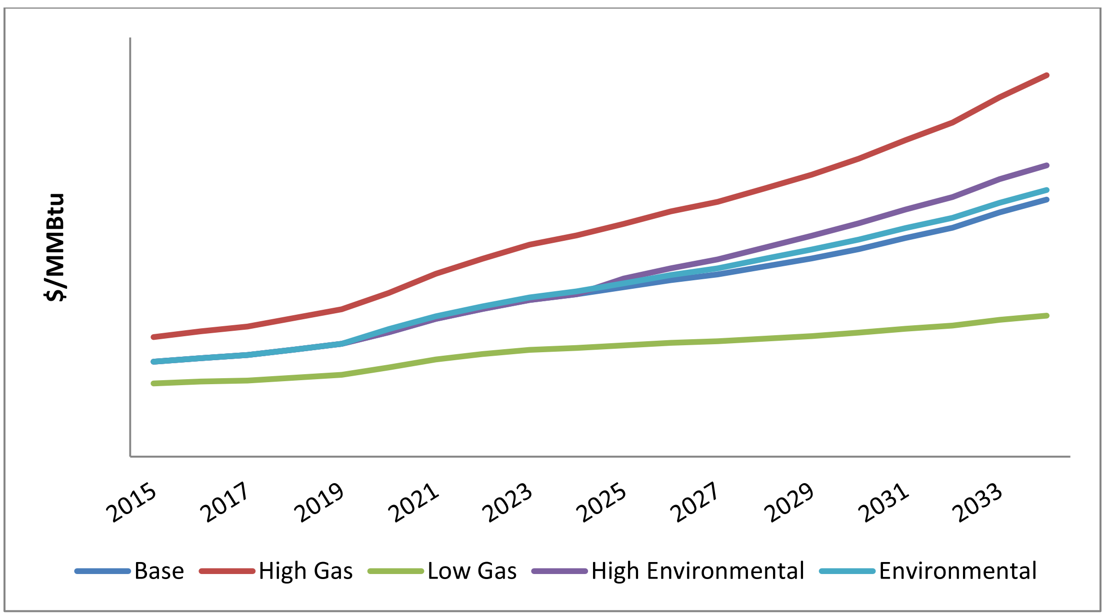
[14] Additional information can be found in IURC Cause No. 44540

Key Driver #2 – Natural Gas Prices

IPL considered five fuel forecasts of NG prices as shown in Figure 4.6. NG pricing has historically been the most volatile, but promising assumptions on shale gas supply and pricing make this fuel source a key resource driver; although, the surge in natural gas plant construction could diminish fuel diversity in the market. See Section 7, Confidential Attachment 5.1, Ventyx IPL IRP Modeling Summary for pricing.

- Base Gas Prices
- High Gas Prices Landscape
- Low Gas Prices Landscape
- Environmental Prices Landscape
- Mass Cap Prices Landscape

Figure 4.6- Natural Gas Sensitivities



Source: Ventyx

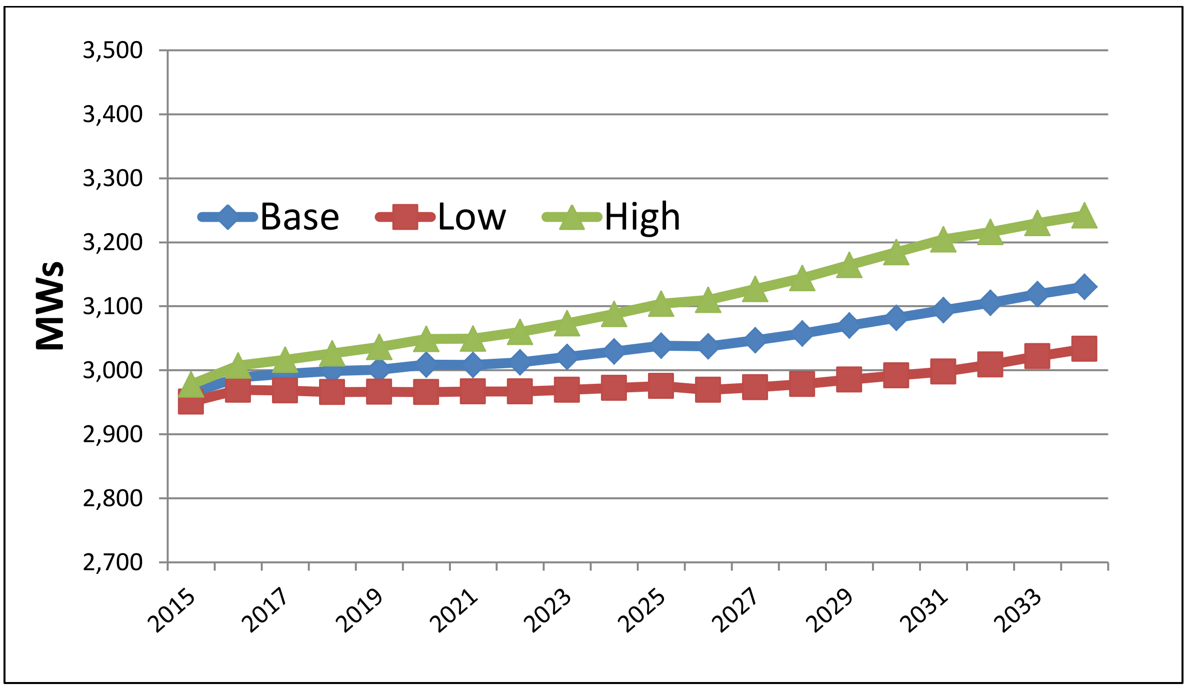
See Section 7, Confidential Attachment 5.1, Ventyx IPL IRP Modeling Summary for pricing.

Key Driver #3 - Load Variation

IPL considered three demand and energy forecasts for load sensitivity. The High and Low Load range was derived from the 2013 IPL-specific State Utility Forecasting Group ("SUFG") forecast. This range was developed primarily based upon economic uncertainty. The forecast scenarios, while based on economic uncertainty, could also be driven by changes in technology, consumer behavioral changes, and State and Federal energy policies. The forecast scenarios should be viewed broadly as demand driven sensitivity scenarios from all load impact sources. For example, the low load forecast could be driven by high DSM levels, a weak economy, or higher distributed generation adoption. See Section 4D for additional details along with the High and Low energy forecast.

- Base Load Forecast (3,131 MW NID in 2034)
- High Load Forecast(3,242 MW NID in 2034)
- Low Load Forecast (3,033 MW NID in 2034)

Figure 4.7- Load Sensitivities (Demand Net of DSM)



Source: IPL

Derived from the three key drivers discussed above, IPL created eight scenarios as shown in Figure 4.8 as a way to screen the capacity expansion resources. In addition to the sensitivities themselves, Ventyx created correlated market prices based on the sensitivities supplied. These scenarios help determine the robustness of possible expansion plans. The use of multiple scenarios allows IPL to identify a Preferred Portfolio that will be competitive in a wide range of future landscapes.

Figure 4.8- IPL's 2014 IRP Modeling Scenarios

Scenario No	Scenario Name	Gas/Market Price	CO_2 Price	Load Forecast
1	Base	Ventyx Base	IPL-EPA Shadow price starting 2020	Base
2	High Load	Ventyx Base	IPL-EPA Shadow price starting 2020	High
3	Low Load	Ventyx Base	IPL-EPA Shadow price starting 2020	Low
4	High Gas	Ventyx High	IPL-EPA Shadow price starting 2020	Base
5	Low Gas	Ventyx Low	IPL-EPA Shadow price starting 2020	Base
6	High Environmental	Ventyx Environmental	Waxman-Markey proxy Ventyx Fall 2013 price starting 2025	Base
7	Environmental	Ventyx Mass Cap	Mass Cap ICF price starting 2020	Base
8	Low Environmental	Ventyx Base	None	Base

Source: IPL

Supply Resource Evaluation

Overall Methodology Description

With the generation resource technologies profiled, the future landscapes identified, and supply resource needs established, the next step was to evaluate the generation technologies against the future landscapes. IPL worked with Ventyx to perform a multi-step evaluation process. First, Ventyx performed a capacity expansion evaluation for the profiled supply resources allowing the model's least-cost planning algorithm to select resources based on resource needs and targeting a minimum revenue requirement objective. Modeling using Ventyx's "Capacity Expansion" module was performed for all future landscapes. Next, based on these results, IPL then derived select resource plans for future landscape analysis. This involved identifying the resource and timing and running the resource portfolio against all future landscapes.

Capacity Expansion Simulation Methodology

[170-IAC 4-7-4(b)(9)] [170-IAC 4-7-7(a)]

The Capacity Expansion simulation uses minimum revenue requirements planning criteria to evaluate generation technologies based on a given set of future landscape assumptions. In this simulation, IPL's retail load, current generating fleet, and future additions are dispatched competitively against MISO-IN market prices, replicating the current MISO market. This is performed by calculating the incremental present value of revenue requirements ("PVRR") for multiple resource expansion plans and selecting the resources and timing that result in the lowest present value. The model is a useful tool in generating informative cost-focused planning insights, based on a given set of future assumptions. Different future landscapes will produce a different set of future drivers and could produce different capacity expansion results.

For the modeling, Ventyx and IPL selected a group of generation options that represent proven and commercially available technologies, as shown in Figure 4.9. Ventyx's Capacity Expansion model was then run for the selected generation technologies against the future landscapes. Additionally, Ventyx's Capacity Expansion model was used to determine if and/or the early retirement of the four units at Petersburg was economic in each scenario.

Confidential Figure 4.9- Supply Resource Options (2013$)

	CT	Combined Cycle – H Class	Nuclear	Photovoltaic	Wind Turbine
Summer (MW)	160	200**	200**	10	50
Winter (MW)	180	212.5**	200**	10	50
Average Heat Rate	[redacted]				
VOM* ($/MWh)	[redacted]				
FOM* ($/kW)	[redacted]				
Capital Cost ($/kW)	[redacted]				

*VOM – Variable Operating and Maintenance Costs, FOM – Fixed Operating and Maintenance Costs
**Partial Units

Source: Ventyx

The expansion simulation modeling is deterministic – looking at one set of future conditions, and does not consider the variance risk of the inputs or other relevant decision criteria. So in that respect, the model does not necessarily generate the preferred solution, but rather information to screen resources and support the overall resource decision making process. Descriptions of the capacity expansion analysis modeling and inputs are discussed below.

Capacity Expansion Results

[170-IAC 4-7-8(b)(7)(C)]

The results of the capacity expansion modeling are presented below. In all scenarios, Eagle Valley ("EV") units 3 through 6 were set to retire in 2016 and Harding Street units 5 through 7[15] were set to be refueled in 2016. Also, all scenarios include the addition of the Eagle Valley CCGT in 2017.

[15] The Harding Street unit 7 refuel from coal to natural gas is currently pending before the IURC in Cause No. 44540.

Figure 4.10 – Capacity Expansion Results

YEAR	Base	High Gas	Low Gas	High Load	Low Load	High Environ-mental	Environ-mental	Low Environ-mental
2015	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW	Market 200 MW
2016	Market 450 MW	Market 450 MW	Market 450 MW	Market 500 MW	Market 450 MW	Market 450 MW	Market 450 MW	Market 450 MW
2017	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT	671 MW EV CCGT
2018-2019								
2020			Retire Pete 1,2, and 4 CC 200 MW					
2021			CC 800 MW Market 100 MW					
2022			CC 200 MW					
2023								
2024				Market 50 MW		Retire Pete 1		
2025				Market 50 MW		CC 200 MW		
2026				Market 50 MW				
2027				CC 200 MW				
2028						Wind 100 MW		
2029						Wind 150 MW		
2030	Market 50 MW	Wind 100 MW				Wind 100 MW	Market 50 MW	Market 50 MW
2031	Retire HSS 5 and 6 CC 200 MW Market 50 MW	Retire HSS 5 and 6 CC 200 MW Wind 150 MW	Retire HSS 5 and 6 CC 200 MW	Retire HSS 5 and 6 CC 200 MW	Retire HSS 5 and 6 CC 200 MW	Retire HSS 5 and 6 CC 200 MW Market 50 MW Wind 50 MW	Retire HSS 5 and 6 CC 200 MW Market 50 MW	Retire HSS 5 and 6 CC 200 MW Market 50 MW
2032	Market 50 MW	Wind 100 MW				Market 50 MW	Market 50 MW	Market 50 MW
2033	Retire Pete 1 CC 200 MW Market 100 MW	Retire Pete 1 CC 200 MW Wind 50 MW Market 50 MW	Market 50 MW	Retire Pete 1 CC 200 MW Market 50 MW	Retire Pete 1 CC 200 MW	Market 50 MW	Retire Pete 1 CC 200 MW Market 100 MW	Retire Pete 1 CC 200 MW Market 100 MW
2034	Retire HSS 7 CC 400 MW Market 150 MW	Retire HSS 7 CC 400 MW Market 100 MW	Retire HSS 7 CC 400 MW Market 100 MW	Retire HSS 7 CC 400 MW Market 50 MW	Retire HSS 7 CT 180 MW CC 200 MW Market 50 MW	Retire HSS 7 CC 400 MW Market 100 MW	Retire HSS 7 CC 400 MW Market 150 MW	Retire HSS 7 CC 400 MW Market 150 MW

Source: Ventyx

The Capacity Expansion results demonstrate IPL's existing fleet is economic in a wide-range of scenarios. As shown in Figure 4.10, Petersburg Unit 3 was favored in all eight scenarios, Units 3 and 4 were favored in seven of the eight, and Unit 1 was favored in six of the eight. Due to the economic value of IPL's existing fleet and with the addition of the Eagle Valley CCGT, IPL's resource needs are met for the majority of the planning period in most scenarios. Resource additions are only selected in the modeling in connection with retirements, or in the high load scenario.

Evaluation of Scenario Resource Plans

The next step incorporated the results of the capacity expansion modeling, along with IPL's view of future drivers and pending legislation, to derive a targeted selection of resource options for landscape scenario evaluation. With no additional build out over the next 15 years in five of the eight scenarios, IPL identified five different resource plans to determine the impact of Petersburg 1 and 2 retiring early, symbolic of the Low Gas and High Environmental results. The five plans were created to represent the results of the capacity expansion model. The build out plans utilize resources that were selected in the capacity expansion results as a way of creating plans that would be competitive across multiple future landscapes, while also considering the impact of diversification. IPL limited the potential of earlier retirements to the two Petersburg units because that is what the capacity expansion results indicated as most economic and in order to maintain a balance in fuel mix and portfolio diversity. The five different resource plans were then tested across the future landscapes in order to evaluate a range of resource options and combinations of resources.

Figure 4.11 shows the five resource plans that were subjected to additional scenario analyses in this IRP. These scenarios were created based on similar resource sizing and consistent resource timing so as to not bias any one technology. Also, in order to isolate the impact of replacing Petersburg 1 and 2, the planning life or age-based retirements of HSS 5 through 7 were replaced with an equivalent capacity CCGT unit, the predominately favored resource in the Capacity Expansion Plan simulation. Plan 1 and 2 also require additional build in 2033, the end of expected life for Petersburg 1, since these plans exclude the early retirement of the unit in 2024.

Figure 4.11 – Scenario Resource Plans (by Operating Capacity)

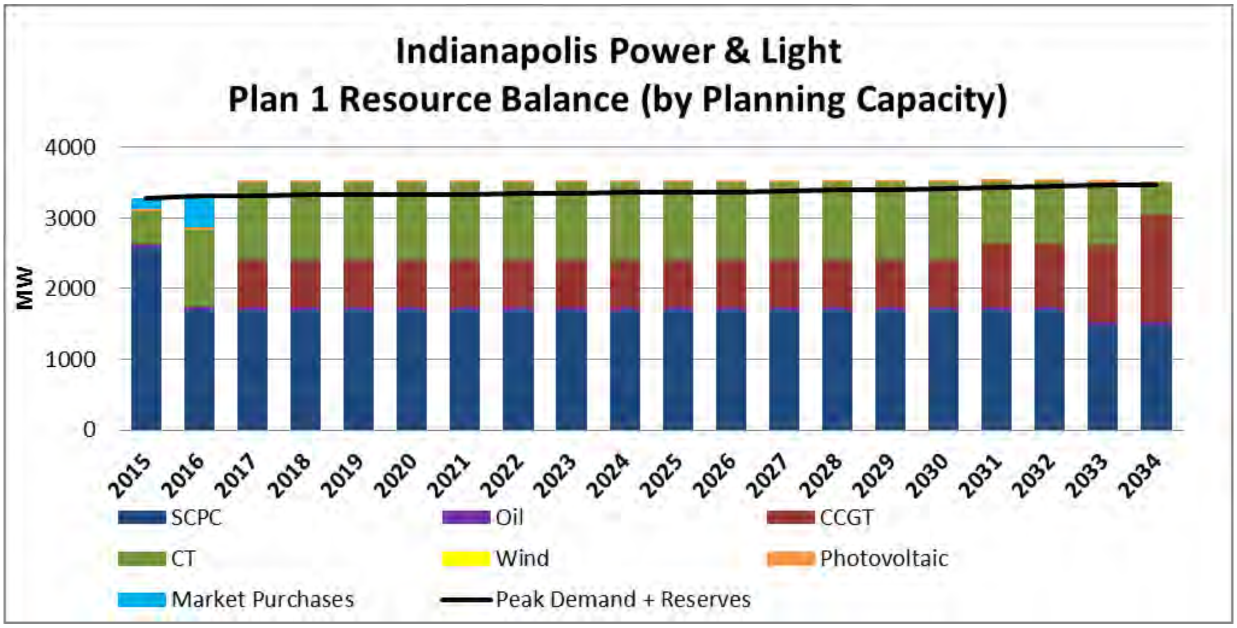
YEAR	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5
2024			Retire Pete 1 & 2	Retire Pete 1 & 2	Retire Pete 1 & 2
2025		Wind 200 MW	CC 600 MW	CT 550 MW & Wind 500 MW	CC 600 MW & Wind 200 MW
2026					
2027					
2028					
2029					
2030					
2031	CC 200 MW	CC 200 MW	CC 200 MW	CC 200 MW	CC 200 MW
2032					
2033	CC 200 MW	CC 200 MW			
2034	CC 400 MW	CC 400 MW	CC 400 MW	CC 400 MW	CC 400 MW

Source: IPL

Plan 1 Expansion

The Plan 1 expansion results, including IPL's existing and proposed generation, are shown in Figure 4.12. For this future landscape, no additional generation is built until the age based retirements of HSS Units 5 and 6 (2031), Petersburg 1 (2033) and HSS Unit 7 (2034). The preferred resource to replace the retired capacity is new CCGT for each retirement.

Figure 4.12 – Capacity Expansion Results for Plan 1



Source: IPL

Plan 1 Expansion by Operating Capacity

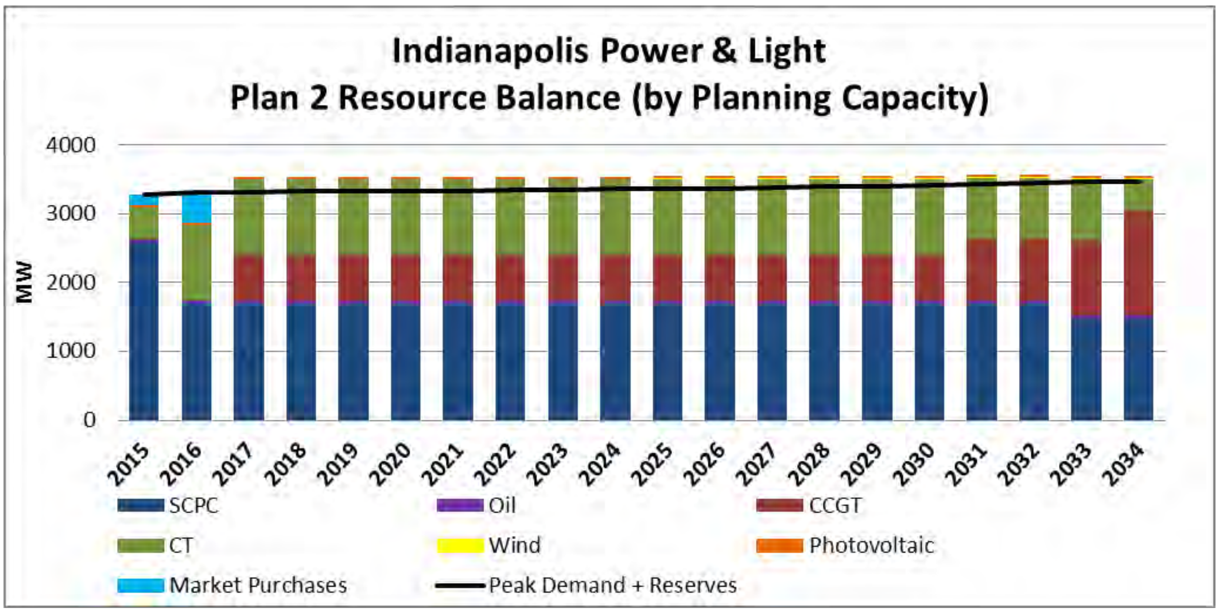
	2015	2016	2017	2018-2024	2025	2026-2029	2030	2031	2032	2033	2034
Nuclear	-	-	-	-	-	-	-	-	-	-	-
CT	-	-	-	-	-	-	-	-	-	-	-
CCGT	-	-	644	-	-	-	-	200	-	200	400
PV	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-

Source: IPL

Plan 2 Expansion

The Plan 2 expansion results, including IPL's existing and proposed generation, are shown in Figure 4.13. For this future landscape, 200 MW of wind generation was built in 2025. Wind was the second most frequent selected resource in the Capacity Expansion simulation. While there is still much uncertainty surrounding Greenhouse Gas Regulation, additional wind resources could be needed for compliance, while also diversifying IPL's generation mix. CCGT has been identified as the preferred resource for the age based retirements of HSS Units 5 and 6 (2031), Petersburg 1 (2032) and HSS Unit 7 (2034).

Figure 4.13 – Capacity Expansion Results for Plan 2



Source: IPL

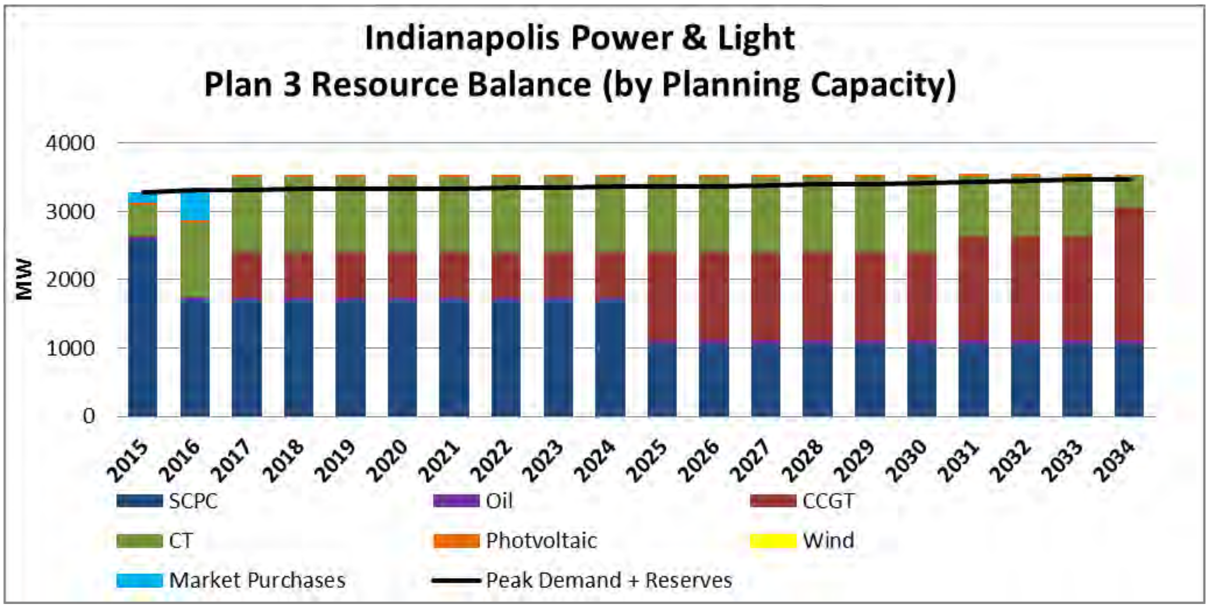
Plan 2 Expansion by Operating Capacity											
	2015	2016	2017	2018-2024	2025	2026-2029	2030	2031	2032	2033	2034
Nuclear	-	-	-	-	-	-	-	-	-	-	-
CT	-	-	-	-	-	-	-	-	-	-	-
CCGT	-	-	644	-	-	-	-	200	-	200	400
PV	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	200	-	-	-	-	-	-

Source: IPL

Plan 3 Expansion

The Plan 3 expansion results, including IPL's existing and proposed generation, are shown in Figure 4.14. For this future landscape, Petersburg units 1 and 2 are retired 10 years prematurely and replaced with an equivalent amount of CCGT. CCGT was the preferred replacement resource in the Capacity Expansion simulation. By replacing Petersburg 1 and 2 with CCGT, IPL's resource mix continues the shift from a predominately coal-fired fleet to the majority being natural gas-fired generation. CCGT has been also identified as the preferred resource for the age based retirements of HSS Units 5 and 6 (2031) and HSS Unit 7 (2034).

Figure 4.14 – Capacity Expansion Results for Plan 3



Source: IPL

Plan 3 Expansion by Operating Capacity

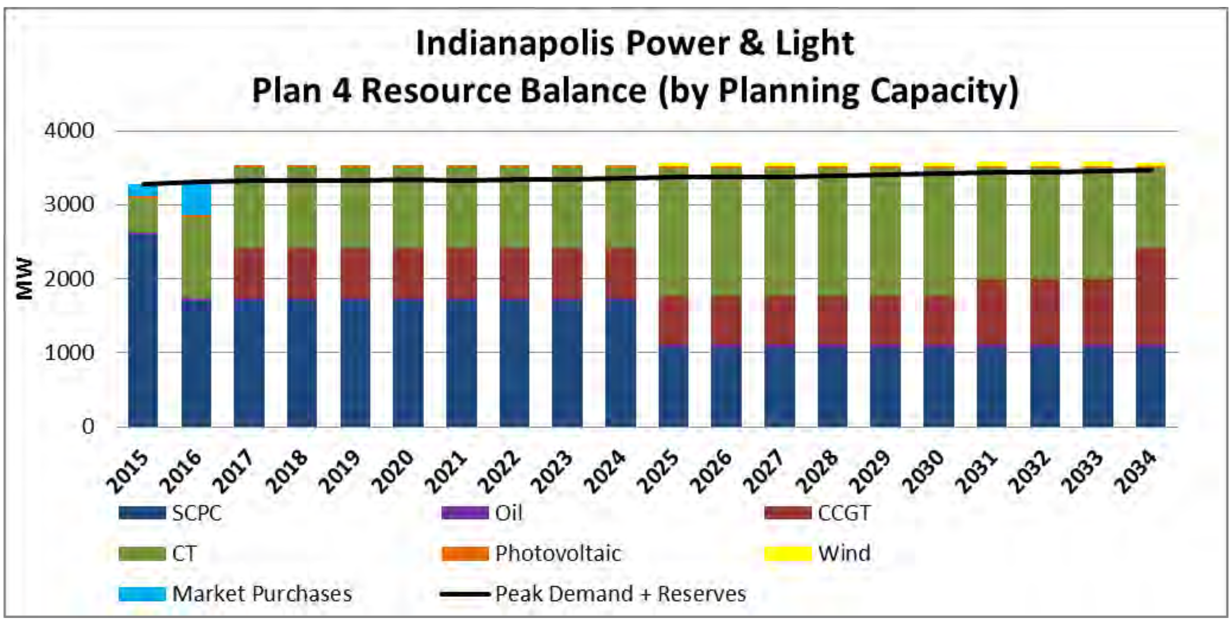
	2015	2016	2017	2018-2024	2025	2026-2029	2030	2031	2032	2033	2034
Nuclear	-	-	-	-	-	-	-	-	-	-	-
CT	-	-	-	-	-	-	-	-	-	-	-
CCGT	-	-	644	-	600	-	-	200	-	200	400
PV	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-

Source: IPL

Plan 4 Expansion

The Plan 4 expansion results, including IPL's existing and proposed generation, are shown in Figure 4.15. For this future landscape, Petersburg units 1 and 2 are retired 10 years prematurely and replaced with an equivalent amount of capacity by a CT and Wind. While the CT was only selected in the Low Load scenario, the CT has the lowest $/KW cost. The CT provides the necessary capacity; however, the expected energy volume is less than a CCGT. By pairing a CT with wind resources, a balance between meeting capacity requirements and providing energy during non-peak conditions can be achieved. By replacing Petersburg 1 and 2 with a CT and Wind, IPL's resource mix continues the shift from a predominately coal-fired fleet to a fleet comprised of primarily natural gas-fired generation and renewable resources. A CCGT has been also identified as the preferred resource for the age based retirements of HSS Units 5 and 6 (2031) and HSS Unit 7 (2034).

Figure 4.15 – Capacity Expansion Results for Plan 4



Source: IPL

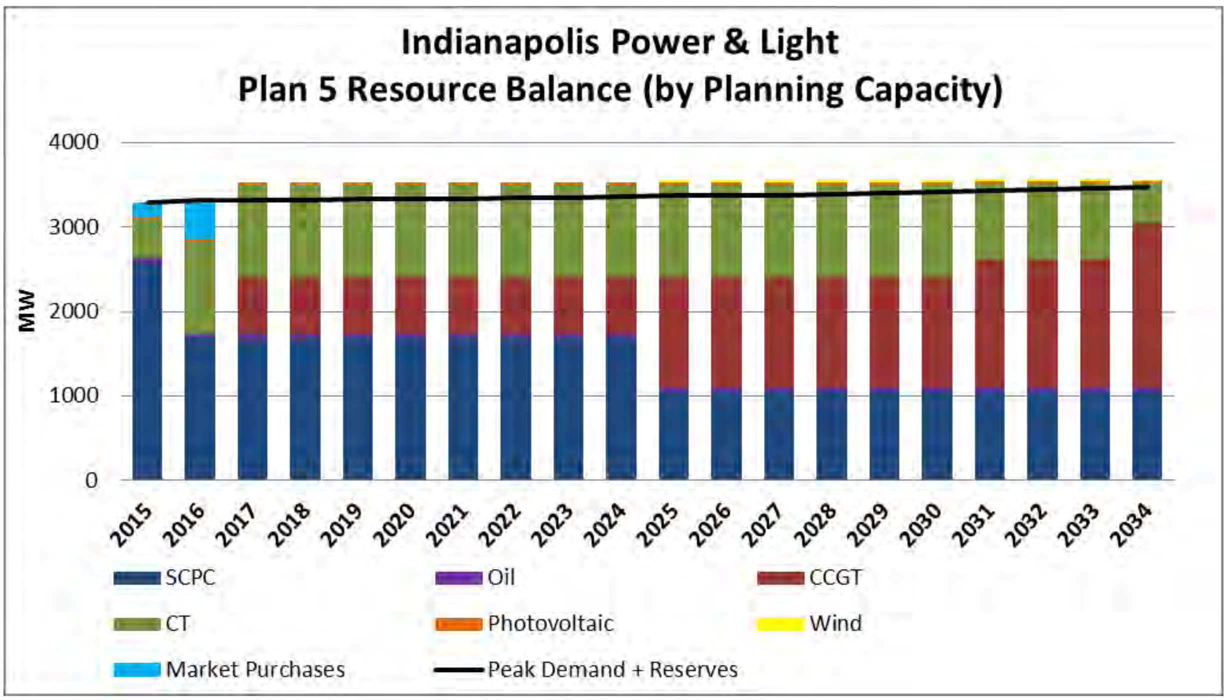
Plan 4 Expansion by Operating Capacity											
	2015	2016	2017	2018-2024	2025	2026-2029	2030	2031	2032	2033	2034
Nuclear	-	-	-	-	-	-	-	-	-	-	-
CT	-	-	-	-	550	-	-	-	-	-	-
CCGT	-	-	644	-	-	-	-	200	-	200	400
PV	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	500	-	-	-	-	-	-

Source: IPL

Plan 5 Expansion

The Plan 5 expansion results, including IPL's existing and proposed generation, are shown in Figure 4.16. For this future landscape, Petersburg units 1 and 2 are retired 10 years prematurely and replaced with an equivalent amount of CCGT while also adding 200 MW of wind resources. This plan combines the top two preferred resources from the Capacity Expansion simulation. A CCGT was the preferred replacement resource in the Capacity Expansion simulation. By replacing Petersburg 1 and 2 with CCGT, IPL's resource mix continues the shift from a predominately coal-fired fleet to a fleet comprised of primarily natural gas-fired generation and renewable resources. A CCGT has been also identified as the preferred resource for the age based retirements of HSS Units 5 and 6 (2031) and HSS Unit 7 (2034).

