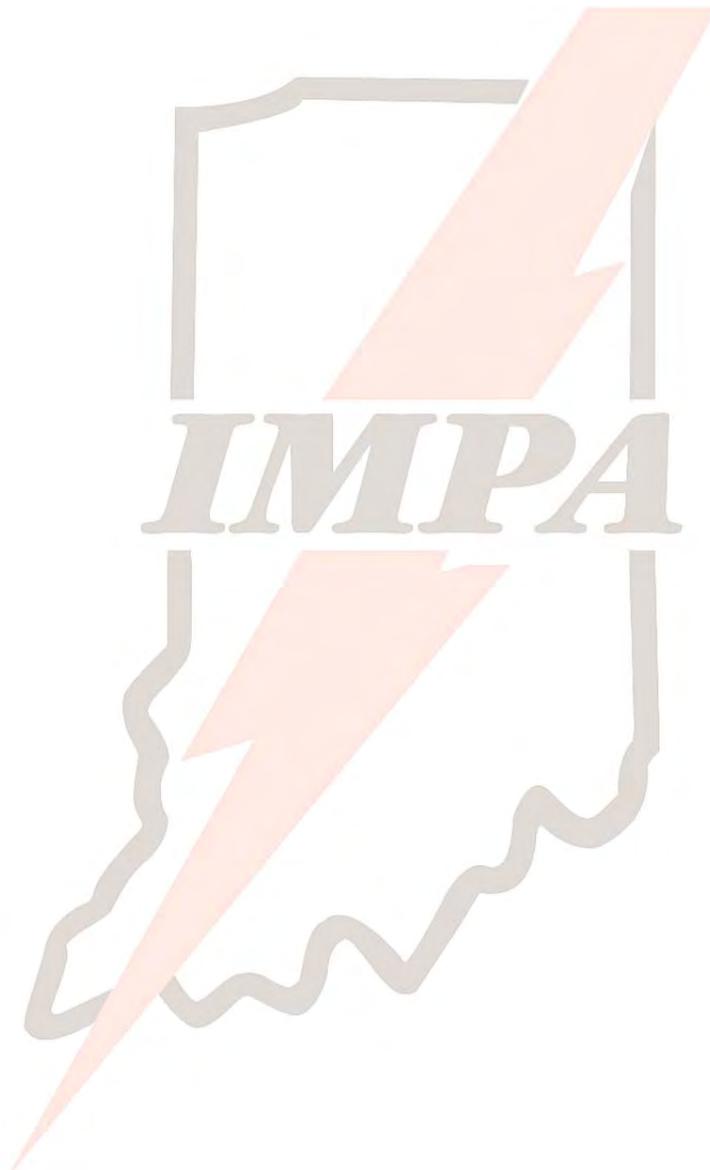# Indiana Municipal Power Agency (IMPA)

2013 Integrated Resource Plan

Date Submitted:
November 1, 2013

Public Version

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Indiana Municipal Power Agency

The opinions expressed in this report are based on Indiana Municipal Power Agency's estimates, judgment and analysis of key factors expected to affect the outcomes of future energy, capacity, and commodity markets and resource decisions. However, the actual operation and results of energy markets may differ from those projected herein.

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1 EXECUTIVE SUMMARY

The Indiana Municipal Power Agency (IMPA) is a wholesale electric utility serving the total electricity requirements of 60 communities under long term power sales contracts. Each of IMPA's 59 members is an Indiana city or town with a municipally owned electric distribution utility. IMPA also serves the Village of Blanchester, Ohio. IMPA regularly reviews its projected loads and resources in order to ensure it is planning to meet its member's long term load requirements in an economical, reliable and environmentally responsible manner. These planning activities are required under IMPA's risk management framework and are necessary to participate in the RTO markets. Pursuant to the requirements of 170 IAC 4-7, IMPA presents its 2013 Integrated Resource Plan (IRP). This report assesses IMPA's options to meet its member's capacity and energy requirements for wholesale service from 2014 through 2033.

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. Both types of resources are compared based on their ability to meet the utility's objectives. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing economic and regulatory conditions.

In 2013, IMPA's coincident peak demand for its 60 communities was 1,187 MW, and the annual energy requirements during 2012 were 6,097,000 MWh. IMPA projects that its peak and energy will grow at approximately 1% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. Since the last IRP was filed, IMPA has added six (6) new members.

IMPA currently uses both supply and demand-side resources to meet its customer peak demand and energy requirements. Current resources include:

- Joint ownership interests in Gibson Station #5, Trimble County Station #1 & #2 and Prairie State Energy Campus #1 and #2;
- Five (5) gas fired combustion turbines owned and operated by IMPA.
- Two (2) gas fired turbines owned by IMPA and operated by Indianapolis Power and Light (IPL);
- Generating capacity owned by four (4) IMPA members;
- Long term power purchases from:
    o Indiana-Michigan Power Company (I&M)
    o Duke Energy Indiana (DEI)
    o Crystal Lake Wind, LLC
- Short term contracts with market participants in MISO and/or PJM;
- Energizing Indiana Statewide Energy Efficiency Program

IMPA's existing resources are diverse in terms of size, fuel type and source, geographic location and vintage. IMPA owns or controls generation in MISO and PJM as well as in the Louisville Gas & Electric/Kentucky Utilities control area. In total, IMPA's generation and contractual resources reside in eight (8) different load zones in Indiana, Illinois, Iowa and Kentucky. This diversity reduces IMPA exposure to forced outages, LMPs, zonal capacity rates and regional fuel costs.

Current demand-side resources include full participation by IMPA in the Energizing Indiana statewide energy efficiency program. IMPA was the only utility in Indiana to voluntarily participate in this program. IMPA participates on behalf of all of its Indiana members. 2012 EM&V verified savings under the Energizing Indiana program were approximately 6.8 MW and 20,564 MWh. In addition to the state program, IMPA offers a demand response tariff, a net metering tariff, energy audits, education and training. In addition, many IMPA members utilize various rate structures aimed at assisting customers in lowering or controlling their energy consumption.

As discussed in the body of this report, IMPA has considered a variety of potential supply and demand-side resources. These are discussed more fully in Section 6. IMPA's analysis has identified a plan that allows it to economically meet its members future load growth while limiting future risks due to unforeseen legal or regulatory outcomes. The description of the modeling and planning process/selection is discussed in Sections 10-13. Based on the analysis discussed in this document, the resource expansion plan is shown below.

Table 1 2013 IRP Expansion Plan – Plan02

	Capacity Losses		Capacity Additions		
Year	MW Lost	Resource	MW Added	Resource	Net MW
2014			3	Solar	3
2015	(24)	G5 reserve/Back-up	3	Solar	(21)
2016	(56)	Member Gen Retirements	185	Advanced CT	128
	(4)	Cost Based PPA Expiration	3	Solar	
2017	(59)	Cost Based PPA Expiration	100	Advanced CC	44
			3	Solar	
2018	(50)	Market Capacity PPA Expiration	3	Solar	(47)
2019			3	Solar	3
2020			3	Solar	3
2021	(9)	Cost Based PPA Expiration			(9)
2022					
2023			100	Advanced CC	100
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
Total	(202)		406		204

IMPA is proceeding with the general plan shown in Plan02. To allow flexibility and take advantage of current market conditions, the Plan may evolve into a version of Plan01 or Plan07, which both have similar underlying build plans over the long-term. These plans are not mutually exclusive, so it is quite possible a hybrid of the plans will ultimately provide the optimal mix of

resources and timing as the costs of the resources becomes clearer.

The following decision tree illustrates the Plan Pursuit strategy:

Figure 1 Plan Pursuit Strategy (2014-2020)
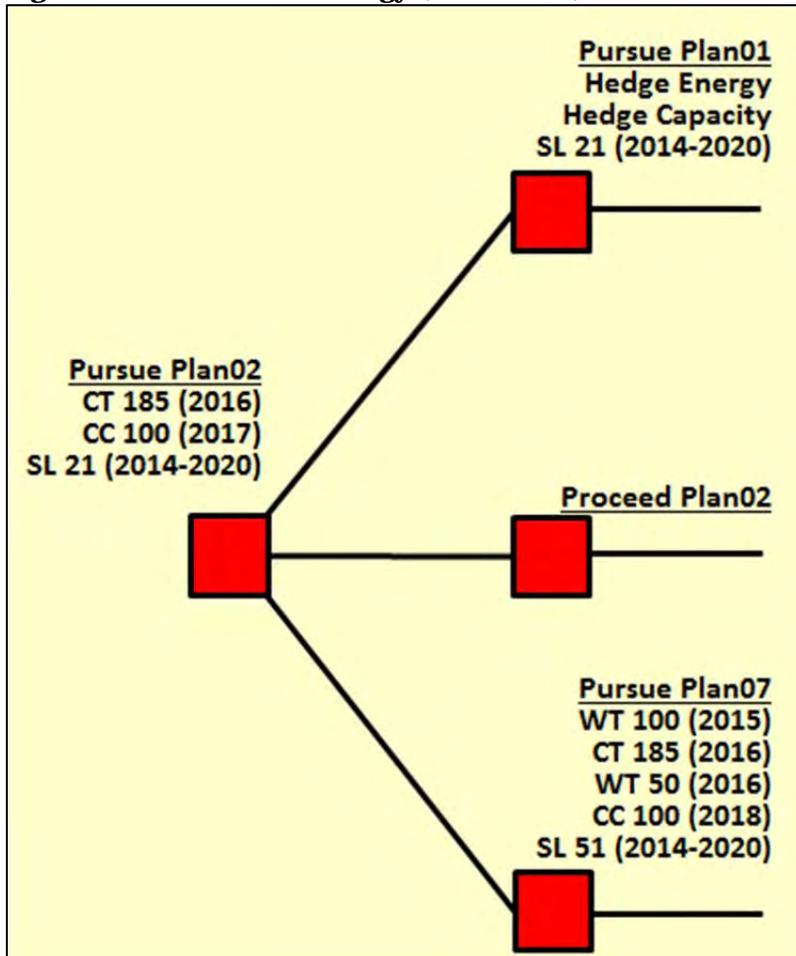
Source: IMPA

Plans 01 and 07 offer unique and distinct alternatives to Plan02 as follows:

1. Plan01 assumes IMPA is able to enter into a market purchase at a lower cost than the build option. This plan would effectively build a virtual CC at a lower cost than IMPA would incur with a PPA or joint ownership of an actual facility. In the stochastic analysis, this plan was consistently the lowest cost plan in the early years of the study. Hedging this position until the 2020-2023 time frame allows IMPA to lock in attractive pricing while letting the regulatory, environmental and economic future shake out.

2. Plan07 is essentially the same as Plan02 except IMPA voluntarily adds additional renewable resources totaling approximately 10% of its energy requirements.   The stochastic analysis shows that this plan performs well in the later years. The reasons are twofold, first, the added renewable sources benefit IMPA in the CO_2 cases through lower emissions costs and second, the positions taken by locking into long term contracts hedge against the market price movements driven by CO_2 legislation.

At this time, IMPA is not proposing the acquisition of any specific resource. IMPA will continue to evaluate resource options matching this plan and bring any firm proposals requiring IURC approval before the Commission at the appropriate time.

1.1 ACTION PLAN

In order to allow flexibility and take advantage of current market conditions, Plan02 may evolve into a version of Plan01 or Plan07, which have similar underlying build plans over the long-term.

IMPA will embark on three simultaneous courses of action to implement this plan, or a hybrid variation thereof.

Plan02
- Begin the process to acquire/design/build/finance an F class style combustion turbine somewhere in the MISO footprint. Potential acquisition methods could include:
  - Self-build
  - Partnership
  - PPA
- Continue development/construction of municipal based solar projects
- Engage known developers on current Combined Cycle projects in the MISO footprint and determine likelihood of project completion

Plan01
- Issue an RFP for the acquisition of long term MISO ZRCs from interested counterparties
- Issue an RFP for the acquisition of long term MISO and PJM physical or financial purchased power swaps from interested counterparties
- Continue development/construction of municipal based solar projects

Plan07
- Begin the process to acquire/design/build/finance an F class style combustion turbine somewhere in the MISO footprint. Potential acquisition methods could include:
  - Self-build
  - Partnership
  - PPA
- Investigate the expanded development/construction of municipal based solar projects
- Engage known developers on current Combined Cycle projects in the MISO footprint and determine likelihood of project completion
- Pursue opportunities for cost effective long-term MISO and PJM Wind PPAs or ownership

Other
- Continue involvement in the Energizing Indiana program through 2014
- Acquire energy efficiency cost/benefit evaluation tools
- Evaluate benefits and costs of continued participation in the Energizing Indiana program compared to a slate of IMPA initiated programs.

2   IMPA OVERVIEW

2.1   INTRODUCTION

Pursuant to the provisions of Indiana Code § 8-1-2.2-1 *et seq.*, IMPA was created in 1980 for the purpose of undertaking the planning, financing, ownership and operation of projects to supply electric power and energy for the present and future needs of the members. IMPA is the full requirements wholesale power provider to its members and customers. While IMPA's customers serve a population in excess of 325,000 people, IMPA has no retail customers itself.   IMPA has entered into separate power sales contracts customers to supply 100% of their electric power and energy requirements. IMPA began serving its members on January 27, 1983.

In addition to increasing its membership/customers from the initial 24 to 60 cities and towns, major milestones in IMPA's history include:

Table 2 Major IMPA Milestones

Date	Milestone
Fall 1982	Acquired an ownership share of Gibson Unit 5
Winter 1983	Began power supply operations to 24 members
Fall 1985	Acquired an ownership share of the Joint Transmission System (JTS)
Spring 1992	Placed Richmond Combustion Turbine Units 1 and 2 into commercial operation
Summer 1992	Placed Anderson Combustion Turbine Units 1 and 2 into commercial operation
Fall 1993	Acquired an ownership share of Trimble County Unit 1
Spring 2004	Placed Anderson Combustion Turbine Unit 3 into commercial operation
Fall 2004	Acquired Units 2 and 3 of the Georgetown Combustion Turbine Station
Fall 2008	Signed Crystal Lake wind energy purchased power agreement
Winter 2011	Placed Trimble County Unit 2 into commercial operation
Summer 2012	Placed Prairie State Unit 1 into commercial operation
Fall 2012	Placed Prairie State Unit 2 into commercial operation

2.2 RECENT ACTIVITIES – KEY EVENTS SINCE LAST IRP

Since IMPA submitted its last Integrated Resource Plan to the IURC on November 1, 2011, the following events have taken place:

- On January 1, 2012, IMPA began participating in the Energizing Indiana statewide energy efficiency program. First year verified program savings were 6.8 MW and 20,564 MWh.

- On February 1, 2012, IMPA began serving the Town of Veedersburg.

- On June 6, 2012, Prairie State Unit #1 was placed in commercial operation.

- On July 1, 2012, IMPA began serving the Town of Coatesville.

- On July 1, 2012, IMPA began serving the Town of Williamsport.

- On October 26, 2012, IMPA closed on the sale of its Power Supply System Refunding Revenue Bonds, 2012 Series A. The purpose of these bonds was to advance refund outstanding bonds at lower interest rates.

- On November 2, 2012, Prairie State Unit #2 was placed in commercial operation.

- On November 1, 2012, IMPA began serving the Town of South Whitley.

- On January 1, 2013, IMPA began serving the Town of Montezuma.

- On January 1, 2013, IMPA began serving the Town of New Ross.

- In January 2013, IMPA purchased the property adjacent to its Carmel, IN headquarters for growth and expansion. Development is continuing on the IMPA campus.

- On May 31, 2013, the IMPA Board of Commissioners approved the development and construction of three solar demonstration projects in locations throughout the state.

- On October 25, 2013, IMPA's board approved the sale of its Power Supply System Revenue Bonds, 2013 Series A. The purpose of these bonds was to fund capital projects on existing assets and advance refund outstanding bonds at lower interest rates.

3 IRP OBJECTIVES AND PROCESS

3.1 IRP RULES (170 IAC 4-7)

The IURC developed guidelines in 170 IAC 4-7-1 *et seq.* for electric utility IRPs in order to assist the IURC in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5. IMPA and seven other utilities across the state of Indiana are subject to the IRP rules. Section 15 of this IRP summarizes the rules, along with an index of IMPA's responses to those rules.

3.2 IMPA IRP OBJECTIVES

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. Both types of resources are compared based on their ability to meet the utility's objectives. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing economic and regulatory conditions.

3.3 IMPA PLANNING CRITERIA

IMPA serves wholesale load in both MISO and PJM and must comply with the resource adequacy requirements of each RTO for its load in that RTO. In its planning process, IMPA utilizes the same UCAP and EFOR method of resource compliance as used in the RTOs. For this IRP, IMPA utilized the most recently available resource planning requirement figures for PJM and MISO. With IMPA's EFOR rates and the combined reliability requirements of PJM and MISO, IMPA's traditionally calculated reserve margin target equates to approximately 15%.

IMPA plans its resources to meet its projected load and does not allow the expansion models to add resources for non-member or speculative sales. IMPA does allow the model to purchase some market capacity in the future, but these are limited to small quantities (<50 MW) and meant to simulate the normal final balancing that takes place in today's RTO capacity markets. This buffer also allows flexibility in the future regarding load uncertainty, energy efficiency, demand response and renewables development.

3.4 IMPA PLANNING PROCESS

Formulating an IRP is a multistep project that utilizes many disciplines including engineering, environmental science, statistics and finance. The basic steps of the IRP process are summarized below, with references to where further information can be found in this document.

1. Evaluation of Existing System - Establishes the basis for future resource planning by identifying the expected future availability of existing supply-side and demand-side resources, including possible upgrades, expansions or retirements of those resources. (Section 4)

2. Long Range Forecast Development - Annually, IMPA develops a 20-year projection of peak demands and annual energy requirements. The load forecast is developed using a time-series, linear regression equation for each load zone. (Section 5)

3. Resource Options and Environmental Compliance – This step involves the selection and screening of various supply-side and demand-side alternatives. Additionally,

transmission service and compliance with future environmental issues are discussed. (Sections 6-8)

4. Evaluation of Resource Alternatives and Resource Optimization – Integrating the alternatives into a common tool used to optimally select and evaluate various scenarios is a key part of the IRP process. IMPA uses a multi-part modeling system consisting of a wholesale market model, a capacity expansion model and a system dispatch and finance model. (Sections 9-12)

5. Sensitivity and Risk Assessment – A crucial part of the IRP process is evaluating how a portfolio performs under various scenarios and how sensitive it is to movements in certain variables. IMPA performs both stochastic sensitivity analysis and certain scenario analyses. (Section 12)

6. Plan Selection – Description of preferred plan and basis for selection. (Section 13)

7. Short Term Action Plan – Description of steps necessary to implement the preferred plan. (Section 14)

4   EXISTING SYSTEM

4.1   IMPA SYSTEM DESCRIPTION

IMPA is a wholesale electric utility serving the total electricity requirements of 60 communities. Each of IMPA's 59 members is an Indiana city or town with a municipally owned electric distribution utility. IMPA also serves the Village of Blanchester, Ohio on a full-requirements contractual basis very similar to its member contracts, except for specific provisions applicable to Indiana municipalities (the most significant being that Blanchester does not have a seat on IMPA's Board of Commissioners). IMPA has no retail customers and no direct communication or other interaction with the member's retail customers, except as specifically requested by the member.

IMPA operates in both the MISO and PJM RTOs. IMPA has load in five IOU load zones and generation resources connected to seven IOU zones within the RTO footprints, plus two resources outside of the RTOs. IMPA's load is divided approximately 2/3 MISO and 1/3 PJM.

Figure 2 IMPA Communities Map
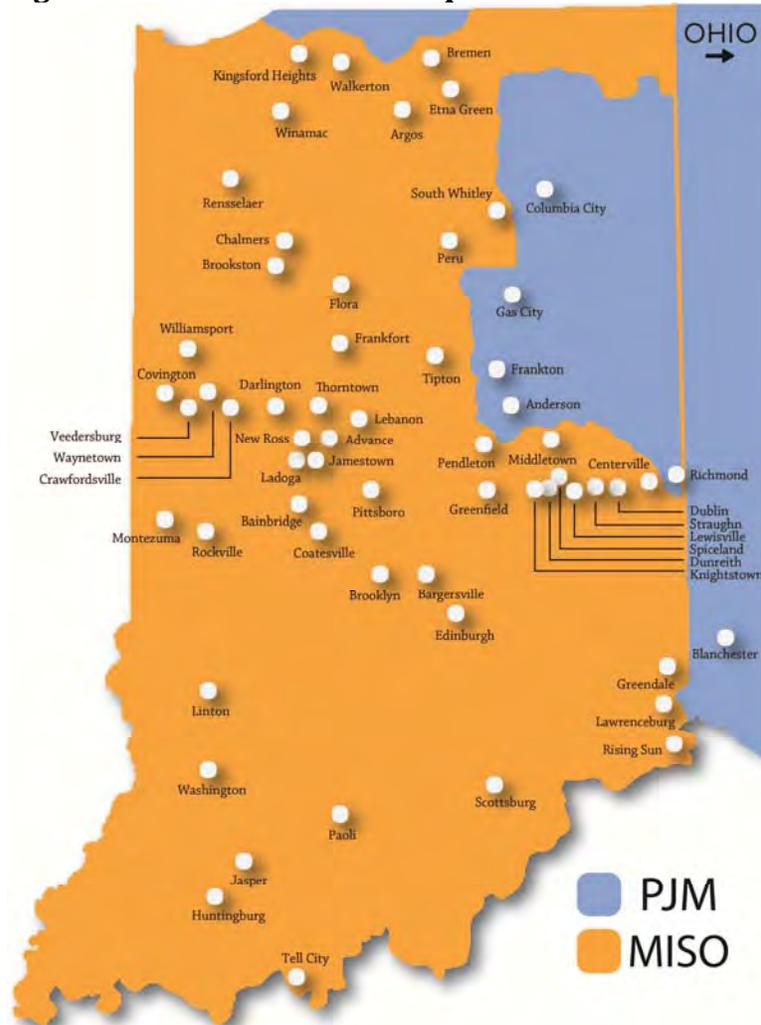
4.2   LOADS AND LOAD GROWTH

IMPA's member and customer communities are located in five different load zones in MISO and PJM. When IMPA began operations in 1983, it served 24 communities. IMPA now serves 60 communities. The following table lists the 60 communities that IMPA serves along with the load zone, RTO in which they are located and the approximate percentage of IMPA's total load.

Table 3 IMPA Communities

RTO	Load Zone	% of Load	Community
MISO	Duke-IN	51%	Advance, Bainbridge, Bargersville, Brooklyn, Centerville, Coatesville, Covington, Crawfordsville, Darlington, Dublin, Dunreith, Edinburgh, Flora, Frankfort, Greendale, Greenfield, Jamestown, Knightstown, Ladoga, Lawrenceburg, Lebanon, Lewisville, Linton, Middletown, Montezuma, New Ross, Paoli, Pendleton, Peru, Pittsboro, Rising Sun, Rockville, Scottsburg, South Whitley, Spiceland, Straughn, Thorntown, Tipton, Veedersburg, Washington, Waynetown, Williamsport
	NIPSCO	7%	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Rensselaer, Walkerton, Winamac
	VECTREN	10%	Huntingburg, Jasper, Tell City
PJM	AEP-IM	31%	Anderson, Columbia City, Frankton, Gas City, Richmond
	Duke-OH	1%	Blanchester, Ohio

In 2013, IMPA's peak demand for its 60 communities was 1,187 MW, and the annual energy requirements during 2012 were 6,097,000 MWh.

Hourly loads are shown in Appendix A and typical annual, monthly, weekly, and daily load shapes for IMPA as a whole are shown in Appendix B. As a wholesale supplier, IMPA does not have the necessary retail load information to draw conclusions concerning disaggregation of load shapes by customer class or appliance.

4.3   EXISTING SUPPLY-SIDE RESOURCES

IMPA currently has a variety of supply-side resources, including: ownership interests in Gibson Unit 5, Trimble County Units 1 and 2, Prairie State Units 1 and 2; seven combustion turbines wholly owned by IMPA; generating capacity owned by four of IMPA's members; long-term firm power purchases from I&M and DEI, as well as short term purchases from various utilities and power marketers in the MISO and PJM energy markets. In 2008, IMPA signed a purchased power agreement for up to 50 MW of wind energy from the Crystal Lake Wind Energy Center in Hancock County, Iowa. The expected renewable energy from this contract will meet approximately 2.5% of IMPA's energy needs. Some of these resources, such as firm power purchases, have contractual limitations that restrict their use to a particular local balancing area or delivery point. Tables summarizing the key characteristics of IMPA's generating units and long term purchased power agreements are shown in Appendices E1 and E2. The resources and contracts are described in more detail on the following pages.

Gibson 5

IMPA has a 24.95% undivided ownership interest in Gibson 5, which it jointly owns with DEI (50.05%) and Wabash Valley Power Association (WVPA) (25.00%). Gibson 5 is a 625-megawatt coal-fired generating facility located in southwestern Indiana. It is equipped with particulate, SO_2 and NO_x removal facilities (SCR) and an SO_3 mitigation process. The boiler has also been retrofitted with low NO_x burners. Fuel supply for Gibson Station is acquired through a number of contracts with different coal suppliers. The coal consists of mostly high sulfur coal sourced from Indiana and Illinois mines. A small amount of low sulfur coal is also purchased. DEI has multiple coal contracts of varying lengths to supply the five units at Gibson Station. Procurement is such that the prompt year's supply is nearly completely hedged while future years are partially contracted two to three years in advance. Coal is delivered by both train and truck. The current targeted stockpile inventory is 45-60 days.

DEI operates Gibson 5 under the Gibson Unit No. 5 Joint Ownership, Participation, Operation and Maintenance Agreement (Gibson 5 Agreement) among DEI, IMPA and WVPA. The Gibson 5 Agreement obligates each owner to pay its respective share of the operating costs of Gibson 5 and entitles each owner to its respective share of the capacity and energy output of Gibson 5. Under a Power Coordination Agreement, IMPA purchases reserve capacity and replacement energy from DEI during forced and maintenance outages of Gibson 5.

Trimble County 1

IMPA has a 12.88% undivided ownership interest in Trimble County 1, which is jointly owned with LG&E (75.00%) and the Illinois Municipal Electric Agency (IMEA) (12.12%). Trimble County 1 is a 514-MW coal-fired unit located in Kentucky on the Ohio River approximately 15 miles from Madison, Indiana. The unit is equipped with particulate, SO_2 and NO_x removal facilities and an SO_3 mitigation process. The boiler burners have been modified to meet the NO_x limits of Phase II of the Acid Rain Program. To date, IMPA's share of the SO_2 and NO_x emissions allowances allocated by EPA and the Kentucky Energy and Environment Cabinet have satisfied IMPA's requirements for such allowances. Trimble County 1 burns high sulfur coal. LG&E purchases coal on a system basis and delivers it on an economic basis to its various power plants. The majority of this coal is from mines in Indiana and Kentucky. All coal is delivered to Trimble County by barge. Due to barge delivery, stockpile inventory levels fluctuate within a targeted 28-49 day level.

LG&E operates Trimble County 1 under a Participation Agreement between LG&E, IMEA and IMPA (Trimble County 1 Agreement). The Trimble County 1 Agreement obligates each owner to pay its respective share of the operating costs of Trimble County 1 and entitles each owner to its respective share of the capacity and energy output of Trimble County 1. Transmission service is provided from the plant to the LGEE-MISO interface.

Trimble County 2

IMPA constructed Trimble County 2 jointly with LG&E and Kentucky Utilities (collectively LG&E) and Illinois Municipal Electric Agency (IMEA). Commercial operation commenced in January 2011. Trimble County 2 is a 750 MW (net) unit with a supercritical, pulverized coal boiler and a steam-electric turbine generator. Unit 2 is equipped with low-NO_x burners, an SCR, a dry electrostatic precipitator, pulse jet fabric filter, wet flue gas desulfurization, and a wet electrostatic precipitator. The coal is eastern bituminous coal (including, potentially, Indiana coal) blended

with western sub-bituminous coal. All coal arrives at the site via barge on the Ohio River. LG&E uses the same procedures for selection and delivery of coal to Trimble County 2 as it uses for Trimble County 1. Trimble County 2 flue gas exhausts through two new flues in the existing site chimney.

The ownership arrangement for Trimble County 2 has the same undivided ownership percentages as for Trimble County 1: LG&E at 75%, IMPA at 12.88% and IMEA at 12.12%. LG&E is acting as operating agent for the owners under a Participation Agreement similar to that used to operate Trimble County #1. Transmission service is provided from the plant to the LGEE-MISO interface.