Figure 4.16 – Capacity Expansion Results for Plan 5



Source: IPL

Plan 5 Expansion by Operating Capacity

	2015	2016	2017	2018-2024	2025	2026-2029	2030	2031	2032	2033	2034
Nuclear	-	-	-	-	-	-	-	-	-	-	-
CT	-	-	-	-	600	-	-	-	-	-	-
CCGT	-	-	644	-	-	-	-	200	-	200	400
PV	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	200	-	-	-	-	-	-

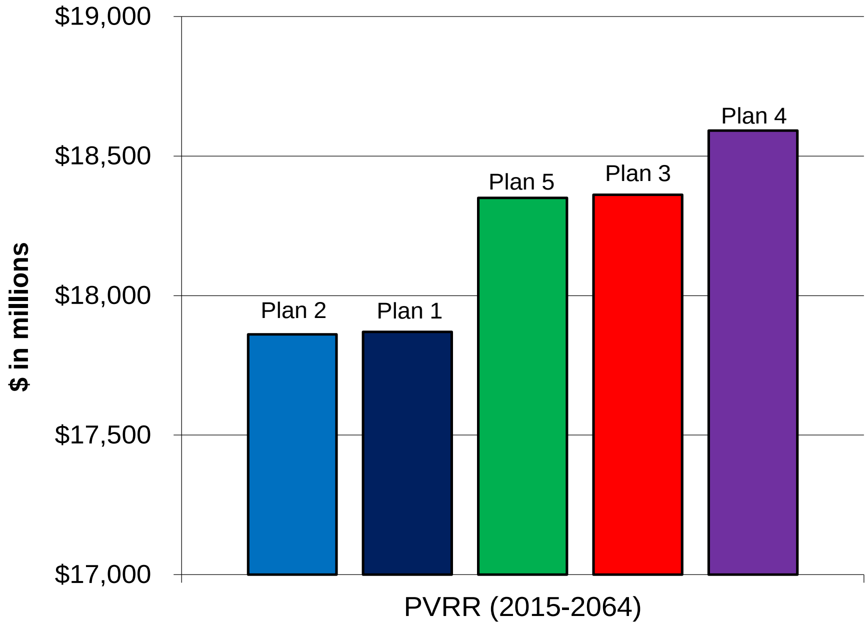
Source: IPL

PVRR Scenario Results for the Resource Plans

[170-IAC 4-7-8(b)(7)(D)]

IPL ran each of the resource plans against six of the eight future landscapes to better understand the potential ramifications of significantly divergent futures around natural gas and CO_2 prices. High and Low Load scenarios were not considered in this phase of the evaluation because load variance does not impact the dispatch or costs of resources. The following section describes the results of these runs. Figures 4.17 through 4.22 show the expected PVRR for the resource plans against Ventyx's future landscapes. Note these prices are for resource plan comparative purposes and do not reflect the total revenue requirements of the IPL business, since current rate base, transmission and distribution, along with other factors are not encompassed.

Figure 4.17 – Base Case PVRR Plan Ranking (2015-2064)

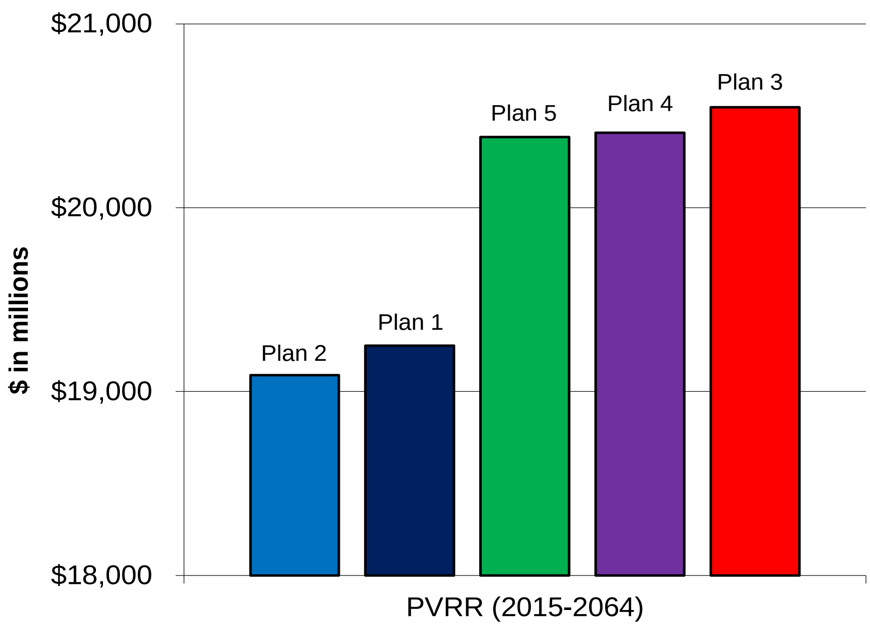


Source: Ventyx

The Base Case results are shown in Figure 4.17. This landscape includes the base gas and market prices, the base load forecast, and the IPL-EPA Shadow price starting in 2020 for coal units. Plans representing IPL's current resource portfolio (Plans 1 and 2) were the lowest-cost resource plans for this landscape.

In all landscapes, Eagle Valley units 3 through 6 were set to retire in 2016 and Harding Street units 5 through 7 were set to be refueled in 2016. Also, all plans include the addition of the Eagle Valley CCGT in 2017.

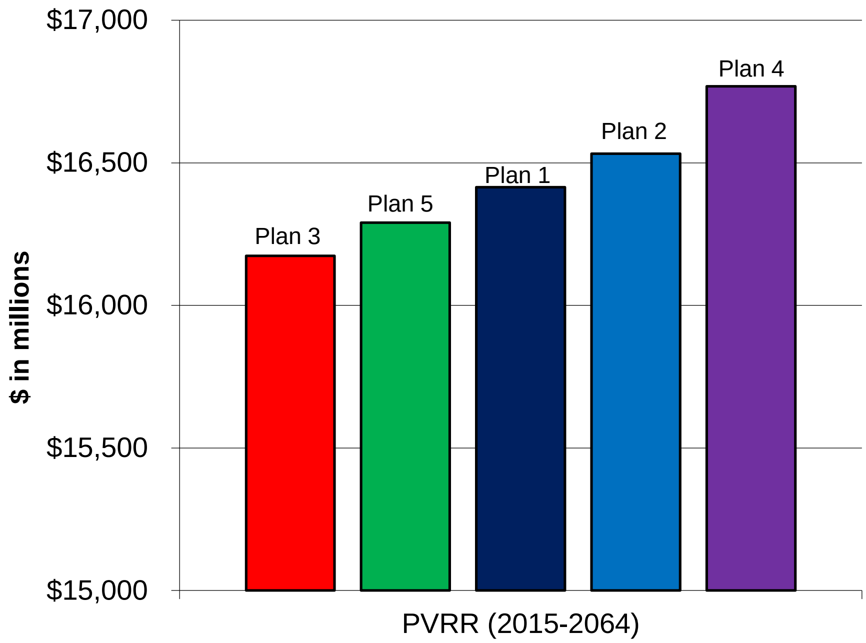
Figure 4.18 – High Gas Case PVRR Plan Ranking (2015-2064)



Source: Ventyx

The High Gas Case results are shown in Figure 4.18. This landscape includes the high gas correlated gas and market prices, the base load forecast, and the IPL-EPA Shadow price starting in 2020 for coal units. Plans representing IPL's current resource portfolio (Plans 1 and 2) were the lowest-cost resource plans for this landscape.

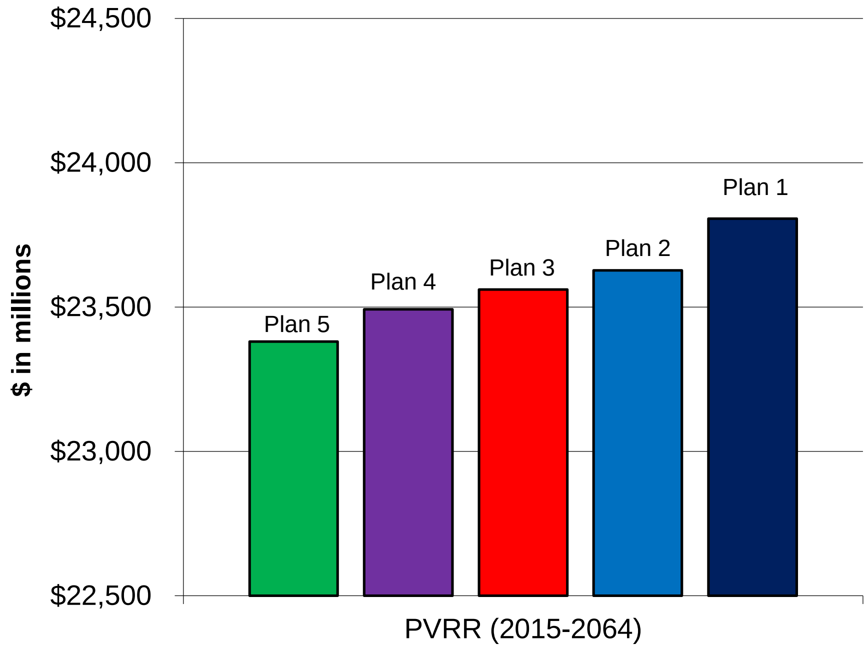
Figure 4.19 – Low Gas Case PVRR Plan Ranking (2015-2064)



Source: Ventyx

The Low Gas Case results are shown in Figure 4.19. This landscape includes the low gas correlated gas and market prices, the base load forecast, and the IPL-EPA Shadow price starting in 2020 for coal units. Plans with a new 600 MW combined cycle in 2025 (Plan 3 and 5) were the lowest-cost resource plan for this landscape. Note that the PVRR for all plans are lowest in this case.

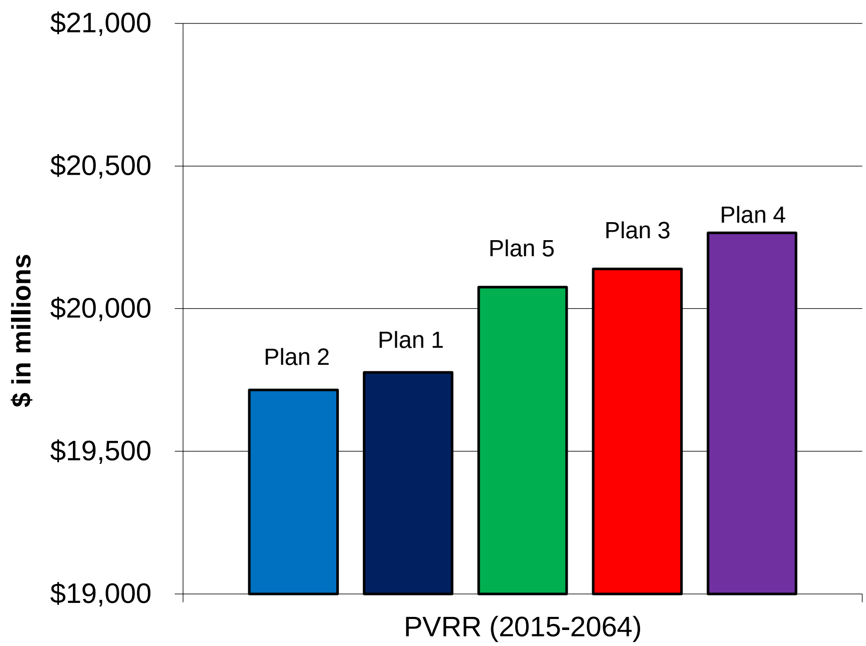
Figure 4.20 – High Environmental Case PVRR Plan Ranking (2015-2064)



Source: Ventyx

The High Environmental Case results are shown in Figure 4.20. This landscape includes Ventyx Environmental gas and market prices, the base load forecast, and the Waxman-Markey proxy Ventyx Fall 2013 CO_2 price starting in 2025 for all CO_2 emitting generation. Plans with new wind generation in 2025 (Plans 4 and 5) were the lowest-cost resource plans for this landscape. Note that the PVRR for all plans are highest in this case.

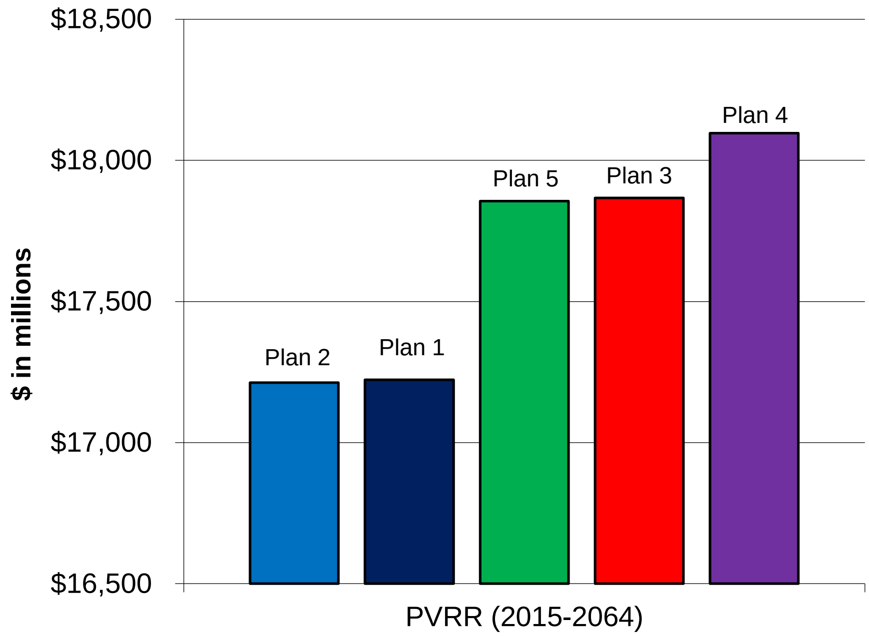
Figure 4.21 –Environmental Case PVRR Plan Ranking (2015-2064)



Source: Ventyx

The Environmental Case results are shown in Figure 4.21. This landscape includes the ICF Mass Cap correlated gas and market prices, the base load forecast, and the ICF Mass Cap CO_2 price starting in 2020 for all CO_2 emitting generation units. Plans representing IPL's current resource portfolio (Plans 1 and 2) were the lowest-cost resource plans for this landscape.

Figure 4.22 –Low Environmental Case PVRR Plan Ranking (2015-2064)



Source: Ventyx

The Low Environmental Case results are shown in Figure 4.22. This landscape includes the base gas and market prices, the base load forecast, and no CO_2 price. Plans representing IPL's current resource portfolio (Plans 1 and 2) were the lowest-cost resource plans for this landscape.

Wind Sensitivities

Under base assumptions, new wind resources are modeled using a 35% capacity factor and their Locational Marginal Price ("LMP") is equivalent to the MISO-IN forecasted market price. However, these modeling assumptions are not consistent with the current actual performance of the wind generation IPL secured under long-term PPAs with Hoosier Wind Farm in Benton County, Indiana and Lakefield Wind Farm in Jackson County, Minnesota. In actuality, these wind generators have yielded capacity factors between 20-25% on an annual basis and receive an LMP significantly lower than the MISO-IN average. The cause of these characteristics is a lack of transmission infrastructure, which causes transmission congestion in the wind corridors and manifests itself by lowering capacity factors as well as LMPs. Sensitivities were then created to reflect and determine the impact of these current characteristics. For Case 1, the historic LMP or market price difference between Lakefield and IPL load was applied, therefore lowering the market price for wind. The LMP differential applied to all planning years in the IRP model is shown below in Figure 4.23.

Figure 4.23 LMP Differential ($/MWh)

Month	On-Peak	Off-Peak
Jan	21.9	19.1
Feb	18.2	16.2
Mar	19.3	17.4
Apr	15.6	14.3
May	12.1	8.7
June	11.6	8.2
July	8.7	6.2
Aug	9.9	7.3
Sept	12.3	9.0
Oct	13.6	10.9
Nov	16.1	13.1
Dec	12.2	10.4

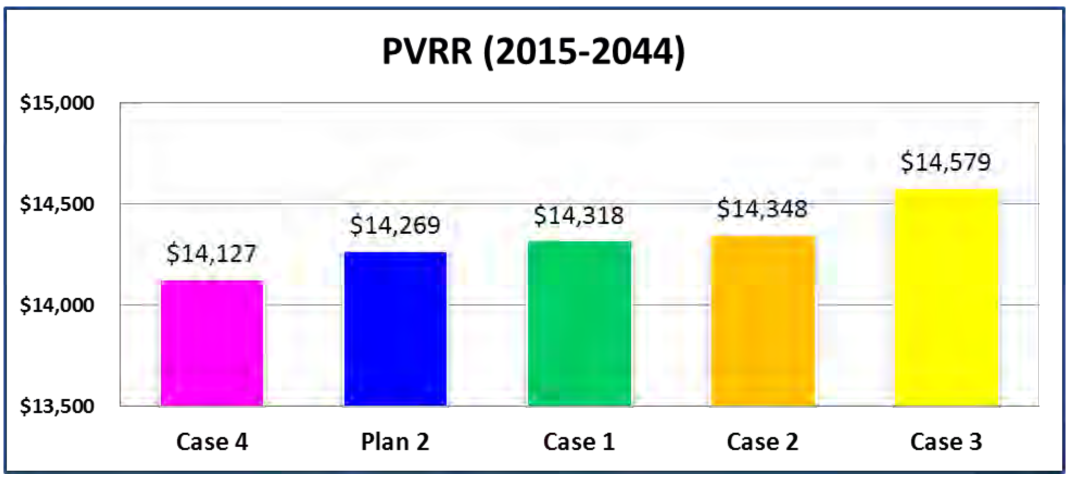
Source: IPL

Case 2 reduces the expected capacity factor for new wind resources to 25%, which was based upon Lakefield's historic capacity factor. Furthermore, IPL modeled potential improvements to wind. In response to stakeholder feedback from a representative from Clean Line Energy, IPL was informed about a project that would build DC transmission lines from Kansas to Indiana thus transferring high capacity factor wind. If completed, the project would provide Indiana access to 50% capacity factor wind. The Clean Line Energy representative discussed utilities could purchase this energy via a PPA for $45/MWH.

The attributes of this project embody Case 3. In attempt to relieve congestion, IPL also considered the impact utility scale batteries could have on wind resources for Case 4. Along with relieving congestion, batteries can minimize intermittency, increase capacity credit, and take advantage of price arbitrage. For this analysis, a 4-hour duration battery equal to 12% of the operating capacity of wind was used. Additional fixed costs of $197/kw/year (2025$)[16] were incorporated in this sensitivity to quantify the cost of the battery. The battery charges during lower market prices hours, corresponding with higher wind speeds, and discharges during peak hours; therefore, shifting the generation from off-peak to on-peak hours.

Wind Sensitivities Results

Figure 4.24 Wind Sensitivity PVRR (2015-2044)



Source: Ventyx

The wind sensitivity results are shown above in Figure 4.24. The sensitivities were than imposed on Plan 2, which includes an additional 200 MW of wind in 2025, of the Base results. Case 1 and 2, as anticipated, escalate the revenue requirement, making wind resources less-cost effective. These sensitivities isolate the two characteristics, but as discussed above, suppressed LMPs and reduced capacity factors are typically interrelated. Despite the multitude of benefits batteries offer, the high capital costs of batteries cause this case to be disadvantageous. The case with the lowest PVRR signifies the Clean Line Energy PPA. Despite significant progress, there is still uncertainty surrounding the DC transmission line construction. IPL will continue to analyze and monitor the progression of transmission capability and technology improvements in the wind industry.

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16 From the State Utility Forecasting Group report "Utility Scale Energy Storage Systems" published in June 2013

Scenario Evaluation Results Summary

[170-IAC 4-7-8(b)(6)(A)] [170-IAC 4-7-8(b)(7)(D)] [170-IAC 4-7-8(b)(7)(E)]

A summary of the results of the future landscapes are presented in Figures 4.25 and 4.26 which show a summary of the PVRR results and the two lowest-cost (PVRR) plans for each landscape respectively. The scenario evaluation focuses on comparing the results of the build out plans in each of the developed scenarios. Particularly, this evaluation measures the robustness of the performance of each plan in all scenarios.

Figure 4.25 – Incremental PVRRs in Each Scenario

PVRR (MM$)	Scenarios						
	Base	High Gas	Low Gas	High Environmental	Environmental	Low Environmental	Average
Plan 1	$17,870	$19,249	$16,415	$23,807	$19,776	$17,223	**$19,057**
Plan 2	$17,861	$19,090	$16,532	$23,628	$19,715	$17,213	**$19,006**
Plan 3	$18,362	$20,546	$16,174	$23,561	$20,139	$17,867	**$19,441**
Plan 4	$18,591	$20,408	$16,768	$23,493	$20,266	$18,096	**$19,604**
Plan 5	$18,351	$20,385	$16,290	$23,381	$20,076	$17,856	**$19,390**

Figure 4.26 – Resource Plan Selection Top Two Summary

PVRR Rank	Base Case	High Gas Case	Low Gas Case	High Environmental Case	Environmental Case	Low Environmental Case
1	Plan 2	Plan 2	Plan 3	Plan 5	Plan 2	Plan 2
2	Plan 1	Plan 1	Plan 5	Plan 4	Plan 1	Plan 1

Source: IPL

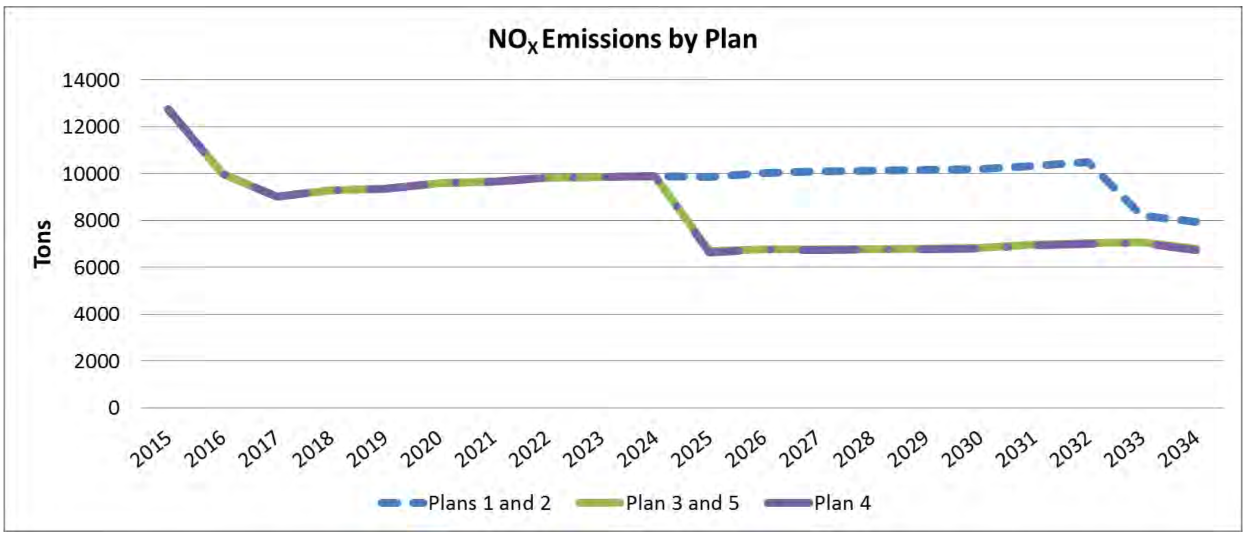
Plans 1 and 2, which both include IPL's existing fleet with proposed refuel and new construction projects, appeared in the top two resources for the majority of the landscapes. The plans with CCGT, CCGT with wind, or CT with wind replacement performed well in the low gas and high environmental scenarios. Nuclear generation did not appear in any of the top spots in all the scenario evaluations.

Comparative Air Emissions by Resource Plan

[170-IAC 4-7-4(b)(8)] [170-IAC 4-7-7(a)(1)]

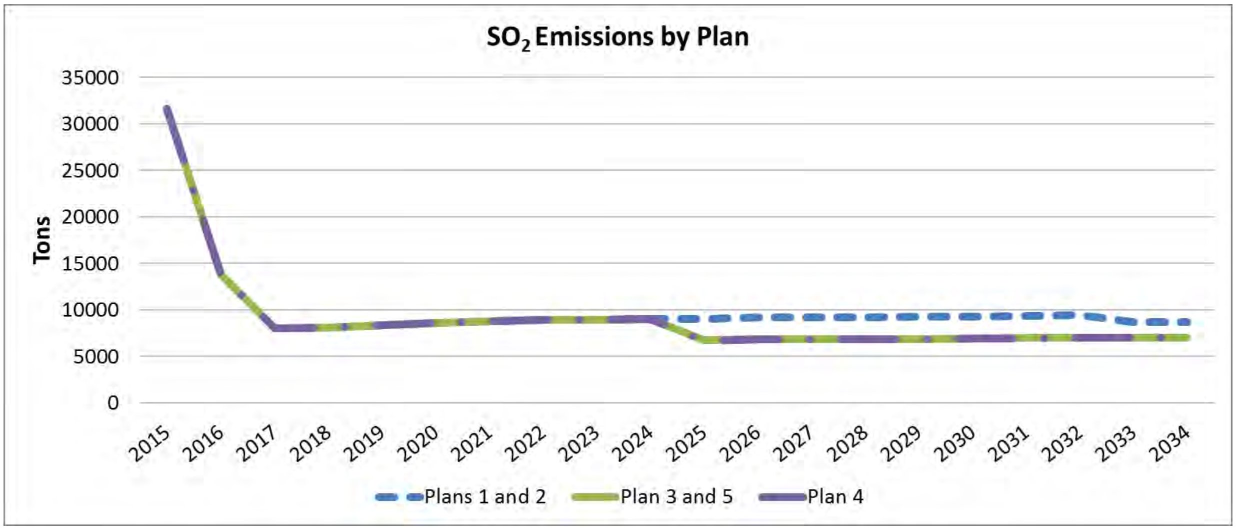
Figures 4.27 through 4.29 provide the air emissions for the five resource plans as modeled by Ventyx. As mentioned above, all plans are identical until 2025 were the plans differ by the retirement of Petersburg units 1 and 2 and the replacement generation selected. All plans demonstrate IPL is making significant advancements in reducing the air emissions of its portfolio over the next three years. In the Ventyx modeling, the costs of NO_X, SO_2 and in most scenarios CO_2 emissions are considered, impacting the dispatch of the emitting units.

Figure 4.27 – NOX Emissions



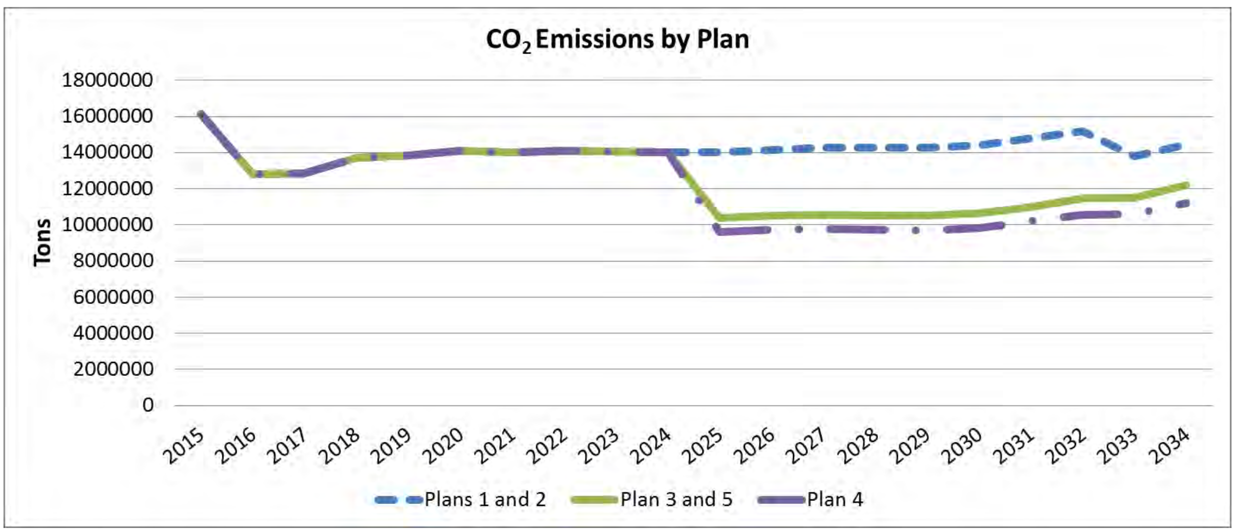
Source: IPL

Figure 4.28 – SO2 Emissions



Source: IPL

Figure 4.29 – CO2 Emissions



Source: IPL

Comparative Annual Costs by Resource Plan

[170-IAC 4-7-8(b)(6)(B)]

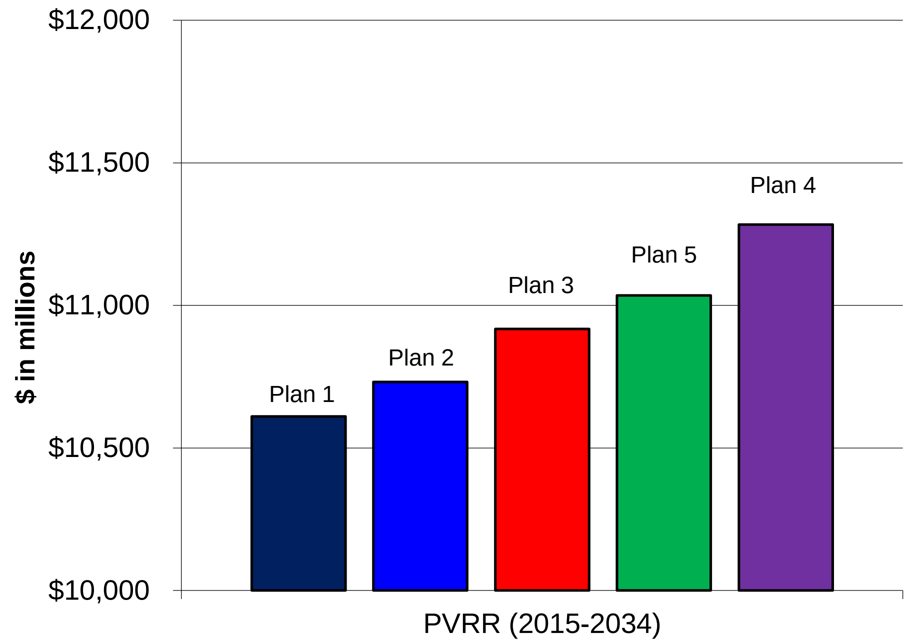
Figure 4.30 provides representative annual revenue requirements for the Base Case for the five resource plans as modeled by Ventyx. The 20 year PVRR of these plans are shown in Figure 4.31 with Plan 1 showing the lowest 20 year PVRR. These costs include existing generation production costs, system capacity and power purchase expense, and incremental new resource costs. The annual costs are best used for comparison purposes to access the relative impacts of new resource plans, and are not intended to represent IPL's full revenue requirements.