Prairie State Project

The Prairie State Energy Campus (PSEC) consists of the Prairie State Units #1 & #2, related electric interconnection facilities, the Lively Grove mine, the near-field coal combustion residuals (CCR) disposal facility, and the Jordan Grove CCR facility disposal facility. IMPA is part of a consortium of organizations that collectively direct the Prairie State Generating Company (PSGC) in operating the PSEC. IMPA has a 12.64% interest in the Prairie State Project. Both units began commercial operation in 2012.

Prairie State is in the southwest part of Washington County, Illinois, approximately 40 miles southeast of St. Louis, Missouri. The plant includes two steam-electric turbine generators totaling approximately 1,600 MW. The plant's two boilers are supercritical, pulverized coal steam generators with low-NO_x burners, SCR's, dry electrostatic precipitators, wet flue gas desulfurization, and wet electrostatic precipitators.

The project also includes contiguous coal reserves owned by the project participants to supply Illinois coal to the power plant. PSGC estimates the project-owned coal reserves will supply the coal required by the plant for approximately 30 years. PSGC owns or controls 100% of the surface property around the mine portal.

IMPA Combustion Turbines

IMPA has seven wholly-owned combustion turbines. Three units are located in Anderson, Indiana (Anderson Station), two units are located near Richmond, Indiana (Richmond Station), and two units are located at the Georgetown Combustion Turbine Station in Indianapolis, Indiana (Georgetown Station).

IMPA operates and maintains the Anderson and Richmond Stations with on-site IMPA personnel. The original four machines are GE-6Bs and Anderson Unit #3 is a GE-7EA. These units operate primarily on natural gas, with No. 2 fuel oil available as an alternate fuel. Natural gas is delivered under an interruptible contract with Vectren. This contract gives IMPA the option to obtain its own gas supplies from various sources with gas transportation supplied by Vectren. IMPA maintains an inventory of No. 2 fuel oil at each station.

IMPA is the sole owner of Units 2 and 3 at the Georgetown Station. Indianapolis Power & Light (IPL) operates these two units on behalf of IMPA. The units are both GE-7EA machines and are gas fired. Citizens Gas delivers the gas to the Station from the Panhandle Eastern pipeline system. IPL has the responsibility to ensure IMPA's units comply with applicable environmental requirements.

Member-Owned Capacity

IMPA members Richmond, Jasper, Peru and Rensselaer own generating facilities. Per the Member Dedicated Capacity Agreements, as amended, Richmond, Jasper and Peru maintain and operate their generating units in compliance with federal and state laws and IMPA schedules and pays them against an appropriate Locational Marginal Price (LMP) determined by PJM or MISO. These members are also paid the RTO auction price for capacity if their respective units clear the market auction. The City of Rensselaer's payments are based on more traditional cost based formulas. The following paragraphs briefly describe the member facilities.

Richmond's Whitewater Valley Station (WWVS) consists of two coal-fired generating units with a current maximum tested capability of approximately 35.0 MW and 64.0 MW, respectively. Richmond purchases coal on a short-term and spot market basis.

Jasper's generating plant consists of one coal-fired unit. Its demonstrated capability is 13.0 MW. Jasper purchases its coal as needed on a short term or spot market basis and it is delivered by truck. Jasper maintains only a small inventory of coal due to minimal operation in recent years but is conveniently located near multiple fuel sources. The generating unit is exempt from the Title IV acid rain and NO_x SIP Call provisions of the CAAA, CAIR, and CSAPR.

Peru's generating plant consists of two coal-fired units (Units 2 and 3) and one black-start diesel. Unit 3 has a tested capacity of 12.1 MW, Unit 2's tested capability is 20.0 MW, and the black-start diesel has a tested capability of 1.8 MW. The units are exempt from the Title IV acid rain and the NO_x SIP Call provisions of the CAAA, CAIR, and CSAPR.

Rensselaer's generating plant consists of six internal combustion engines with a total tested capability of approximately 18 MW. Four of the six machines are designed to operate on natural gas and No. 2 diesel fuel oil. Unit 5 can operate on diesel only and Unit 15 on natural gas only. Units 6, 10 and 11 are currently operated on No. 2 fuel oil only. Unit 14 is dual fuel capable and burns natural gas as a primary fuel with fuel oil as either a backup or mixture.

The Rensselaer generating plant is exempt from the Title IV Acid Rain provisions of the CAAA, CAIR and CSAPR requirements since all the units are under 25 MW. Unit 5 was recently reclassified as an "emergency unit" for compliance with the RICE Rule. This means Unit 5 can be operated for emergency use only and is not considered a capacity resource.

Firm Power Purchases

On January 1, 2006, IMPA began taking firm power and energy from I&M under a "Cost-Based Formula Rate Agreement for Base Load Electric Service." Initially, this agreement provided IMPA with base load power and energy for a twenty-year period. The initial contract quantity under this agreement was 150 MW. IMPA may increase its purchases by up to 10 MW each year to a maximum delivery of 250 MW. The current contract quantity is 190 MW. I&M's demand and energy charges are calculated each year according to a formula that reflects the previous year's costs with an annual "true-up" the following year. I&M is responsible for providing the capacity reserves under this contract. The contract was extended in 2010 and now has an expiration date of May 31, 2034.

On June 1, 2007, IMPA began taking firm power and energy from DEI under a "Power Sale Agreement for Firm Energy and Capacity." This agreement provides IMPA with 50 MW of base load power and energy. DEI recalculates its demand and energy charges each year according to a formula that reflects the previous year's costs with an annual reconciliation. DEI is responsible for providing the capacity reserves under this contract. This contract expires May 31, 2017.

On June 1, 2007, a new Power Coordination Agreement between IMPA and DEI became effective. Pursuant to this agreement, DEI provides Reserve Capacity, Back-Up Energy and Planning Reserves, and other similar services related to IMPA's entitlement share of Gibson 5. This agreement expires December 31, 2014 at which time IMPA will be responsible for supplying the reserves for its share of Gibson 5.

Throughout 2012, IMPA entered into long-term power supply agreements with six former DEI wholesale customers; Veedersburg, Coatesville, Williamsport, South Whitley, Montezuma and New Ross. As part of the agreement with the customers, their preexisting full requirements contracts with DEI were assumed by IMPA. The six contracts are similar to IMPA's existing DEI cost based rate and have expiration dates between 2015 and 2021.

Other Power Purchases
On October 7, 2008, IMPA entered into a contract with Crystal Lake Wind, LLC for the purchase of up to 50 MW of wind energy from the Crystal Lake Wind Energy Center in Hancock County, Iowa. Deliveries under the contract commenced on November 15, 2008. The contract expires December 31, 2018.

IMPA has entered into various monthly purchased power contracts with multiple counterparties to supplement the power and energy available to it from other resources. IMPA engages in both physical and financial transactions for capacity and energy.

Green Power
IMPA offers a green power rate to its members, for pass through to their retail customers. Under this rate, IMPA will obtain and provide green power for a small incremental cost over its base rate. As discussed above, IMPA currently has a contract for the purchase of wind energy. The expected annual output from this contract provides approximately 2.5% of IMPA's total energy requirements.

Net Metering Tariff
On January 28, 2009 the Board approved IMPA's net metering tariff. This tariff allows for the net metering of small renewable energy systems at retail customer locations. At this time, IMPA knows of six net metering installations in its member's service territories.

IMPA has been approached by customers wishing to install larger renewable systems that exceed the maximum size allowed under the net metering tariff. IMPA's preferred method of handling these large systems is to sign a contract to purchase the power as is done with the industrial customers referenced below. At this time, there are no larger renewable installations taking advantage of this offer.

Retail Customer-Owned Generation

IMPA has a contract with one commercial/industrial customer of an IMPA member to purchase excess generation from its onsite generation facilities. Under the current contract, the customer has been selling small amounts of energy to IMPA under a negotiated rate.

IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. A review of the EPA industrial boiler database reveals approximately 15 industrial boiler installations in IMPA member communities. At this point, IMPA is uncertain of the size or condition of these facilities. While under the right circumstances CHP systems would be beneficial to both the customer and the agency, the operating conditions and economics must be in place for both parties in order for a CHP project to go forward.

With the exception of emergency back-up generators at some hospitals, factories and water treatment plants, IMPA knows of no other non-renewable retail customer generation in its members' service territories.

4.4   EXISTING DEMAND-SIDE RESOURCES

Existing demand-side resources consist of programs coordinated by IMPA as well as those implemented by its members. A discussion of existing programs is provided below.

IMPA Streetlight Upgrades Program

IMPA, on behalf of its participating communities, was one of 20 grant applicants selected from around the country in June 2010 to receive a Department of Energy (DOE) grant from the General Innovation Fund Program through the Energy Efficiency and Conservation Block Grant program. IMPA was awarded $5 million on behalf of its members to implement local streetlight retrofitting programs in the Agency's member communities.

The original plan called for the replacement or retrofit of approximately 6,800 streetlights with an estimated annual savings of approximately 3.4 million kilowatt hours (kWh) collectively for 19 participating communities. The plan also went one step further with all the communities involved agreeing to set aside 50 percent of the financial savings realized as a result of reduced power usage to fund future energy efficient improvements in the community.

The street light selection process was so successful that IMPA was able to extend the original plan from approximately 19 communities, 6,800 lights and 3.4 million kilowatt-hours of savings to 32 communities, approximately 11,000 lights and 6.1 million kilowatt-hours of savings.

Over the course of 2011, the participating communities replaced and retrofitted their existing streetlights with the new energy efficient lights.   IMPA, with its team of participating communities, was the first grant recipient to complete its project under this DOE grant program.

IMPA Energy Efficiency Program

In early 2011, IMPA launched the IMPA Energy Efficiency Program, designed to help commercial and industrial customers in the Agency's 59 member communities save money through incentives for implementing energy-saving measures in four different categories: energy efficient lighting; heating, ventilation and air conditioning; motors, fans & drives; and refrigeration, food service and controls. IMPA worked with member utilities to market the program, educate customers and build relationships with local vendors to implement the energy saving measures. During 2011, the Agency as a whole saw approximately 90 companies participate in the program, representing 25 member communities throughout the state of Indiana.   The cumulative savings from these efficiency efforts is 7.6 million kWh annually. If an average home consumes 12,000 kWh per year, then the program has effectively reduced the amount of energy required to power over 633 homes.

Community Energy Program (CEP)

During 2011, IMPA also assisted member communities in applying for the opportunity to participate in a Community Energy Program (CEP) offered through the Indiana Office of Energy Development. Eight members were awarded with CEP-provided energy audits of the public facilities in their communities and personalized strategic energy plans with both short and long-term energy efficiency goals.

The program included an inventory of all energy usage at public facilities in the city, a full energy audit to identify potential energy saving measures, an established baseline for utility bills, a list of short and long-term energy goals for the community, suggestions to streamline energy decision-

making and purchasing processes, ideas for funding energy efficiency projects, as well as a public meeting to inform the entire community about the new, comprehensive energy plan. The CEP was funded through the Energy Efficiency and Conservation Block Grant Program, the same program that provided funds for the street lighting effort.

IMPA Participation in the Statewide TPA CORE Program

IMPA has been an active participant in the state Demand-Side Management Coordination Committee (DSMCC) since its inception in early 2010. Several members of IMPA's staff heavily participated in the development of the Third Party Administrator (TPA) and Evaluation, Measurement and Verification (EM&V) RFPs and actively participated in the vendor bid reviews and final vendor selection.

The Energizing Indiana initiative began Jan. 2, 2012, and was created to help utilities achieve the significant energy savings required by an Indiana Utility Regulatory Commission (IURC) order.

The initiative offers five programs:
- Commercial & Industrial
- Schools – Education & Assessments
- Residential Lighting
- Home Energy Assessments
- Income Qualified Weatherization

Commercial & Industrial

Energizing Indiana's Commercial and Industrial (C&I) Prescriptive Rebate Program is specifically designed to help facility managers and building owners achieve long-term, cost-effective energy savings.

A prescriptive rebate structure provides the business or organization with rebates based on the installation of energy efficiency equipment and system improvements. Upgrades can include Lighting, Variable Frequency Drives (VFDs), HVAC, and efficient ENERGY STAR® commercial kitchen appliances.

Objectives of the C&I Prescriptive Rebate Program are to:
- Help C&I facilities lower electric energy consumption
- Help C&I customers decrease their overall energy costs
- Encourage vendors and contractors to actively promote and install energy-efficient technologies for their C&I customers

Figure 3 Energizing Indiana Commercial and Industrial Rebates

Source: Energizing Indiana

Schools – Education & Audits

Through the Education Program, Energizing Indiana and the utility provider connect with students in 5th grade to help them learn about energy efficiency and how they can make an impact at their school and home.

Fifth grade students at participating schools receive classroom curriculum education and Energizing Indiana take-home efficiency kits filled with energy saving devices. The educational materials encourage students and their families to better manage their energy use and make good decisions about the products they buy every day.

The School Audit and Direct Install Program helps administrators and building managers discover and realize energy savings in their classrooms and schools. As our schools age, energy costs rise and efficiency drops. Energizing Indiana Energy Advisors conduct thorough building energy efficiency assessments, providing detailed reports to school officials on the benefits of energy efficiency and the savings associated with operational improvements. Many schools may also be eligible for rebates under the Commercial & Industrial Rebate program to implement improvements in their facilities.

Energy Advisors assess the heating, ventilation and air-conditioning (HVAC) systems of the school to determine if they are operating efficiently. In addition, they may inspect air duct sealing, insulation levels and more to evaluate a facility's energy consumption and heating and cooling efficiency.

Each participating school receives a complete report to enable near- and long-term energy planning, and advisors will help staff understand rebates that may be available to them for facility improvements.

The school also receives several energy saving devices, including:
- Two (2) Vending Machine Timers
- Ten (10) 18 Watt Compact Florescent Light Bulbs (CFLs)
- Ten (10) Commercial Smart Power Strips with Occupancy Sensors and
- Fifteen (15) Room Lighting Occupancy Sensors

Additional energy saving equipment is available.

Figure 4 Energizing Indiana School Education & Audits

School Programs

Through the Education Program, Energizing Indiana® and your local utility provider connect with students in fifth and sixth grades to help them learn about energy efficiency and how they can make an impact at school and home.

Connecting with Students through Education

Students at participating schools receive classroom education and Energizing Indiana take-home efficiency kits filled with energy-saving devices designed to open students' and their parents' eyes to the energy-saving potential of simple, easy-to-implement conservation practices. It's a fun and informative program that encourages students and their families to better manage energy use and make good decisions about the products they buy every day. All the materials are curriculum-based and carry lifelong lessons that students will use as they become energy consumers.

Connecting with Schools through Building Audit and Direct Install

The Building Audit and Direct Install Program helps administrators and building managers discover energy savings in classrooms and schools.

As our schools age, energy costs rise, and efficiency drops. Energizing Indiana energy advisors conduct thorough building energy efficiency assessments, install energy-efficient products and provide detailed reports to school officials on the benefits of energy efficiency and the savings associated with operational improvements. Many schools may also be eligible for rebates under the Commercial & Industrial Rebate program to implement improvements in facilities.

Energy advisors assess the heating, ventilation and air conditioning systems, as well as the lighting, kitchen appliances, insulated levels and other building systems needed. Energy advisors will install products including: vending machine controllers, CFL lamps, occupancy-sensing power strips, lighting occupancy sensors and LED "EXIT" signs.

Each participating school receives a complete report to enable energy planning, and advisors will help staff understand rebates that may be available to them for facility improvements.

ENERGIZING INDIANA
Together we'll do powerful things.

Visit us online at:
www.*energizing*indiana.com
for additional program information and to enroll
or call 1.888.446.7750

Source: Energizing Indiana

Residential Lighting

All consumers can benefit from the Residential Lighting program, which provides discounts on energy-efficient lighting available at participating retail locations. Energizing Indiana works with local retailers to provide instant discounts on compact fluorescent light (CFL) bulbs, lighting fixtures and lighting controls.

Figure 5 Energizing Indiana Residential Lighting

Source: Energizing Indiana

Home Energy Assessments

During a Home Energy Assessment, an energy advisor assesses the home's energy use, recommending appropriate efficiency measures and installing a kit of energy saving items. Assessments can raise the home's performance, lower energy bills, improve in-home air quality and increase the home's value. An Energy advisor guides the customer step by step through the process to produce long-term, cost-effective energy savings by:

- analyzing their energy use
- inspecting the home's air duct sealing, insulation levels and more to evaluate the home's energy consumption and heating and cooling efficiency.
- the direct installation of energy-saving measures—CFL bulbs, energy efficient sink aerators and showerheads as well as water heater pipe insulation.

Figure 6 Energizing Indiana Home Energy Assessments

Source: Energizing Indiana

Income Qualified Weatherization

Income qualified homeowners can participate in the Income Qualified Weatherization program, during which Energizing Indiana makes weather-related efficiency improvements at the home. An Energizing Indiana Energy Advisor performs a complete assessment:

- replace traditional incandescent bulbs with energy-efficient compact fluorescent light bulbs (CFLs)
- insulate water pipes
- install energy efficient faucet aerators and shower head(s)
- conduct blower-door directed air sealing
- improve insulation levels as indicated by testing

Figure 7 Energizing Indiana Income Qualified Weatherization

Source: Energizing Indiana

Energy Efficiency and Conservation Education

IMPA has long promoted energy efficiency and conservation in its member communities. IMPA includes such information, developed both from public and internal sources, in the Municipal Power News, a publication which IMPA mails to members' customers' homes and businesses three or four times each year. The Agency also provides literature containing conservation and efficiency tips to member communities for distribution in their local utility offices or events.

Each issue of Municipal Power News includes a small energy efficiency quiz. Customers may enter their answers in a drawing at IMPA. Correct responders are mailed a small energy efficiency kit consisting of CFLs, weather stripping, outlet insulators and energy savings tips. IMPA has distributed approximately 700 of these kits through this and other delivery mechanisms.

IMPA's website at www.impa.com includes energy efficiency, conservation and safety information for consumers as well as providing the APOGEE online energy audit application, as discussed below. These new web pages include conservation tips, renewable and environmental information, and safety facts, as well as links to energy websites like Energy Star® and the U.S. Department of Energy.

IMPA staff also assists its members and their customers by providing walk-through energy audits and recommendations for power factor improvements to individual industrial customers.

Compact Fluorescent Light (CFL) Rebate Program

In the fall of 2008, IMPA began distributing CFL rebates in its communities. Working in conjunction with General Electric, IMPA distributed coupons worth $1 off any package of CFL bulbs. With the planned Statewide TPA implementation date of January 1, 2011, this program ended in 2010 with the last distribution of coupons occurring in the summer of 2010.

Demand Response

On December 10, 2010, IMPA's board approved Demand Response tariffs in order to utilize demand response programs offered under the MISO and PJM tariffs. At this time, no customers have signed up for the program.

Member Programs

IMPA's members have implemented a variety of programs and projects tailored to their individual systems to reduce peak demand and encourage efficient energy utilization. Most of these programs are rate or customer service related. Examples include coincident peak rates, off-peak rates, power factor improvement assistance, load signals to customer-owned peak reduction or energy management systems, AMI/AMR and streetlight replacement with more efficient lamps.

Home Energy Suite™

In March of 2009 IMPA contracted with APOGEE Interactive for the online Home Energy Suite™. This is an online application that allows customers to input information regarding their home and appliances and determine approximate consumption and costs of electricity. The application features many useful pages that allow consumers to see which appliances are costing them the most money, where they can save money, potential savings from higher efficiency appliances, etc. The site is hosted on IMPA's website, with most member communities offering links from their websites (some smaller towns do not have utility websites and high speed internet access is not available in all IMPA communities). The site is also advertised in IMPA newsletters.

Figure 8 IMPA Home Energy Calculator
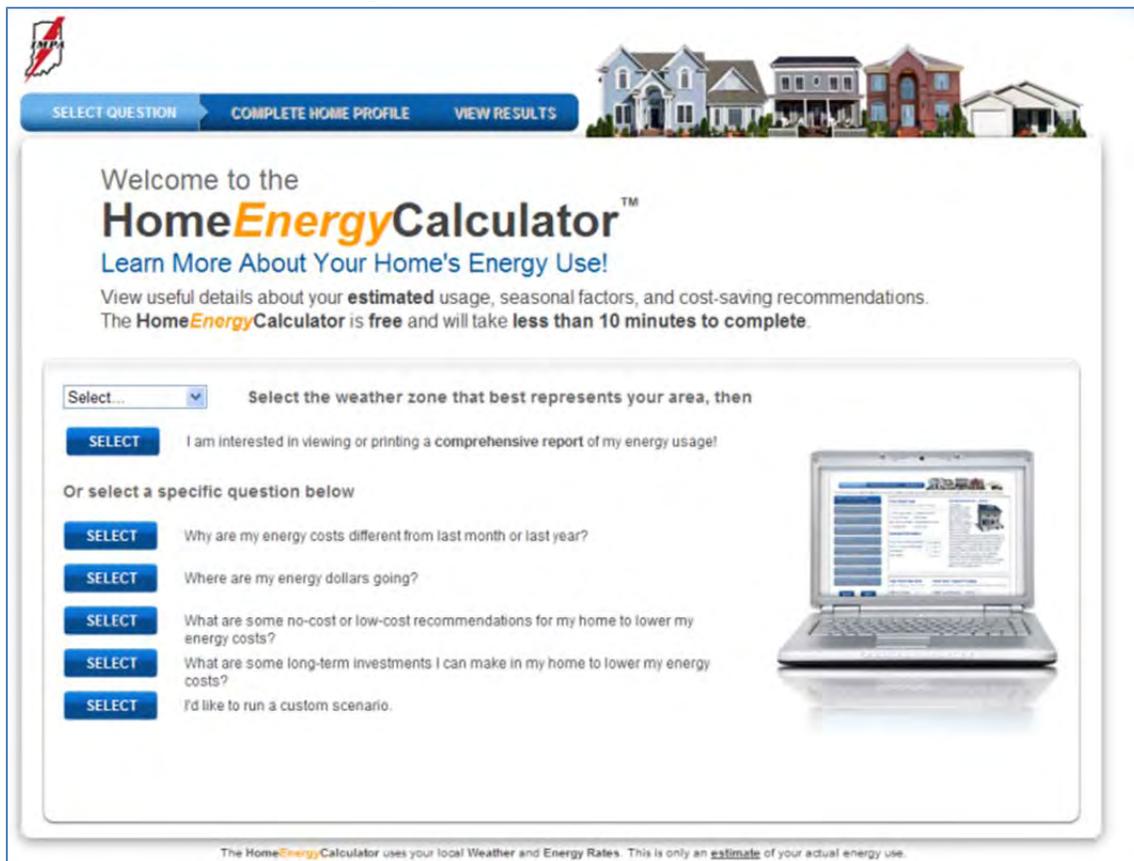
Source: IMPA

Since 2009, IMPA's energy efficiency programs have continued to grow with a cumulative savings of 34,497 MWh.

Table 4 Energy Efficiency Results (2009-2012)

MWh – Annual	Actual 2009	Actual 2010	Actual 2011	Actual 2012
Residential Rebate (IMPA)	214			
Street Lights (IMPA)		6,100		
C&I Prescriptive (IMPA)			7,619	
C&I Prescriptive (CORE)				13,931
Residential Lighting (CORE)				4,493
Low Income (CORE)				180
Home Audit (CORE)				933
Schools (CORE)				1,027
Annual Total	214	6,100	7,619	20,564
Cumulative Total	214	6,314	13,933	34,497

Source: IMPA

4.5 IMPA TRANSMISSION

A large portion of IMPA's load is connected to the Joint Transmission System (JTS) that is jointly owned by DEI, IMPA and WVPA. Pursuant to the terms of the Transmission and Local Facilities Ownership, Operation and Maintenance Agreement (the "T&LF Agreement") and the License Agreement, IMPA dedicated and licensed the use of its portion of the JTS to itself, DEI and WVPA. DEI and WVPA similarly dedicated and licensed the use of their facilities to IMPA. The T&LF Agreement provides mechanisms for the owners to maintain proportionate ownership shares and to share proportionately in the operating costs and revenues from the JTS.

IMPA does not operate transmission facilities. DEI is responsible for the operation and maintenance of the JTS. In addition, DEI performs all load and power flow studies for the JTS and recommends improvements or expansions to the JTS Planning Committee for its approval. DEI files the FERC Form 715 on behalf of the entire JTS. See Appendix H for a statement on Form 715.

IMPA is a member of MISO as a Transmission Owner (TO). DEI and WVPA are also Transmission Owner members of MISO. The higher voltage facilities of the JTS are under the operational and planning jurisdiction of MISO. The initial purpose of MISO was to monitor and control the electric transmission system for its transmission owner members in a manner that provides all customers with open access to transmission without discrimination and ensures safe, reliable, and efficient operation for the benefit of all consumers. Although MISO has since expanded its mission to include the operation of various markets, it also continues to fulfill this initial purpose.

Approximately 67% of IMPA's load is connected to delivery points on MISO-controlled transmission lines of the JTS, NIPSCO and Vectren. The remaining portion of the members' load is connected to delivery points on the AEP and Duke-OH transmission systems, located in the PJM footprint. IMPA is a transmission dependent utility (TDU) for all load not connected to the JTS system, approximately 50%. IMPA purchases Network Integration Transmission Service (NITS) under the appropriate transmission owner's NITS tariff.

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5 LOAD FORECAST

As a basis for this integrated resource plan, IMPA developed a 20-year monthly projection of peak demands and annual energy requirements.   This part describes the forecast methodology, forecast results, model performance, and alternate forecast methodologies.

5.1 LOAD FORECAST METHODOLOGY

IMPA uses IBM's SPSS Predictive Analytics Software for generating its load forecasts using time series analysis. Causal time series models such as regression and ARIMA will incorporate data on influential factors to help predict future values of that data series. In such models, a relationship is modeled between a dependent variable, time, and a set of independent variables (other associated factors). The first task is to find the cause-and-effect relationship.

ARIMA stands for Auto Regressive Integrated Moving Average. An ARIMA model can have any component, or combination of components, at both the non-seasonal and seasonal levels. The name autoregressive implies that the series values from the past are used to predict the current series values. While the autoregressive component of an ARIMA model uses lagged values of the series values as predictors, the moving average component of the model uses lagged values of the model error as predictors. The integration component of the model provides a means of accounting for trend within a time series model.

The SPSS forecasting software was used to create monthly forecasts for each IMPA load zone for both coincident peak demand and energy requirements. The ARIMA method allows for the development of a mathematical equation that accounts for both a seasonal influence and an overall trend based on the data available.

5.2 LOAD DATA SOURCES

IMPA used 104 observations of monthly historical energy and demand requirements in developing all the forecast models, except for Blanchester which only had 72 observations available and six new IMPA members where 60 observations were gathered from the prior supplier. Also, to create a consistent historical database for developing the statistical models, additional demand and energy data for Argos, Huntingburg, Jasper and Straughn (part of NIPSCO, SIGECO and DEI load zones) were included for the period prior to their respective IMPA memberships.

Monthly historical heating and cooling degree-days (HDD and CDD) and daily maximum and minimum temperatures data were obtained, for the period 2003 through 2012, from the National Oceanic and Atmospheric Association—NOAA (www.noaa.gov). The mean temperature was calculated from the average of the daily maximum and minimum temperatures. The build-up temperature data, was calculated by the summation of the coincident peak date maximum temperature times 10/17, previous day maximum temperature times 5/17 and the second day back maximum temperature times 2/17. This variable had a greater statistical significance in the demand models than maximum temperature. Weather data was selected from three different weather stations in Indiana and one from Ohio for their proximity to IMPA's 60 member communities; the Indianapolis weather station for the AEP and Duke IN load zones, South Bend for NIPSCO, Evansville for Vectren and Cincinnati for Blanchester.

Economic variables from the Bureau of Economic Analysis (www.bea.gov) used in the models include US Real Gross Domestic Product (GDP), Indiana real personal income and the Indiana unemployment rate. Average wholesale electric price was determined for each member from the actual historical IMPA power bills to the members aggregated by supply area and divided by the total energy purchased in that area. Both the GDP and the average electric price were deflated by the Consumer Price Index for all Midwest urban consumers.

5.3 LOAD FORECAST MODEL DEVELOPMENT

Since 2011, IMPA has generated forecasts for each of IMPA's five load zones on the same basis as power is dispatched and reported to MISO and PJM. Multiple models were created and the best fit models were chosen after careful attention was given to the statistics, growth rates and load factors, making sure all were within an acceptable range and reflect the historical data. Developing demand and energy forecast models for five zones allowed greater attention to statistics and model detail than could be done by forecasting the member cities individually.