Figure 4.30 – Comparative Annual Revenue Requirements by Plan (Base Case), Incremental Average Annual Revenue Requirements (cents/kWh)

Year	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5
2015	0.32	0.32	0.32	0.32	0.32
2016	1.31	1.31	1.36	1.36	1.36
2017	1.46	1.46	1.49	1.49	1.49
2018	1.71	1.71	1.73	1.73	1.73
2019	1.92	1.92	1.94	1.94	1.94
2020	2.30	2.30	2.32	2.31	2.32
2021	2.68	2.68	2.70	2.70	2.70
2022	3.07	3.07	3.09	3.08	3.09
2023	3.57	3.57	3.59	3.58	3.59
2024	3.86	3.86	3.93	3.91	3.93
2025	4.17	4.45	4.36	5.26	4.63
2026	4.35	4.72	4.91	5.89	5.27
2027	4.58	4.89	5.13	5.99	5.43
2028	4.79	5.05	5.36	6.10	5.61
2029	5.04	5.26	5.62	6.24	5.82
2030	5.30	5.48	5.91	6.46	6.08
2031	5.66	5.80	6.28	6.77	6.42
2032	6.10	6.21	6.76	7.17	6.87
2033	6.67	6.76	7.15	7.51	7.23
2034	7.33	7.39	7.71	8.05	7.77

Source: Ventyx

Figure 4.31 – Base Case PVRR Plan Ranking (2015-2034)



Source: Ventyx

Results Summary and Resource Selection Overview

[170-IAC 4-7-8(b)(1)]

The supply resource selection at IPL combines information from both the quantitative part of the evaluation, that is the capacity expansion results and future landscape scenario results, and risks associated with resource planning especially environmental, fuel pricing, and load variation, creating a robust evaluation process.

The capacity expansion results which are presented in Figure 4.10 establish IPL's current resource projects (Eagle Valley CCGT and refuel of HSS Units 5 through 7) will be sufficient to satisfy IPL's capacity requirement until 2031. However, in two scenarios, the capacity expansion modeling results determine it would be economic to retire one or multiple units at Petersburg. Over the last five years of the IRP planning period, IPL's fleet is expected to undergo significant changes as Petersburg 1 along with HSS 5 through 7 approach their anticipated retirement dates. To replace these retired units, CCGT, CT, and wind were the selected resources with CCGT appearing in the majority of the capacity expansion scenarios. Nuclear and solar resources did not appear in any of the landscapes. IPL has experienced a large influx of early adoption of DG solar due in large part to its feed-in-tariff, Rate REP as described in Section 4A. Additional DG is not included in the short-term forecast absent further financial incentives. IPL recognizes the installed costs for solar are decreasing, however, modeling limitations do not allow dynamic costs to be included. Therefore, the 2016 IRP will include updated cost which may find solar to be a cost-effective option.

Since the capacity expansion modeling did not identify an additional need for generation without the early retirement of IPL's coal units, IPL derived build out plans to highlight the potential impact of retiring Petersburg units 1 and 2 early. The build out plans, as shown in Figure 4.11, utilize resources that were selected in the capacity expansion results as a way of creating plans that would be competitive across multiple future landscapes. The plans representing IPL's existing thermal generation, Plans 1 and 2, had the lowest PVRR in the Base, High Gas, Environmental, and Low Environmental that is the plans with moderate or low CO_2 costs. Replacing Petersburg 1 and 2 with CCGT had the lowest PVRR in the Low Gas Scenario while CCGT and wind as the replacement had the lowest PVRR in the High Environmental scenario. The scenario analysis results are shown in Figure 4.17. Wind, firmed by a CT, also performed well the High Environmental case due to the high and imminent CO_2 cost benefits, but generally finished behind the CCGT. The scenario analysis results are shown in Figures 4.17 through 4.22.

The plans representing IPL's existing thermal generation were in the top two selected resources in four (4) of the six (6) future landscapes. These results demonstrate the ability of our current fleet to perform well with and without CO_2 costs, and with low and moderate natural gas prices. From a risk perspective, with the addition of the Eagle Valley CCGT, IPL's generation portfolio will have a balanced fuel mix, limiting its fuel risk exposure.

While the difference in PVRR was unsubstantial in most instances, Plan 2, representing an additional 200 MW of wind resources, typically outperformed Plan 1. However, as further discussed in the wind sensitivity section above, IPL models new wind resources at a capacity factor of 35% and an LMP equal to the MISO-IN price, both of which are improvements from the actual current characteristics of Hoosier and Lakefield Wind Farms. These assumptions are based upon the belief that transmission capabilities will be improved to resolve the current conditions. Also, a great deal of uncertainty surrounds requirements of the proposed EPA Clean Power Plan.

In the upcoming years, IPL will better understand the congestion improvements created from transmission expansion to potentially improve wind capacity factors. Since compliance for the proposed Clean Power Plan could start as early as 2020, IPL will continue to analyze the benefits of adding additional renewables to its portfolio between now and then. Nevertheless, IPL's capacity requirement will be met by the addition of the Eagle Valley CCGT along with existing generation improvements, therefore, IPL's existing resources, or Plan 1, is IPL's Preferred Portfolio. From both a minimum revenue requirements perspective and a risk mitigation perspective, IPL's existing portfolio eliminates the need for new generation in the IRP planning period. This strategic direction is supported by quantitative results and is the basis for IPL's Preferred Resource Portfolio.

IPL's Preferred Portfolio

[170-IAC 4-7-8(b)(1)] [170-IAC 4-7-8(b)(4)] [170-IAC 4-7-8(b)(8)]

IPL's Preferred Portfolio is focused on deriving a low cost, low risk, reliable plan to serve customer load, while complying with all federal, state, and IURC mandates.

As outlined in Figure 4.1, IPL's resource selection strategy takes a systematic approach including an assessment of existing resources, determination of resource needs, inclusion of all cost-effective and/or required DSM and renewables, and then uses Ventyx Capacity Expansion and scenario analysis modeling of supply options to identify the balance of IPL's resource plan.

The selected IPL Preferred Portfolio includes its four large scrubbed coal-fired units at Petersburg, including all required environmental compliance enhancements, its gas-fired peaking units, including the approved refuel of HSS 5 and 6 along with the proposed refuel of HS7, 300 MW of wind from PPAs, 98 MW of solar Rate REP, forecasted DSM resources, and the addition of the Eagle Valley CCGT. When replacement is needed for the units nearing their anticipated retirement dates (HSS 5 and 6 and Petersburg Unit 1), CCGT has been identified as the preferred resource. The details of the selected Reference Plan are described below.

Existing Core Base Load Resources

IPL and other coal-fired utilities will continue to face new environmental requirements. A number of additional environmental rules – either proposed or final – affect these units. These rules include but are not limited to the Cross State Air Pollution Rule ("CSAPR"), National Ambient Air Quality Standards ("NAAQS"), Cooling Water Intake Structures Rule, Coal Combustion Residuals ("CCR") Rule, and federal Effluent Limitations Guidelines ("ELG") for Steam Electric Generating Stations. Additional requirements could also result from settlement or litigated outcome of the Notice of Violation ("NOV") and Finding of Violation from EPA received in October 2009 related to alleged violations of the New Source Review ("NSR"). These regulations and requirements would potentially require IPL to incur additional expenses for compliance in the future.

Demand Side Management

The IPL short-term action plan (2015-2017 Action Plan) for demand side management ("DSM") was filed and approval is currently pending approval before the IURC in Cause No. 44497. The three year plan in Cause No. 44497 covers the years 2015-2017. Although cost and savings information was developed and presented for 3 years, IPL is only seeking spending approval to deliver the programs for the first 2 years (2015-2016), to facilitate flexibility with expected future DSM legislation. This proceeding specifically seeks approval of DSM programs and budgets for 2015 and 2016. In response to stakeholder input, IPL engaged AEG to update its forecast from 2017 to create a full 20 year projection for this IRP. It accounts for the elimination of IURC annual savings targets and the opt-out provision of large customers, due to Senate

Enrolled Act 340. IPL include the forecasted twenty (20) years of DSM savings in the load forecast. However, Future programs will be developed for the balance of the IRP period and presented in subsequent IURC proceedings. The twenty year forecast is provided in Section 7, Attachment 4.7, DSM Supporting Documents. For more information, please see Section 4B.

Renewables Generation/Climate Change

Renewables technologies represent a resource that primarily targets potential future requirements for GHG regulation, and specifically any federal or state RES legislation. EPA's Clean Power Plan, which establishes the proposed Best System of Emissions Reductions available for existing sources in accordance with Section 111(d) of the Clean Air Act, includes renewables as a "building blocks," or measures of reduction, for compliance. Specifically, EPA based the standards on re-dispatch to renewables from a 2012 value of 3% of Indiana's total generation to a value of 6.6% by 2029.

IPL's preferred portfolio includes a renewables generation component of about 300 MW of wind secured under two long-term PPAs and 98 MW of solar under Rate REP to meet any future RES requirement. Under the terms of the existing PPAs, IPL receives all of the energy and Renewable Energy Credits ("RECs") from the two wind farms. The null[17] energy is used to supply the load for IPL customers and, in the absence of any mandatory federal or state RES, IPL is currently selling the associated wind RECs and plans to sell solar RECs, but reserves the right to use RECs from the PPAs to meet any future RES requirement. The 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 PPAs and next to credit IPL customers through its fuel adjustment clause proceedings. When the RECs associated with the production of null energy from the Wind PPAs are sold to a third party, IPL shall not claim that energy as renewable energy on behalf of its retail customers. Absent a clear renewables requirement, no additional renewables resources are planned.

Power/Capacity Purchases

Historically, IPL has relied on short-term capacity markets for up to 300 MW of its capacity requirements. However, for the period 2015 to 2016, IPL will be facing additional challenges as MISO capacity prices continue to rise and retirements increase to comply with new EPA regulations. As discussed above, IPL will be retiring Eagle Valley coal-fired units 3-6 by April 16, 2016, six weeks before the end of the MISO Planning Year ("PY") 2015-2016. With a favorable FERC waiver decision, IPL will not need to purchase replacement capacity for this

17 The Green-e Dictionary (http://www.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."

timeframe. Along with a bilateral purchase of 100 MW, IPL has effectively minimalized its exposure to the price volatility of the MISO Capacity auction for PY 15-16.

PY 2016-2017 represents a dissimilar story as IPL's capacity position will be short up to 350-400 MW, due to the retirement of the Eagle Valley coal units mentioned above. IPL has mitigated its exposure through a bilateral agreement of 100 MW and is nearing the completion of another 200 MW purchase.

IPL will continue to evaluate the purchase of some or all of its remaining projected volume difference between its actual Planning Reserve Margin Requirement and its own resources plus bilaterally purchased Zone 6 Zonal Resource Credits, with either bilateral purchases or sales, or auction purchases or sales.

With the addition of the Eagle Valley CCGT just prior to the MISO Planning Year 2017-2018, IPL projects that its resources will exceed its MISO Planning Reserve Margin Requirement for 2017-2018 by 250 MWs. IPL will evaluate whether to sell the extra Zonal Resource Credits bilaterally before the auction or to sell the extra Zonal Resource Credits in the 2017-2018 MISO Resource Planning Auction.

Transmission and Distribution

IPL's electric transmission and distribution (T&D) facilities are designed to provide safe, reliable, and low cost service to its customers as described in section 4C. IPL's has studied the need for transmission, substation and distribution enhancements and designed projects to support the preferred resource portfolio. Specifically, accommodating generation additions and retirements while improving operational flexibility is paramount to ensure deliverability of power into the IPL load zone. These projects include the installation of new 345 kV breakers, autotransformers, and 138 kV capacitor banks to improve power import capability from the 345 kV system to load centers on the 138 kV system as well as distribution system improvements to accommodate DG at Rate REP project locations. Several projects associated with the new CCGT will be completed in 2015 and 2016. In addition, IPL plans to install a Static Volt Ampere Reactive ("VAR") System to provide dynamic voltage and reactive power support.

IPL has enhanced its distribution system through smart grid investments that enable demand response through CVR and interconnect its Rate REP projects. People in multiple areas of IPL worked closely to develop efficient procedures and successfully interconnect the DG sites. Based on the proposed location and feeder interconnection, specific engineering site studies were performed to determine if the distribution system could reliably support the DG resource without impacting the service reliability of existing customers. Line extension projects were engineered and constructed as needed. To date, ten (10) projects with capacity of 500 kW to 10 MW have been connected to IPL's smart grid network to enable remote switching for IPL to safely work on distribution lines without any chance of DG backfeed. See Section 4C for more information on these projects and IPL's transmission and distribution planning criteria.

IPL's business practices include regular reviews of transmission and distribution system needs occurs with operations, construction and engineering personnel. If needed, adjustments are made to current or proposed projects to accommodate field or directional changes such as changes in IPL's preferred resource portfolio. Monthly large project coordination meetings facilitate this nimble process and include budget and schedule reviews. T&D will likely continue to play a larger role in resource planning in the future as DR, smart grid and DG become more prevalent. T&D projects typically are deployed more quickly than generation projects as evolution occurs to improve system capabilities incrementally.

Summary

The IRP presented herein and the selected Preferred Portfolio represents IPL's current view on the future electricity landscape and sensitivities around that landscape, and the resources that will reliably and cost-effectively meet customers' future electricity needs within expected legislative, EPA, and IURC requirements. Resource planning is a continuous process with the IRP representing a key snapshot of the planning horizon. In addition to IRP studies, IPL also monitors for special situational opportunities. IPL will pursue improvements to existing programs and assets as well as new, prudent, and advantageous resources as the need and deemed benefits of such resource options are clearly identified.

Section 4A. RESOURCE OPTIONS

World events and trends play a big role in forecasting future resource possibilities. This is particularly true this year with many new regulations being promulgated by EPA. With this changing landscape, IPL has worked diligently to identify, characterize and evaluate a broad selection of demand side, renewable and supply options.

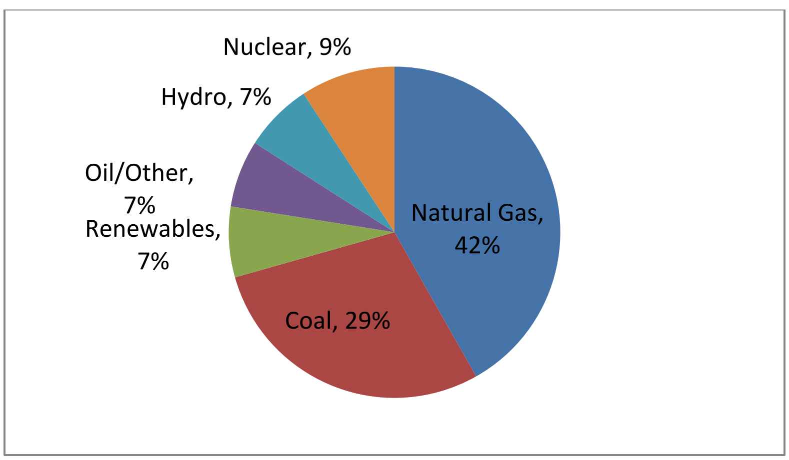
Generation Technology

National Resource Mix[18]

The U.S. currently maintains a domestic generation mix dominated by coal and natural-gas as Figures 4A.1 and 4A.2 illustrate.

The use of natural gas as a source of capacity and energy is starting to catch up with coal. Between the last IPL IRP in 2011 and the statistics for 2012, natural gas has increased its share of capacity and energy by 3 and 7 percentage points respectively – an increase for natural gas of 18% for capacity and 30% for energy. Most of these gains have come at the expense of coal.

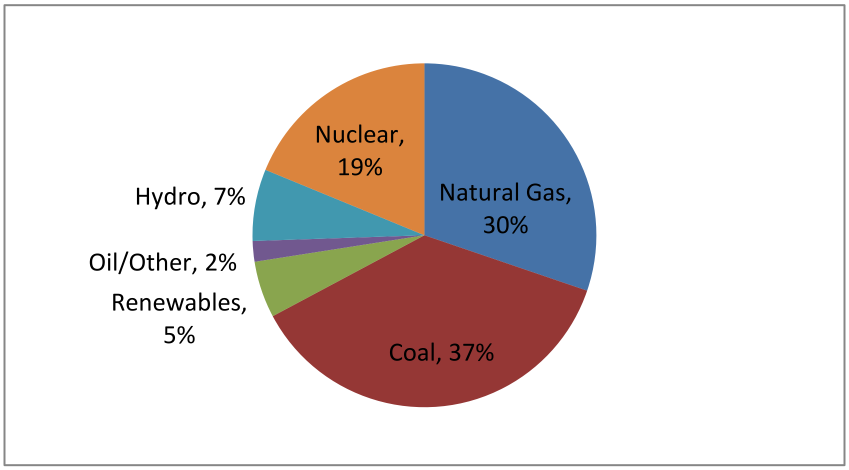
Figure 4A.1 – U.S. Generating Capacity by Fuel Type (2012)



Source: EIA

18 The source for all resource mix comments in this section is *Electricity & Fuel Price Outlook*, *Midwest Spring 2014*, Ventyx, unless otherwise noted.

Figure 4A.2 – U.S. Electric Power – Electricity Production (2012)

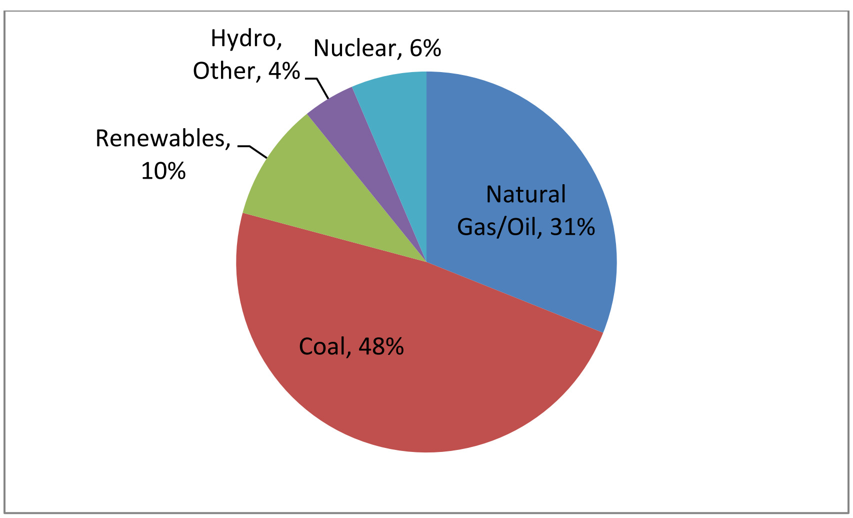


Source: EIA

MISO Resource Mix

As a member of MISO, and a participant in the energy market for this Regional Transmission Organization ("RTO"), IPL has access to the diverse resources of the 13 states and part of the Province of Manitoba in the MISO North/Central Regions (parts of an additional four states make up the MISO South Region). As shown in Figure 4A.3, the MISO North/Central Region relies heavily on coal-fired generating resources for capacity.

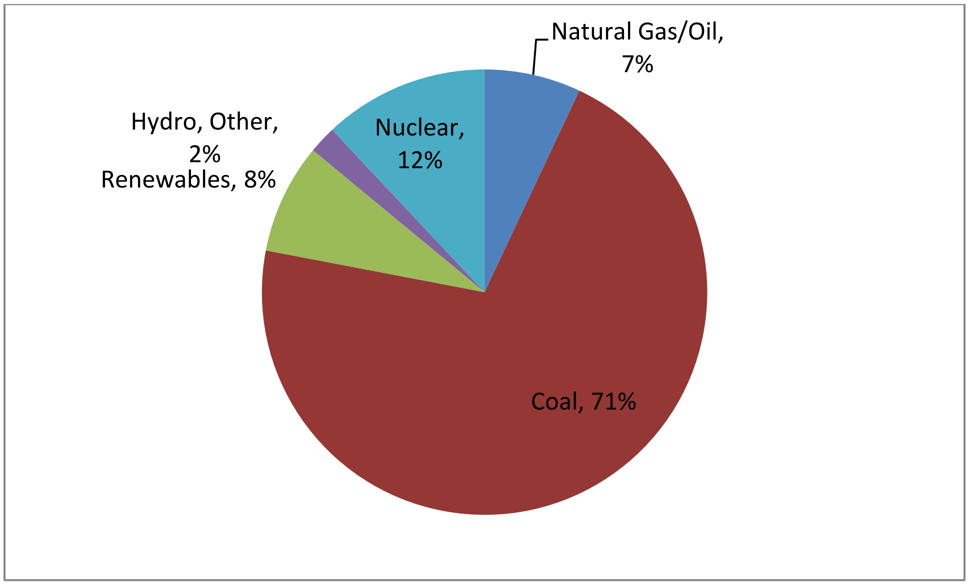
Figure 4A.3 – MISO Generating Capacity by Fuel Type (2013)



Source: MISO, "The Changing Power Generation Fleet," February 6, 2014

As an energy source, coal plays an even larger role in the production of electrical energy, where it dominates with a 71% share. Here too, however, there has been a decline of 5% since 2011 when coal was responsible for 75% of the energy production in MISO.

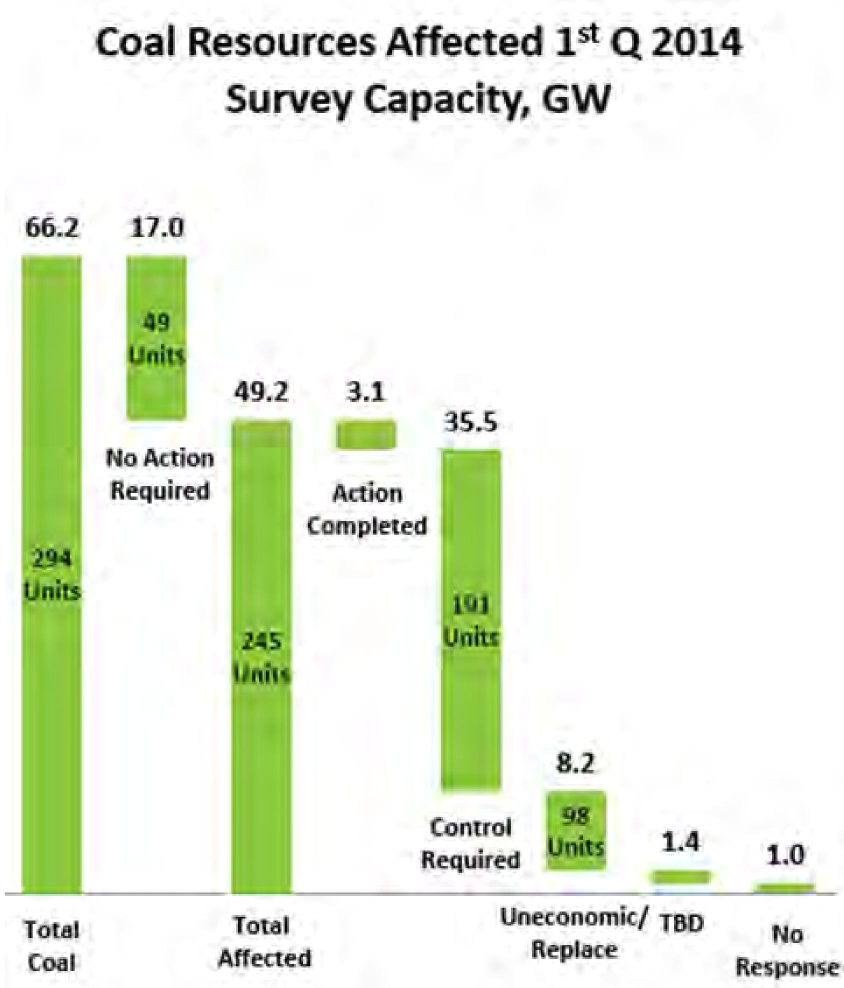
Figure 4A.4 – MISO Generating – Electricity Production (2013)



Source: MISO, "The Changing Power Generation Fleet," February 6, 2014

The next largest fuel-type is natural-gas fired generation, which accounts for almost 31% of the generating resources in the MISO North/Central Regions. Because these resources are higher-cost than most of the other resources in MISO, they produce less than 7% of the energy in the region (which is up from 5% in 2009). Natural gas capacity frequently sets the price in MISO. Energy production from natural gas is expected to increase within the MISO North/Central Regions. Due to EPA regulations, a significant portion of the coal fleet is forced into retirement. MISO surveys of member generators indicate that at least 8.2 GW of coal resources will retire due to the MATS regulation as noted in Figure 4A.5 below:

Figure 4A.5 – MISO Coal Units Affected by MATS



Source: MISO, "2014 Q1 EPA Survey Update"

The mix of generation is relatively homogeneous across the sub-regions within the MISO North/Central Regions; however, the north and west sub-region hosts most of the wind resources, while the east has the largest quantity of nuclear resources.

Supply Side Options

[170-IAC 4-7-6(c)(1)] [170-IAC 4-7-7(a)]

For planning purposes, IPL selected a group of reference units that represent proven and commercially available technologies, as well as emerging technologies considered viable in the next five to 10 years. In addition to traditional generating units, transmission projects, efficiency improvements and smart grid resources are considered as part of IPL's portfolio. IPL submits transmission expansion and improvement projects to MISO as part of its transmission planning process. MISO determines the benefits of such projects and includes those that are cost effective in its MISO Transmission Expansion Plan ("MTEP") on an annual basis. IPL will build out two (2) market efficiency projects including the Petersburg to Breed 345 kV line upgrade and a Petersburg 345 to 138 kV autotransformer upgrade as described in the short-term action plan. IPL determines ways to improve system stability and flexibility to improve import capability. IPL does not currently have any Multi Value Projects ("MVP") however, MISO continues to study MVP projects. In addition, IPL considers and implements transmission improvements to support additional or upgraded generating resources. These are both described in Section 4D

IPL considers efficiency improvements that may provide additional generating capacity such as a technique known as "fogging" whereby inlet air is cooled to increase gas turbine outputs. This is described in the short-term action plan (Section 5) as part of technology applications. Analysis is underway, therefore, no specific incremental capacity in terms of MWs are included in the preferred resource portfolio.

Smart grid assets have been included in this IRP and the preferred resource portfolio in the form of 20 MWs through IPL's Conservation Voltage Reduction ("CVR") program. Two-way communicating devices at distribution substations and capacitor bank locations allow IPL to remotely lower the system voltage incrementally to reduce peak demand. The voltage levels on the feeders and at Advanced Metering Infrastructure ("AMI") meters are monitored to ensure service voltage limits are maintained.

For the first time, a significant amount of distributed generation ("DG") resources are also included in this IRP. This DG is comprised of approximately 66 MW of solar facilities located at customer premises as described below and in Section 4C.

The reference units represent two natural gas-fired options, and three nuclear/renewables choices. A Battery Energy Storage System ("BESS") was not included as a separate new resource in the Ventyx model due to the current economics precluding it from being selected by the model as a resource[19.] Unlike previous years, coal options were not considered since Supercritical Pulverized Coal ("SCPC") no longer appears to be a viable option due to EPA 111(b) regulations on greenhouse gas emissions for new sources. Likewise, IPL has not considered Integrated Gasification Combined Cycle ("IGCC") since this technology has yet to become widely adopted.

Natural Gas

- Simple Cycle Combustion Turbine ("CT")
- Combined Cycle Gas Turbine – H-Class ("CCGT")

[19] See Section 2 for more information about IPL's plans to research BESS options on its 138 kV grid.

Nuclear and Renewables

- Nuclear
- Wind
- Solar
- Hydroelectric[20]

The technology and size of units selected for capacity additions will depend on a number of factors including, among others, load and energy demand growth and best available technologies at time of construction. In the write-up on technology below, IPL indicates the size in megawatts of each unit under consideration. So as to not skew the results, IPL is using a "common size" of 200 MW for the CCGT and Nuclear options. This would represent a portion of those plants and not the full output so that IPL can analyze the underlying need and not be overly concerned about minimum unit size. In reality, however, IPL would build or buy the appropriate sized unit, perhaps with partners if the size does not correspond to minimum unit size.

A brief description of each of the technology alternatives currently or potentially available to IPL to meet future capacity needs follows.

Please note that all capital costs provided below are derived from Ventyx assumptions for "overnight costs". As the name implies, overnight costs represent pricing the costs of a unit as if it could be built in one day. Separate assumptions on commodity and labor-price inflation are included in the Ventyx modeling to adjust these costs to the year a unit is brought online. In addition, Allowance for Funds Used During Construction ("AFUDC") costs is also included in the model runs. Note that Figure 4A.7 below does not include either commodity-price and labor-price inflation or AFUDC.

Natural Gas

[170-IAC 4-7-6(c)(1)] [170-IAC 4-7-7(a)]

IPL has evaluated two types of natural gas-fired generation in the IRP analysis. Natural gas-fired units have historically had low dispatch rates in the Midwest due to a competitive installed coal-fired fleet. However, increasing regulation of coal generation coupled with increased discoveries of natural gas supply may lead to a significant increase in natural-gas fired generation in the Midwest. Please note that all capacity numbers represented below are approximate winter outputs.

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[20] In the IPL 2011 IRP, the Company determined hydroelectric power was not a viable resource. There have been no significant changes since the analysis performed for the 2011 IRP; hence, hydroelectric power has not been included in this IRP.

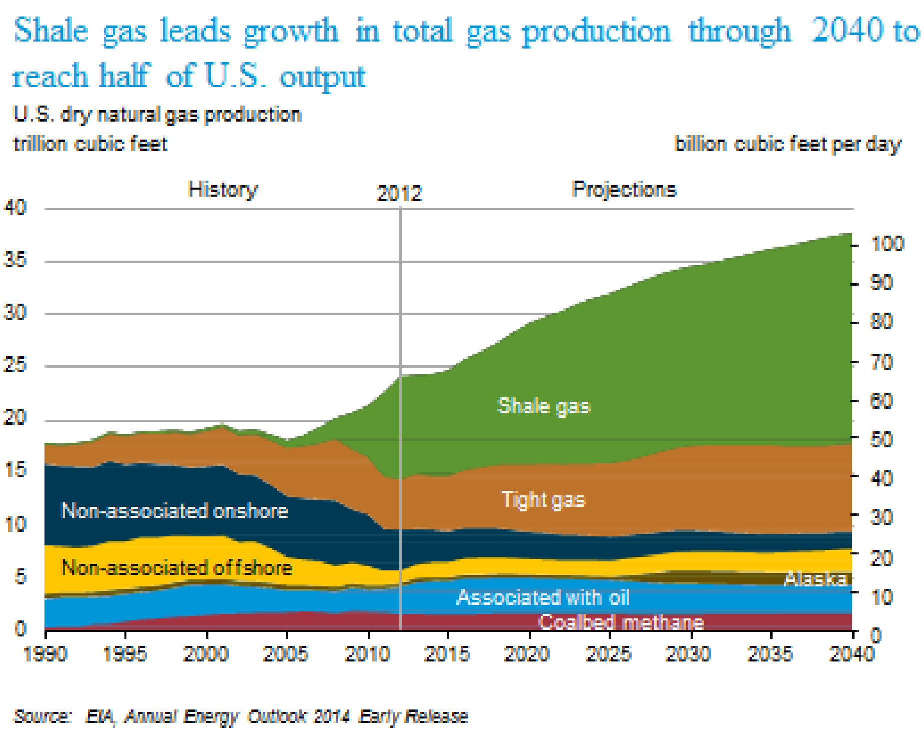
Shale and the New Gas Supply Paradigm

Natural gas alternatives are increasingly important in the analysis of new supply options for two reasons: first is the significant pressures felt by U.S. utilities to retire existing coal assets and the difficulty in permitting new coal-fired generation. As important, however, is the emergence of shale gas and the significant increase in available U.S. natural gas resources.

Geologists have long known that shale formations contained significant amount of natural gas, the formations are not porous and the gas cannot flow freely when wells are drilled. The breakthrough in commercial drilling in shale formations was combining the practice of horizontal drilling coupled with hydraulic fracturing (the process of using high pressure liquids to create cracks in the shale which allow the gas to flow)[21].

Between 2005 and today, the rate and range of shale gas development expanded in many parts of the county. "In addition to the Barnett, producers began intensively developing plays in the Woodford, north of the Barnett in Texas and Oklahoma; the Fayetteville in Arkansas; and the Haynesville in Louisiana/East Texas. During this time development also began in the Marcellus Shale of the eastern United States." [22] In 2014 the Annual Energy Outlook, the domestic supply picture has changed as noted below in Figure 4A.6:

Figure 4A.6 – Projected Domestic Gas Supply



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21 *Task Force on Ensuring Stable Natural Gas Markets*, 2011 Report, Bipartisan Policy Center and American Clean Skies Foundation, pp. 35-36.