Models were developed in the SPSS software with demand and energy as the dependent variables. Forecasts were obtained for each independent variable. Weather variables cannot be forecasted for more than a week or so with any level of accuracy, therefore, monthly averages of the historical monthly data were used. The weather data was normalized for each month using the past nine years, 2003 through 2012, and then this normalized weather was repeated annually from 2013 through 2033. The economic variables were projected using forecasted growth rates from the United States Congress Congressional Budget Office's (CBO) Budget and Economic Outlook: Fiscal Years 2012 to 2022 report (www.cbo.gov). For years 2023 through the 2033 the growth trend assumption for 2022 was continued.

For the demand model, the dependent variable was the load zone coincident peak demand (kW). The independent variables typically included temperature build-up during summer months, minimum monthly temperatures for the winter months, average monthly temperatures during the spring and fall shoulder months, and various economic variables. The temperature data was converted to Celsius so that the majority of the winter data was negative and produced a negative coefficient. As mentioned previously, the temperature build-up variable is composed of a weighted average of the temperature of the peak day plus the previous two days. The monthly temperatures were from the historical monthly coincident peak dates which were normalized for the forecast.

The dependent variable in the energy model was the sum of each load zone monthly energy requirements (kWh). The independent variables were CDD, HDD, and economic variables.

5.4 SPSS MODEL SELECTION

The SPSS software produced model fit parameters, residual errors and variable coefficients. The R-square, t-Statistics and coefficients were then evaluated to determine whether to keep or eliminate a model. The statistical validity of each forecast model was evaluated focusing on the R-square and error residuals of the models, the sign of each coefficient and the significance of each t-Statistic of the variables. For example, all weather variables should have a positive sign on the coefficient indicating that as the temperatures increase, the load increases. The one exception is minimum temperature (Celsius) for the winter months. In this case, the sign would be a negative reflecting an inverse relationship; as the temperatures decrease, the loads increase. All economic variables should have a positive sign as well, indicating as the economy grows, electricity use will

increase. The exception here is the average electric price; the sign of the coefficient would be negative, because as the costs of electricity rises, usage should decrease.

The t-Statistics of most variables were significant, minimum 2.0, the exception being the AEP and Duke OH areas, which had a couple of variables at 1.9. These variables influence the growth for the forecasts and are significant enough to still be considered.

The R-square statistic measures how successful the fit of the model is in explaining the variation of the data—a 1.0 R-square would explain 100% of the variation. In selecting models, higher R-squares with higher t-statistics were used to determine the best models for the forecast.

5.5 LOAD FORECAST DEVELOPMENT

Having input the monthly projections of the independent variables for 2013 to 2033, the SPSS software was used to compute the forecasts from the selected demand and energy models. For quick visual analysis of the load curves and growth rates, the SPSS software also generated a graph of the forecasted and backcasted data, which is fitted over the historical data. The SPSS software completed monthly demand and energy projections from 2013 to 2033 and backcasted from 2004 to 2012. The forecasted data that are output from the SPSS was then transferred into Microsoft Excel for further analysis. Using the forecasted energy and demand data, monthly and annual load factors and annual growth rates were calculated. The growth rates between demand and energy forecasts and the load factor trends for each control area were evaluated for consistency.

Only demand and energy projections with consistent growth rates and load factors were chosen for the forecasts. No adjustments were made for potential gain or loss of large customers. All the individual control area forecasts are aggregated to produce the IMPA forecast.

5.6 LOAD FORECAST RESULTS

The forecast of IMPA's expected peak demands and annual energy requirements is shown in the table below. The resulting long-term average growth rate is slightly below 1% for peak demand and slightly over 1% for energy.

Table 5 IMPA Expected Peak Demands and Annual Energy – Before EE

Year	Peak Demand (MW)	Energy Requirements (MWh)
2014	1,223	6,274,153
2015	1,237	6,402,655
2016	1,248	6,510,194
2017	1,260	6,605,575
2018	1,273	6,692,914
2019	1,282	6,766,555
2020	1,293	6,840,797
2021	1,303	6,913,119
2022	1,314	6,986,387
2023	1,325	7,058,074
2024	1,335	7,130,748
2025	1,346	7,204,538
2026	1,358	7,279,578
2027	1,369	7,355,930
2028	1,381	7,433,693
2029	1,393	7,512,949
2030	1,406	7,593,749
2031	1,419	7,676,175
2032	1,432	7,760,259
2033	1,445	7,846,056
CAGR %	0.89%	1.21%

The historical data reflect the impacts of IMPA and its members' past DSM programs.   Since the effects of the DSM programs are relatively small in comparison to the magnitude of the loads, IMPA made no specific adjustment to its base forecast to reflect changes in the future.

5.7 WEATHER NORMALIZATION

To evaluate load growth, it is important to quantify the percentage of the actual historical load which was a function of non-normal weather. This requirement is precisely why IMPA's forecasting models include weather variables. The models identify the portion of the actual load which has been influenced by weather.

To weather normalize the historical data, IMPA first multiplies the coefficient(s) of the independent variables representing weather by the actual weather data.   Then the same coefficients are multiplied by the normal weather data. The difference between the value derived using the actual weather and the normal value is used to adjust the actual loads to create the weather-normalized historical data.

Figure 9 Weather-Normalized Historic Peak Demand
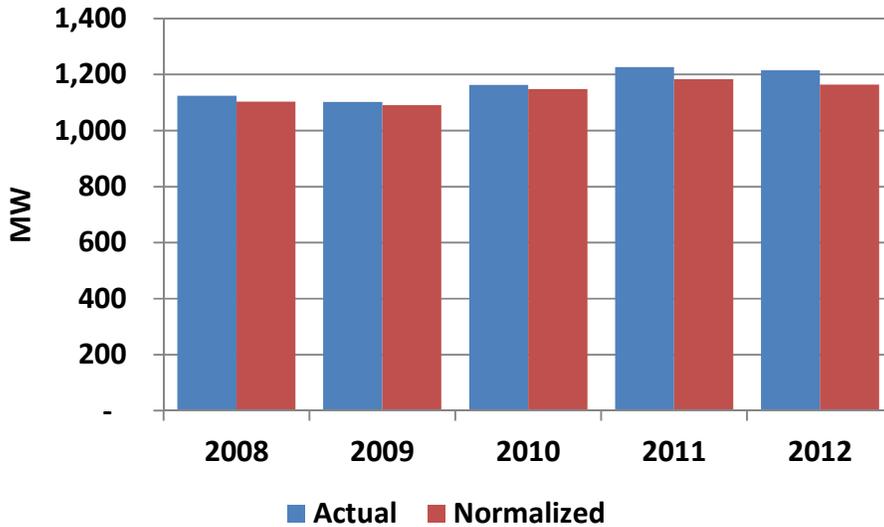
Source: IMPA

Figure 10 Weather-Normalized Historic Energy
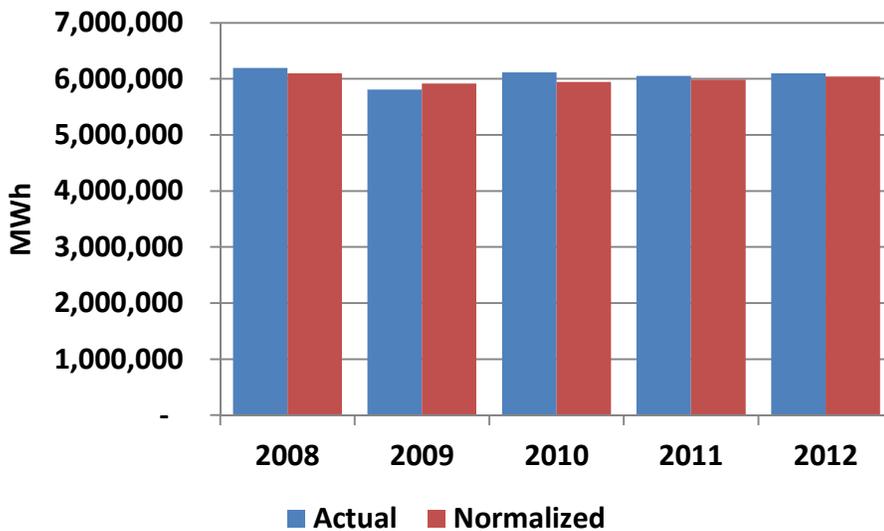
5.8 LOAD FORECAST UNCERTAINTY

This section describes assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and energy requirements. Two cases/scenarios were developed as described herein.

The first forecast variation dealt with uncertainty in the economy. To develop the high and low economic cases, low and high scenarios of the CBO economic variables described earlier were used. The high growth case increased the annual growth rate in demand and energy by .44% and .54% respectively. The low growth case lowered the growth rates by .40% and .50%.

Further addressing forecast uncertainty, IMPA evaluated the uncertainty associated with weather variations. To anticipate the magnitude of possible load variation under weather extremes, two "extreme weather" peak demand forecast scenarios were developed for each area. The baseline forecast for normal peak demand and energy requirements are based on average weather conditions. Extreme weather demand scenarios are based on the most extreme weather which occurred during each month over the historical data period—2003 to 2012. The extreme weather scenario produces a peak demand which is 4% higher than the normal weather peak in 2014. A similar method was used for mild weather. The mild weather scenario reduced the peak demand 3% from the forecasted peak demand.

The alternate forecasts are shown on the following pages. Details of the forecasting models and model results are shown in Appendix D.

Table 6 Load Forecast – Economic Uncertainty

Year	Low Economic Scenario		High Economic Scenario	
	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)
2014	1,211	6,210,126	1,235	6,338,657
2015	1,221	6,310,671	1,253	6,496,153
2016	1,228	6,388,902	1,268	6,634,652
2017	1,236	6,453,995	1,285	6,762,569
2018	1,244	6,510,180	1,303	6,884,017
2019	1,249	6,551,756	1,318	6,993,387
2020	1,255	6,593,007	1,334	7,105,048
2021	1,260	6,631,265	1,349	7,216,655
2022	1,266	6,669,563	1,367	7,330,938
2023	1,271	6,705,207	1,383	7,445,607
2024	1,276	6,740,739	1,401	7,563,300
2025	1,281	6,776,271	1,419	7,684,221
2026	1,287	6,811,883	1,438	7,808,576
2027	1,292	6,847,640	1,457	7,936,541
2028	1,298	6,883,605	1,477	8,068,276
2029	1,304	6,919,800	1,497	8,203,968
2030	1,310	6,956,283	1,519	8,343,755
2031	1,315	6,993,074	1,541	8,487,796
2032	1,321	7,030,203	1,564	8,636,262
2033	1,328	7,058,588	1,587	8,789,287
CAGR %	0.49%	0.71%	1.33%	1.75%

Table 7 Load Forecast – Weather Uncertainty

Year	Low Scenario		High Scenario	
	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)
2014	1,187	5,897,643	1,272	6,684,043
2015	1,201	6,026,134	1,286	6,812,534
2016	1,212	6,133,661	1,297	6,920,062
2017	1,224	6,229,030	1,309	7,015,430
2018	1,237	6,316,356	1,322	7,102,757
2019	1,246	6,389,985	1,331	7,176,385
2020	1,257	6,464,213	1,342	7,250,614
2021	1,267	6,536,522	1,352	7,322,923
2022	1,278	6,609,777	1,363	7,396,178
2023	1,289	6,681,451	1,374	7,467,851
2024	1,299	6,754,111	1,384	7,540,511
2025	1,310	6,827,887	1,395	7,614,288
2026	1,322	6,902,914	1,407	7,689,314
2027	1,333	6,979,252	1,418	7,765,652
2028	1,345	7,057,000	1,430	7,843,400
2029	1,357	7,136,242	1,442	7,922,642
2030	1,370	7,217,027	1,455	8,003,427
2031	1,383	7,299,437	1,468	8,085,837
2032	1,396	7,383,505	1,481	8,169,906
2033	1,409	7,352,494	1,494	8,138,894
CAGR %	0.91%	1.20%	0.85%	1.07%

5.9   LOAD FORECAST MODEL PERFORMANCE

The following tables compare IMPA forecasts used in the last four IRPs with actual results.

Table 8 Load Forecast Performance – Peak Demand

Year	Actual	Normalized	2011 IRP	2009 IRP	2007 IRP	2005 IRP	Normalized Deviation From Most Recent IRP	Increase in IMPA Members*
2006	1,082	1,076				1,090	-1.3%	8
2007	1,161	1,143				1,121	1.9%	2
2008	1,125	1,103			1,265	1,140	-12.8%	1
2009	1,102	1,091			1,294	1,159	-15.7%	1
2010	1,163	1,149		1,134	1,308	1,177	1.3%	1
2011	1,226	1,184		1,155	1,322	1,196	2.5%	
2012	1,215	1,164	1,168	1,172	1,336	1,215	-0.3%	4
CAGR %	1.95%	1.33%		1.66%	1.37%	1.83%		

Table 9 Load Forecast Performance – Energy Requirements

Year	Actual	Normalized	2011 IRP	2009 IRP	2007 IRP	2005 IRP	Normalized Deviation From Most Recent IRP	Increase in IMPA Members*
2006	5,426,236	5,522,140				5,558,827	-0.7%	8
2007	5,957,491	5,843,662				5,728,295	2.0%	2
2008	6,193,164	6,097,488			6,292,085	5,829,988	-3.1%	1
2009	5,810,167	5,918,489			6,482,521	5,931,687	-8.7%	1
2010	6,112,550	5,947,164		6,065,212	6,551,133	6,033,392	-1.9%	1
2011	6,051,425	5,984,393		6,191,982	6,619,200	6,135,103	-3.4%	
2012	6,097,288	6,042,314	6,160,345	6,312,798	6,686,761	6,236,820	-1.9%	4
CAGR %	1.96%	1.51%		2.02%	1.53%	1.94%		

*The forecasts in these tables were developed prior to the years shown and therefore did not reflect the addition of new members. However, new member load is included in the actual and normalized data.

5.10 ALTERNATE LOAD FORECAST METHODOLOGIES

Rate Classification/Sector Methodology

IMPA has not generated forecasts by rate classification or sector. Since IMPA does not sell directly to retail customers, it does not have direct access to customer billing units. To generate a customer sector forecast, IMPA would need to collect several years of annual historical billing summary data from each of its sixty (60) members. In addition, the criteria for determining member rate classes can change over time, and it would be nearly impossible to ensure consistent sector data back through the historical period. Finally, different members identify sectors (or classes) of customers differently. For example, two members may have a large power rate classification. Under this classification, one member's largest customer may be a 10 MW

industrial load whereas the other may be a single 200 kW customer. For these reasons, IMPA is unable to perform sector forecasting.

End-Use Methodology

Another forecast methodology is end-use. The data requirements for an end-use model are extensive. They include detailed information on appliance saturations and usage patterns in the residential sector, data on building and business types in the commercial sector and detailed equipment inventories, lighting types, and square footage area in the industrial sector. IMPA's member communities are not uniform, consisting of various ages of homes and businesses. The age of the residents and vintage of the houses can have a significant impact on the saturation of various appliances. To collect the proper saturation data at the member level, IMPA would need to collect a valid sample of each member's customers. A valid sample is approximately 300 customers whether the community is large or small. Additionally, since the response rate to surveys is typically 30% to 35%, IMPA would need to survey at least 1,000 customers in each community. This requirement makes end-use sampling unreasonable, considering that IMPA would need to sample 25% to 30% of all the customers its members serve. Most investor-owned utilities, while serving thousands more customers, would only need to sample about 1,000 customers to ensure a valid sample. Therefore, IMPA cannot realistically utilize this type of a forecast model.

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6   RESOURCE OPTIONS

6.1   SUPPLY-SIDE OPTIONS

Potential supply-side options include upgrades to existing generating capacity, construction or acquisition of additional generating capacity, and entering into additional contracts for purchased power. New IMPA-owned capacity could include generating units constructed and owned by IMPA or participation in the ownership of either existing or new generating units with third parties. Purchased power could include purchases from other utilities, independent power producers or power marketers. While IMPA is well situated to construct, own and operate smaller generating facilities such as peaking plants, landfill gas plants, and possibly even wind turbine plants, as a practical matter, IMPA would expect to participate with others in the development of any new large generation resources. Joint development of resources would enable IMPA to enjoy the economies of scale of a larger facility and at the same time adhere to the principle of diversification.

Additional Upgrades or Retirements of Existing Capacity
IMPA's existing generating capacity consists of its undivided ownership interests in Gibson 5, Trimble County 1 and 2, Prairie State 1 and 2, seven wholly-owned combustion turbines and member generating capacity that is dedicated to IMPA for its use. IMPA is not aware of any potential upgrades to the jointly-owned coal units that could increase their output capability. Each of IMPA's generating members has reviewed its generating capacity to examine the feasibility of plant upgrades and improvements. All feasible upgrades have been implemented, and IMPA is not aware of any other potential upgrades to this capacity.

All IMPA-owned units were given the opportunity to retire in the capacity expansion runs. This is performed by allowing the expansion model to opt to close an existing resource and replace it with other alternatives. When a unit is retired in this manner, all future capital expenditures, O&M and fuel costs disappear, however, all remaining bond obligations associated with the facility remain. Given that none of IMPA's existing resources require substantial new capital investment in the study period, no IMPA-owned units were selected for retirement.

For purposes of this IRP, IMPA assumes the member generation at Peru, Jasper and Rensselaer (diesels) retires at the end of 2015. Actual retirement dates will vary as none of the plants are specifically slated for retirement at this time. As such, the plans shown in this report could change depending on actual retirement dates or plant conversions.

New Resources
The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit type and model. For example, IMPA does not screen various brands and models of CTs against each other to determine the generic CT for use in the IRP expansion. CT pricing is sufficiently compressed that one CT brand over another will not cause the expansion model to select a CT when a CT is not needed or vice versa. The selection of the actual brand and model to construct would be determined in the bid and project development process.

The traditional generating resources considered in this study include:

- Nuclear (100 MW from a 1100 MW unit)
- Coal-fired steam generation (100 MW from a 750 MW unit)
- Integrated Gasification Combined Cycle (IGCC) (100 MW from a 600 MW unit)
- Advanced combined cycle (CC) units (100 MW from a 400 MW unit)
- Advanced gas-fired combustion turbines (CT) (185 MW)
- Aero-derivative combustion turbine (100 MW)
- Gas-fired high efficiency internal combustion (IC) units (10 MW units in multi-unit sets of 50 MW)

Capital costs, operating costs and operating characteristics for these sources were taken from _Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants_, US Energy Information Administration, April, 2013. See Appendix F for detailed expansion unit data.

During IMPA's consideration of supply-side resources, it assumes any new resource would comply with the applicable environmental requirements. Such requirements specify that the potential resource undergoes an environmental review prior to the beginning of construction and that the potential resource complies with any environmental constraints. If IMPA petitions the IURC for approval relating to new supply-side resource, IMPA would include information concerning these environmental matters, including the results of any due diligence investigations.

Power Purchases
Although IMPA has not identified any specific long-term firm purchased power options at this time, it will continue to consider such options as they may become available in the future.

Energy Markets
IMPA participates in both the MISO and PJM markets for balancing capacity and short-term purchases/sales. IMPA does not believe it is prudent to rely on these short term capacity and energy markets to meet its long-term requirements and allows the expansion model to add resources to meet its RTO resource obligations. However, in the expansion analysis, small amounts of annual market capacity purchases (50 MW MISO, 25 MW PJM) are allowable.

For purposes of this IRP, IMPA limits the installation of new resources to those needed to serve its own load. Although IMPA will sell short–term surplus capacity and energy through the organized markets, IMPA will not install generation for the purpose of speculative sales. The expansion model is set to limit the quantity of off system sales. This has the effect of limiting the selection of new resources to those required to meet IMPA's load since units won't be selected based on large off system revenues.

6.2 RENEWABLE OPTIONS

In addition to the traditional resources discussed above, the expansion model was allowed to select from a variety of renewable resources as well. The renewable alternatives included in the expansion analysis are shown below.

- Wind - Build (50 MW)
- Wind - PPA (50 MW)
- PV Solar (small facilities at member locations)
- Bio Mass (25 MW)
- LFG (2.5 MW units in sets of 10 MW)

Pricing for all of the renewable alternatives was based on indicative market quotes from renewable energy providers or industry documentation of installed and operating costs.

See Appendix F for detailed expansion unit data.

IMPA is in the process of developing solar park projects. As of this writing, IMPA is developing solar parks in three member communities. Each park is planned to be 1 MW in size. Two parks will utilize fixed-tilt mounting system and the third will utilize single-axis tracking.

The base case assumes 21 MW of solar park development over the next seven (7) years. Additional renewable energy additions were left up to the expansion model to determine.

6.3   DEMAND-SIDE OPTIONS

As part of IMPA's long-term strategic plan which was approved by the Board of Commissioners in 2009, an aspirational energy efficiency target of 10% reduction in projected demand and energy requirements by 2020 through cost effective energy efficiency programs was established. The first step in achieving the target is to gain experience and evaluate the success of a variety of residential, commercial, and industrial programs through participation in the Indiana state-wide core program referred to as Energizing Indiana.

Energizing Indiana (Core Programs)

At this time, Energizing Indiana is the primary vehicle for energy efficiency savings and the majority of the budgeted expenditures are for those programs. The programs are:

- C&I Prescriptive Rebates
- Residential Home Lighting
- Low Income Weatherization
- Home Energy Audits
- School Audits and Education

Table 10 Energizing Indiana (2012-2014)

MWh - Annual	Energizing Indiana		
	Actual 2012	Target 2013	Target 2014
C&I Prescriptive (CORE)	13,931	26,495	28,000
Residential Lighting (CORE)	4,493	4,628	4,000
Low Income (CORE)	180	1,625	1,250
Home Audit (CORE)	933	909	750
Schools (CORE)	1,027	656	650
TOTAL	20,564	34,313	34,650

Source: IMPA

Core Plus Programs

In addition to the core programs discussed above, IMPA is investigating a variety of additional energy efficiency programs subject to the cost effectiveness and success of the core programs. The "core plus" programs under consideration include:

Commercial and Industrial Customized Audits

This program would provide member commercial and industrial loads with assistance in improving the energy efficiency of their installations. Such efforts could include, lighting retrofits, day lighting, high efficiency pumps/motors as well as variable speed drives. The program would be customer specific based on the audit performed by IMPA or member representatives.

High Efficiency Residential Appliances

This program is envisioned to be a rebate program for the purchase of high efficiency appliances that exceed the minimum federal standards. Initial program targets would likely be Energy Star® rated home appliances such as washers, dryers, refrigerators and ranges. Programmable thermostats would also be a component of this program.

HVAC and Home Envelope

This program would seek to incentivize the early retirement of low efficiency HVAC equipment nearing the end of its useful life and to encourage and promote home envelope improvement measures.

Refrigerator Turn In

This program would incentivize customers to turn in inefficient second refrigerators.

New Construction

This program would encourage the installation of high efficiency lighting, HVAC, appliances and building envelope at the time of new building construction. This program may apply to both residential and commercial construction.

Commercial and Industrial Demand Response

Utilize the previously mentioned Demand Response tariff to provide capacity to meet RTO planning needs.

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7 ENVIRONMENTAL

7.1 COMPLIANCE WITH CURRENT RULES

The majority of IMPA's current resources are not substantially impacted by the Environmental Protection Agency's (EPA) rules slated to go into effect in the next three (3) years.   The following sections describe compliance actions IMPA expects to be taken at its generating facilities in connection with environmental rules.

General

On December 23, 2008, the U.S. Court of Appeals for the D.C. Circuit remanded the Clean Air Interstate Rule (CAIR) to the EPA, but did not vacate the rule. This ruling left CAIR in place until the EPA issued a new rule consistent with the court's decision. The final replacement rule, the Cross-State Air Pollution Rule (CSAPR), was issued by EPA in July 2011. CSAPR was subsequently vacated by the D.C. Circuit Court in August 2012. The EPA then petitioned the D.C. Circuit Court for rehearing en banc, and this petition was denied in January 2013. The United States, through the Solicitor General, petitioned the U.S. Supreme Court in March 2013 to review the D.C. Circuit Court's decision on CSAPR. In June 2013 the U.S. Supreme Court agreed to hear the CSAPR case of the U.S. Government. The U.S. Supreme Court is expected to issue its decision by June 2014. Compliance with CAIR is necessary through this time period and potentially after, until CSAPR or its replacement is phased in.

CAIR required reductions in nitrous oxide (NO_x) and sulfur dioxide (SO_2) emissions. The CAIR NOx program began in 2009 with its first phase and included both ozone season requirements and annual requirements. The second phase, which is meant to further reduce the state's NO_x allocation from U.S. EPA, will begin in 2015. There will be separate allowances allocated and allowance accounts set up for the annual and ozone season rules.

The CAIR SO_2 requirements began in 2010 and required that units "cover" each ton of emissions with two (2) SO_2 allowances issued to units under the Title IV Acid Rain program, if the vintage of the allowance was 2010 or later (2009 and earlier vintage allowances could be used on a 1:1 ratio). In 2015 and beyond, each ton of emissions must be "covered" with two and eighty-six hundredths (2.86) allowances.

Following the vacating of the Clean Air Mercury Rule (CAMR), the EPA subsequently announced its decision to develop more encompassing hazardous air pollutant emissions standards for power plants under the Clean Air Act (Section 112, MACT standards) consistent with the D.C. Circuit's opinion vacating CAMR. EPA issued a proposed rule, Mercury and Air Toxics for Power Plants (MATS), in March 2011. The final rule became effective in April 2012 and was reconsidered and updated in April 2013 with revised emission limits for new or reconstructed units. Compliance is required for units greater than 25 MW by April 2015, or April 2016 if an extension is granted by the permitting authority for those units installing upgraded equipment for compliance.

The utility industry is now likely faced with a more stringent regulatory scheme for managing CCRs due to the EPA's consideration of new regulations for CCRs. The EPA issued a proposed rule on June 21, 2010. Comments were taken through November, 19, 2010 on two alternative proposals. Environmental groups filed suit against the EPA in April 2012 to force the EPA to take action on the proposed rule. A final EPA rule is expected by the end of 2013 or early in 2014.

Gibson #5

Gibson #5 currently complies with the SO_2, NO_x, particulate matter and opacity requirements of the Clean Air Act and Phase II of the Acid Rain Program. Gibson 5 also complies with CAIR NO_x and SO_2 regulations in 40 CFR 96 and 326 IAC 24. To date, IMPA's share of the SO_2 and NO_x emissions allowances allocated by the EPA and the Indiana Department of Environmental Management (IDEM) have satisfied IMPA's requirements for such allowances.

Gibson 5 complies with the annual and seasonal requirements of the NO_x rule by operating its Selective Catalytic Reduction system (SCR) on an annual basis. IMPA expects its share of allowances in both phases to satisfy the CAIR NO_x emissions of Gibson 5.

Compliance with the CAIR SO_2 rule at Gibson 5 was aided by a significant investment to upgrade the unit's flue gas desulfurization system (FGD). This upgrade was done during an extended maintenance outage in the spring of 2008 with final modifications completed in the fall of 2009. IMPA expects its share of allowances to satisfy the CAIR SO_2 emissions of Gibson 5 during the first phase. IMPA anticipates that Gibson 5's combustion and its FGD will be further optimized to help meet compliance with Phase 1 of CSAPR or its replacement while the investment strategy for long term compliance is determined. Gibson 5 will likely need to purchase allowances for SO_2 until the investment strategy is determined, final rule criteria are known, and potential future capital additions are in place.

Gibson filed for, and received, a MATS extension from the IDEM. Final plans for MATS compliance are being made and will be in place prior to April 2016.

Non-hazardous solid waste from this bituminous coal fired unit consists of the following Coal Combustion Residuals (CCR): fly ash, bottom ash, and fixated sludge from the SO_2 scrubber. The solid waste is disposed of in a mono-purpose solid waste disposal facility on the site or beneficially reused in the close out of the East Ash Pond surface impoundments at the site. DEI also actively pursues other alternative reuse of CCRs.

Small quantities of hazardous wastes may be generated from time to time from normal plant activities and may include spent solvents from parts cleaning and paint-related wastes, etc. Gibson Station normally operates as a Small Quantity Generator (<1000 kg per month). All hazardous wastes generated at Gibson Station are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that particular waste.

Trimble County #1

Trimble County 1 currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act. Trimble County 1 also complies with the CAIR NO_x and SO_2 regulations in 40 CFR 96 and 401 Kentucky Administrative Rule 51.