22 Ibid.

With traditional domestic U.S. gas drilling, most operations are in relatively unpopulated areas. Shale gas operations include more populated areas, leading to more chance of public opposition and possible water pollution. The natural gas industry and environmental officials have begun paying more attention to these issues and must take the steps necessary to avoid any significant environmental degradation.

Simple-Cycle Combustion Turbine

For purposes of the IRP analysis, IPL assumed the incremental addition of a 160 MW CT in its expansion planning. Conventional frame CTs are a mature technology, widely used for peaking applications. The units are characterized by low capital costs, low non-fuel variable Operation and Maintenance Costs ("O&M"), modular designs and short construction lead times. However, one disadvantage of CTs is the relatively high average heat rate, cost of fuel and resulting high operation costs at higher capacity factors.

IPL has substantial experience in both the construction and operation of CTs. IPL unit additions include Georgetown Generating Station ("Georgetown") Unit 1 (100 MW) added in 2000 and Harding Street Generating Station ("HSS") CT 6 (183 MW) added in 2002. IPL also purchased Georgetown Unit 4 in 2007 (100 MW). IPL will continue to consider CTs as a generation option due to their flexibility in adding small increments of capacity within a relatively short time frame. IPL also continues to monitor developments in CT technology and will consider CT alternatives in any decision for future capacity additions.

See environmental characteristics and capital costs assumed for IRP modeling in Figure 4A.7.

Combined Cycle Gas Turbine

For purposes of the IRP analysis, IPL assumed the incremental addition of a 200 MW CCGT. The typical combined cycle installation consists of gas turbines discharging waste heat into a heat recovery steam generator ("HRSG"). The HRSG supplies steam that is expanded through a steam turbine cycle driving an electric generator. Combined cycle units have the distinct advantage of being the most efficient fossil-fueled process available. IPL has recently begun construction on a 671MW F-class CCGT at Eagle Valley. It is anticipated that by the commercial operation date of any new CCGT, that either G- or H-class machines will be widely in-service with other North American utilities and will represent a good choice for IPL. IPL has modeled an H-Class machine in its analysis. In addition, the units have low pollutant emissions, low water consumption levels, reduced space considerations and modular construction. IPL continues to monitor developments in CCGT technology and will consider CCGT alternatives in any decision for future capacity additions.

See environmental characteristics and capital costs assumed for IRP modeling in Figure 4A.7.

Nuclear and Renewables

[170-IAC 4-7-6(c)(1)] [170-IAC 4-7-7(a)]

Nuclear

With increasing concern about GHG, there has been a renewed interest in additional investment in nuclear generation. While the debate over nuclear plant siting is controversial and the plants are extremely capital intensive, additional electricity production by nuclear power is promoted on the basis of mitigating increases in GHG emissions. Countervailing views on the "nuclear renaissance" are that the technology is too expensive and the accident at the Fukushima Daiichi plant in Japan should make regulators hesitant to approve new reactors.

A total of 23 new reactors are before the Nuclear Regulatory Commission (NRC) for a combined construction and operating license (COL). These new reactors are all located in the Midwest, Southeast and Texas. Despite this rather large figure, Ventyx notes that the "high uncertainty around construction cost estimates and the ability to obtain financing, Ventyx is assuming that only Vogtle 3&4 and VC Summer 2&3 in the Carolinas will be constructed plus the completion of the TVA's partially constructed Watts Bar 2 reactor, scheduled to be completed in December 2015."

Summary details of the two projects are noted below:

	Vogtle 3&4	**VC Summer 2&3**
Primary Utility	Southern Company	South Carolina Electric & Gas
Reactor	Westinghouse AP1000	Westinghouse AP1000
Completion	2017 (Unit 3) 2018 (Unit 4)	2017 (Unit 2) 2018 (Unit 3)

Ventyx also notes that in "August 2012, the NRC denied a license for the Calvert Cliffs nuclear power plant in Maryland. The judges said the applicants cannot receive a combined license to build and construct an Areva nuclear plant at Calvert Cliffs since the applicants are owned by a US Corporation that is 100% owned by a foreign corporation."

IPL has chosen to include a nuclear option within this analysis. It is not anticipated that IPL will build a greenfield nuclear plant. Rather, it is assumed that IPL could participate as a minority participant in the development of a new nuclear plant at an existing site if such development could overcome permitting issues. IPL continues to monitor developments in nuclear technology and will consider nuclear alternatives in any decision for future capacity additions.

See environmental characteristics and capital costs assumed for IRP modeling in Figure 4A.7.

Wind

Recent introduction of large-scale, utility-grade wind turbine generators ("WTG") has made wind energy a commercially viable technology in Indiana and the U.S. Indiana in particular has benefited from the widespread adoption of increasing wind tower heights. The 80 meter turbine height which is common in Benton County can more readily utilize the increased wind speeds found at higher elevations. Likewise, the Midwest is favored with several very good wind basins, allowing generation to be diversified and take advantage of metrological variances.

Wind speeds are important in determining WTG performance. The power available to drive WTG is proportional to the cube of the speed of the wind. In other words, a doubling in wind speed leads to an eight-fold increase in power output.

Higher wind speeds are not only important for generation; they also tend to lower the cost per kWh of the electricity produced. This is because wind parks generally have very high fixed costs (i.e., most of the cost of operating a wind park is the initial capital and financing costs). Spreading this cost over more hours per year reduces the hourly cost of electricity.

Currently, IPL's resource plan has an available renewables generation component of approximately 300 MW of energy secured under two long-term Wind Power Purchase Agreements ("PPAs"). Under the terms of the Wind PPAs, IPL receives all of the energy and Renewable Energy Credits ("RECs") from the two wind farms. The null[23] energy is used to supply the load for IPL customers and, in the absence of any mandatory federal or state renewable energy standard ("RES"), IPL is currently selling the associated RECs, but reserves the right to use RECs from the Wind PPAs to meet any future RES 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. When the RECs associated with the production of null energy from the Wind PPAs are sold to a third party, IPL shall not claim that energy as renewable energy on behalf of its retail customers.

Good wind sites are usually located far from the main load centers, and therefore transmission system expansion may be required to connect the load centers with the wind-rich sites. IPL continues to monitor developments in wind technology and will consider wind alternatives in any decision for future capacity additions.

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[23] The Green-e Dictionary (http://www.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."

See environmental characteristics and capital costs assumed for IRP modeling in Figure 4A.7. The cost is the same for in state or out of state wind, but the capacity factor will vary depending on the location of the resource.

Solar

The total U.S. solar market grew more than 120% in 2010 – from 349 MW to 782 MW – and included approximately 48,000 photovoltaic ("PV") systems. These were mostly rooftop systems, but there were also a significant number of utility-scale projects, with eight projects greater than 10 MW.[24] As noted in the Rate REP Feed-In Tariff section below, IPL is on pace to have approximately 98 MW of PV systems commissioned by June 2015. IPL continues to monitor developments in PV technology and will consider PV alternatives in any decision for future capacity additions.

IPL's model allowed additional solar to be selected in 10 MW blocks. See environmental characteristics and capital costs assumed for IRP modeling in Figure 4A.7.

Hydroelectric Resources

The use of water-power to generate electricity is one of the oldest generation resources still in use today. In addition, hydroelectric power remains by far the largest source of renewable energy in the world, including North America.[25] In the IPL 2011 IRP, the Company determined hydroelectric power was not a viable resource. There have been no significant changes since the analysis performed for the 2011 IRP; hence, hydroelectric power has not been included in this IRP.

MW Capacity, Performance Attributes, and Installed Costs

[170-IAC 4-7-7(a)] [170-IAC 4-7-7(a)(1)]

The Supply Side Resources considered in IPL's IRP modeling are listed below in Figure 4A.7 along with their assumed MW capacity, performance attributes, and installed costs.

24 http://www.solarelectricpower.org/

25 *Power Engineering*, June 2009 "Hydroelectricity: The Versatile Renewable," page 32.

Confidential Figure 4A.7 – IRP Supply Side Resource Options

				Emission Rates		
	MW Capacity	Base/Peaker/ Intermittent	Cost per Installed KW	SO_2 (lb/MWh)	No_x (lb/MWh)	CO_2 (lb/MWh)
Simple Cycle Gas Turbine	160	Peaker	[redacted]			
Combined Cycle Gas Turbine - H-Class	200	Base				
Nuclear	200	Base				
Wind	50	Intermittent				
Solar	10	Intermittent				

Source: Ventyx

Distributed Generation, Net Metering and Feed-In Tariff

[170-IAC 4-7-4(b)(5)] [170-IAC 4-7-6(c)(1)] [170-IAC 4-7-7(a)]

Distributed Generation

IPL continues to identify and inventory customers who own distributed generation ("DG") (in addition to those already identified and contacted for possible participation in IPL's Standard Contract Rider No. 15, Load Displacement) for inclusion in future distribution planning studies. Transmission and Distribution impacts are discussed in Section 4C. As a Company, we stay connected to our customers in order to gage their interest in DG through public outreach events. IPL recognizes factors in addition to costs may motivate customers to install DG, such as environmental attributes, customer empowerment, energy independence, increased reliability, and social activism. Due to a large occurrence of early adoption from Rate REP and the Indiana climate, IPL believes its service territory will see little growth in DG.

Rate REP (Renewable Energy Production)

IPL's Rate REP is a three-year pilot renewable energy feed-in tariff approved by the IURC that went into effect on March 30, 2010 and concluded in 2013. Under Rate REP, IPL was authorized to purchase all of the energy produced by customer-sited solar photovoltaic, wind, or biomass systems and receives all of the Renewable Energy Credits ("RECs). The null[26] energy from the customer-sited systems is used to supply the load for IPL customers and, in the absence of any mandatory federal or state renewable energy standard ("RES"), IPL plans to sell the associated RECs, but reserves the right to use RECs from Rate REP agreements to meet any future RES requirement.[27] When the RECs associated with the production of null energy produced by customer-sited solar photovoltaic, wind, or biomass systems are sold to a third party, IPL shall not claim that energy as renewable energy on behalf of its retail customers.

IPL has executed and the IURC has approved forty (40) agreements for a total nameplate capacity of approximately 98 MW (alternating current ["AC"]). As of September 1, 2014, there were 26 operating projects totaling 66 MW of nameplate capacity; 11 MW are under construction and an additional 21 MW have not started construction. All projects are expected to be completed by June, 2015. See Section 7, Attachment 8.1 and Attachment 8.2, Rate REP for the solar projects and their location in the IPL service territory.

IPL is currently working with MISO to receive capacity credit for these Rate REP projects in future Planning Years. As more historical data is gathered, IPL will have a better understanding of the capacity value, but due to the intermittent nature of these resources, only 30 MW are included in IPL's generation planning reserves.

Net Metering

In 2011, the IURC expanded the Net Metering rules to include all customers and increased the maximum nameplate rating to 1 MW. As of September1, 2014, IPL has 51 net metered customers that include 8 commercial customers and 43 residential customers. Total nameplate capacity of these installations is approximately 240 kW. This increase in residential participation has been influenced by the decline in PV panel costs and IPL's DSM incentives that will expire at the end of 2014. Commercial customers continue to have limited participation. Due to low retail rates and expiring tax credits, it is expected that few, if any, commercial customers will participate in Rider 9 in a tangible manner. Additional residential customers may participate in Rider 9 as a result of lower PV system costs but overall volume will continue to be low and will not impact the IRP.

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26 The Green-e Dictionary (http://www.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."

27 Rate REP was approved by the IURC and if IPL chooses to monetize the RECs that result from the agreements, the ratemaking treatment of those transactions will be the same as the Wind PPAs to benefit customers (Hoosier Wind Farm - IURC Cause No. 43485, Lakefield Wind Farm – IURC Cause No. 43740, Rate REP – IURC Cause No. 44018).

Section 4B. DEMAND SIDE MANAGEMENT

Demand Side Management

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

IPL's demand side management ("DSM") program is comprised of load management DSM and energy efficiency. With the passage of Senate Enrolled Act 340 ("SEA 340") and the resulting pause in the efforts to meet the IURC targets for DSM, the DSM evaluation for this IRP is driven by a more traditional analysis that identifies the market potential for cost effective DSM.

In April 2014, IPL engaged the consulting firm Applied Energy Group (formerly EnerNOC) to assist in the development of a short term (2015-2017) DSM action plan and a longer term (2018-2034) DSM forecast. The DSM short term action plan was intended to provide evidence in support of IPL's May 30, 2014 filing to the IURC for approval of DSM programs, while the longer term DSM forecast was intended to support the future of DSM for purposes of IPL's resource planning and in particular this IRP.

While the primary driver in developing the amount of energy efficiency DSM resources in the prior IRP was the IURC's Generic Order (Cause No. 42693-S1)[28], these targets were suspended with the passage of SEA 340 in March 2014. As IPL has indicated before, other factors such as increasing customer interest, higher supply-side resource costs and federal environmental rules, already had IPL moving in the direction of DSM playing a significantly greater role in IPL's resource strategy. Despite the absence of state DSM targets, IPL believes DSM is a valuable resource and expects to continue offering a broad range of cost-efficient programs to its customers.

The forecast of future DSM (2018-2034) that was completed by Applied Energy Group is discussed and incorporated in IPL's Load Forecast (Section 4D) and modeled by Ventyx in the Integration section (Section 4). The Integration section addresses historical and current DSM initiatives as well as local and national developments that influence IPL's DSM strategy for the future. The development of IPL's proposed 3-Year Demand Side Management Plan ("3-Year DSM Plan")[29], dated May 30, 2014, including the screening methodologies, cost-benefit analysis and proposed programs, is described in this Section and a copy of the Plan is included in Section 7, Attachment 4.1, DSM Supporting Documents.

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[28] The IURC Order in Cause No. 42963-S1 (dated December 9, 2009) – the Generic Phase II Order – established targets for Energy Efficiency achievement that are significantly greater than historical energy efficiency efforts in Indiana.

[29] In Cause No. 44497, IPL has proposed a 3-Year Demand Side Management Plan. While IPL filed a 3 year Action Plan for the years 2015-2017, IPL is only seeking spending authority from the Commission for a 2 year period (2015-2016).

IPL Historical DSM Programs

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

IPL was among the first utilities in Indiana to implement a comprehensive DSM program. IPL has offered DSM on essentially a continuous basis since 1993 with average annual DSM expenditures over the past five (5) years exceeding $16 million per year.[30]

The IPL DSM efforts from 2003 to 2009 focused on low income weatherization, energy efficiency education, and demand response programs including the Air Conditioning Load Management Program, which provides demand savings but limited energy savings. Subsequent to the issuance of the Phase II Generic Order, IPL efforts became primarily focused on the energy efficiency savings to achieve compliance with the Order. IPL forecasts achievement of approximately 456 GWh savings by year end 2014, which is approximately 92% of the cumulative Commission targets through the end of 2014.[31]

A summary of IPL's historical DSM program offerings since 2010 is detailed in Figure 4B.1.

[30] As stated in the 2014 IPL annual DSM status report filed under IURC Cause No. 42693.
[31] *Ibid*

Figure 4B.1 – DSM Program History (2010-2014)

Cause No.	Date Approved	Expiration Date	Programs	Authorized Program Expenditures
43623	2/10/2010	2/9/2013	• Residential On-site Audit with Direct Install (Core) • Residential Prescriptive Lighting (Core) • Energy Efficiency Schools – Kits Program (Core) – extension • Income-Qualified Weatherization (Core) - extension • Residential ACLM Program (Core Plus) – extension • Residential Energy Assessment Program (Core Plus) • Residential New Construction ES Plus (Core Plus) • Residential 2nd Refrigerator Pick-Up (Core Plus) • Res & C&I Renewable Energy Incentives (Core Plus) • Commercial and Industrial ("C&I") Prescriptive (Core) • C&I ACLM (Core Plus) • C&I Custom (Core Plus) • C&I Retro-Commissioning (Core Plus) • C&I New Construction (Core Plus)	Total budget: $26.0M
43911	11/4/2010	11/4/2013	• Energy Efficiency Schools Program – Audits (Core)	Total budget: $560,000

Cause No.	Date Approved	Expiration Date	Programs	Authorized Program Expenditures
43960	Initial Approval Date 11/22/2011 Amended in 43623-DSM-5 on 6/20/12	12/31/2013 While this was initially approved as a 3 year plan, it was compressed to a 2 year plan	**CORE PROGRAMS** • Residential Home Energy Assessment • Residential Lighting • Energy Efficiency Schools - Education Component - Audit Component • Income-Qualified Weatherization • Commercial and Industrial ("C&I") Prescriptive **CORE PLUS PROGRAMS** • Resident New Construction • Residential On-Line Energy Assessment with Kit • Residential 2nd Refrigerator Pick-Up • Residential Peer Comparison Report • Residential ACLM Program • Residential High Efficiency HVAC • Residential Renewable • Residential ACLM Program (Core Plus) • Residential High Efficiency HVAC • Residential Renewable Energy Incentives • C&I Business Energy Incentives - Customer - Prescriptive • C&I ACLM • C&I Renewable Energy Incentives	$63.1 M Initial Authority $54.5 M – First Amendment to the Settlement Agreement
44328	11/25/13	12/31/2014	• One Year Extension of Cause No. 43960. Programs offerings remained the same except for IPL ceased to offer High Efficiency HVAC	Total budget: $23.7 M
44497	Pending	Proposed 2 Year Plan – Requesting that Term Begins on January 1, 2015	• IPL has requested the extension of the current Program offerings with the exception of the Residential New Construction; Renewable Energy Incentives for Residential and Business Customers and the Residential New Construction Programs. IPL has proposed the continuation of all of the other programs. IPL has also proposed one new Program – Small Business Direct Install.	Total budget: $63.6M

Source: IPL

Online Energy Feedback (PowerView)

IPL's online energy feedback has been available for all IPL customers that create a sign-on since its July 2010 inception. For Residential customers, daily energy consumption along with a historical view is displayed on a one-day delayed basis through a web-portal. Industrial and Commercial customers can also access similar information at the iplpower.com website.

IPL Current DSM Programs

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

IPL's current portfolio of DSM programs was approved in November 2013 in Cause No. 44328. IPL is currently offering all five of the programs that were designated as Core Programs by the IURC in its Generic Order. This comprehensive set of programs provides energy efficiency opportunities for all IPL customers. Delivery of most of the Core Programs will transition from delivery by the statewide third party administrator ("TPA") to IPL in January, 2015.

The programs approved in Cause No. 44328 are listed in the table above. The residential programs are generally a continuation of the prior program offerings that were initially approved in Cause No. 43623[32]. In some cases, these programs have been successfully offered by IPL for several years (i.e., Air Conditioning Load Management ["ACLM"]).

Note that the Core and Core Plus designations are from the Generic Order and these labels will cease to be relevant as the TPA program delivery concludes at the end of 2014 and IPL moves into the role of having primary responsibility for the delivery of all of these DSM programs.

As is detailed in IPL's Annual Compliance Filings made with the IURC on July 1st of each year, IPL DSM programs in total have generated significant demand and energy savings. The most recent IPL DSM Compliance Filing, as filed on July 1, 2014, is provided in Section 7, Attachment 4.2, DSM Supporting Documents. This compliance filing demonstrates that although the IURC targets were suspended by the passage of SEA 340, IPL expects to be at or near achievement of the prior Commission targets on a cumulative basis at the end of 2014.

IPL's ACLM ("CoolCents®") and Income Qualified Weatherization Programs are IPL's longest continually offered DSM programs. The Residential ACLM program has been offered since 2003 and represents the largest DSM program in terms of customer participation and peak demand reduction. At the end of 2013, IPL had deployed approximately 39,650[33] switches, which is equivalent to about 27 MW of summer peak reduction capability. When the demand savings from IPL's other demand response tariff riders are considered there is approximately 83 MW[34] of total peak demand reduction available to IPL.

Nuclear and solar resources did not appear in any of the landscapes. IPL has experienced a large influx of early adoption of DG solar due in large part to its feed-in-tariff, Rate REP as described

[32] The IURC issued an Order approving Cause No. 43623 on February 10, 2010.
[33] Residential Air Conditioner Load Management Program EM&V Final Report, August 7, 2014, Table 8, p. 10.
[34] Includes 27 MW of ACLM, 20 MW of Conservation Voltage Reduction, and 36 MW of load curtailment/interruptible programs.

in Section 4A. Additional DG is not included in the short-term forecast absent further financial incentives. IPL recognizes the installed costs for solar are decreasing, however, modeling limitations do not allow dynamic costs to be included. Therefore, the 2016 IRP will include updated cost which may find solar to be a cost-effective option.

Of current offerings, the most significant DSM programs in terms of energy efficiency savings in 2014 are forecast to be the Core C&I Prescriptive Program (approximately 55,000 MWh) and the Residential Core Plus Peer Comparison Report (approximately 29,000 MWh).

Current Load Curtailment/Interruptible Programs

In addition to the energy efficiency DSM programs and the ACLM demand response program described above, IPL also has a number of Load Curtailment/Interruptible programs that are offered under its tariff and targeted to C&I customers. At the end of 2013, IPL had 36 MW of demand response programs under contract with C&I customers. This is a decrease from the amount available in 2011, in part as a result of the recent economic downturn and of the shutdown of facilities that previously participated but no longer can due to EPA restrictions on emissions from diesel generators. In most cases, the incentives offered are adjusted annually to reflect changes in power market conditions. The currently approved programs are described below.

- Standard Contract Rider No. 14 (Interruptible Power). Rider 14, IPL's first interruptible/curtailable rider has been available since the early 1990s. IPL has one customer participating on Rider 14. This customer represented 9.3 MW of interruptible load.
- Standard Contract Rider No. 15 (Load Displacement). The IURC approved this Rider in April 2001. This Rider is available to customers who contract with IPL and agree to operate their generators at IPL's request to displace their own load. Rider 15 contributed approximately 25.4 MW to IPL's 2014 summer load reductions.
- Standard Contract Rider No. 17 (Curtailment Energy). Rider 17 has been available since 1999 for customers who contract with IPL and agree to curtail their load to a Firm Power Level at IPL's request. Rider 17 contributed approximately 1.7 MW to IPL's 2014 summer load reductions.
- Standard Contract Rider No. 18 (Curtailment Energy II). Rider 18 has been available since 2000 for C&I customers who contract with IPL and agree to curtail their load to a Firm Power Level at IPL's request. Each Rider 18 participant selects their own Firm Power Level and the energy price at which they agree to curtail load. No customers participated on this Rider in 2014.
- Standard Contract Rider No. 23 (Market Based Demand Response). Rider 23 has been available since 2011 for C&I customers on rates HL, PL, PH and SL and aggregators of customers ("ARCs") who wish to participate through IPL in the MISO energy market. No customers have elected to participate in this Rider due to low rates in the market.

- Special Rate SS Agreements. Several Rate SS (Small Secondary Service) customers with loads that exceed the 75 kW demand typically allowed by that rate, are allowed by the tariff to be served on Rate SS under special agreements. These customers typically have sporadic loads and very low load factors. The total diversified Rate SS Special interruptible load for 2014 was approximately 9.6 MW. Due to notification requirements and other non-conforming issues, these resources are not counted towards IPL's Module E resource requirements at the MISO but are nevertheless valuable to IPL as a measure to prevent load from coming onto the system at critical times.

Indiana Developments – The Changing Landscape

The landscape for DSM in Indiana has changed significantly since the last IPL IRP was completed in 2011. Prior DSM efforts were influenced by the significant energy efficiency targets established in the IURC Phase II Generic Order. These targets provided the direction for the amount of DSM efforts in the State of Indiana through 2014. The Generic Order also established five Core DSM Programs and identified the mechanism for these Core programs to be delivered.

The IURC's Generic Order established the Demand Side Management Coordination Committee ("DSMCC") that solicited bids and selected a statewide TPA to deliver the Core Programs on behalf of the jurisdictional electric utilities. After a rigorous process, GoodCents® was selected as TPA by the DSMCC. In July 2011, the IURC approved the contract with GoodCents® and since, the DSMCC and GoodCents® worked diligently to deliver the Core Programs on behalf of the jurisdictional utilities beginning in January, 2012. The delivery of DSM programs by GoodCents will conclude on December 31, 2014. The DSMCC has remained in place to manage the wind-down of the Core Program delivery by GoodCents and to manage other transition related issues.

Senate Enrolled Act 340

The 2013-2014 Indiana General Assembly passed SEA 340, which, among other things, (1) provided the industrial customers with demand at a single site greater than one MW the opportunity to opt-out of participation in utility sponsored energy efficiency programs, and (2) eliminated the Generic DSM Order's savings goals.

SEA 340 provides that an industrial customer that meets the definition of a "Qualifying Customer" may opt-out by providing notice to its electricity supplier. Once a Qualifying Customer has opted out, the utility may not charge the customer rates that include energy efficiency program costs. The statute defines "energy efficiency program costs" as including: "(1) program costs; (2) lost revenues; and (3) incentives approved by the commission."

SEA 340 also allows customers to opt back in to participation and payment for utility-sponsored energy efficiency programs. A customer who opts back in must participate in the energy efficiency program for at least 3 years (and must pay energy efficiency program rates for such 3-year period).

Cause No. 44441 – Qualifying Customer Opt-Outs

The procedures for customer opt out were proposed and approved by the Commission in Cause No. 44441. In accordance with these procedures, IPL has made a good faith effort to notify Qualifying Customers of their ability to opt-out of participating in DSM programs, and defined the date ranges by which the customer must provide notice to opt-out. The Qualifying Customer's intention to opt-out of DSM participation in the second half of 2014, had to be received by IPL on or before June 1, 2014. The opt-out elections were applied to bills beginning with than July 1, 2014. Any Qualifying Customer providing notice after June 1, 2014, but before November 15, 2014, is eligible for opt-out effective January 1, 2015. After January 1, 2015, Qualifying Customers will only be able to opt-out on a calendar year basis with an effective date of January 1st of each year.

Figure 4B.2 below provides the Qualifying Customer opt-out schedule as proposed by the utilities.

Figure 4B.2 – Qualifying Customer Opt-out Schedule

Notice Must be Received On or Before:	Effective Date of Opt Out:
June 1, 2014	July 1, 2014
November 15, 2014	January 1, 2015
November 15, 2015	January 1, 2016
November 15, 2016	January 1, 2017
November 15, 2017	January 1, 2018
November 15, 2018	January 1, 2019

Source: IPL

While it is still uncertain to what extent customer opt-out will reduce the market potential for DSM in IPL's service territory, there will be some reduction in DSM potential. However, the reduction in DSM opportunities may be mitigated to the extent that large customers create energy efficiency projects on their own.

As of the July 1, 2014 initial opt-out opportunity, a total of 42 IPL large customers with approximately 3,640 GWh of sales, have provided notice to opt-out of DSM program participation. This represents about 12.5% of total IPL retail sales. In total, IPL has approximately 150 customers that are served at over 200 sites eligible to opt-out of participation in its DSM programs. In aggregate, eligible customers including those who could opt-out but haven't necessarily done so, represent about 25% of IPL's total retail sales.

National Developments – The Changing Landscape

Without question, the most significant national development regarding energy efficiency is the rule that was recently proposed by the EPA to regulate CO2 as discussed in Section 3 of this IRP. Labeled the Clean Power Plan ("CPP"), the proposed rule was issued pursuant to Section 111(d) of the Clean Air Act. The EPA has identified four specific building blocks on which compliance with the target state CO2 emission rates can be achieved. Energy efficiency is one of these four building blocks along with heat rate improvements at existing power plants; additional generation by renewable energy resources and nuclear energy. The State of Indiana and IPL are still early in evaluating and commenting on the proposal and trying to understand the role that energy efficiency ("EE") and these other building block will play in compliance.

Due to the evolving nature of the rulemaking and legal challenges, it is unknown whether the CPP will ultimately go into effect. However, while the ultimate disposition of the rulemaking is unknown, it is prudent for IPL to actively plan for the eventuality that this rule, or other carbon constraints, will result in an increasing role for energy efficiency.

Although the specific level of energy efficiency that might be necessary for Indiana to achieve compliance with the Clean Power Plan is not known at this time, the EPA assumes that at some point Indiana is capable of achieving an incremental annual energy efficiency amount of 1.5% per year[35]. The cumulative amount of energy efficiency that EPA has assumed for Indiana under Option 1 (compliance by 2029) is 11.11%. This amount of energy efficiency is expected to be difficult to achieve, but if Indiana is eventually required to comply with the Clean Power Plan, EE will have a significant role in the compliance plan.

Beyond the implications of the CPP for EE in the future, there has continued to be an uptick in the scale and scope of energy efficiency nationally as well as locally. Data shows that the significant increase in DSM efforts in Indiana has continued to be in synch with national developments. According to the 2013 State Energy Efficiency Scorecard report from the American Council for an Energy Efficient Economy ("ACEEE")[36], total spending on customer-funded energy efficiency programs has increased from approximately $2.5 billion in 2007 to approximately $6.0 billion in 2012.

There has not been significant recent Federal legislation regarding energy efficiency since the passage of the American Recovery and Reinvestment Act of 2009 ("ARRA").[37] This legislation injected more than $11 billion ARRA funds directly into state energy efficiency programs. ARRA includes several additional provisions modifying and expanding the scope of the energy

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[35] http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

[36] "The 2013 State Energy Efficiency Scorecard", American Council for an Energy-Efficient Economy by Annie Downs, Sara Hayes, , Max Neubauer, , Seth Nowak, Shruti Vaidyanathan, Kate Farley, Celia Cui and Anna Chittum, November 2013, Table 2, page 9.

[37] The inclusion of EE/DSM in the EPA proposed CPP may significantly impact future EE efforts nationally.

efficiency effort. For example, on-site renewables, including solar photovoltaic ("PV"), hot water systems, small wind systems, and geothermal heat pumps are also eligible for a tax incentive worth 30% of the total cost, without a cap.

Many of the Federal tax provisions designed to encourage energy efficiency expired at the end of 2013. Tax credits for combined heat and power systems, fuel cell and microturbines, and accelerated depreciation for smart meters and smart systems remain in place.

Perhaps the most significant long-term consequence of ARRA is the impact on building codes. In order for states to receive the appropriate funds from the ARRA, they must adopt more stringent building codes (2009 IECC and ASHRAE 90.1-2007 for commercial). The ARRA also calls for 90% compliance with these higher codes by 2017. Indiana stakeholders are discussing a utility funded program that would encourage builders and others to achieve compliance with the updated building codes, but a methodology to assure attribution of savings has yet to be determined and agreed upon. This has possible relevance in planning for CPP compliance.

There have been limited demand response developments since the completion of the prior IPL IRP in 2011. In its Order 719, FERC instructed MISO to remove barriers to participation in demand response as part of their Ancillary Services Market ("ASM"). Through its Demand Response Working Group ("DRWG"), in which IPL participates, MISO is working through the attendant issues including, baseline determinations; technical performance requirements, such as communications, measurement, and verification; compensation and the potential conflict with state regulatory authority. The IURC completed an investigation into demand response in Indiana in IURC Cause No. 43566. In response to the IURC's order, IPL filed Standard Contract Rider No. 23 -- Market Based Demand Response Rider, which was approved by the IURC on March 7, 2011. Rider 23 provides customers the opportunity to submit bids through IPL to MISO for Emergency Demand Response and Demand Response Resource Type 1 economic energy. To date, no IPL customers have participated on Rider 23.

IPL's DSM Strategy

IPL has continuously offered DSM programs to benefit customers and optimize demand side resources since 1993. Following the IURC's Generic DSM Order through the passage of Senate Enrolled Act 340, IPL's DSM Strategy had been to comply with the energy efficiency targets established by the IURC in the Phase II Generic Order. Recent IPL DSM Plan filings up to and including the DSM Plan for 2014 (Cause No. 43960) were filed with the intention to have adequate energy efficiency offerings and sufficient funding to allow IPL to achieve the IURC's energy efficiency targets.

Following the passage of SEA 340, IPL voluntarily developed and filed for approval of the 2015-2016 DSM plan with the Commission to continue to offer customer programs. This plan provides for the delivery of a significant amount of DSM savings to our customers (approximately 1.1% of sales per year). The company expects to continue to propose and deliver additional cost-effective programs consistent with the IURC IRP and CPCN rules for demand side management options. The specific programs to be delivered beyond the current three-year planning horizon will be identified and proposed in subsequent IPL DSM plans to be filed with the Commission.

IPL's DSM initiatives will only be successful with broad customer participation. Therefore, customer adoption remains the most important element of successful DSM implementation. IPL must continue to ensure that the customer has positive interactions with IPL's many program partners and IPL will continue to carefully choose these partners and monitor their efforts.

The elements of the IPL 2015-2017 DSM Action Plans will:

- Continue to grow IPL's successful demand response program "CoolCents®"
- Continue to provide premise based Home Energy Audits that includes the installation of low cost energy efficiency measures
- Continue to provide weatherization services for income-qualified customers
- Continue to promote and encourage our customers to take advantage of IPL's web-based energy manage tools
- Continue to provide energy efficiency kits as a fulfillment for participation in the web based on-line audits
- Continue to provide the opportunities for customers to have their second refrigerators and freezers picked up and recycled
- Continue to periodically provide customers with a Peer Comparison Energy Report
- Continue to provide energy efficiency programs to C&I customers by providing prescriptive rebates for lighting, pumps, and motors
- Continue to provide a Custom energy efficiency program to C&I customers that provides funding for projects that do not fit into the Prescriptive program
- Introduce a small business customer audit and direct install program
- Continue to evaluate future DSM expansion capabilities including leveraging the two-way metering capabilities and advanced grid functionality

IPL's Screening Process and Evaluation

Screening of demand side measures is a multi-step process. Measures are first qualitatively screened and then logically grouped into prospective programs. These programs are then systematically evaluated with the aforementioned cost effectiveness tests. IPL calculates future avoided costs and compares them to projected savings.

DSM Cost Effectiveness

[170-IAC 4-7-7(b)]

The cost effectiveness of the DSM programs is built upon avoided supply costs which include capacity and marginal production costs, as well as program design and delivery features. The program success attributes are discussed below:

(a) *Conservation and load management programs that are correlated to or can be applied coincident to the peak demands of the utility*. A strong correlation of DSM to peak load drives proportionately enhanced capacity reductions, along with some level of energy reductions, depending on the specific program. The "peak correlation" attribute is significant to the success of the program because avoided costs are maximized. The type of customer loads targeted will include, for example, ACLM that helps control IPL's system peak.

(b) *Conservation and load management programs with efficient delivery channels*. IPL looks to wisely employ incentives targeted to encourage specific measures through traditional low-cost and effective delivery channels. These channels include the new appliance and the new construction markets, where more efficient appliance or insulation specifications could most cost-effectively be substituted for less efficient ones with minimal incremental material costs. The primary benefit to using these channels is the avoidance of labor-intensive removal and upgrade costs of replacement programs.

(c) *Conservation and select load management programs with long-life measures*. This will include new construction projects such as insulation, low-e glass, efficient heat pumps, and air conditioners that can last the life of the home in some cases, or nearly 15 years in others. Load management programs that require upfront capital (such as ACLM) also need to be designed for long-life to justify initial costs and balance the DSM portfolio demand and energy savings.

(d) *Conservation programs where government efficiency regulations have yet to happen, and where large efficiency improvements can still be realized*. Starting in 1987 with the National Appliance Energy Conservation Act that established minimum efficiency requirements for 12 types of residential appliances sold in the United States ("U.S.")., the law has been amended several times to include mandates for additional minimum efficiency standards for additional appliances and other electric products. An example of this standards improvement is the setting of new efficiency standards for light bulbs which begins in 2012.

(e) *Conservation and load management programs that have been successfully identified elsewhere*. Simply put, if DSM programs are not cost-effective in high-cost energy states, such as California, New York, or even Illinois, they will not be cost effective in Indiana. Indiana electric customers generally, and IPL customers specifically, benefit from some of the lowest electric prices in the nation. So it can be difficult to develop cost-effective DSM products to offer. IPL studies Midwestern DSM programs, reviews trade magazines, seeks stakeholder input at industry conferences and solicits advice from conservation advocates for potential conservation and load management programs.

(f) *Conservation programs that benefit electric customers who are financially least-likely to be able to participate on their own because of the higher initial costs of such measures.* Income can be a barrier to customers' decisions to participate in energy efficiency and therefore it is appropriate to consider DSM investments targeted to the economically disadvantaged. Over the prior 10 years, IPL has provided weatherization services through its DSM program to several hundred income qualified residential customers, reducing their energy consumption, while improving their comfort and ability to pay their electric bills. Without the IPL program, the majority of these customers would not have been in a position to make these investments in energy efficiency measures.

(g) *Load management programs that take advantage of advances in information technology -- specifically those that allow customers to respond to price signals either manually or via automated systems to economically shift load to off-peak periods, and/or conserve the load entirely.* Information technology capabilities are increasing, while some costs have decreased. IPL monitors this area for cost-effective applications including DSM and demand response measures as time based rate offerings.

IPL delivers some programs jointly with Citizens Gas. Using the same contractor and delivering both gas and electric measures in the same visit reduces overhead costs and improves cost-effectiveness by delivering more measures than if the companies delivered the measures separately.

Avoided Costs

[170-IAC 4-7-4(b)(12)] [170-IAC 4-7-6(a)(5)] [170-IAC 4-7-6(a)(6)] [170-IAC 4-7-6(b)(2)] [170-IAC 4-7-8(b)(5)] [170-IAC 4-7-8(b)(6)(C)]

The marginal cost of capacity including generation, transmission, distribution, capacity, and the marginal cost of production, including fuel, quantifiable emission costs, and variable operating and maintenance costs are the primary value drivers of the avoided cost benefits associated with a given load reduction.

IPL capacity costs and marginal production costs were fairly flat over the last decade. These costs have risen in recent years and are expected to trend higher as more environmental restrictions on coal-fired production are implemented. Representative values from the tariff rate Cogeneration Service ("CGS") over the prior years are shown in Figure 4B.3 below:

Figure 4B.3 – Historical Avoided Capacity and Production Costs

Year	Avoided capacity costs ($/kW/Month)	Avoided production costs (Cents/kWh, Off Peak)
1998	2.87	1.53
1999	2.84	1.55
2000	2.91	1.54
2001	2.85	1.82
2002	3.00	1.55
2003	2.94	1.33
2004	2.85	1.42
2005	3.13	1.39
2006	3.08	1.41
2007	3.17	1.62
2008	4.76	2.14
2009	6.18	2.66
2010	6.05	1.93
2011	7.19	2.20
2012	7.30	2.46
2013	7.42	2.57
2014	7.39	2.65

Source: IPL

The avoided capacity costs for 2014 were used in the DSM modeling for the updated DSM Action Plan filed in Cause No. 44497. IPL included the marginal cost of capacity (inclusive of savings in generation capacity, and transmission and distribution capacity). The avoided energy costs are from the Ventyx Midwest Fall 2013 Reference Case. The marginal cost of production includes fuel, emission costs and variable operating and maintenance costs.

For this IRP modeling, the marginal generation capacity cost was calculated to be [redacted]/kW/year which included avoided fixed O&M and the avoided transmission and distribution ("T&D") capacity costs that were assumed at 10% of the avoided generation value[38]. The DSM programs were also credited with avoided T&D line losses of 4.95%, which is a calculation that IPL performs annually. The 4.95% credit was also applied to the avoided energy cost values for the line losses that are avoided by the DSM measure being implemented at the point of use. Future avoided capacity and production costs are shown in Section 7, Confidential Attachment 4.3, DSM Supporting Documents.

[38] The marginal generation capacity cost is based on the deferral of a simple cycle combustion turbine with an installed cost of [redacted]/kW.

Evaluation Process

[170-IAC 4-7-7(b)] [170-IAC 4-7-7(d)(1)] [170-IAC 4-7-7(d)(2)]

Programs are evaluated using the four traditional California Standard Practice Methodology cost effective tests: These include the Participant Cost Test ("PCT"), Utility Cost Test ("UCT"), Rate Impact Measure ("RIM") Test and the Total Resource Cost Test ("TRC"). A general description of the major tests – including the tests' components and objectives is presented in Section 7, Attachment 4.4, DSM Supporting Documents. The equations for the four traditional California Standard Practice Methodology cost effective tests are expressed in Section 7, Attachment 4.9, DSM Supporting Documents.

IPL systematically uses these tests to derive its prospective DSM programs. First, IPL will look for all programs that pass the RIM test which is the most difficult test to pass. This is both a measure of program efficiency and fairness. Any program passing this test represents both an efficient program and one that benefits all other non-participating customers as well.

Next, IPL looks for programs that pass both the TRC and UCT tests. The TRC test addresses whether the delivered DSM measure is truly efficient – although it does not speak to fairness. So while society as a whole may be served, it is the participant that generally derives much of the benefit, while other customers absorb much of the costs. The UCT addresses whether the delivered DSM measure lowers utility costs. While a positive benefit/cost result of the UCT value lowers revenue requirements (measured in dollars), it may not lower customer rates (measured in dollars per kWh, as included in the RIM test).

The TRC and UCT values are considered for any program that does not pass the RIM test. Since programs that do not pass the RIM test tend to raise rates, IPL must balance the desire to promote efficiency with the need to maintain economical rates. Programs that fail the TRC test may still be considered for implementation for reasons of market continuity, market transformation, public education, synergy with other programs, or other reasons that make interruption or termination of a program a problem for future implementation or creates an adverse perception in the marketplace.

Finally, IPL ensures that the screened DSM measures and programs pass the PCT test which examines the net benefits to the participants of the program. This process has been consistently used by IPL since the development of the 2008 MPS. This and subsequent refinements made to the programs included in the DSM program pending in Cause Nos. 43623, 43960 and 44497.

In Cause No. 44497, IPL also introduced the concept of a hybrid test which was identified as the Customer Balance Test ("CBT"). The CBT can be used to assess the degree of subsidization between participants and non-participants. The calculations for this test are discussed below. The programs that are found to be cost-effective from the UCT and TRC test perspective can be further ranked by the CBT ratio. The CBT is not used as a pass/fail test but serves as an indicator that programs that did pass the TRC or UCT tests but also had a low CBT ratio should be further examined to determine whether other factors warranted their inclusion in the DSM Plan. IPL presented information on the CBT at the IRP Contemporary Issues Workshop on October 23.

Including programs that passed the TRC or UCT is consistent with the Commission's DSM rules, which require that at least one of the tests listed above be used to evaluate the cost-effectiveness of a DSM program. However, simply passing the TRC or UCT only means the program is cost-effective from a particular viewpoint and may not necessarily mean the program is equitable and in the interest of all customers. While certain programs do not pass the traditional benefit-cost tests these programs do have other societal benefits or the benefits are difficult to quantify and have been generally accepted subject to budget restrictions. Specifically, low-income weatherization programs typically do not pass these cost-effectiveness tests, but IPL believes it is important to offer low-income customers DSM program offerings in order to give such customers the opportunity to participate in programs that will help them control their energy usage and their energy bills.

The CBT tests attempts recognize that not everyone in the customer population receives a net benefit for programs that pass the TRC test. There will be some cross-subsidization between participants and nonparticipants within a customer group but this needs to be minimized to a reasonable extent. For example, the TRC ratio can be greater than 1.0 if a small group of participants benefit a great deal at the expense of a large number of non-participants so long as the benefit averaged over all customers is sufficient. This can raise equity issues among customers. To provide an indication of some balance between these different perspectives, the CBT compares the adverse rate impacts with the aggregate cost savings such that the net benefits of the TRC test must equal or be greater than the net costs of the RIM test. Expressed as a formula:

$$\text{CBT} = \frac{\text{NPV Net Benefits of TRC (Avoided Costs – Utility Costs – Participant Costs)}}{\text{NPV Net Costs of RIM (Utility Costs + Lost revenue – Avoided Costs)}}$$

This ratio, while not eliminating all subsidization between participants and non-participants, does balance the benefits with the total costs which now include rate impacts.

DSM – Benefit/Cost Test Results

[170-IAC 4-7-7(b)] [170-IAC 4-7-7(c)]

The benefit/cost test results and the Net Present Values ("NPV") of the programs' impact are found in Section 7, Attachment 4.5, DSM Supporting Documents. The DSM programs were evaluated using a discount rate of 8.55%, which is IPL's most recent weighted average cost of capital.

IPL's informational programs form just a part of the customer's knowledge base and when combined with other knowledge-based initiatives (Energy Star®, government information, etc.), and with easy availability of efficiency measures (efficient lighting and appliances in hardware and mass-merchandise stores) ultimately influence the decision process. These program benefits are difficult to quantify, but undoubtedly influence the market and have a place in a comprehensive and cost-effective DSM portfolio such as IPL's.

Market Potential Study - Future DSM Market Analysis

[170-IAC 4-7-8(b)(4)]

In 2012, IPL in collaboration with Citizens Energy and each respective DSM Oversight Board retained the consulting firm Applied Energy Group ("AEG") (formerly EnerNOC)[39] to complete a Market Potential Study ("MPS") and Action Plan for the period 2014-2017. Since the completion of the 2012 MPS and Action Plan, Senate Enrolled Act 340 ("SEA 340") was passed into law, significantly changing the structure of DSM in Indiana. In response to SEA 340, IPL re-engaged AEG to update the last three years of its DSM Action Plan.

The most significant change to the original Action Plan as developed by AEG related to measure level details. In the updated Action Plan, AEG adjusted measure level participation forecasts, per unit costs, per unit savings, and measure life assumptions. These measure level assumptions have changed primarily as a result of: (1) Evaluation, Measurement & Verification ("EM&V") of IPL's DSM programs; and (2) Adoption of the Indiana Technical Resource Manual ("IN TRM"). In addition to adjusting the measure level assumptions, AEG refreshed the programs' cost-effective results to account for the revised costs and savings to be reflected in the updated Action Plan. As part of refreshing the economics, IPL provided more recent avoided cost information to AEG.

The updated Action Plan reflects decreased savings projections for the Business Energy Incentive Prescriptive and Business Energy Incentive Custom programs, in relation to the prior Action Plan to account for the reduction in savings potential due to opt-out. In other words, as customers begin to opt out of participating in IPL's DSM programs, the pool of potential participants decreases.

[39] The EnerNOC resource planning group, including all the principals who had worked on the 2012 MPS, was acquired by Applied Energy Group in the 2nd Quarter of 2014. Therefore all references to EnerNOC have been changed to Applied Energy Group.

DSM Plan Forecasted Savings (2015-2017)

[170-IAC 4-7-6(a)(6)] [170-IAC 4-7-6(b)(4)] [170-IAC 4-7-6(b)(5)] [170-IAC 4-7-6(b)(6)] [170-IAC 4-7-6(b)(7)] [170-IAC 4-7-6(b)(8)]

The following table, Figure 4B.4, summarizes the program forecasts (energy and demand impacts) for the IPL 2015-2017 DSM Action Plan proposed in and approval pending in Cause No. 44497. Year 1 program delivery is coincident with 2015 and so on.

Figure 4B.4 – Total Demand and Energy Impacts of Proposed DSM

Program Year	Energy Savings MWh-Annual Incremental	Demand Savings kW- Annual Incremental
2015	122,860	59,196
2016	126,441	60,904
2017	129,903	62,603
Total	379,204	182,703

Source: IPL

Target demand and energy savings, by program by year, are found in Section 7, Attachment 4.6, DSM Supporting Documents. These savings are expressed on a Net basis.

The estimated bill reduction, participation incentive, program cost, and energy (kWh) and demand (kW) savings per participant for each program are provided in Section 7, Attachment 4.10, DSM Supporting Documents. This attachment also includes the estimated program penetration rate.

DSM Plan Proposed Programs (2015-2017)

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

The proposed DSM programs for both Residential and C&I customers are described below. See Section 7, Attachment 4.1, DSM Supporting Documents for the entire 3-Year DSM Plan that was filed in Cause No. 44497. The majority of these programs are currently being offered to IPL customers. IPL proposed to eliminate 3 programs in this filing (largely on the basis of cost-effectiveness):

- Residential New Construction

- Residential Renewable Energy Incentives[40]
- Commercial and Industrial Renewable Energy Incentives

Residential Programs

[170-IAC 4-7-6(b)(1)] [170-IAC 4-7-6(b)(3)]

Residential Lighting Program

The Residential Lighting Program is an existing IPL program that has been available to IPL customers since 2003. The goal of the Residential Lighting Program is to increase the penetration of high efficiency Energy Star® ("ES") qualified lighting in the homes of IPL residential customers. This program will provide IPL residential customers with the opportunity to purchase energy efficient light bulbs, while traditionally these lights have been primarily Compact Fluorescent Lights ("CFLs"), LEDs are becoming available in significantly more types at a much lower prices.

Therefore, LED technologies will be increasingly emphasized as their market readiness increases. The program will provide upstream "buy-downs" for certain products such as compact fluorescent lamps so that customers pay a lower price at the point of purchase without needing to apply for a rebate. The upstream buy-down activity is a component of the program's focus on market transformation that will increase the demand for high efficiency products.

Residential Home Energy Assessment Program

The goals of the existing Residential Home Energy Assessment Program are to produce long-term, cost-effective electric savings in the Residential market sector by helping customers analyze and understand their energy use, recommending appropriate weatherization measures, and facilitating the direct installation of specific low-cost energy saving measures.

This program is designed to generate energy savings for IPL residential customers by providing low-cost energy efficiency measures and improvement recommendations tailored to customer homes.

Residential Income Qualified Weatherization Program

The Residential Income Qualified Weatherization Program is the continuation of an IPL program that has been available to IPL customers since 1993. Goals of the Residential Income Qualified Weatherization Program are to produce long-term energy and demand savings for qualifying low-income residential customers by providing professionally-installed energy efficiency

[40] In Cause No. 44623, the Commission required IPL to meet certain conditions to continue to offer the Renewable Energy Incentive Programs. IPL's experience has been that there is no evidence of market transformation with these programs.

measures and improvements tailored to customers' homes as well as providing education on ways to reduce energy consumption. This program has generally been jointly delivered with Citizens Energy.

Participating households receive the following types of assistance:

- In-Home Audits and Education—On-site inspections and tests used to identify the applicability of energy-savings measures the program offers and to educate residents about ways to reduce their energy usage.
- Direct Installation of Measures—Install measures to reduce energy use in the home at no charge to residents.

Residential School Kits Program

The Residential School Kits Program is an existing program that achieves cost-effective energy savings by educating students and their families about energy efficiency in their homes. This program incorporates an educational module provided to grade school students, along with a take-home kit of energy efficiency measures. Measures include CFLs and low-flow fixtures. It targets students to help them learn about energy efficiency and how they can apply it at school and at home.

Residential Online Energy Assessment Program

The Residential Online Energy Assessment Program is an existing IPL program, launched in July 2010, which educates consumers on their home energy use and identifies potential areas where they can take action to reduce their energy consumption. This program continues to be promoted with a combination of marketing materials directing customers to IPL's website to complete an online audit of their home. The web-based energy audit tool (branded as *Home Energy Inspector*) provides customers with information on: (1) no-or low-cost ways to reduce energy consumption, (2) identifies possible investment opportunities in energy efficiency improvements, and (3) describes how a customer's energy bill is calculated. Armed with this information, customers are better equipped to make informed decisions in managing their consumption and energy costs. Customers that complete the brief energy assessment will be provided an energy efficiency kit at no charge that includes low-cost, easy-to-install energy-saving water fixtures and CFLs for self-installation.

Residential Appliance Recycling Program

This existing program was introduced to IPL residential customers in May 2010. The Residential Appliance Recycling Program is a program that provides for the removal and disposal of operable but inefficient secondary refrigerator and freezer units. Many households retain these older refrigerator or freezer units in a garage or basement and often do not realize how inefficient they are. This program provides education on the cost of keeping an older, often underutilized unit along with the opportunity to have the unit removed at no cost and recycled in an environmentally-sound manner.

Residential customers with eligible units can schedule a date to have the unit(s) picked-up at no charge and will also receive an incentive payment for each unit. The current incentive the customer receives for allowing the removal of the appliance is $30 per unit. IPL is proposing to increase this incentive to $40 beginning in 2015. IPL's contractor removes the units and hauls the appliance to a facility where the components, including cooling systems and insulation which are potentially harmful to the environment, can be completely recycled. The process used captures hazardous materials and recycles over 95% of the metal, glass and plastic components.

The Room Air Conditioner Pick-Up and Recycling Program is bundled with the Refrigerator Recycling program described above and provides for the removal and disposal of operable but inefficient window/room air conditioner units. This program is intended as an add-on to the Second Refrigerator Pick-Up and Recycling Program, in that a customer who schedules a pick-up of a refrigerator or freezer unit may also relinquish an older, inefficient room air conditioner unit and receive an incentive for both appliances. The incentive for a room air conditioner unit is $20. Air conditioner unit pick-ups will only be scheduled for customers who are also having a refrigerator and/or freezer picked-up on the same visit.

The units will be taken to the recycling facility and decommissioned and dismantled in an environmentally-responsible way. This program will ensure that these older, inefficient units are permanently taken off the electric grid.

Residential Air Conditioning Load Management Program

The Residential ACLM Program is a continuation of a program that IPL has offered since 2003. IPL currently has approximately 35,000 customers participating in this program. The program consists of the remote dispatch and control of an ACLM switch installed on participating customers' central cooling units (central air conditioners and heat pumps). The goal of the program is to reduce summer system peak loads. The central cooling units are generally expected to be cycled at a 40% duty cycle strategy using the True Cycle[41] adaptive approach. Key provisions of the program are as follows:

- Enrolled residential customers receive a $5 credit on their bill for each of the months of June, July, August and September that they participate equaling up to $20 per year.
- IPL's contractor, GoodCents®, installs the switch on the outside of the customer's home near the central cooling equipment; and
- IPL can control the customer's central cooling unit during peak demand periods for the five months of May through September.

[41] True Cycle is the proprietary term for the logic that the switch vendor Cooper (Cooper acquired Cannon) uses to operate the ACLM during control events that considers uncontrolled air conditioner operation.

IPL utilizes its Automated Meter Reading (“AMR”) system to assist in conducting a “metered maintenance” program on its switches as a cost-effective means to identify switches needing to be repaired or replaced.

Residential Multi-Family Direct Install Program

This program is designed to affect the energy efficiency of rental apartment units through the installation of energy-efficient, high-performance water fixtures (i.e., showerheads and faucet aerators) and CFLs. The program educates tenants about the energy benefits of these installed measures and behavior changes that will have a lasting impact on their energy and water consumption.

The program targets multi-family complexes with units that are either all-electric or have natural gas-fueled storage water heaters. In the latter situation, IPL partners with Citizens Gas to jointly deliver and share costs for this program.

This program is available at no charge, which is an important consideration since property owners will not typically have an incentive to make investments that provide energy efficiency benefits to the tenants who pay the utility bills.

The program first targets property-management companies as well as property owners in an effort to secure agreements to treat multiple properties through a single point of contact before targeting owners and managers of single properties.

Residential Peer Comparison Reports Program

The Peer Comparison Energy Reports Program utilizes behavioral science-based marketing to provide customized energy consumption information to IPL residential households, engage those households in their energy consumption as compared to their peers, and thus drive changes in behavior that result in measurable energy savings.

Selected households receive a printed and mailed quarterly energy report that combines their energy usage data with demographic and housing data to provide a picture of their energy consumption trends and how those trends compare with similar households. The report contains customized suggestions for reducing energy consumption, including information about key IPL energy efficiency programs.

By comparing a household’s energy use to others, including their "most efficient" neighbors, and showing specific actions that those other households took to save energy, the reports provide both goals and a sense of competition that have shown to produce sustained energy-conservation behaviors.

Commercial and Industrial Programs

[170-IAC 4-7-6(b)(1)] [170-IAC 4-7-6(b)(3)]

Business Energy Incentives Program

Business Custom and Prescriptive Incentives Program is an existing IPL program that has been available to IPL customers since September 2010. The C&I Prescriptive Program goal is to produce long-term cost-effective electric savings in the C&I market sector. Savings are achieved by offering incentives structured to cover a portion of the customer's incremental cost of installing prescriptive efficiency measures.

Small Business Direct Install Program

IPL has proposed a new program for delivery in 2015, the Small Business Direct Install Program. The Small Business Direct Install program provides a suite of targeted, highly cost-effective measures to small businesses in a quickly deployable program delivery mechanism, along with education and program support to help business customers reduce their energy bills.

The program will provide several direct-install measures at no additional cost to participants, such as lighting replacements, programmable thermostats, occupancy sensors, vending machine controls, and low-flow water fixtures. The program also connects customers with other programs in the portfolio and a network of qualified trade allies/contractors that can install follow-on measures to provide deeper energy savings.

Business Air Conditioning Load Management Program

The Business ACLM Program is a companion program to the Residential ACLM Program. This program (also branded as CoolCents®) was launched in June 2010 to Rate SS and Rate SL customers. This program provides significant demand savings along with some energy savings to participating customers. Customers who enroll in the program have an ACLM switch installed on their facility cooling equipment. This allows IPL the opportunity to cycle the equipment during times of system peak usage. The switches will be controlled at the same time as the Residential ACLM customer switches. In return for participating, a customer must agree to allow IPL to control 50% of its cooling load and receives an incentive on the basis of net tons of controlled air conditioning load. Customers will receive a $5/ton credit on their utility bill during the billing months of June, July, August and September for each net ton enrolled.[42]

Other Proposed DSM Programs through Cause No. 44478

[170-IAC 4-7-6(b)(1)]

The City of Indianapolis asked IPL to support its plan to implement an all-electric car sharing program with its partner, Bolloré Group/BlueIndy. Up to 1,000 car charging stations are

[42] See IPL Rider 13 Tariff sheet at iplpower.com.

proposed at approximately 200 locations. IPL understands this would be the largest deployment of such an EV car-sharing program in the United States. IPL entered into a settlement agreement with the OUCC in the BlueIndy case (IURC Cause No. 44478) which includes the evaluation of three additional DSM programs: LED Street lighting, an energy management pilot based on the ISO 50001 standard, and demand response using electric vehicle batteries to provide power to the grid as described below in the electric vehicle section. If the settlement agreement is approved by the Commission, IPL will move forward to plan the implementation of these programs.

Evaluation, Measurement and Verification ("EM&V")

The key to assessing demand and energy savings is the evaluation of IPL's DSM programs by an independent third-party as a utility industry best practice. Evaluations of the Core and Core Plus programs have been performed by TECMarket Works. IPL's EM&V reports have been provided to the Commission pursuant to the General Administrative Order ("GAO") related to the Commission's August 2014 report to the Indiana General Assembly.

DSM Forecast (2018-2034)

[170-IAC 4-7-6(b)(4)] [170-IAC 4-7-6(b)(5)] [170-IAC 4-7-6(b)(6)] [170-IAC 4-7-6(b)(7)]

The DSM estimates through 2017 contained in this IRP reflect the estimated demand and energy savings for DSM programs for the three years for which approval is being sought in IURC Cause No. 44497. IPL engaged Applied Energy Group ("AEG") to complete a DSM potential forecast for the period 2018-2034. The full report is included in Section 7, Attachment 4.7, DSM Supporting Documents. The following information is excerpted from the AEG Report (Indianapolis Power & Light Demand Side Management Potential for 2015-2034).

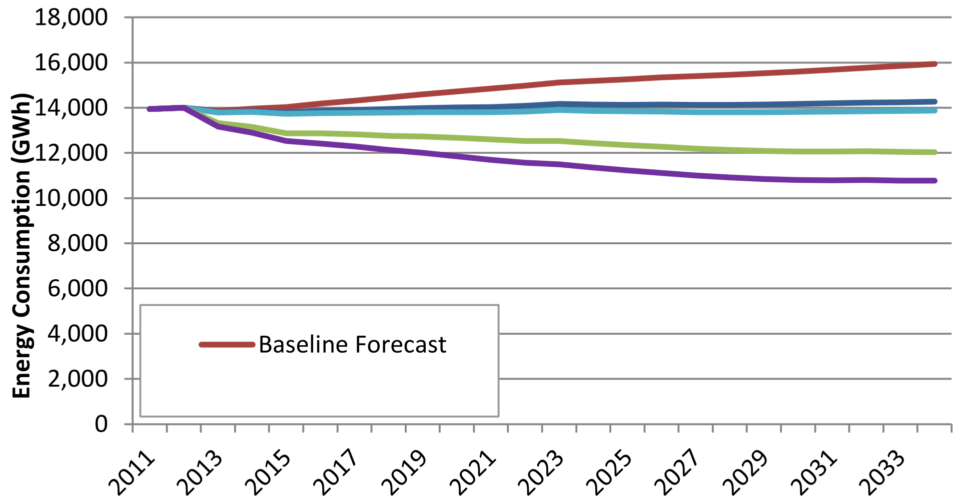
To develop the DSM potential forecasts, AEG used a bottom-up analysis approach following the major steps listed below. A more detailed description of the analysis approach is included in the 2012 MPS in Section 7, Attachment 4.8, DSM Supporting Documents.

- Performed a market characterization to describe sector-level electricity use for the residential, commercial, and industrial sectors for the base year, 2011 within IPL's service territory. This included existing information contained in prior Indiana studies, specific updates to the IPL customer database since the 2012 MPS, AEG's own databases and tools, and other secondary data sources such as the American Community Survey (ACS) and the Energy Information Administration (EIA).
- Developed a baseline projection of energy consumption and peak demand by sector, segment, and end use for 2011 through 2034. This 20-year timeframe was a requirement for the IPL integrated resource plan, and had not been developed in the 2012 MPS or previous Action Plans, which only focused on years through 2017.

- Defined and characterized several hundred DSM measures to be applied to all sectors, segments, and end uses.
- Estimated the Technical, Economic, Maximum Achievable, and Realistic Achievable potential from the efficiency measures. This involved a step to calibrate the participation, savings, and spending levels of Realistic Achievable potential to align with those filed in IPL's 2015-2017 DSM Action Plan.

The following Figure 4B.5 illustrates the forecasted amount of DSM savings potential relative to the baseline projection over the IRP period.

Figure 4B.5 – Forecasts of Potential (GWh)



Source: AEG

The information in Figure 4B.5 is summarized in the following Figure 4B.6:

Figure 4B.6 – Summary of Overall DSM Potential

	2015	2016	2017	2020	2025	2029	2034
Baseline Forecast (GWh)	14,033	14,186	14,319	14,722	15,260	15,526	15,940
Cumulative Savings (GWh)							
Realistic Achievable	234	320	412	706	1,125	1,378	1,665
Maximum Achievable	305	419	540	915	1,417	1,718	2,067
Economic Potential	1,163	1,323	1,495	2,057	2,914	3,438	3,911
Technical Potential	1,509	1,770	2,034	2,877	4,030	4,681	5,172
Energy Savings (% of Baseline)							
Realistic Achievable	1.7%	2.3%	2.9%	4.8%	7.4%	8.9%	10.4%
Maximum Achievable	2.2%	3.0%	3.8%	6.2%	9.3%	11.1%	13.0%
Economic Potential	8.3%	9.3%	10.4%	14.0%	19.1%	22.1%	24.5%
Technical Potential	10.8%	12.5%	14.2%	19.5%	26.4%	30.2%	32.4%

Source: AEG

This DSM outlook is based upon information known today. The impacts of DSM beyond 2017 will depend on the attributes of future programs selected including the load profiles of the measures, program measure duration, program participation and free riders. These factors will change over time along with continued technology advances and large industrial customer participation rates to shape future DSM programs and outcomes. In addition, assumptions around how these programs impact IPL's peak demand and reduce capacity needs, as well as whether DSM will remain cost-effective at the levels identified, remain uncertain. As stated on the cover page to the AEG 20 year forecast, programs were included in the forecast based on a Total Resource Cost (TRC) threshold result of one (1) or greater, while IPL's DSM portfolios of offerings typically have an aggregate TRC value greater than 1. While the TRC test has recently served as a significant threshold for program selection, future cost-effectiveness tests may include other criteria and significantly affect offerings. Future public policy, including the Clean Power Plan and Indiana's legislative direction, will influence IPL's determination of the appropriate level of DSM beyond 2017.