Trimble County 1 complies with the CAIR NO_x rules by operating the SCRs on an annual basis. IMPA expects its share of allowances to satisfy the CAIR NO_x emissions at Trimble County. Compliance with the CAIR SO_2 rule is accomplished through the increased efficiency achieved through the significant investment made to upgrade the Trimble County 1 FGD system in the fall

of 2005. IMPA expects its share of allowances to satisfy the CAIR SO_2 emissions of Trimble County 1. Trimble County 1 would also be affected by CSAPR or its replacement.

Solid waste from the bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCRs to third parties. LGE actively pursues alternative reuse of CCRs.

Trimble County 1 is affected by the MATS rule, has received a one year extension from the Kentucky Department of Air Quality. LGE is in the process of making final determination for the additional equipment required to comply with the MATS Rule.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LGE's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

Trimble County #2
As with Trimble County 1, compliance with CAIR is necessary until a decision on CSAPR is made by the Court or a replacement rule is implemented.

Trimble County 2 is subject to the MATS rule and is fully equipped for compliance.

Solid waste from the bituminous and sub-bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCRs to third parties. LGE actively pursues alternative reuse of CCRs.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LGE's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

Prairie State Project
Prairie State Units 1 and 2 are subject to CAIR and CSAPR or its replacement, pending the Supreme Court's decision. The Prairie State units receive CAIR NO_x allowances from Illinois' new unit set aside which meet most of its NO_x emission requirements. Any remaining NO_x allowances that are needed for compliance are purchased along with all the required SO_2 allowances required for compliance with the Title IV Acid Rain program and the CAIR SO_2 rule.

The Prairie State units are subject to the MATS rule and are fully equipped for compliance.

Solid waste from these mine-mouth bituminous coal fired units consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid, dry waste is disposed at the near-field landfill. The breaker waste from the mine is disposed at the Jordan Grove facility via truck transport. This is a 1,100 acre site located near Marissa, IL. Jordan Grove was previously operated as a surface coal mine. The material is disposed under an Illinois Department of Natural

Resources mining permit and an NPDES permit. PSGC actively pursues alternative reuses of CCRs.

Hazardous waste generation at Prairie State is similar to Gibson Unit 5 and Trimble County. All hazardous wastes generated by Prairie State are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that particular waste.

IMPA Combustion Turbines
All of IMPA's Combustion Turbine stations comply with the existing requirements of the Clean Air Act. This compliance is achieved through Title V Operating Permit restrictions on fuel consumption and the use of lean pre-mix fuel/air injectors or water injection for NO_x control. The stations meet CAIR NO_x emission allowance requirements with allocated and purchased allowances. The stations comply with their respective Acid Rain Permits using the Excepted Methodologies in 40 CFR 75. SO_2 allowances are either purchased or transferred from other IMPA-owned source allocations.

Compliance with CAIR is necessary until a decision is made by the U.S. Supreme Court regarding CSAPR or its replacement rule is implemented.

The Anderson and Richmond turbines can operate on pipeline natural gas or No. 2 low sulfur fuel oil. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Each plant has chemical storage for use in its demineralized water treatment plant. At times hazardous waste may need to be disposed of when the chemical tanks are cleaned. A licensed contractor is hired to do this cleaning, remove the waste, and properly dispose of the waste. Infrequently, oily waste may be removed from collecting tanks located at the site. This waste is also disposed of using properly licensed vendors. Other waste disposal is similar to household waste and is removed by a licensed refuse removal company.

The Georgetown units are single fuel units that operate solely on pipeline natural gas. There is no chemical storage on site and the plant's parts washer contains non-hazardous solvent. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Most waste disposal consists of waste similar to household waste and is removed by a licensed refuse removal company. There may be, at infrequent times, oily waste removed from onsite collecting tanks. This waste is also disposed of using properly licensed vendors.

7.2 COMPLIANCE WITH FUTURE RULES
IMPA makes no assumptions as to future environmental rules or laws. For purposes of this analysis, it is assumed that all future resource options comply with the existing environmental rules in place at the time of installation.

While IMPA did not assume carbon legislation in its deterministic base cases, the stochastic analysis includes many draws containing carbon legislation in the form of a carbon cap and trade with a phased out allowance schedule.

7.3 RENEWABLE ENERGY AND NET METERING

IMPA current renewable energy sources consist of a 50 MW wind contract and the 3 MW of PV solar currently under development. Pending the results of the initial solar parks, IMPA may expand its solar developments in the future.

At this time, IMPA has approximately six participants in its net metering program.

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8   TRANSMISSION AND DISTRIBUTION

8.1   FUTURE TRANSMISSION ASSUMPTIONS

As noted previously, IMPA is a member of MISO as a TO within the DEI area and is a TDU within the NIPSCO and Vectren areas of MISO. IMPA is also a TDU receiving transmission service from PJM for its loads in that footprint.

MISO performs all of the transmission system planning for the facilities under its operational control, which includes most of the JTS. In the DEI load zone, DEI performs any additional transmission system planning functions on behalf of the three owners of the JTS (see Appendix H for statement regarding Form 715). IMPA participates in the joint owners' Planning Committee, which reviews major system expansions planned by DEI. IMPA assists its members where needed in determining when new or upgraded delivery points are required and coordinates any studies, analysis or upgrades with other utilities.

Rates for MISO and PJM area-specific NITS and ancillary services were escalated to reflect increased cost for transmission service over the study period. Additionally, charges for the MISO Multi Value Project (MVP) adder (Schedule 26) were increased at a rate much higher than inflation based on projections provided by MISO. This reflects the large increase in Schedule 26 charges due to the construction of the MVP projects over the next decade.

Each year, IMPA pays a significant amount of money for RTO congestion and losses. IMPA has investigated with consultants and the RTOs methods by which IMPA could invest in transmission improvements as another way to help mitigate congestion risk at some of its resource Commercial Pricing Nodes (CPNODES). At this time, no economic upgrades have been found, but IMPA continues to research viable projects.

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9 SOFTWARE OVERVIEW

IMPA utilizes the Ventyx Strategic Planning Suite ("Strategic Planning") and Risk Analyst tools to perform its resource planning studies.

9.1 STRATEGIC PLANNING SUITE

Strategic Planning consists of three integrated modules that pass inputs and results between the modules. Each module is designed to address specific business problems associated with the power industry.

Figure 11 Strategic Planning Suite Cut Sheet

Source: Ventyx

Horizons Interactive

The Horizons Interactive market module develops forward price curves and analyzes power, fuel, emissions, energy, and capacity markets. The simulated forward market trajectories are used by the next set of modules in the Suite.

Capacity Expansion Module

The Capacity Expansion module is an optimization screening tool that completely enumerates the possible combinations of new resource additions, demand-side management programs, and strategic retirements. The screened resource plans are then evaluated in greater detail in the MIDAS Gold module.

MIDAS Gold

Once the forward curves and optimized resource plans are developed, the MIDAS Gold module is used to create IMPA specific business structures complete with pro forma financials and rate making. The module mimics utility operation by combining unit commitment and dispatch with market purchases and sales and IMPA Member revenue requirements/rate making; providing a complete analysis of each resource plan and scenario.

9.2 RISK ANALYST TOOLS

To assess the risk of the various plans, IMPA utilizes a variety of analytical tools and techniques. Among these are decision trees, risk profiles, tornado charts, dominance charts, and trade-off diagrams. When selecting a preferred plan, strong consideration is given for the robustness of the plan in addition to the relative cost of the plan.

Figure 12 Risk Analyst Tools Cut Sheet
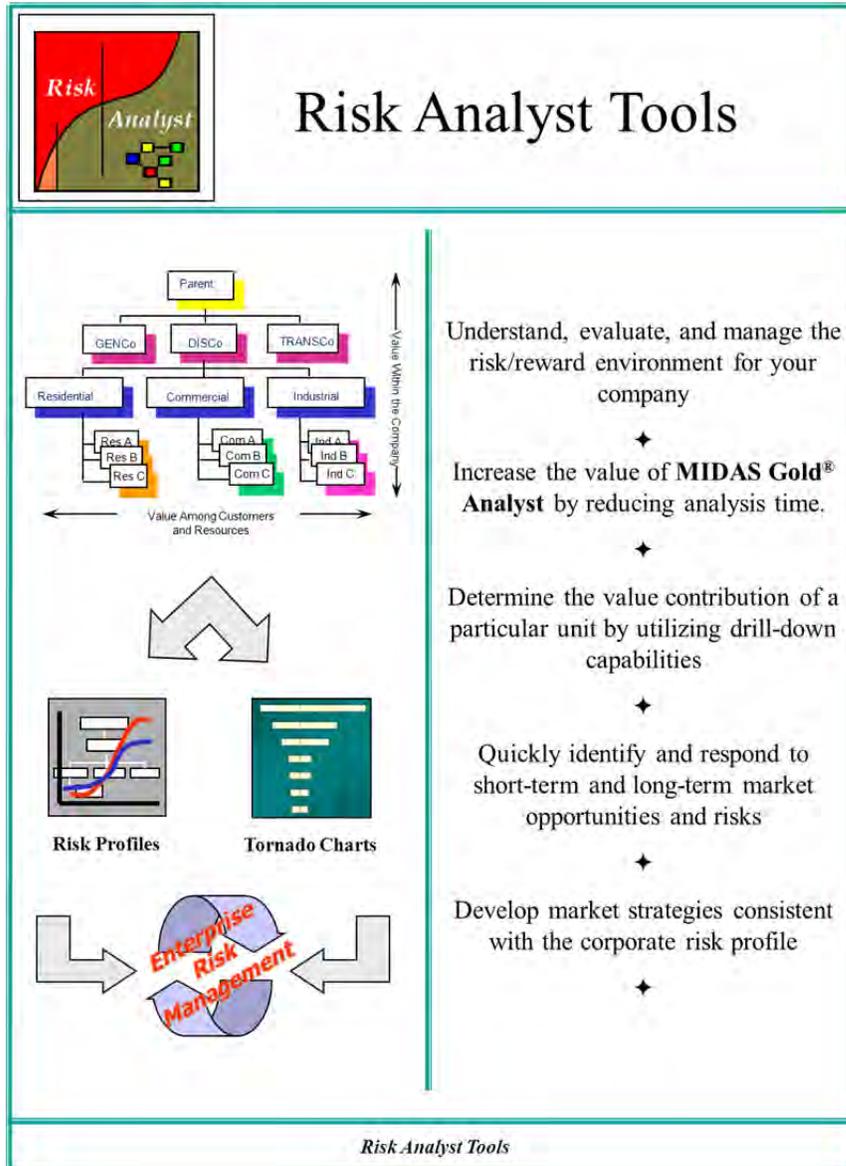
Source: Ventyx

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10 MARKET PRICE FORMATION

With the implementation of the RTO energy and capacity markets, the future cost of market power and energy is one of the most critical aspects of utility planning. No longer can utilities simply plan as islanded entities, building for their own load in a vacuum. Planning must incorporate a reasonable and realistic forward view of the market.

IMPA utilizes market price projections for all planning activities, from short term hedging decisions to long term planning. The following pages discuss IMPA's methodology for creating the market price forecasts used in various aspects of its planning processes.

10.1 HORIZONS INTERACTIVE MODULE

The Horizons Interactive market module performs an hourly, chronological, calendar-correct simulation which iteratively considers the market dynamics of power, fuels, transmission, emissions, and renewables.

The model database includes all North American generating assets, hourly loads, transmission interties, fuel supply, etc. The created market prices for energy and capacity are easily transferable to the Capacity Expansion and MIDAS Gold modules.

Figure 13 Horizons Interactive Cut Sheet

Source: Ventyx

Zonal Markets

As a market participant with generation and load in both the Midcontinent Independent Transmission System Operator (MISO) and PJM Interconnection (PJM), IMPA is interested in forward energy and capacity price curves for five market zones (3 in MISO and 2 in PJM) where IMPA has resources and load.

- PJM – AEP (AEP-DAYTON HUB)
- MISO – Indiana (INDIANA HUB)
- MISO – Illinois (ILLINOIS HUB)
- MISO – Iowa (IOWA ZONE)
- PJM - DEOK (DEOK ZONE)

Figure 14 Zonal Price Points of Interest
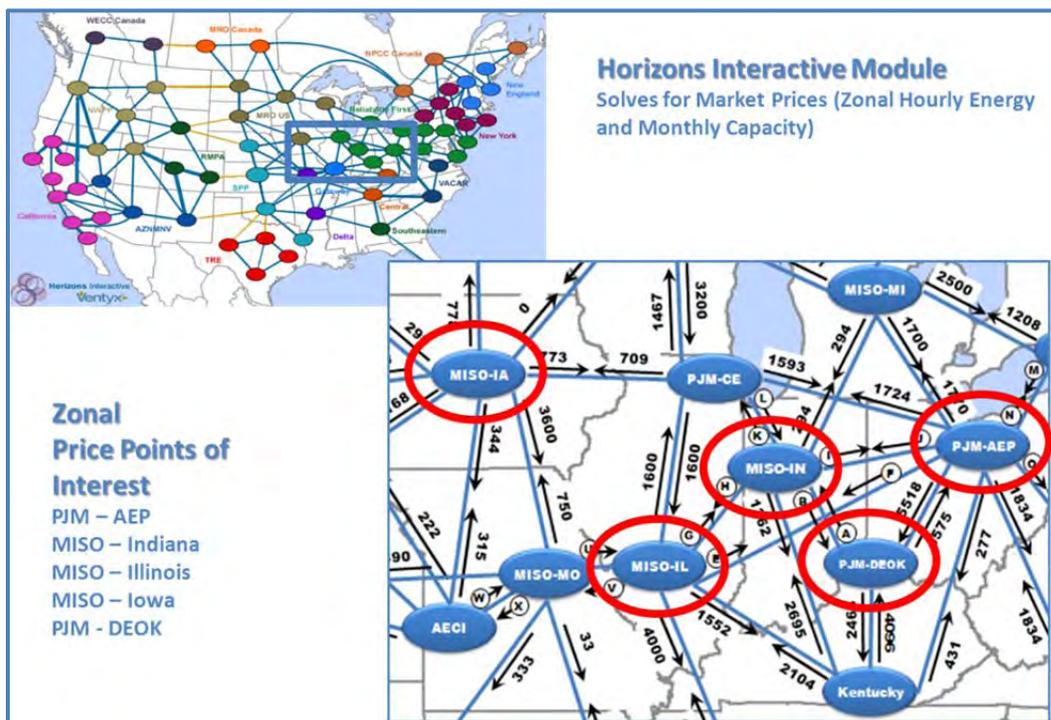
Source: Horizons Interactive

Bid Behavior

Power prices are formed each hour, based on the bids submitted by individual generators. In general, the marginal unit determines the market clearing price where a unit's bid includes variable costs such as fuel, emissions, and variable O&M. In practice, generators employ a wide variety of strategies that are consistent with the cost characteristics of their generating portfolio. Conversely, RTOs forecast demand and run a security-constrained, least-cost dispatch model to select which generators to run to meet the load subject to transmission and other system security constraints.