Electric Vehicles

IPL is implemented an Electric Vehicle ("EV") program, which developed integrated charging infrastructure in homes, businesses and public parking facilities, with partial Smart Grid Investment Grant ("SGIG") funding support from the U.S. Department of Energy ("DOE") and the State of Indiana Office of Energy Development. IPL received authority to defer the non-grant funded portion of this project in Cause No. 43960 for future rate recovery. Approximately 162 of the 200 planned charging stations have been installed in homes and businesses. IPL received approval for both a time of use ("TOU") EVX rate for customer premises and a public EVP rate. To date, approximately 100 customers participate in rate EVX.

Figure 4B.7 – Electric Vehicle Time of Use Rate

		Non-Holiday Weekdays	Holidays & Weekends	Price / kWh
Summer (Jun- Sept)	Peak	2pm-7pm		12.150 ¢
	Mid-Peak	10am-2pm; 7pm-10pm	10am-10pm	5.507 ¢
	Off-Peak	12am-10am; 10pm-12am	12am-10am; 10pm-12am	2.331 ¢
Winter (Jan - May; Oct - Dec)	Peak	8am-8pm	8am-8pm	6.910 ¢
	Off-Peak	12am-8am; 8pm-12am	12am-8am; 8pm-12am	2.764 ¢

Source: IPL Rate EVX tariff sheet

IPL found that approximately 76% of the electricity used for EVX charging occurred during off-peak periods, an additional 4% occurred during mid-peak, and the remaining 20% occurred during peak periods in 2013. While the impacts of the total 2013 EVX usage of nearly 400 MWh representing a very small fraction of the total IPL residential and small commercial retail sales are modest[43], IPL customers have responded favorably to manage this new load during off-peak periods.

The public EV rate, EVP, is based upon a flat fee of $2.50 regardless of the duration of the charging session and applied for twenty two (22) chargers at eight (8) area public locations. The public systems may be used by any customer or visitor to Indianapolis using a keyfob and credit card based system. While public charging is less robust than expected, it mitigates range anxiety for EV drivers and includes higher usage in 2013 than in 2012. In 2013, 292 subscribers utilized the public units with total usage of 10,600 kWh between January 1, 2013, and December 31, 2013, with an average of 883 kWh consumed per month. This is a 204% increase in kWh per month over the previous year.

Please see IPL's 2013 Electric Vehicle Program Report for more information at: https://www.iplpower.com/Business/Programs_and_Services/Electric_Vehicle_Charging_and_Rates/.

As described above, the City of Indianapolis asked IPL to support its plan to implement an all-electric car sharing program with its partner, Bolloré Group/BlueIndy for up to 500 EVs and 1,000 car charging stations. The practice of utilizing EV batteries to feed a distribution system as proposed in settlement agreement for this project is often referred to as Vehicle to Grid ("V2G"). If approved, IPL will work with BlueIndy to determine the technical feasibility of piloting this technology and closely monitor and report grid impacts of the BlueIndy project. IPL included EV impact projections in this IRP as described in Section 4D Energy Sales Forecast.

[43] IPL's 2013 aggregate residential and small commercial customer sales totaled over 7,000,000,000 MWh as shown in Section 7, Attachment 6.1 - 10 Yr. Energy and Peak Forecast.

Section 4C. TRANSMISSION AND DISTRIBUTION

Transmission

[170-IAC 4-7-4(b)(10)(C)] [170-IAC 4-7-6(a)(5)]

IPL provides electric power principally to the city of Indianapolis and portions of the surrounding counties. The IPL transmission system includes 345 kV and 138 kV voltage levels. The 345 kV system consists of a 345 kV loop around the city of Indianapolis and 345 kV transmission lines connecting the IPL service territory to the Petersburg power plant in southwest Indiana. At Petersburg, IPL has 345 kV interconnections with American Electric Power ("AEP") and Duke Energy Midwest ("DEM"), and 138 kV interconnections with DEM, Hoosier Energy, and Vectren ("SIGE"). In the Indianapolis area, IPL has 345 kV interconnections with AEP and DEM and 138kV interconnections with DEM and Hoosier Energy. Autotransformers connect the 345 kV network to the underlying IPL 138 kV transmission system which is also networked and principally serves load. See Section 7, Confidential Attachment 1.1, Transmission and Distribution Supporting Documents for the 2014 FERC Form 715 for a geographic outline of the IPL service territory and the one-line connection diagram showing the IPL facilities.

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

IPL transmission plans are based on transmission planning criteria and other considerations. Other considerations include load growth, equipment retirement, decrease in the likelihood of major system events and disturbances, equipment failure or expectation of imminent failure.

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

A summary of IPL transmission planning criteria follows. IPL transmission planning criteria are periodically reviewed and revised.

- Limit transmission facility voltages under normal operating conditions to within 5% of nominal voltage, under single contingency outages to 5% below nominal voltage, and under multiple contingency outages to 10% below nominal voltage. In addition to the above limits, generator plant voltages may also be limited by associated auxiliary system limitations that result in narrower voltage limits.

- Limit thermal loading of transmission facilities under normal operating conditions to within normal limits and under contingency conditions to within emergency limits. New and upgraded transmission facilities can be proposed at 95% of the facility normal rating.
- Maintain stability limits including critical switching times to within acceptable limits for generators, conductors, terminal equipment, loads, and protection equipment for all credible contingencies including three-phase faults, phase-to-ground faults, and the effect of slow fault clearing associated with undesired relay operation or failure of a circuit breaker to open.
- Install and maintain facilities such that three-phase, phase-to-phase, and phase-to-ground fault currents are within equipment withstand and interruption rating limits established by the equipment manufacturer.
- Install and maintain protective relay, control, metering, insulation, and lightning protection equipment to provide for safe, coordinated, reliable, and efficient operation of transmission facilities.
- Install and maintain transmission facilities as per all applicable Indiana Utility Regulatory Commission rules and regulations, ANSI/IEEE standards, National Electrical Safety Code, IPL electric service and meter guidelines, and all other applicable local, state, and federal laws and codes. Guidelines of the National Electric Code may also be incorporated.
- The analysis of any project or transaction involving transmission facilities consists of an analysis of alternatives and may include but is not limited to the following:
    - Initial facility costs and other lifetime costs such as maintenance costs, replacement cost, aesthetics, and reliability.
    - Consideration of transmission losses.
    - Assessment of transmission right-of-way requirements, safety issues, and other potential liabilities.
    - Engineering economic analysis, cost benefit and risk analysis.
- Plan transmission facilities such that generating capacity is not unduly limited or restricted.
- Plan, build, and operate transmission facilities to permit the import of power during generation and transmission outage and contingency conditions. Provide adequate import capability to the IPL 138 kV system in central Indiana assuming the outage of the largest base load unit connected to the 138 kV system.
- Maintain adequate power transfer limits within the criteria specified herein.
- Provide adequate dynamic reactive capacity to support transmission voltages under contingency outage or other abnormal operating conditions.
- Provide adequate dynamic reactive capacity to support transmission voltages under contingency outage or other abnormal operating conditions.

- Minimize and/or coordinate MVAR exchange between IPL and interconnected systems.
- Generator reactive power output shall be capable of, but not limited to, 95% lag (injecting MVAR) and 95% lead (absorbing MVAR) at the point of interconnection to the transmission system.
- Design transmission substation switching and protection facilities such that the operation of substation switching facilities involved with the outage or restoration of a transmission line emanating from the substation does not also require the switched outage of a second transmission line terminated at the substation. This design criterion does not include breaker failure contingencies.
- Design 345 kV transmission substation facilities connecting to generating stations such that maintenance and outage of facilities associated with the generation do not cause an outage of any other transmission facilities connected to the substation. Substation configurations needed to accomplish this objective and meet safety procedures are a breaker and a half scheme, ring bus or equivalent.
- Avoid excessive loss of distribution transformer capacity resulting from a double contingency transmission facility outage.
- Coordinate planning studies and analysis with customers to provide reliable service as well as adequate voltage and delivery service capacity for known load additions.
- Consider long-term future system benefits and risks in transmission facility planning studies.

IPL transmission facilities are also planned and coordinated with the flowing reliability criteria.

- The reliability standards of the North American Electric Reliability Council ("NERC") including the Transmission System Planning Performance Requirements ("TPL") standards, Modeling Data Analysis ("MOD") standards, and Facility Ratings ("FAC") standards. The NERC reliability standards may be found on the NERC website at http://www.nerc.com.
- The regional reliability standards of the reliability entity Reliability First -("RF"). The RF reliability standards may be found on the RF website at http://www.rfirst.org.
- The IPL Transmission Planning Criteria can be found on the MISO website at https://www.misoenergy.org/Library/Repository/Study/TO%20Planning%20Criteria/IPL%20TO%20Planning%20Criteria.pdf.

There is no measure of system wide reliability that covers the reliability of the entire system that includes transmission and generation.

Assessment Summary

[170-IAC 4-7-4(b)(10)(A)] [170-IAC 4-7-4(b)(10)(B)] [170-IAC 4-7-6(a)(5)] [170-IAC 4-7-6(d)(1)] [170-IAC 4-7-6(d)(3)] [170-IAC 4-7-6(d)(4)]

As a member of MISO, IPL actively participates in the MISO annual coordinated seasonal assessments ("CSA") of the transmission system performance for the upcoming spring, summer, fall, and winter peaks. The CSAs are performed to provide guidance to system operators as to possible acute system conditions that would warrant close observation to ensure system reliability. Planned and unplanned outages are modeled to determine system impacts.

As a member of MISO, IPL actively participates in the Midwest Transmission Expansion Plan ("MTEP") process. MISO annually performs these rigorous studies to facilitate a reliable and economic transmission planning process. The MTEP study process identifies economic values including congestion and fuel saving and reductions in operating reserves, system planning reserve margins, and transmission line losses of a proposed transmission project or portfolio.

System congestion is analyzed through the MISO MTEP. Top Congested Flowgate Analysis is performed by MISO in this process to identify near-term system congestion and a Congestion Relief Analysis is performed to explore longer-term economic opportunities. The Market Efficiency Planning Study process, also performed as part of the MTEP, builds on the study methodologies of both analyses and further improves them by appropriately linking the two processes to identify both transmission issues and economic opportunities. The study results are discussed among MISO members throughout the process as well as reported in the MTEP study report provided by MISO.

The seasonal assessments and MTEP analysis may be found on the MISO website at URL:

https://www.misoenergy.org/Planning/SeasonalAssessments/Pages/SeasonalAssessments.aspx
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

RF also performs annual assessments of transmission system performance for the upcoming summer and winter peak seasons, for near-term and long-term shoulder peak load conditions, and from time to time will perform near long-term transmission assessments for off-peak load conditions based on information from each transmission planner including IPL. The transmission system seasonal assessment summarizes the projected performance of the bulk transmission system within ReliabilityFirst's footprint for the upcoming summer peak season and is based upon the studies conducted by Reliability First staff, MISO, PJM, and the Eastern Interconnection Reliability Assessment Group (ERAG). As an entity within the reliability region of Reliability First, IPL actively participates and reviews the studies and study processes of the assessments.

RF develops a series of power flow cases and performance assessments with expected power transfers and long term power purchases and sales. RF also performs First Contingency Incremental Transfer Capability (FCITC) analysis. This analysis shows adequate power transfer capability to support load growth and long term power purchases and sales. FCITC cannot be used as an absolute indicator of the capability of a power system; FCITC is only determined for specific system conditions represented in the study case. Any changes to study case specific conditions, such as: variations in generation dispatch, system configuration, load, or other transfers not modeled in the study case, can significantly affect level of determined transfer capability

These assessments may be found on the RF website at URL: https://www.rfirst.org/reliability/Pages/default.aspx

The IPL assessment of transmission system performance is also performed annually in conjunction with the RF and MISO assessments. The IPL assessment follows the NERC TPL standards to assess transmission performance in peak near-term and long-term conditions and other sensitivity conditions.

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

Key Results

[170-IAC 4-7-4(b)(10)(D)]

- IPL operates its transmission system efficiently with strong ties to interconnecting companies.
- IPL does not jointly own or operate any transmission facilities.
- The transmission facility outages with the greatest impact on IPL facility loadings are those internal to IPL. Of greatest impact are double-contingency outages on the west side of the service area in an arc stretching from Guion to Rockville to Thompson substations and around the Harding Street Generating Station ("HSS").
- The transmission facility outages with the greatest impact on IPL area voltages are those in neighboring utilities. In particular, these are the AEP Rockport-Jefferson 765kV line and the Duke Cayuga-Nucor 345kV line. IPL will continue to review the impact on voltage resulting from these facility outages, and will monitor available reactive resources to help mitigate this impact and for general voltage support.
- The most critical generating unit affecting the IPL area is HSS Unit 7. This is due to its size, its immediate proximity to the local IPL area load, and that IPL generating units at Petersburg are over 100 miles from the IPL service area making it difficult for them to have a large impact on local area voltages.

Individually and combined, these transmission performance assessments demonstrate that IPL meets the system performance requirements of NERC TPL-001, TPL-002, TPL-003, and TPL-004. From these transmission performance assessments, the IPL transmission system is expected to perform reliably and with continuity over the long term to meet the needs of its customers and the demands placed upon it.

- NERC TPL-001: System performance under normal (no contingency) conditions (Category A)
- NERC TPL-002: System performance following loss of a single bulk electric system element (Category B)
- NERC TPL-003: System performance following loss of two or more bulk electric system elements (Category C)
- NERC TPL-004: System performance following extreme events resulting in the loss of two or more bulk electric system elements (Category D)

IPL continuously seeks to upgrade its ability to model the transmission system and to more accurately forecast its performance. This includes review of available computer software, data collection techniques, equipment capabilities and parameters, and developments in industry and academia. IPL upgraded its current-day and next-day planning software in 2013. It also includes information sharing with neighboring transmission owners and regional transmission organizations.

Based on its own individual efforts, as well as in concert with others, IPL constantly works to ensure that its transmission system will continue to reliably, safely, efficiently, and economically meet the needs of its customers.

IPL's FERC Form 715 was submitted by MISO and is in Section 7, Confidential Attachment 1.1, Transmission and Distribution Supporting Documents to provide additional documentation of the IPL's planning and reliability criteria.

The FERC 715 was based on MTEP 13 studies which contain the most recent power flow study available to IPL including interconnections. In MTEP 13, MISO conducted regional studies using models for 2015 Summer Peak, 2018 Summer Peak, 2018 Shoulder Load, 2018 Light Load, 2018 Winter Peak, 2023 Summer Peak, and 2023 Shoulder Load. The MTEP 13 dynamic simulations identified no system stability needs and meet the NERC standards.

Transmission Short Term Action Plan

[170-IAC 4-7-6(d)(2)]

For the forecast period, IPL currently plans to add or modify the following transmission facilities. The estimated cost for all facilities is in Section 7, Confidential Attachment 1.3, Transmission and Distribution Supporting Documents.

Transmission Plans for the New Eagle Valley CCGT in 2015

- Transmission line upgrades are needed to deliver the capacity and energy of the New Eagle Valley CCGT into the MISO market.
    - Pritchard – Centerton rating increase to 305 MV
    - Centerton – Honey Creek rating increase to 305 MVA
    - Honey Creek – Southport rating increase to 305 MVA
    - Pritchard – Mullinix rating increase to 272 MVA
    - Mullinix – Glens Valley rating increase to 272 MVA
- The 1200A line disconnect switches at Honey Creek, and Centerton substations are scheduled for replacement to increase the rating on the above lines
- All three existing 138 kV circuit breakers rated 800 ampere at Mooresville substation are scheduled to increase the rating of line 132-24
- The terminal equipment for the 132-21 line is scheduled for replacement to be compatible with the protection scheme at the new 138 kV Eagle Valley substation. The terminal equipment includes a wave trap, disconnect switches, and relays, etc.

Transmission Plans for the New Eagle Valley CCGT in 2016

- A new Eagle Valley to Franklin Township line rated 322 MVA minimum is scheduled for installation from the new Eagle Valley substation. This line will utilize the spare tower position on the Petersburg to Francis Creek to Hanna 345 kV line. The line will include fiber optic conductors in the static wire for communication.

- Two new line terminals are scheduled for installation at the Franklin Township substation to accommodate the routing of the 138 kV line transmission line from the new Eagle Valley 138 kV substation. The terminal equipment includes breakers, disconnect switches, relays, etc.
- A breaker and a half bus design 138 kV Eagle Valley substation is scheduled to be installed for the new CCGT power plant located on the existing Eagle Valley site by April 16, 2016.
- Transfer all four existing 138 kV transmission lines at the existing Eagle Valley plant Pritchard substation.

Misc. Transmission Line Jobs – 2015

- Various transmission line surveys and upgrades are needed to increase the line during contingency loading conditions to meet NERC reliability standards.

Petersburg to Duke Wheatland to AEP Breed Line- 2015

- The upgrade of the IPL Petersburg to Duke Wheatland to AEP Breed 345 kV line from 956 to at least 1386 MVA has been approved by MISO as a market efficiency project. The project is eligible for cost sharing and is included in the MISO MTEP.

Hanna Substation Upgrade - 2016

- The upgrade of the Hanna Substation include two new 345 kV breakers, the replacement of a 275 MVA autotransformer with a 500 MVA autotransformer, and a breaker and a new 138 kV breaker and a half bus design. Will increase import capability into the IPL 138 kV transmission system improves reliability, and allows for better operational flexibility.

Thompson Substation Upgrade - 2016

- The upgrade of the Thompson Substation include a new 345 kV breakers, the relocation of the 275 MVA Hanna autotransformer and two 138 kV breakers. The project increase imports capability into the IPL 138 kV transmission system, improves reliability, and allows for better operational flexibility.

Static VAR System (SVS) - 2016

- The project includes a new Static VAR System (SVS) like a Static VAR Compensator (SVC) or Static Synchronous Compensator (STATCOM) at the Southwest 138 kV substation. The SVC would have a nominal continuous rating of –100 Mvar inductive to +300 Mvar capacitive at 138kV. The STATCOM would have a nominal continuous rating of –100 Mvar inductive to +250 Mvar capacitive at 138kV. The primary application and need for the SVS is for the transient voltage response for transmission events. The SVS would also be used for continuous voltage regulation. The project increase imports capability into the IPL 138 kV transmission system, improves reliability, and allows for better operational flexibility.

Transmission Expansion Cost Sharing

The methodology for the socialization of transmission expansion costs has been one of the significant drivers of uncertainty in the past several years. MISO and the transmission owners began development of a methodology for the sharing of costs for reliability projects in 1994, and shortly thereafter launched into development of a methodology for the sharing of costs of projects deemed to be "economic." Economic projects are those projects that are not needed to meet NERC criteria for reliability but for which there may be an economic benefit. In 2010, MISO filed and FERC accepted a cost sharing methodology for transmission projects built to meet the renewable mandates of states within the footprint. These projects are called Multi-Value Projects ("MVP"). The costs of these projects are socialized across the footprint regardless of the need of load. Included in the MVP filing was a renaming of "Economic" projects; they are now called Market Efficiency Projects ("MEP").

FERC Order 1000

Since the last IRP, both at the state level and in the MISO tariff, the right of first refusal for transmission projects needed for reliability has been preserved. Effective with the 2015 planning cycle, due to the implementation of FERC Order 1000, the right to develop Market Efficiency and Multi-Value transmission projects has opened up to third party transmission developers. This event necessitates a process to qualify transmission developers and to select a developer to build the project. This will add up to three years to the process of placing transmission enhancements in service. FERC demands that incumbent utilities who wish to bid on projects not directly connected to their own transmission systems compete with third parties for the right to build and therefore must submit a developer application to MISO for evaluation. If the project is directly connected to the incumbent's transmission system, no application is required; however the incumbent still must compete for the right to build MEPs or MVPs. To preserve its right to develop transmission projects of all types and locations, IPL will complete the application process dictated by the MISO tariff. As one result of implementation of FERC Order 1000, MISO has proposed numerous changes to the project types that will be vetted through the stakeholder process in the coming months. Additionally, due to the integration of Entergy into the MISO system at the end of 2013, changes to the kV blight lines of MEPs and MVPs are proposed. If those bright lines are lowered as proposed, IPL will be required to pay a greater portion of the shared costs of transmission in the now much larger footprint.

To preserve its option to bid to build transmission projects other than reliability projects, IPL is required to submit an application to MISO to qualify as a transmission developer under the Order 1000 rules. FERC requires incumbent transmission developers to qualify on the same terms and conditions as new transmission developers. IPL submitted its application on August 4, 2014.

Distribution

[170-IAC 4-7-8(b)(8)]

IPL's Electric Distribution System Plans are based on various criteria and parameters that are used to determine expansion and replacement requirements. The criteria and parameters include: consideration of load growth, equipment load relief, timely equipment replacement to optimize performance, effects of major system events, reliability improvements, national Electric Safety Code (NESC) requirements, and industry guides and design standards.

Distribution construction projects are based on the results of IPL's small area load studies. Grid area data, such as historical data, land use statistics, and demographic customer data, provide the basis for long-range demand projections. These projections are modified for the short-term on the basis of known customer additions and recent historical substation load growth, since the grid area data cannot predict short-term deviations from long-term statistical trends. Distribution substations additions or improvements are scheduled when projected area loads cannot be served from existing substations, or if existing substation facilities reach their design limits. Circuit construction is scheduled to utilize newly installed substation capacity, to provide relief to circuits projected to exceed design capacity or to improve reliability or operational performance. Short-term operating remedies are used to delay construction only with the agreement of the Distribution Operations Department.

A 4.16 kV to 13.2 kV conversion plan consists of the replacement of critical transformers and the conversion of radial circuits where 13.2 kV sources are available to avoid overloads on critical substations. This plan is formulated to avoid the failure of adjacent substations that may lead to a cascading outage event. Any equipment with remaining life that is removed due to conversion is used to provide adequate capacity to the remaining 4.16 kV loads, to provide spare units to cover unforeseen transformer or switchgear failures, and to permit the retirement of equipment which has outlived its useful life and cannot provide reliable service. The conversion schedule is developed to complete the proposed plan with minimum capital expenditures and to maintain system continuity.

Industrial substation expansion is scheduled to provide capacity for known industrial load additions and to relieve existing or anticipated overloaded facilities. Several customers, either by internal policy or government regulations, may be required to maintain 100% emergency capacity, and the company's additional investment is recovered through excess facility agreements. IPL's policy is to provide such service to certain public service customers, such as hospitals and communications facilities provided the customer meets specific engineering design criteria.

IPL maintains a capacitor program to provide sufficient reactive power (known as volt amperes reactive or "VARs") to maintain adequate distribution voltage under all probable operating conditions and to economically reduce facility loading. Through its Smart Grid Initiative, funded in part through an U.S. Department of Energy ("DOE") Smart Grid Investment Grant ("SGIG"), IPL recently upgraded its capacitor control system to improve operators' the remote monitoring and control capability with two-way verifications from each location. Please see the following section for more details about smart grid efforts.

Smart Grid Initiative

IPL deployed advanced technologies as part of its DOE-funded Smart Energy Project to accomplish the following functions:

- Strategically automate distribution equipment to improve reliability
- Build upon equipment and systems which are in place to minimize undepreciated assets and minimize costs
- Utilize Advanced Metering Infrastructure ("AMI") for approximately 10,000 customers to accomplish 100% automated meter reading, and integrate interactive system outage and voltage information
- Upgrade communications infrastructure to support long-term requirements

IPL's distribution system includes the following features:

- Supervisory Control and Data Acquisition ("SCADA") functionality enables remote device monitoring and control for 90% of its distribution customers.
- Automated controls are used in 100% of its 1,300 switched capacitor banks.
- Nearly 225 automated reclosers with microprocessor-based programmable remote controls and 50 automatic distribution line switches are in use to reduce customer exposure to outages.
- SCADA functionality was extended to the Central Business District ("CBD") network in downtown Indianapolis through network protector relays and communicating fault indicators on the network.
- A Distribution SCADA (dSCADA) software system has been implemented on the radial distribution network throughout the service territory to link new devices.
- Upgraded microprocessor-based distribution feeder relays have been installed for approximately 300 circuits to enable remote configuration and estimated fault location data to operators.
- An automated Conservation Voltage Reduction ("CVR") program has been implemented through the deployment of smart microprocessor-based Transformer Load-Tap Changer ("LTC") controllers and upgrading capacitor controls from one-way to two-way functionality as described below.

IPL is using common communication systems for the AMI and DA systems to form a robust foundation for additional deployment of "advanced technology" components. For more details about IPL's smart grid efforts, please see Section 7 Attachment 1.2, Transmission and

Distribution Supporting Documents which contains information from the DOE website: smartgrid.gov.

Advanced Metering Systems

IPL has been using an Automatic Meter Reading ("AMR") system for its energy-only metered customers since 2001 to automatically read meters and provide one-day delayed energy information to customers through a web-portal known as PowerView®. Since the AMR system operates well as designed, IPL initiated AMI to capture its demand meters which are still manually read. The DA devices shared common communication networks with AMI. IPL recently renegotiated a long-term metering technology contract to operate both systems through 2016. After 2016, all advanced metering will be transitioned to a single system.

Smart Grid Benefits

[170-IAC 4-7-6(a)(5)]

Smart Grid, or Distribution Automation ("DA"), will enhance outage restoration with the additional reclosers and advanced relays allowing sections of circuits to be isolated if there is a fault on the system which allows fewer customers to experience a service interruption. In addition, quicker service restoration results when operators may back-feed sections of circuits. Circuits may also be operated more efficiently with interactive information received from devices with two-way communication equipment.

A CVR program allows IPL to reduce system peak demand during peak hours of the year. This voltage reduction through interactive operations monitoring on the 13.2 kV distribution system is planned through multiple circuit devices, two-way communications, and a distribution SCADA control software system. Essentially, IPL will operate the system at slightly lower voltages at the substation bus but still within industry standard limits. Real time voltage readings from two-way communicating capacitor controls and meters are collected to verify compliance with service requirements. Partial system tests in 2012 through 2014 continue to indicate positive results with the largest test reducing demand by 7 MW per hour based on an average voltage reduction at each substation bus of 1%. IPL may also avoid purchasing power from the market during those times when demand and prices are highest. IPL successfully achieved the ability to modify the MISO business practices to "count" this capacity as a Load Modifying Resource (LMR) within the context of the MISO market. IPL estimates achieving up to 40 MW of peak load reductions through CVR if voltage is reduced by 2.5% at each substation bus, however, IPL conservatively registered 20MWs for CVR in MISO and included it in this IRP. See Section 7, Attachment 1.4, Transmission and Distribution Supporting Documents for the IPL CVR Baseline Report dated February 2014.

In 2010, engineering estimates of DA reliability impacts related to the smart grid project projected a reduction in the System Average Interruption Frequency Index ("SAIFI") of 11%.

Representative results measured from January 2014 to July 2014 indicate actual improvements of 12.1% for SAIFI when major event days are excluded.

Distributed Generation Connections

[170-IAC 4-7-4(b)(5)] [170-IAC 4-7-6(a)(5)]

IPL has successfully connected 66 MW of solar distributed generation (DG) since 2012 through its Rate Renewable Energy Production (REP) program. This includes eight (8) utility scale sites ranging in size from 500 kW to 10 MW in nameplate alternating current capacity. IPL's experience with solar facilities indicates no significant impact to its transmission system. This is due to many factors including the decision to limit the total capacity per site to 10 MW, connect the facilities at 13 kV, and establish the engineering criteria for a maximum of 10 MW connected per substation transformer. IPL is not aware of any occurrence of backfeed on its transmission system including during non-peak hours.

Distribution circuit impacts have been monitored and mitigated through its DG interconnection working group. Specifically, remote control capabilities are enabled through reclosers connected to IPLs DA network. Protection settings for the inverter control systems, reclosers and IPL feeder relays are reviewed by IPL engineers and adapted as needed to avoid "nuisance" tripping which isolates the DG from the IPL grid. IPL monitors the output of the sites over 500 kW in real-time through its dSCADA system. IPL will continue to evaluate the business practices as more DG comes on-line. Section 4A contains more information about existing and "new" solar resources.

Electric Vehicle Projects

As described in section 4B, IPL initiated an electric vehicle (EV) pilot program which included the deployment of one hundred sixty two (162) chargers. Minimal impacts to the distribution grid have been monitored through separate meters for each charger location. Transformer loading analysis has been completed for each site with no replacements necessary

IPL's 2013 Electric Vehicle Program Report can be found under a link located at: https://www.iplpower.com/Business/Programs_and_Services/Electric_Vehicle_Charging_and_Rates/

IPL is using lessons learned from the pilot to plan an all-electric car sharing project with the City of Indianapolis and BlueIndy to include approximately 1,000 chargers to support up to 500 new EVs throughout the greater Indianapolis area as described in testimony in the IURC Cause No. 44478. IPL plans to optimize engineering, construction and back-office practices from its small pilot to efficiently implement this program to improve the distribution infrastructure in preparation for the mobile EV loads.

IPL continues to support the growth of EVs in its service area through these programs. Awareness of EV charging locations allows engineers to verify existing facility capacity and upgrade requirements. To date these have been limited to customers' service and panel upgrades but any future transformer replacements will be managed closely by IPL. Understanding grid impacts will help IPL to create and implement future demand response programs to release battery energy to the grid during peak periods.

IPL's area EV penetration has been slower than anticipated in the 2011 IRP. Should EV load growth increase significantly, the high load growth scenario in this IRP reflects related impacts as described in Section 4D.

Cyber Security and Interoperability Standards

IPL recognizes interoperability and strong cyber security practices are essential to advanced technology deployment. IPL employs specific cyber security business practices and procedures and is working closely with vendors to assure that current and proposed Smart Grid standards and procedures are employed. IPL has a dedicated staff including a Certified Information Systems Security Professional ("CISSP") to ensure that cyber security is maintained at each stage of system deployment. IPL tests and updates its security plan to mitigate any foreseen threats to key infrastructure components. IPL monitors and protects its network on a 24/7 basis with intrusion prevention systems to identify any malicious activity targeting or originating from corporate assets, including outside attempts to gain access to the system.

IPL vendors who may affect cyber security risk undergo a screening process which includes a thorough questionnaire and interview process to identify risks and mitigation plans.

IPL also seeks vendors who could commit to physical equipment security and utilize open protocols and standards to support interoperable system components wherever possible. While some customization is required to interface to legacy systems, IPL prefers vendors that utilize standards-based security features of application servers versus proprietary methods to quickly adapt through configuration to new requirements as they unfold and become adopted standards.

The smart grid system is being designed with security best practices incorporated from an architectural standpoint to facilitate security from the beginning of a project. Implementation of security best practices at each system junction point ensures authenticity and reliability of data transport.

Future Smart Grid Expectations

IPL will continue to leverage smart grid investments to provide resource planning benefits, realize operational efficiencies, increase the understanding of equipment performance and to develop asset lifecycle plans. Detailed analysis of field device data being collected through the two-way communications systems will enhance these capabilities. In addition, IPL operations staff plans to use the data to complete the following:

- Leverage fault locations from relays to dispatch trouble crews more effectively and reduce service restoration times.

- Use relay event data to indicate the need for breaker maintenance
- Optimize CVR on distribution circuits to maximize peak load reductions and minimize substation transformers load tap changer operations
- Use CBD SCADA operations as a catalyst for network protector maintenance frequency
- Use CBD fault indicators for cable loading and fault analysis
- Refer to capacitor control and AMI meter voltage information to assess power quality
- Consider time based rates and prepaid metering service offerings

There are plans to upgrade some legacy DA and telecommunication equipment to use the new platforms over the next few years as well.

Transmission and distribution assets will likely play a larger role in future resource planning as distributed resources including DG, DR, and smart grid initiatives increase to provide capacity and energy benefits. IPL plans to optimize operations of these interrelated efforts.

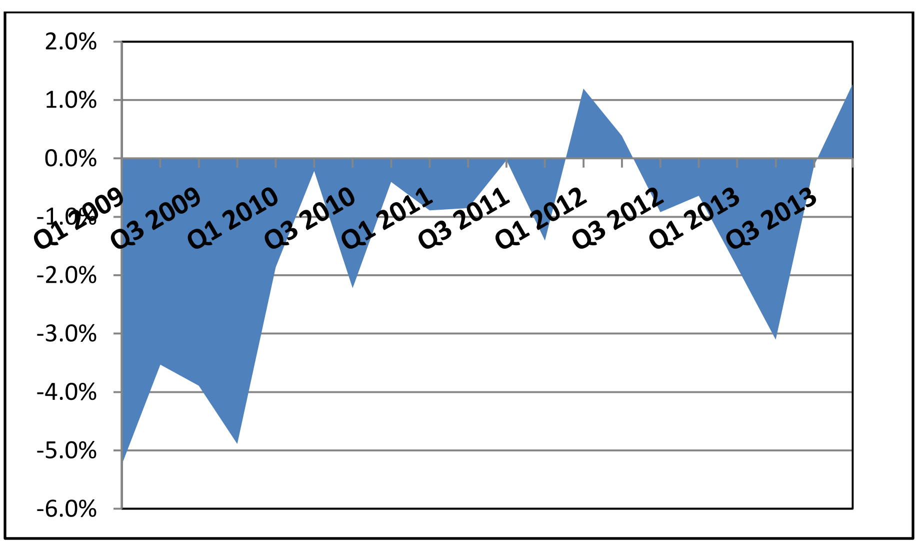
Section 4D. MARKET TRENDS AND FORECASTS

This section addresses IPL short-term and long-term energy and demand forecasts, model performance, and forecast error, as well as fuel planning, procurement practices and pricing forecasts. Specific data to support the narratives may be found in Section 7.

Load Forecast Overview Short Term

Economic conditions have fairly stabilized in IPL's service territory since the conclusion of the recession that began in 2008. Household-growth in the Marion-county area has been increasing since 2011, and is set to grow at 1.4% over the next three years. Employment rates have been improving steadily since 2010; personal-income is projected to grow albeit at a modest rate compared to 2011 levels because much of the employment-gains are believed to have been in the low-wage sectors. The short-term projected growth rates for these are 1.8% and 1.2% respectively. Energy sales have consequently recovered since the recession, but have not mirrored the overall growth in economic parameters. This is in part due to the structural shift in energy-consumption induced as a result of increasing appliance-efficiencies. Even if better than recession-levels, quarter over quarter growth in 2013 has been negative as depicted in Figure 4D.1 below. IPL's forecasting models, which will be discussed later, depict impending energy sales growth after accounting for the impacts of forecasted demand side management ("DSM") with a compound annual growth rate ("CAGR") over the next three years of 0.7%. This growth rate is then forecasted to decrease after the initial recovery phase because of an economic slow-down.

Figure 4D.1 – Year-Over-Year Change in Historical Weather Normalized kWH Sales



Source: IPL

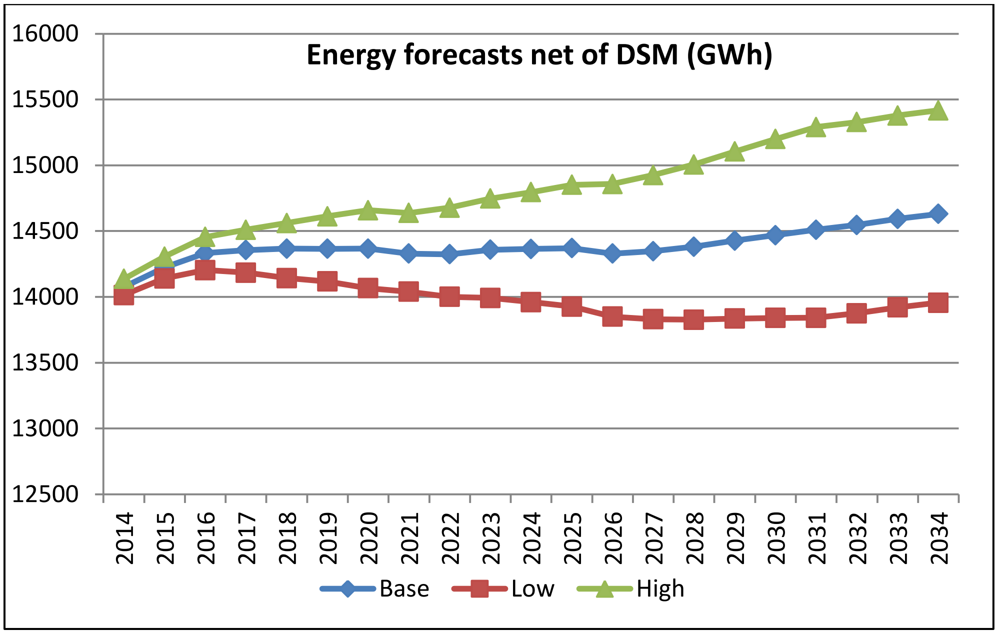
Load Forecast Overview Long Term

[170-IAC 4-7-4(b)(6)] [170-IAC 4-7-5(a)(6)] [170-IAC 4-7-5(b)]

IPL's long-term load forecast shows that growth will be impacted by organic energy-efficiency trends and DSM load impacts almost as much as the econometric variables. This forecast is based on econometric and end-use based modeling of IPL's gross internal demand ("GID") load and energy forecast plus incorporation of IPL's DSM expectations. Assumptions around DSM program free riders, program duration/degradation, and coincident peak load reductions were used to calculate a total internal demand ("NID") forecast. Sales before any DSM adjustments are expected to grow at a compound annual growth rate of 1.2% over the next three years, and 0.7% over the next 20 years. The growth-rate drops to 0.7% over the next three years after DSM savings are netted out. In other words, DSM is forecasted to address 42% of the estimated load growth.The estimated net energy efficiency DSM impact on the load and energy forecast is 1,575 GWH (337 MW) by 2034. IPL assumes an average 23% free-ridership/spill-over impact. These assumptions and corresponding forecast impacts could vary considerably as specifics of the DSM programs are continually evaluated and updated.

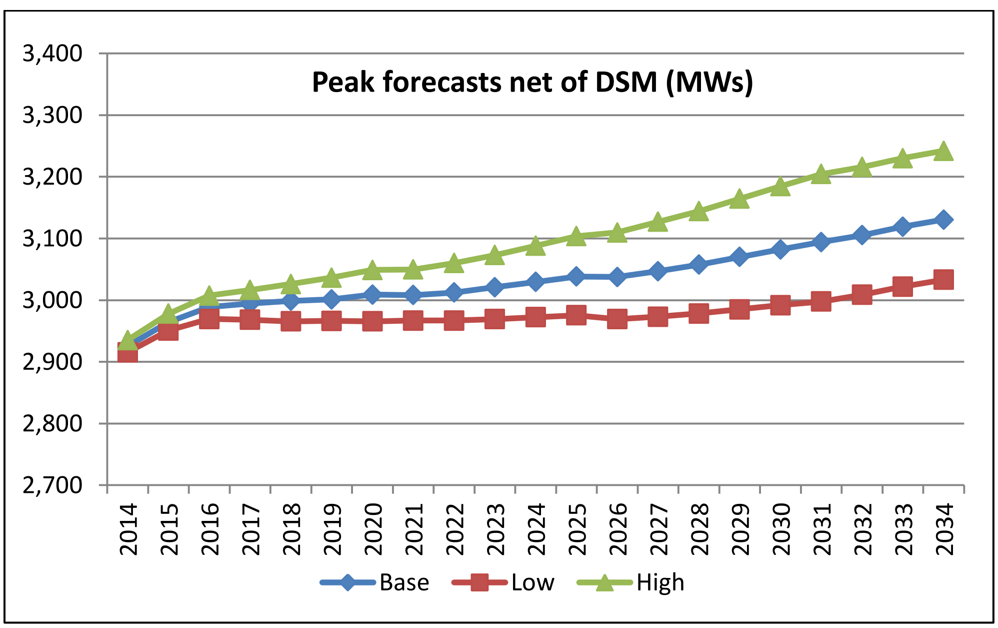
To capture forecast uncertainty in Ventyx's IRP modeling, IPL selected three energy and peak forecast scenarios: 1) Base load, 2) Low load, and 3) High load, with the Base load being the most probable. These energy and peak forecasts are shown in Figure 4D.2 and Figure 4D.3. These forecasts were derived by applying the low and high ranges of the State Utility Forecasting Group's (SUFG) 2013 IPL-forecast to IPL's internal forecast. Although this range, as modeled by the SUFG, is primarily driven by economics, we interpret the range to represent uncertainties resulting from: economic activity, DSM program impacts and technological and behavioral changes. For reference, IPL's base case with net DSM impacts represents a peak load forecast growth at 0.3% CAGR with 3131 MW of net internal demand ("NID") by 2034. IPL's forecast range, as modeled by Ventyx in the Capacity Expansion module, ranged from 0.2% CAGR (3,033 MW) for the Low Load forecast to 0.5% CAGR (3,242 MW) for the High Load forecast by 2034. The impact of this forecast uncertainty on the expansion plan modeling is discussed in Section 4, Integration. Sales forecasts by rate and IPL peak forecast, for the first 10 years, may be found in Section 7, Attachment 6.1, Forecasting Data Sets. The low and high range forecast data for all twenty years are provided in Section 7, Attachment 6.2, Forecasting Data Sets.

Figure 4D.2 Energy Forecast Range



Source: IPL

Figure 4D.3 Peak Forecast Range



Source: IPL

IPL creates the internal load and energy forecast spanning ten years due to constraints in economic data availability. For this IRP, the average growth rate of the tail-end years (final three years) is used to extrapolate the forecast over twenty years. Figure 4D.4 below shows the data behind the base line forecast in Figures 4D.2 and 4D.3.

Figure 4D.4 – Energy Sales and Peak Forecasts Net of Energy Efficiency DSM

Year	Energy Forecast (MWh)	YOY % Change	Peak TID (MW)	YOY % Change
2014	14,075,327		2926	
2015	14,223,236	1.1%	2965	1.3%
2016	14,332,600	0.8%	2989	0.8%
2017	14,355,903	0.2%	2995	0.2%
2018	14,366,218	0.1%	2999	0.1%
2019	14,365,853	0.0%	3001	0.1%
2020	14,366,838	0.0%	3009	0.3%
2021	14,329,494	-0.3%	3008	0.0%
2022	14,324,115	0.0%	3013	0.1%
2023	14,358,194	0.2%	3021	0.3%
2024	14,364,022	0.0%	3030	0.3%
2025	14,370,741	0.0%	3038	0.3%
2026	14,329,665	-0.3%	3038	0.0%
2027	14,347,078	0.1%	3047	0.3%
2028	14,381,659	0.2%	3058	0.3%
2029	14,427,629	0.3%	3070	0.4%
2030	14,469,065	0.3%	3082	0.4%
2031	14,510,624	0.3%	3094	0.4%
2032	14,546,314	0.2%	3105	0.4%
2033	14,592,712	0.3%	3119	0.4%
2034	14,630,095	0.3%	3131	0.4%

Source: IPL

Energy Sales Forecast

[170-IAC 4-7-4(b) (1)] [170-IAC 4-7-4(b)(2)] [170-IAC 4-7-4(b)(4)] [170-IAC 4-7-4(b)(6)] [170-IAC 4-7-5(a)(8)] [170-IAC 4-7-5(a)(9)]

IPL's forecasting effort is based on statistically adjusted end-use econometric modeling and takes into account factors including:

- Economic variables
- Energy efficiency standards
- New technology penetration

- Weather
- DSM

IPL employs an econometric model that also makes use of some end-use impacts in order to accommodate efficiency measures, appliance saturation and new technology penetration, such as electric vehicles. This methodology was developed for IPL by Itron, Inc. ("Itron"), a consulting firm that assisted IPL with past retail energy forecasts. Additional detail with respect to this end-use technique may be found in Section 7, Confidential Attachment 6.3, Forecasting Data Sets. Estimates of appliance saturation and efficiency are obtained from the U.S. Energy Information Administration ("EIA"), a statistical information agency of the U.S. Department of Energy ("DOE"). EIA information is modified by Itron to better reflect appliance saturation and end-use efficiency impacts within IPL's jurisdictional territory. This data can be found in Section 7, Confidential Attachment 6.4, Forecasting Data Sets.

IPL's forecast also includes an estimate to reflect customer adoption of plug-in hybrid electric vehicles ("PHEV") and electric vehicles. It is estimated that up to 10% of IPL's customers may purchase a new car in any given year. An annual adoption rate of hybrid electric vehicles, based on a report published by the Electric Power Research Institute (EPRI)[44], is applied to this number. The usage per car is assumed to be 2,477 kWh per year, and cars are assumed to have a 7-year use-span. This usage compares to approximately 3,900 kWh per year per IPL residential EVX customer in 2013.[45] The cumulative estimated energy-impact, as listed below in Figure 4D.5, is added to the forecast.

[44] IPL modified the rate set forth in 'Environmental Assessment of Plug-In Hybrid Electric Vehicles' by the Electric Power Research Institute (EPRI), July 2007 to a less aggressive adoption rate, which is reflective of IPL's service territory.

[45] As shown in IPL's 2013 report available at this link: https://www.iplpower.com/Business/Programs_and_Services/Electric_Vehicle_Charging_and_Rates/

Figure 4D.5 Electric-Vehicle Assumptions Applied to Load Forecast

Year	Assumed Annual EVs Sold	Cumulative EVs Sold	Annual Electricity Consumption per Car (kwh)	Cumulative Load (MWH)
2014	165	313	2477	776
2015	221	534	2477	1,324
2016	306	841	2477	2,083
2017	421	1,261	2477	3,124
2018	564	1,825	2477	4,520
2019	792	2,617	2477	6,483
2020	909	3,526	2477	8,734
2021	1,022	4,548	2477	11,266
2022	1,136	5,684	2477	14,080
2023	1,250	6,934	2477	17,175

Source: IPL

As of 2013, the actual total number of registered electric vehicles in the Indianapolis area is 211[46]. The BlueIndy program is expected to add 500 electric vehicles. IPL recognizes the variance between forecasted and actual EVs deployed and anticipates the availability of BlueIndy public chargers may foster adoption of additional EVs in the area. The forecast of electric-vehicles and estimation of their impact on the load will be refined in subsequent IRP analysis as and when more information specific to IPL's service area becomes available.

IPL gathers information about residential and commercial customer adoption of end-use appliances, penetration and consumption patterns through means that vary from scheduled surveys that are described in the IRP rule. These methods include DSM program data collection such as home energy audits, refrigerator recycling, air conditioning load management program participation, the evaluation measurement and verification process for DSM programs. Requests for new commercial and residential service extensions are managed through engineering and connections groups where load information such as square footage and HVAC specifications are used to estimate projected customer consumption. Similarly, existing and new IPL industrial customers remain in close contact with individual Strategic Account Representatives to address the addition of new loads. This information is shared with appropriate engineering and resource planning staff to prepare for significant forecasted demand changes.

In addition, virtually all of IPL's meters are read daily since the completion of the smart grid project in 2013.[47] IPL is able to understand system loading and evaluate any concerns in real-

[46] Source: Indiana Bureau of Motor Vehicles

[47] Less than 1% of the meters read may be unreachable due to obstructions such as vehicles or trees or communication issues.

time as well as utilize information for forecasting from its meter data management system if needed.

IPL's NID is net of incremental DSM as projected by AEG. AEG's DSM forecast was adjusted to account for prorated implementation of programs and the fact that the base forecast has historical DSM (up till 2014) embedded in it owing to the use of actual historical consumption data. Figure 4D.6 shows the cumulative DSM impact applied to the forecast.

Figure 4D.6 DSM Assumptions Applied to Load Forecast

Year	Cumulative Energy Forecast (MWh)	Cumulative Energy Efficiency Peaks (MW)
2014	60,942	11
2015	119,587	19
2016	207,416	37
2017	295,970	57
2018	386,788	73
2019	484,327	93
2020	567,922	110
2021	674,654	131
2022	769,184	151
2023	830,724	168
2024	910,577	183
2025	995,088	199
2026	1,128,097	225
2027	1,201,352	240
2028	1,259,135	255
2029	1,305,910	268
2030	1,357,487	281
2031	1,409,738	295
2032	1,468,342	310
2033	1,516,762	322
2034	1,574,806	337

Source: IPL

IPL's retail sales forecast is the summation of individual rate class forecasts. The bulk of IPL's econometric models is multi-regression in nature and is generated for each major rate class of IPL's retail customers. The models require monthly inputs and provide monthly outputs, thereby allowing for a true monthly sales forecast rather than one which parses quarterly or annual data. The sales forecasting effort is accomplished using models that are based on billing cycle sales. Simulation models are then created to convert billing cycle information into a calendar month format. This allows for modeling actual information without exposure to unbilled estimation that is integral with a calendar month approach. An overview of IPL's current forecast, both sales and peaks, are expressed in Figure 4D.4 above. The “YOY % Change” column is an indication of year-over-year growth.

The models that support the base level forecast are developed as either average-use models by rate or aggregated-sales models by rate. The homogeneity of the residential rate class allows for the use of average-use techniques. A forecast of the number of customers and the average-use of an individual customer is generated for each residential rate. IPL’s Commercial and Industrial (“C&I”) customers are more heterogeneous and an aggregated-sales by rate methodology has been found to be superior. Average-use models have been tested for these larger customers; however, the load variation of these customers makes an average-use approach statistically untenable.

Economic drivers, one of the independent variables, are re-specified for each iteration of the forecast. Econometric forecasts modeling software is typically limited to two or three economic drivers per modeling run. The inclusion of more drivers generally causes a collinearity problem which degrades the predictive power of the model. The main economic drivers used in IPL’s most current forecast are as follows:

Residential Economic Drivers

- Total Households Marion County – to estimate number of customers
- Real Household Income Indianapolis - to estimate average KWh use
- Household Size Indianapolis – to estimate average KWh use

Small C&I Economic Drivers

- Indianapolis Non-Manufacturing Employment – to estimate rate SS and SH KWh requirement

Large C&I Economic Drivers

- Indianapolis Non-Manufacturing Employment – to estimate rate SL and PL KWh requirement
- Indianapolis Manufacturing Employment – to estimate rate PH & HL KWh requirement

Moody’s Economy.com supplies the economic drivers used by IPL. These are provided on a local, Metropolitan Statistical Area (“MSA”), statewide, and national basis. IPL’s models are generally better using local specified drivers than ones that are broader in scope. A compilation of the drivers used, as well as others provided by Moody’s Economy.com can be found in Section 7, Confidential Attachment 6.5, Forecasting Data Sets. As previously mentioned, the driver sets used are unique to the current forecast effort. Past or future forecasts may be specified using a different set of drivers that are statistically superior at different points in time. IPL’s models are created with a 10-year horizon for internal purposes and then inflated at an average rate of 0.6% for the subsequent 10 years on a before-DSM basis. Summer and winter peaks are inflated at an average rate of 0.7% on a before-DSM basis.

Historic weather and customer information are also important drivers of IPL's retail forecast models. The actual weather information is obtained from the National Oceanic and Atmospheric Administration ("NOAA") and includes heating degree days ("HDD") and cooling degree days ("CDD"). The most recent 30-year averages of monthly HDDs and CDDs are used as 'normals' for the forecast period. The customer information applied in IPL's retail forecasts (customer counts by rate, KWh sales by rate, and billing day information) are all acquired from confidential IPL customer records. Input data sets used in the modeling effort may be found in Section 7, Attachments 6.6, 6.7 and 6.8, Forecasting Data Sets. These attachments are segmented down to the three classes of customers: residential, small C&I, and large C&I. Data found in these attachments includes customer counts by rate, sales history by rate, weather information, and model outputs, as well as statistical specifications of each model.

Peak Forecast

[170-IAC 4-7-4(b) (1)] [170-IAC 4-7-4(b)(2)] [170-IAC 4-7-4(b)(6)] [170-IAC 4-7-5(a)(8)]

As a member of MISO, IPL supplies monthly forecasts in response to MISO's emphasis on balancing monthly peak supply and demand. To meet this requirement, IPL develops a monthly peak forecast by means of a "hybrid" model that utilizes both econometric drivers and energy-efficiency impacts, similar to the energy models described above. From the monthly values, a summer-peak (allotted to July) and a winter-peak (allotted to January) are identified. IPL's peak models reflect the GID. Adjustments are then made for incremental projections of energy efficiency DSM initiatives to create the TID. IPL created high and low ranges for the peak forecast, similar to the energy forecast, for the IRP modeling. The forecast data can be found in Section 7, Attachment 6.2, Forecasting Data Sets.

The peak model is linked to the energy forecast model in such a way that the same economic variables drive the peak forecast. Average temperatures/degree-days associated with historical peak-days form the weather bases. Specification of the models, including all history, incorporated driver variables, and output may be found in Section 7, Attachment 6.9, Forecasting Data Sets. Summer peak projections are highlighted in Figure 4D.4 above and the monthly forecast of peaks is available in Section 7, Attachment 6.1, Forecasting Data Sets.

Model Performance and Analysis

[170-IAC 4-7-5(a)(5)] [170-IAC 4-7-5(a)(7)] [170-IAC 4-7-5(a)(4)]

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

During forecast development a number of models are analyzed at the rate level. The adjusted R-squared statistic, Mean Absolute Percent Error ("MAPE"), the Durbin-Watson statistic, and reasonableness of each model to IPL are statistically evaluated. The IPL Forecasting group targets adjusted R-squared values better than 90%; this is accomplished in nearly all cases. Further, MAPE needs to be less than 2% and the Durbin-Watson statistic is targeted around 2.0. IPL considers independent variables with T-statistics of at least 2.0 acceptable. This judgment is somewhat subjective and dependent upon the implied importance of the variable. The other statistical measures considered are discussed in Section 7, Confidential Attachment 6.10, Forecasting Data Sets.

"Out of Sample Testing" is another methodology that IPL uses to gauge model performance. This methodology involves withholding a year of history from the model and then assessing how well the model is able to predict previous historic results.

Occasionally, a model that performs well from a statistical standpoint may not seem reasonable when further inspected. Excessive specification of independent variables is one cause of this situation. The investigation of rates of change between recent history and model-generated predictions can identify models that are statistically valid yet unreasonable. When disagreement between a model and common sense inspection arises, additional investigation and/or specification are required. (Recent history must be weather-corrected to allow for meaningful comparisons.) Models of individual rates, after undergoing comprehensive review, are summed to create a proposed forecast. The proposed forecast is then evaluated against aggregated weather-adjusted history as a final test before the forecast is recommended.

IPL uses different methodologies to obtain weather-normalized energy sales and demand. Energy sales are normalized to the most recent 30-year averages of HDDs and CDDs. Demand is normalized to the historical average of the peak producing weather conditions. One method of obtaining weather-corrected energy sales or demand is to re-run the models as simulations with normal weather substituted for actual weather. The difference between predicted energy sales or demand (actual weather) and simulated energy sales or demand (normal weather) is the amount the actual energy sales or demand should be adjusted to give normalized energy sales or demand. Another method is to take the difference between actual weather and normal weather and multiply it by an appropriate weather coefficient for the given conditions. This adjustment is the amount the actual energy sales or demand should be adjusted by to give normalized energy sales or demand. The weather coefficient is obtained by analyzing the current daily response to weather. In effect, this allows behavior changes that may exist compared to more historical approaches in long-term models.

Evaluation of the variance of energy sales and peak demand is looked at each month after weather adjustments have been completed. IPL's forecasting staff uses this information to consider model performance. As long as monthly variance moves reasonably with current "knowns" like economic factors and/or weather, a conditional approval supports the forecast.

However, should variance move contrary to “knowns,” investigation of possible bias and other elements are undertaken. A similar determination, but with greater detail is made at year-end. Actual and weather-adjusted results are compared to the forecasted values generated each of the previous five years. This is done with respect to energy sales at the class level, namely residential, small C&I, and large C&I. Summer peak and winter peak, both actual and weather-adjusted, are reviewed in similar fashion.

The Mean Percent Error (MPE) is used to evaluate overall forecast performance after the fact. Two interesting comparisons that gauge IPL’s forecasting ability are those that compare weather-adjusted annual GWH sales and weather-adjusted summer peak to their respective forecasts. IPL’s one-year-out energy forecast, as measured by MPE, is on average, within 1.7% of weather-adjusted sales. The summer MPE peak forecast averages 2.4%. IPL targets a one-year forecast error of less than 2%. Occasionally, rapidly changing external conditions, such as the extreme winter of 2013-14, can cause fluctuations that exceed this bandwidth. However, reviewing forecast updates on a quarterly basis will allow IPL to make both tactical adjustments in the short-term and initiate additional scenario analyses in the long term. Figures 4D.7 and 4D.8 highlight IPL’s overall retail energy sales and summer peak demands forecast performance, respectively, for the last 10 years. The remainder of the forecast error analyses, at the class level, may be found in the previously mentioned Section 7, Attachment 6.11, Forecasting Data Sets.

Figure 4D.7 – Forecast Error Analysis: Weather-Adjusted Energy Sales vs. Forecasts

ANNUAL "INDIANAPOLIS ONLY" GWH SALES						
Adjusted & Forecasted						
		Forecast Made:				
For	Adjusted	One	Two	Three	Four	Five
	Sales *	Year Ago	Years Ago	Years Ago	Years Ago	Years Ago
2003	14,543 920	14,561.734	15,077.845	15,143.833	15,385.066	15,346.251
		0.1%	3.7%	4.1%	5.8%	5.5%
2004	14,759.085	14,588.136	14,767.804	15,327.185	15,446.414	15,756.329
		-1.2%	0.1%	3.8%	4.7%	6.8%
2005	14,928 377	14,917.100	14,809.058	14,966.217	15,620.768	15,752.324
		-0.1%	-0.8%	0.3%	4.6%	5.5%
2006	14,959 551	15,221.281	15,164.506	14,996.604	15,153.834	15,938.745
		1.7%	1.4%	0.2%	1.3%	6.5%
2007	14,971.610	15,255.687	15,452.281	15,408.373	15,157.356	15,364.855
		1.9%	3.2%	2.9%	1.2%	2.6%
2008	14,956 362	15,264.979	15,427.470	15,702.410	15,620.741	15,334.846
		2.1%	3.1%	5.0%	4.4%	2.5%
2009	14,296 266	15,208.790	15,472.539	15,612.025	15,932.337	15,838.873
		6.4%	8.2%	9.2%	11.4%	10.8%
2010	14,120.637	14,287.148	15,356.932	15,702.517	15,817.438	16,173.497
		1.2%	8.8%	11.2%	12.0%	14.5%
2011	14,010.057	14,172.293	14,420.894	15,463.008	15,832.780	16,020.434
		1.1%	2.8%	9.4%	11.5%	12.5%
2012	14,011 544	14,268.134	14,391.694	14,717.444	15,591.706	16,066.858
		1.8%	2.6%	4.8%	10.1%	12.8%
2013	13,878.196	14,118.020	14,263.240	14,491.940	14,783.227	15,721.475
		1.7%	2.7%	4.2%	6.1%	11.7%
Mean % Error		1.7%	3.7%	5.5%	6.9%	8.6%

Source: IPL

Figure 4D.8 – Forecast Error Analysis: Weather-Adjusted Summer Peak Demands vs. Forecasts

SUMMER PEAK DEMANDS

Adjusted & Forecasted

		Forecast Made:									
For	Adjusted Peak Demand	One Year Ago	Two Years Ago	Three Years Ago	Four Years Ago	Five Years Ago	Six Years Ago	Seven Years Ago	Eight Years Ago	Nine Years Ago	Ten Years Ago
2003	3023	3061	3202	3144	3129	3102	3091	3101	3035	3038	3081
		1.3%	5.9%	4.0%	3.5%	2.6%	2.2%	2.6%	0.4%	0.5%	1.9%
2004	3085	3042	3106	3260	3195	3179	3156	3146	3160	3078	3079
		-1.4%	0.7%	5.7%	3.6%	3.0%	2.3%	2.0%	2.4%	-0.2%	-0.2%
2005	3108	3167	3088	3149	3318	3245	3227	3211	3202	3223	3120
		1.9%	-0.6%	1.3%	6.8%	4.4%	3.8%	3.3%	3.0%	3.7%	0.4%
2006	3165	3110	3203	3132	3191	3376	3297	3275	3267	3259	3288
		-1.7%	1.2%	-1.0%	0.8%	6.7%	4.2%	3.5%	3.2%	3.0%	3.9%
2007	3177	3195	3156	3243	3173	3233	3430	3348	3322	3322	3319
		0.6%	-0.7%	2.1%	-0.1%	1.8%	8.0%	5.4%	4.6%	4.6%	4.5%
2008	3153	3197	3231	3190	3264	3215	3277	3483	3402	3370	3379
		1.4%	2.5%	1.2%	3.5%	2.0%	3.9%	10.5%	7.9%	6.9%	7.2%
2009	2902	3218	3236	3293	3236	3313	3257	3321	3536	3457	3419
		10.9%	11.5%	13.5%	11.5%	14.2%	12.2%	14.4%	21.8%	19.1%	17.8%
2010	2886	3117	3253	3274	3343	3281	3354	3300	3364	3590	3514
		8.0%	12.7%	13.4%	15.8%	13.7%	16.2%	14.3%	16.6%	24.4%	21.8%
2011	2905	2943	3173	3287	3312	3391	3327	3395	3344	3408	3644
		1.3%	8.4%	11.6%	12.3%	14.3%	12.7%	14.4%	13.1%	14.7%	20.3%
2012	2822	2938	3001	3253	3320	3350	3445	3372	3429	3388	3453
		4.0%	6.0%	13.3%	15.0%	15.8%	18.1%	16.3%	17.7%	16.7%	18.3%
2013	2839	2928	2975	3047	3311	3352	3388	3489	3418	3484	3432
		3.0%	4.5%	6.8%	14.2%	15.3%	16.2%	18.6%	16.9%	18.5%	17.3%
Mean % Error		2.7%	4.7%	6.5%	7.9%	8.5%	9.1%	9.6%	9.8%	10.2%	10.3%

Source: IPL

IPL Fuel Planning

[170-IAC 4-7-4(b)(7)]

IPL procures and manages a reliable supply of fuel for its generating units at the lowest long-term cost reasonably possible, consistent with maintaining low long-term busbar cost and compliance with all environmental requirements and/or guidelines. Busbar costs reflect those needed to produce a kilowatt of energy to the transmission grid.

IPL seeks competitive prices for coal through the use of the solicitation and negotiation process. IPL considers all material factors, including, but not limited to, (a) availability of supply from qualified suppliers, (b) current inventory levels, (c) forecast of fuel usage, (d) market conditions and other factors affecting price and availability, and (e) existing and anticipated environmental standards. IPL prepares long-term projections of fuel purchased, annual inventory levels, quality and delivered cost for each plant.

For the coal-fired units, IPL maintains coal inventory at levels sufficient to ensure service reliability, to provide flexibility in responding to known and anticipated changes in conditions, and to avoid risks due to unforeseen circumstances. Inventory targets are established based upon forecasted usage, deliverability and quality of the required fuel to each unit, the position of the unit in the dispatch order, risk of market supply-demand imbalance, and the ability to conduct quick market transactions. The general level of inventory throughout the year is adjusted to meet anticipated conditions (i.e., summer/winter peak load, transportation outages, unit outages, fuel unloading system outages, etc.).

Natural gas (“NG”) is currently purchased on a daily basis as required based on availability and pricing from several suppliers for its NG fired units. IPL’s existing natural gas units have run intermittently which did not justify the need for contracts with fixed demand charges. As a larger portion of its generation will move to NG, IPL recently negotiated NG contracts. NG procurement includes commodity pricing, transportation and delivery components for the new Eagle Valley CCGT and planned refueled HSS units IPL will negotiate commodity pricing prior to plant start-ups expected in late 2015 and 2016. IPL has secured firm delivery as well as no-notice and park/loan services which are used for unexpected unit starts & stops to mitigate fuel availability risks. IPL maintains firm transportation to liquid supply zones for the new Eagle Valley CCGT unit which can also serve the Harding Street units. As generating units are refueled to NG, IPL will contract for additional firm transportation as necessary. Since the Georgetown units are used for peaking needs only, firm NG contracts are not cost-effective. IPL contracts with Citizens Gas for firm redelivery and balancing services to the generating units located at the Harding Street and Georgetown plants.

Fuel Price Forecasting and Methodology

[170-IAC 4-7-4(b)(2)] [170-IAC 4-7-6(a)(3)]

The fuel forecasts used in the IPL 2014 IRP modeling are based on Ventyx’s “Midwest Fall 2013 Power Reference Case, Electricity and Fuel Price Outlook”. These fuel forecasts and their related explanations also appear in Ventyx’s “2014 Integrated Resource Plan Modeling Summary”, dated October 13, 2014. See Section 7, Confidential Attachment 5.1, Ventyx IPL IRP Modeling Summary for additional details.

A forecast of average annual fuel costs by IPL generating unit is found in Figure 4D.9.

Confidential Figure 4D.9 – IPL Average Annual Fuel Forecast per Generating Unit (Nominal $/MMBtu)

	Petersburg 1-4	Eagle Valley 3-6	Harding Street 5&6	Harding Street 7	Eagle Valley CCGT	Harding Street Natural Gas Units
2015	[redacted]					
2016	[redacted]					
2017	[redacted]					
2018	[redacted]					
2019	[redacted]					
2020	[redacted]					
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					
2026	[redacted]					
2027	[redacted]					
2028	[redacted]					
2029	[redacted]					
2030	[redacted]					
2031	[redacted]					
2032	[redacted]					
2033	[redacted]					
2034	[redacted]					

**Individual Unit Natural Gas prices will vary slightly due to differing delivery charges.*

Source: IPL

Market Transactions

IPL offers all of its generating resources into the MISO energy market and IPL's load is bid into the MISO energy market. Therefore, IPL has no scheduled power import and export transactions, neither firm nor non-firm.

Section 5. SHORT-TERM ACTION PLAN

[170-IAC 4-7-9(1)(A)]

As suggested in the revised 170 IAC 4-7-9, IPL has included a comparison of the last IRP short-term action plan to what actions actually transpired, a summary of actions planned for the next three years (3) including a schedule and budgetary costs as well as a description of its Preferred Resource Portfolio.

Comparison to Last IRP

[170-IAC 4-7-9(4)]

IPL measures its progress and success in relation to the IRP objective by comparison of the previous IRP goals and what actually transgressed. The 2011 IRP short-term action plan was centered on developing cost-effective DSM programs to meet aggressive IURC energy efficiency requirements, complying with strict new EPA rules that had the potential to force early retirements of small coal-fired units, and the need to begin the process of replacing that capacity with new generation, most likely a CCGT.

The majority of the items identified are in the process of being implemented. The IURC DSM targets identified in the 2011 IRP were abolished in May 2014 as a result of legislation, yet IPL expects to be at or near the former IURC DSM targets by the end of 2014. The IURC issued a report of the DSM to the legislature in August 2014 detailing historical accomplishments for all Indiana utilities.

Many actions were taken over the past three years as a result of EPA rules including significant changes to existing generation as described below. In addition, several autotransformers, transmission lines and substation breakers identified in the 2011 short-term action plans were upgraded. See Figure 5.1 below for details on the Company's 2011 IRP objectives and implementation status.

Figure 5.1 – IPL 2011 IRP Objectives and Implementation

2011 Objectives	Implementation as of October 2014	IURC Cause No.
Retire the six (6) small unscrubbed coal-fired units by 2016 (EV Units 3-6 and HSS 5 and 6)	• Eagle Valley Units 3 through 6 will be retired by April 16, 2016 • Harding Street Station Units 5 and 6 will be refueled to natural gas	• N/A • 44339
Retire four (4) oil-fired units by 2015 (HSS Units 3 and 4 and EV Units 1 and 2)	• In 2013, IPL retired the four oil-fired units (HSS Units 3 and 4 and EV 1 and 2) mentioned along with HSS GT 3	• N/A
Retrofit "Big 5" to comply with EPA MATS regulation (Pete 1 through 4 and HSS 7)	• IPL received IURC approval to proceed to retrofit Petersburg units and construction is underway • IPL has sought approval to refuel HSS Unit 7 to natural gas	• 44242 • 44540
Meet IURC established DSM targets (Cause No. 42693)	• IPL expects to be at or near cumulative targets at the end of 2014. IURC targets have been suspended with the passage of SEA 340. IPL will continue to offer cost-effective DSM, including its proposed 2015/16 Plan proposed to the IURC.	• 44497
Select and implement preferred resource to replace retirements	• IPL received approval to construct 644 to 685 MW[48] EV CCGT (Cause No. 44339)	• 44339
Reduce capacity exposure resulting from IPL shortage in Planning Years 2015-2016 and 2016-2017	• IPL has purchased 100 MWs of Capacity for the two stated planning periods and nears completion of an agreement for an additional 200 MW for PY 2016-2017 • IPL achieved a successful FERC wavier to mitigate exposure from the "6 week" gap • Implemented operational enhancements to increase the Unforced Capacity on existing units • Achieved capacity credit for the Conservation Voltage Reduction program	• N/A
Complete Distributed Automation and Advanced Metering Infrastructure Projects	• Projects have been completed and are fully operational	• N/A

Source: IPL

48 IPL is constructing a 671 MW CCGT.

2014 Short Term Action Plan

Environmental

IPL's short-term action plan focuses on compliance with the changing environmental landscape and maintaining the viability of IPL's base load generating units. IPL is currently in the process of installing MATS controls on the Petersburg coal-fired units as shown above.

Additionally, IPL is preparing for compliance with new National Pollution Discharge Elimination System ("NPDES") permit limitations. On August 28, 2012, the IDEM issued NPDES permit renewals to Petersburg and Harding Street. These permits contain new Water Quality Based Effluent Limits ("WQBELs") and Technology-Based Effluent Limits ("TBELs") for the regulated facility NPDES discharges with a compliance date of October 1, 2015 for the new WQBELs. IPL sought and received approval to extend the compliance deadline to September 29, 2017 through Agreed Orders from IDEM. The NPDES permits limit several pollutants, but the new mercury and selenium limits drive the need for additional wastewater treatment technologies at Petersburg and Harding Street. IPL determined that installation of the necessary wastewater treatment technologies and other potential future environmental requirements in addition to the necessary Mercury and Air Toxic Standard (MATS) controls described in IPL's case-in-chief Cause No. 44242 was not the reasonable least cost plan for HSS. Instead, IPL is currently proposing to refuel HSS Unit 7 to operate on natural gas which reduces the cost to comply with environmental regulations and reduces the impact on the environment.

Review of the impact of new air, water, and waste regulations is ongoing as these regulations are still being developed. IPL will continue to evaluate its compliance options as the requirements become more defined. Aside from MATS and NPDES implications, this IRP represents no additional technology investments or Operation and Maintenance ("O&M") costs associated with potential new air, water, and waste regulations.

Demand Side Management

The IPL short-term action plan (2015-2017 Action Plan) for demand side management ("DSM") was filed and approval is currently pending before the IURC in Cause No. 44497. This proceeding specifically seeks approval of DSM programs and budgets for 2015 and 2016. The 2015-2017 Action Plan was based on an update of the Market Potential Study that was completed in 2012. In 2012 IPL, in collaboration with Citizens Energy and each respective Oversight Board retained the consulting firm EnerNOC (now Applied Energy Group or "AEG")[49] to complete a Market Potential Study ("MPS") and Action Plan for the period 2014-2017. Since the completion of the 2012 MPS and resulting Action Plan, Senate Enrolled Act 340 ("SEA 340") was passed into law, significantly changing the structure of DSM in Indiana. IPL

[49] The EnerNOC resource planning group, including all the principals who had worked on the 2012 MPS, was acquired by Applied Energy Group in the 2nd Quarter of 2014. Therefore references to EnerNOC have generally been changed to AEG.

re-engaged AEG to update its 2015-2017 Action Plan to account for the elimination of IURC annual savings targets and the opt-out provision of large customers and to identify cost-effective achievable DSM potential in the 2015-2017 timeframe.

The Action Plan was adjusted to reflect decreased savings projections by approximately 20% compared to savings projections in IPL's 2014 DSM Plan.

Figure 5.2 – DSM Annual Savings Projections

Program	2014 Annual Savings Projection (MWh)	Average 2015-2017 Annual Savings Projection (MWh)	% Reduction
Business Prescriptive	98,636	78,813	(20%)

Source: IPL

The three year plan in Cause No. 44497 covers the years 2015-2017. Although cost and savings information was developed and presented for 3 years, IPL is only seeking spending approval to deliver the programs for the first 2 years (2015-2016) as listed below. If approved, IPL will continue to offer a broad range of cost effective programs to our customers as shown in Figure 5.3. For more information, please see Section 4B.

Figure 5.3 – DSM Programs Proposed in Cause No. 44497

Programs
Residential Lighting
Residential Income Qualified Weatherization
Residential Air Conditioning Load Management
Residential Multi Family Direct Install
Residential Home Energy Assessment
Residential School Kit
Residential Online Energy Assessment
Residential Appliance Recycling
Residential Peer Comparison Reports
Business Energy Incentives - Prescriptive
Business Energy Incentives – Custom
Small Business Direct Install
Business Air Conditioning Load Management

Source: IPL

IPL forecasted twenty (20) years of DSM savings that are included in the load forecast. Future programs will be developed for the balance of the IRP period and presented in subsequent IURC proceedings. The twenty year forecast is provided in Section 7, Attachment 4.7, DSM Supporting Documents.

In addition, IPL entered into a settlement agreement with the OUCC in the BlueIndy case (IURC Cause No. 44478) which includes three potential new DSM programs: LED Energy Efficient Streetlighting Program, assessing customer strategic energy management (ISO 50001 or similar program), and determining the potential feasibility of using the BlueIndy electric vehicle batteries to provide electricity back to the IPL grid as a demand response resource If approved by the Commission, IPL will move forward to plan specific details in the near future.

Transmission

IPL's has studied and is evaluating the need for transmission and substation projects for retirement of generation connected to the IPL 138 kV system to ensure deliverability of power into the IPL load zone. These projects include the installation of new 345 kV breakers, autotransformers, and 138 kV capacitor banks to improve power import capability from the 345 kV system to load centers on the 138 kV system. Several projects associated with the new CCGT will be completed in 2015 and 2016. In addition, IPL plans to install a Static VAR System (SVS) to provide dynamic voltage and VAR support. See Section 4C and Section 7 – Confidential Attachment 1.3 for detailed project information.

Distribution

IPL has completed its distribution automation ("DA") and Advanced Metering Infrastructure ("AMI") plans funded in part by a Smart Grid Investment Grant ("SGIG") awarded by the U.S. Department of Energy ("DOE") as described in section 4. These assets will be optimized for continued service restoration improvements, to connect additional solar distributed generation facilities of approximately 30 MW, and to utilize the conservation voltage reduction ("CVR") program to reduce demand by between 20 and 40 MW during peak conditions. In addition, data collected will be mined for asset management improvements to complete condition based maintenance and replacements. Estimated expenses are allocated in the capital budget process and do not exceed average annual expenditures; therefore they are not specifically highlighted in the IRP.

Research & Development/Technology Applications

IPL continually evaluates emerging technologies, new applications of technologies and contemporary methods to improve operational excellence, identify future business opportunities and enhance long-term planning. Specifically, (1) energy storage, (2) enhanced combustion turbine output options, (3) the expansion of electric transportation, and (4) utilizing smart grid assets are included as part of these efforts.

(1) IPL is investigating the possibility of installing a Battery Energy Storage System ("BESS") within its grid to provide ancillary services. This could be up to a 20 MW facility located on the IPL 138 kV transmission system, which will also facilitate local

stakeholder education. See Section 2, Changing Business Landscapes, for more information about the potential BESS installation.

(2) IPL considers efficiency improvements that may provide additional generating capacity such as a technique known as "fogging" whereby inlet air is cooled to increase gas turbine outputs. Analysis is underway, therefore, no specific incremental capacity in terms of MWs are included in the preferred resource portfolio.

(3) IPL proposed expanding local electric transportation infrastructure in its proceeding before the IURC in 2014. If approved, this project will support the first all-electric car-sharing program in the U.S. through the installation of up to 1,000 Electric Vehicle Supply Equipment ("EVSE") units at approximately 200 locations throughout the IPL service territory. The project is expected to begin later this year and be completed in mid-2016.

(4) IPL will continue to utilize smart grid system assets to support its Conservation Voltage Reduction ("CVR") program. Two-way communicating devices at distribution substations and capacitor bank locations allow IPL to remotely lower the system voltage incrementally to reduce peak demand. The voltage levels on the feeders and at Advanced Metering Infrastructure ("AMI") meters are monitored to ensure service voltage limits are maintained. In addition, IPL plans to leverage the AMI assets for power quality monitoring overall and future energy management possibilities for inclusion in DSM programs.

Preferred Portfolio

Subsequent to the 2011 IRP, as mentioned above, IPL received approval to construct a 644 to 685 MW[50] Eagle Valley CCGT (IURC Cause No. 44339). Once in-service, this approval along with IPL's other current generation will allow IPL to meet its peak demand until other unit retirements are necessary. Therefore, IPL's preferred portfolio includes no additional generation in the time horizon of the short-term action plan, extending out until the anticipated retirement of Petersburg 1 along with Harding Street Units 5 through 7 in the early 2030's. The determination and additional details surrounding IPL's preferred portfolio can be found in Section 4 - Integration. Significant changes, comprising the reasonable least cost plan, will be made to IPL's current coal-fired fleet to meet recent environmental requirements as described below.

Existing Generation

Environmental requirements, specifically the Mercury and Air Toxics rule ("MATS") and the National Pollutant Discharge Elimination System ("NPDES") along with potential future environmental regulations, significantly impacted the evaluation process of the six unscrubbed coal-fired units and continue to have a large impact on IPL's larger coal fleet. Eagle Valley coal Units 3 through 6 are nearing the end of their useful lives, making future investments for EPA

[50] IPL is constructing a 671 MW CCGT.

compliance uneconomical. These units will be retired to coincide with the MATS compliance date in April 2016. To maintain generation to serve load, IPL requested and received approval (Cause No. 44339) to construct a 644 to 685 MW[3] CCGT, which is projected to be in-service by April 2017 as mentioned above.

Harding Street Station Units 5 and 6 represent the other two unscrubbed units in IPL's fleet. Due to the close vicinity to load, these units provide a large reliability benefit to IPL's system. Based on reliability and economic factors in the evaluation, IPL determined refueling HSS Units 5 and 6 - along with HSS Unit 7 – to natural gas in 2016 is the reasonable least cost plan.

Refueling HSS Units 5 through 7 and the addition of the 671 MW Eagle Valley CCGT allows IPL to diversify its portfolio in addition to providing economic energy solutions to its customers. Additionally, IPL's resource plan recognizes the value and reliability offered by its four coal-fired units located in Petersburg. Additional environmental compliance investments controls on these units continue to be cost-effective and necessary over the next two to three years.

Capacity Needs (2015-2017)

Historically, IPL has relied on short-term capacity markets for up to 300 MW of its capacity requirements. However, for the period 2015 to 2016, IPL will be facing additional challenges as MISO capacity prices continue to rise and retirements increase to comply with new EPA regulations. As discussed above, IPL will be retiring Eagle Valley coal-fired units 3-6 by April 16, 2016, six weeks before the end of the MISO Planning Year ("PY") 2015-2016. Under MISO's current resource adequacy requirements, a capacity resource that clears a planning reserve auction must be available during the entire commitment period, otherwise replacement capacity from the same Load Resource Zone ("LRZ") must be secured to avoid compliance penalties. On June 20, 2014, IPL submitted a request to FERC to waive the replacement requirement needed during the stated 6 week span. This request was granted by FERC on October 15, 2014, eliminating the need to replace capacity during that time span and avoiding unnecessary costs for IPL customers.

To mitigate the MISO Planning Resource Auction price volatility risk, IPL has bilaterally purchased 100 MWs of Zone 6 Zonal Resource Credits at a fixed and known price for the PY 2015-2016 resulting in a minimal net capacity requirement. For PY 2016-2017, IPL has purchased 100 MWs of Zone 6 Zonal Resource Credits at a fixed and known price and nears completion of an agreement for an additional 200 MW. This results in a net capacity requirement ranging from 50 to 100 MW.

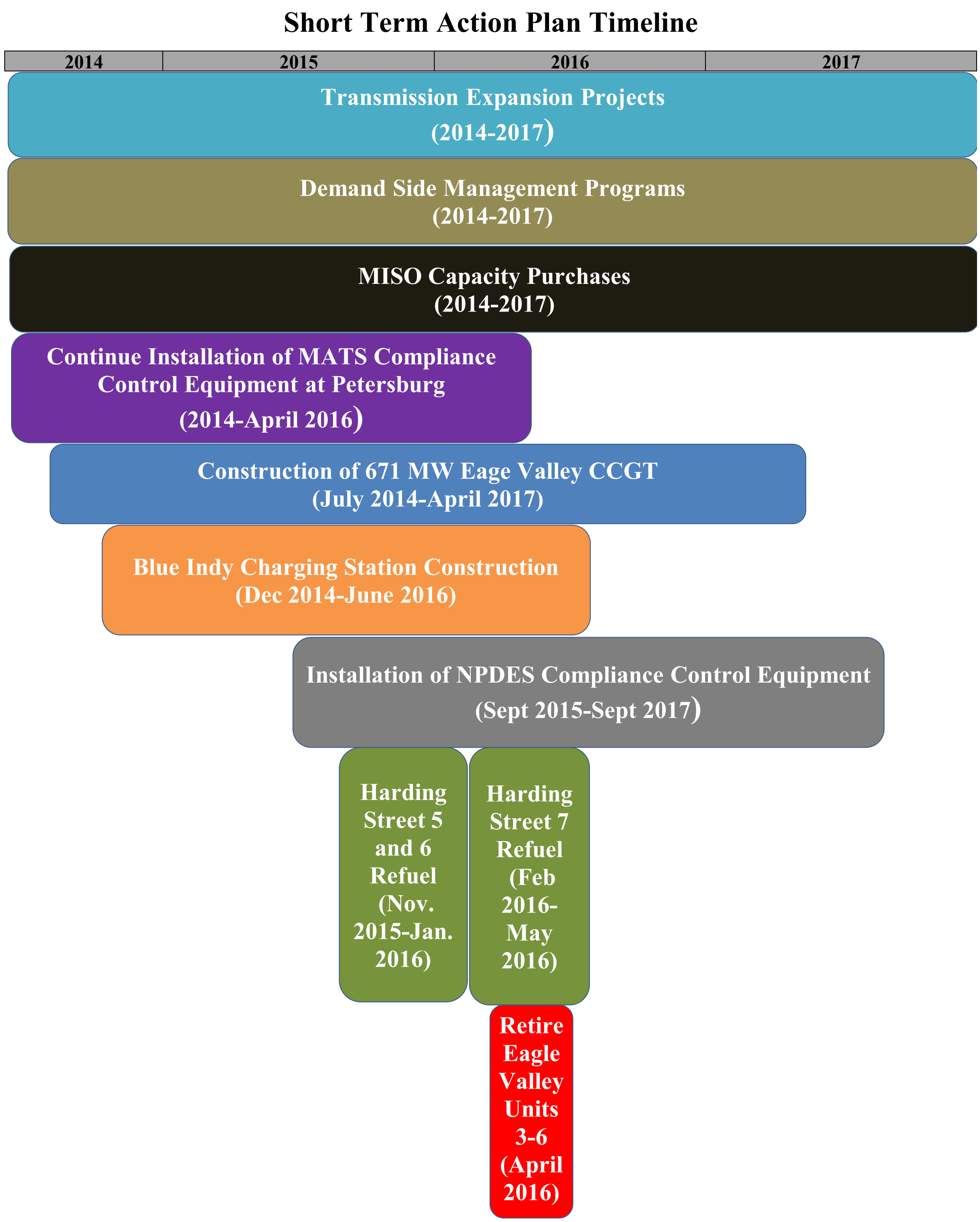
IPL will continue to evaluate the purchase of additional capacity to meet the difference between its actual Planning Reserve Margin Requirement and secured resources with bilateral purchases or sales, auction purchases or sales, additional demand response, or other resources. Starting in Planning Year 2017-2018, with the addition of the Eagle Valley CCGT, IPL projects that its resources will exceed its MISO Planning Reserve Margin Requirement for 2017-2018 by 240 MWs which it plans to optimize in the capacity market.

2014 Short Term Action Plan Summary

[170-IAC 4-7-9(1)(B)] [170-IAC 4-7-9(2)] [170-IAC 4-7-9(3)]

This short-term planning period focuses on managing the impacts of implementing the recommendations that resulted from the 2011 IRP, including meeting reliability needs in 2015 and beyond through transmission system upgrades during the "gap year" of June 2016 through May 2017 when new and refueled generation resources will not be available. The following recommendations are in the process of being implemented. The short-term action plan covering 2015 through 2017 identifies the initial steps toward IPL's longer-term resource strategy as shown below in Figures 5.4 and 5.5, which include a timeline of the projects mentioned above and their projected costs.

Figure 5.4 – Short Term Action Plan Timeline



Source: IPL

Figure 5.5 – Short Term Action Plan Current Capital and DSM Cost Estimates

Project	Timing	Current Estimated Cost[51]
MATS[52]	2014-2016	$460M
Eagle Valley 671 MW CCGT	2014-2017	$590M
Harding Street Units 5&6 Refuel	2015-2016	$36M
Harding Street Unit 7 Refuel[53]	2015-2016	$134M
Waste Water Compliance (NPDES)	2015-2017	$258M
Transmission Expansion	2014-2017	$100M-$120M
MISO Capacity Purchases	2015-2017	$10M-$15M
Demand Side Management Programs	2015-2016	$67M
Blue Indy-Electric Vehicle Project	2014-2016	$16M
Total Costs		$1,671M-$1,696M

Source: IPL

IPL will monitor the progression of the above action items to ensure they are completed within the budgeted costs and in a timely manner. Consistent with business operations related to major projects, IPL will regularly review progress and success in relation to these IRP objectives. In addition, subsequent IRPs will include a comparison of these short term IRP goals to what actually transpires in the future.

[51] These costs do not include O&M, carrying charges, or AFUDC.
[52] These reflect current projections based on the refuel of HSS Unit 7.
[53] These include estimated coal pond and ash pond closure costs.

Section 6. ACRONYMS

Acronym	Reference
3-Year DSM Plan	IPL's 2015-2017 Demand Side Management Plan proposed in Cause No. 44497
AC	Alternating current
ACEEE	American Council for an Energy Efficient Economy
ACESA	American Clean Energy and Security Act of 2009
ACI	Activated carbon injection
ACLM	Air-Conditioning Load Management
AEG	Applied Energy Group
AEP	American Electric Power
AFUDC	Allowance for Funds Used During Construction
AG	Indiana Office of the Attorney General
AHRI	Air Conditioning, Heating & Refrigeration Institute
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ARRA	American Recovery and Reinvestment Act of 2009
ASM	Ancillary Services Market
ATC	Available Transmission Capability
BA	Balancing Authority
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BESS	Battery Energy Storage System
C&I	Commercial and industrial
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CAGR	Compound annual growth rate
CAIR	Clean Air Interstate Rule
CBD	Central Business District
CCGT	Combined cycle gas turbine
CCOFA	Closed-Coupled Overfire Air
CCR	Coal Combustion Residuals
CCS	Carbon capture and sequestration
CCT	Clean coal technology
CDD	Cooling degree days
CEM	Customer Energy Management System Program

Acronym	Reference
CESQG	Conditionally exempt small quantity generator
CFL	Compact Fluorescent Light
CGS	Cogeneration Service
CIP	Critical Infrastructure Protection
CISSP	Certified Information Systems Security Protocol
CO_2	Carbon dioxide
CONE	Cost of New Entry
CoolCents®	IPL’s Air Conditioning Load Management Program
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
CT	Combustion turbine
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DA	Distribution Automation
DOE	U.S. Department of Energy
DRWG	Demand Response Working Group
dSCADA	Distribution SCADA
DSI	Dry sorbent injection
DSM	Demand Side Management
DSMCC	Demand Side Management Coordination Committee
ECM	Electronic Commutated Fan
ECS	Energy Control System
EFORd	Equivalent Forced Outage Rate demand
EIA	U.S. Energy Information Administration
EIS	Enterprise Information Services
ELG	National effluent limitation guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ER	Energy Resource
ES	ENERGY STAR®
ESP	Electrostatic precipitator
EV	Electric Vehicles or Eagle Valley Generating Station
FAC	Fuel Adjustment Clause
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FOB	Free On-Board
Fracking	Hydraulic fracturing

Acronym	Reference
GDP	Gross Domestic Product
Georgetown	Georgetown Generating Station
GHG	Greenhouse gas
GID	Gross internal demand
HAPs	Hazardous air pollutants
HDD	Heating degree days
HERS	ENERGY STAR® Home Energy Rater Index
Hg	Mercury
HRSG	Heat recovery steam generator
HSS	Harding Street Generating Station
HVAC	Heating, ventilation and air-conditioning
IDEM	Indiana Department of Environmental Management
IEA	Indiana Energy Association
IEEE	Institute of Electrical and Electronics Engineers
ICAP	Installed Capacity
IGCC	Integrated Gasification Combined Cycle
IMM	Independent Market Monitor
IPL	Indianapolis Power & Light Company
IRP	Integrated Resource Plan
Itron	Itron, Inc.
IURC	Indiana Utility Regulatory Commission
JCSP	Joint Coordinated System Plan
LAER	Lowest Achievable Emission Rate
LMR	Load Modifying Resource
LNB	Low NO_x Burner
LNG	Liquid natural gas
LOLE	Loss of Load Expectation
LQG	Large quantity generator
LSE	Load Serving Entity
LTC	Transformer Load-Tap Changer
MACT	Maximum Achievable Control Technology
MAIFI	Mandatory Average Interruption Frequency Index
MAPE	Mean Absolute Percent Error
MATS	Mercury and Air Toxics Standard
MECT	Module E Capacity Tracking
MGD	Million gallons per day
MISO	Midcontinent Independent Transmission System Operator, Inc.
MOD	Transmission Planning Standards, part of NERC Reliability Standards
MOPR	Minimum Offer Price Requirements

Acronym	Reference
MPE	Mean Percent Error
MPP	Multi-Pollutant Plan
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	MISO Transmission Expansion Plan
MVA	Mega Volt Amplifier
MVP	Multi-Value Projects
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NID	Net internal demand
NIST	National Institute of Standards and Technology
NN	Neutral Net
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen oxide
NPDES	National Pollution Discharge Elimination System
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance costs
OUCC	Office of Utility Consumer Counselor
PC	Pulverized coal
Pete	Petersburg Generating Station
PHEV	Plug-In hybrid electric vehicle
PJM	PJM RTO; "PJM Interconnection"
$PM_{2.5}$	Particulate matter less than 2.5 microns
PPA	Power Purchase Agreement
PRMR	Planning Resource Margin Requirements
PRM_{UCAP}	Planning Reserve Margin on UCAP
PT	Participant cost test
PV	Photovoltaic
PVRR	Present value of revenue requirements
Rate EVP	IPL Tariff: Experimental Service for Electric Vehicles Charging on Public Premises
Rate EVX	IPL Tariff: Experimental Time of Use Service for Electric Vehicles Charging on Customer Premises
Rate REP	IPL Tariff: Renewable Energy Production
Rate SS	IPL Tariff: Small Secondary Service
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RES	Renewable Energy Standards
RFC	Reliability *First* Corporation
RFP	Request For Proposal

Acronym	Reference
RIM	Ratepayer impact measurement
RTO	Regional Transmission Organization
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SFT	Simultaneous Feasibility Study
SGIG	Smart Grid Investment Grant
SIGE	Vectren
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur dioxide
SOFA	Separated Overfire Air
SQG	Small quantity generator
TBEL	Technology based effluent limits
TID	Total internal demand
TOU	Time of use
TPA	Third Party Administrator
TPL	Transmission Planning Standards, part of NERC Reliability Standards
TRC	Total resource cost
TVA	Tennessee Valley Authority
U.S.	United States
UCAP	Unforced Capacity
UCT	Utility cost test
Ultra SCPC	Ultra Supercritical Pulverized Coal
VAR	Reactive Power
Utility MACT	Utility Maximum Achievable Control Technology
WQBEL	Water quality based effluent limits
WTG	Wind turbine generators

Section 7. ATTACHMENTS - SEE VOLUME 2

Confidential Attachment 1.1 (FERC Form 715 Cover Letter) [170-IAC 4-7-4(b)(10)(A)] [170-IAC 4-7-4(b)(10)(B)]

Attachment 1.2 (US DOE IPL Smart Energy Project)

Confidential Attachment 1.3 (Cost of Transmission Expansion Projects) [170-IAC 4-7-6(d)(2)]

Attachment 1.4 (CVR Demand Response Verification)

Attachment 2.1 (2013 IPL System Load) [170-IAC 4-7-4(b)(13)]

Attachment 3.1 (Load Research Narrative) [170-IAC 4-7-4(b)(3)][170-IAC 4-7-5(a)(1)][170-IAC 4-7-5(a)(2)]

Attachment 3.2 (2013 Hourly Load Shape Summary) [170-IAC 4-7-4(b)(3)][170-IAC 4-7-5(a)(1)][170-IAC 4-7-5(a)(2)]

Attachment 4.1 (DSM Case - Cause No. 44497)

Attachment 4.2 (July 1, 2014 DSM Status Report)

Confidential Attachment 4.3 (DSM Future Avoided Costs) [170-IAC 4-7-6(b)(2)]

Attachment 4.4 (Standard DSM Benefit Cost Tests) [170-IAC 4-7-4(b)(12)][170-IAC 4-7-7(b)] [170-IAC 4-7-7(d)(1)]

Attachment 4.5 (DSM Benefit Cost Results) [170-IAC 4-7-4(b)(12)] [170-IAC 4-7-7(b)] [170-IAC 4-7-7(c)]

Attachment 4.6 (DSM 15-17 Costs and Energy and Demand Savings)

Attachment 4.7 (AEG's DSM Forecast) [170-IAC 4-7-6(b)(4)] [170-IAC 4-7-6(b)(5)] [170-IAC 4-7-6(b)(6)] [170-IAC 4-7-6(b)(7)]

Attachment 4.8 (2012 MPS)

Attachment 4.9 (Benefit Cost Test Equations) [170-IAC 4-7-7(d)(2)]

Attachment 4.10 (DSM Per Participant Data) [170-IAC 4-7-6(b)(4)][170-IAC 4-7-6(b)(5)][170-IAC 4-7-6(b)(6)][170-IAC 4-7-6(b)(7)]

Confidential Attachment 5.1 (Ventyx IPL-IRP 2014 Report)

Attachment 6.1 (10 Yr Energy and Peak Forecast) [170-IAC 4-7-4(b)(2)]

Attachment 6.2 (20 Yr High and Low Range Forecast) [170-IAC 4-7-4(b)(2)]

Confidential Attachment 6.3 (End Use Modeling Technique)

Confidential Attachment 6.4 (EIA End Use Data) [170-IAC 4-7-4(b)(2)]

Confidential Attachment 6.5 (Energy - Forecast Drivers) [170-IAC 4-7-4(b)(2)]

Attachment 6.6 (Energy - Input Data Set 1) [170-IAC 4-7-4(b)(2)] [170-IAC 4-7-5(a)(3)]

Attachment 6.7 (Energy - Input Data Set 2) [170-IAC 4-7-4(b)(2)] [170-IAC 4-7-5(a)(3)]

Attachment 6.8 (Energy - Input Data Set 3) [170-IAC 4-7-4(b)(2)] [170-IAC 4-7-5(a)(3)]

Attachment 6.9 (Peak - Forecast Drivers and Input Data) [170-IAC 4-7-4(b)(2)]

Confidential Attachment 6.10 (Model Performance - Statistical Measures)

Attachment 6.11 (Forecast Error Analysis)

Attachment 7.1 (Non-Technical Summary) [170-IAC 4-7-4(a)]

Attachment 8.1 (Rate REP Projects)

Attachment 8.2 (Rate REP Map)

Attachment 9.1 (IRP Public Advisory Meeting Presentations)