During high load hours, there may be barely sufficient generation to meet loads. During these times, the revenue collected by individual generators increases with the scarcity and congestion present in the market and can, over time, contribute significantly to the coverage of financing and other fixed costs. The collection of scarcity revenue is consistent with a functioning market, providing a price signal to the market that additional resources may be necessary.

Congestion/Scarcity Function

To capture the market bid behavior, a congestion/scarcity function is added to the system marginal cost curves. A "typical" congestion/scarcity function is shown on the next page. This function is for illustrative purposes only as the actual function(s) are calibrated to mimic the bid behavior of each zone in Horizons Interactive. The inflection points of the curve are adjusted to meet the bid behavior and specific resources in each zone.

For example, the scarcity inflection point for a zone with 95% coal generation would slide far to the right as this zone is price-taker, thus scarcity would likely not be added to their bid. Conversely, the scarcity inflection point for a zone with 50% combustion turbines would slide to the left as this zone would collect scarcity to recover a portion of their start-up and fixed costs else they would prefer not to run the combustion turbines.

The congestion inflection point reflects the impact of low or even negative LMPs. In zones with high congestion, which is often linked to wind generation, the price signal at times may be below marginal cost or even below zero to incent generation to either back down or shut down.

In 2013, MISO implemented its Dispatchable Intermittent Resources (DIR) initiative which allows renewable generation to be treated like any other generation resource in the market and, for the first time, participate in the region's real-time energy market. Now wind can automatically be dispatched within a designated range based on an offer price and wind conditions. This enables wind to submit offers and receive dispatch instructions rather than be manually curtailed when transmission constraints limit renewable energy generation to reach the broader market region.

Figure 15 Congestion/Scarcity Function
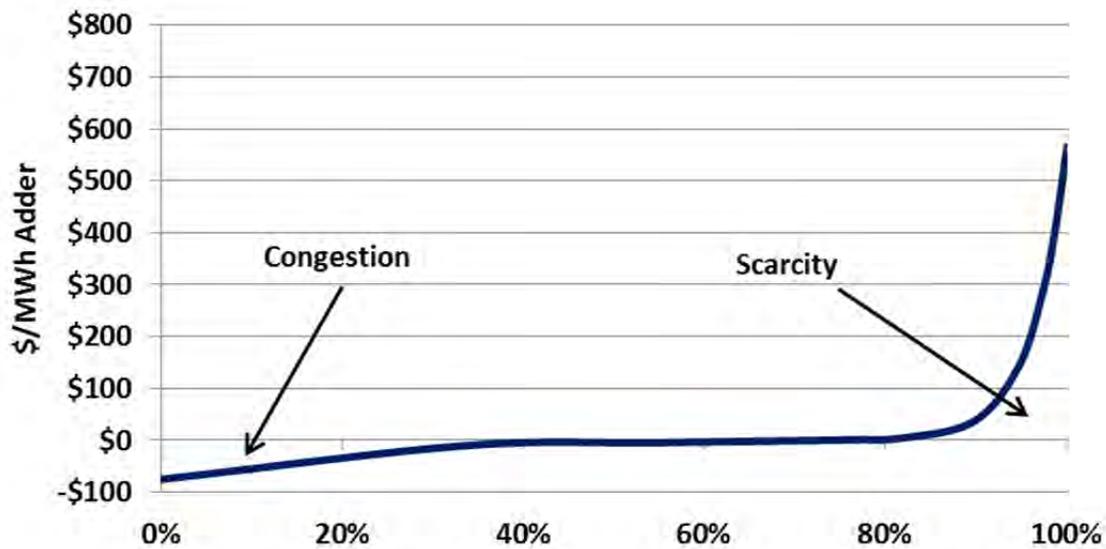
Source: IMPA

Horizons Interactive - Market Database

The Horizons Interactive (Horizons) database is populated with Ventyx Velocity Suite – Market Ops information.

- Operational information is provided for over 11,000 generating units
    - Heat Rates
    - Emissions
    - FO/MO Rates
- Load forecasts by balancing authority and historical hourly load profiles
- Transmission capabilities
- Coal price forecast by plant with delivery adders from basin
- Gas price forecast from Henry Hub with basis and delivery adders

When running the simulation in Horizons, the main process of the simulation is to determine hourly market prices and monthly capacity prices. Unit outages are based on a unit derate and maintenance outages may be specified as a number of weeks per year or scheduled as is the case for nuclear unit refueling schedules.

Resource Expansion

The market-based resource expansion algorithm builds resources from a list of candidate resources based on unit profitability and minimum reserve margin requirements as defined by the capacity demand curve constructs. Non-profitable units are retired based on three consecutive years of failing to recover fixed operating costs.

The market-based resource expansion algorithm is an important aspect of Horizons Interactive as it dynamically adds resources consistent with the rules of the prevailing RTO. For example, PJM utilizes the cost of new entry (CONE) and a variable resource requirement (VRR) curve as shown in the figure below while MISO uses a resource adequacy requirements (RAR) curve.

Figure 16 PJM VRR Curve
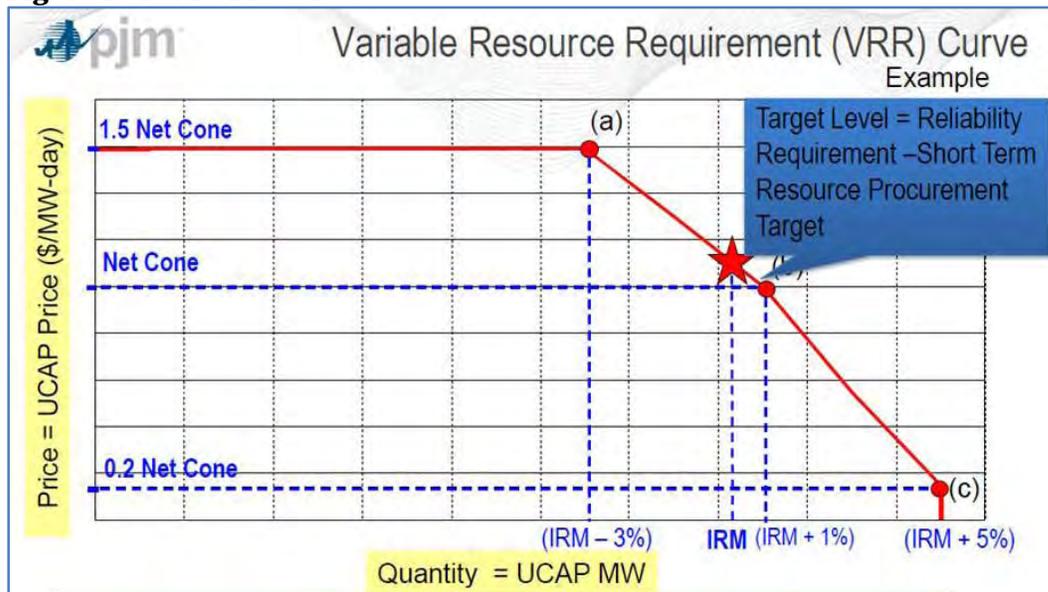
Source: PJM

Zonal Simulation Process

The Horizons Interactive simulation process performs the following steps to determine price:

- Hourly loads are summed for all customers within each zone.
- For each zone in each hour, all available hydro and load modifying renewable power is used to meet firm power sales commitments.
- For each zone and day type, the model calculates production cost data for each dispatchable unit and develops a dispatch order.
- The model calculates a probabilistic supply curve for each zone considering forced and planned outages.
- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among zones.
- The model records and reports details about the generation, emissions, costs, revenues, etc. associated with these hourly transactions.

Nodal Simulation Process

As discussed earlier in this section, IMPA uses Horizons Interactive to solve <u>zonal</u> energy prices for large geographic regions, at a minimum the entire Eastern Interconnection, and often all eight NERC regions. The reason for solving large regions is to capture the full impact of policies (EPA rules, legislation, renewable portfolio standards, etc.) as well as impacts of commodity price swings (natural gas, coal, SO_2, NO_x, CO_2, etc.).

IMPA operates in the MISO and PJM RTOs which utilize <u>nodal</u> energy prices. Nodal prices are determined by matching offers from generators to bids from consumers <u>at each node</u> to develop a supply and demand equilibrium price on an hourly interval.

The price of electricity at each node on the network is a calculated "shadow price", in which it is assumed that one additional megawatt-hour is demanded at the node in question, and the incremental cost to the system that would result from the optimized redispatch of available units establishes the production cost of the megawatt-hour. This is known as nodal or locational marginal pricing (LMP).

There are two generally accepted nodal solutions.
- Security-constrained economic dispatch solution (SCED)
- Zonal flow gate constrained economic dispatch with Nodal Algebraic Model solution (NAM)

SCED: This is the more detailed and resource intensive solution. To create LMPs, MISO and PJM incorporate a security-constrained, least-cost dispatch calculation with supply based on the generators that submitted offers and demand based on bids from load-serving entities at the nodes in question in 5-minute intervals. Where constraints exist on a transmission network, there is a need for more expensive generation to be dispatched on the downstream side of the constraint. Prices on either side of the constraint separate giving rise to congestion pricing. Both RTOs use proprietary software for the creation of LMPs and are generally interested in the formation of day-ahead and real-time LMPs which creates the transparent energy market.
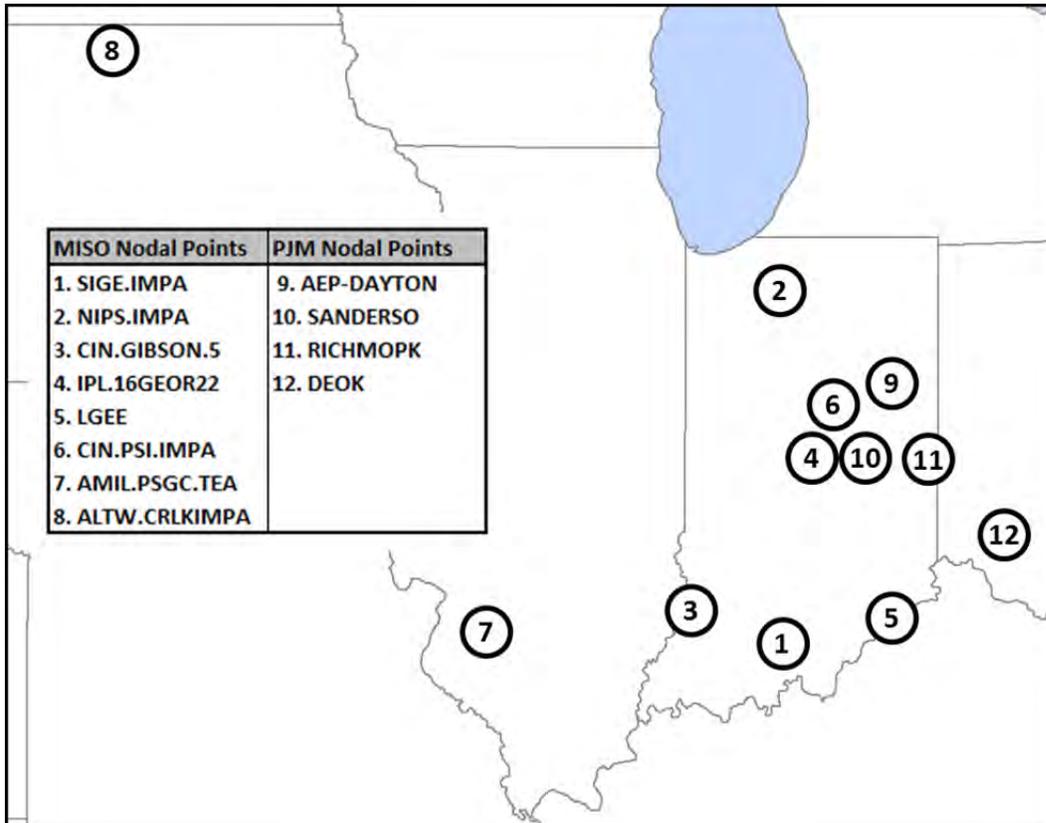
For long-term planning, security-constrained economic dispatch models require detailed knowledge and assumptions of the resources, load, and transmission system. The transmission system is modeled as either an AC or DC power flow simulation to forecast congestion. Unfortunately, SCED models are generally limited to a minimal number of scenarios and years due to the computational time requirements of the software and hardware making it difficult to perform stochastic analysis or even a few scenarios in a timely fashion.

NAM: The NAM technique uses the zonal topology described earlier in this section to solve for zonal hourly market clearing prices for multiple scenarios and years across the entire North American electricity footprint where zones are separated by flow gate transmission constraints. For the formation of nodal prices, an algebraic solution is applied using historical volatility, correlations, and basis spreads between the zonal and nodal points of interest. For long-term planning this technique has enormous benefits as it accommodates multiple scenarios and years. IMPA's methodology is to solve for zonal prices and then apply algebraic hourly spreads to the zonal price to create nodal prices. While this method relies heavily on past historical basis spreads, correlation, and volatility, it is flexible enough to incorporate adjustments to reflect

changes in the resource mix and transmission infrastructure. Since IMPA is interested in 50 stochastic simulations for 20 years, the NAM technique is the preferred solution.

IMPA is generally interested in the following nodal prices.

Figure 17 Nodal Price Points of Interest

MISO Nodal Points	PJM Nodal Points
1. SIGE.IMPA	9. AEP-DAYTON
2. NIPS.IMPA	10. SANDERSO
3. CIN.GIBSON.5	11. RICHMOPK
4. IPL.16GEOR22	12. DEOK
5. LGEE	
6. CIN.PSI.IMPA	
7. AMIL.PSGC.TEA	
8. ALTW.CRLKIMPA	

Source: IMPA

Nodal Algebraic Multipliers: The following figure illustrates an example of the algebraic multipliers for a given node by time-of-day and month. These multipliers are applied to the zonal forecast in the zone in which they reside.

Figure 18 Nodal Algebraic Multipliers
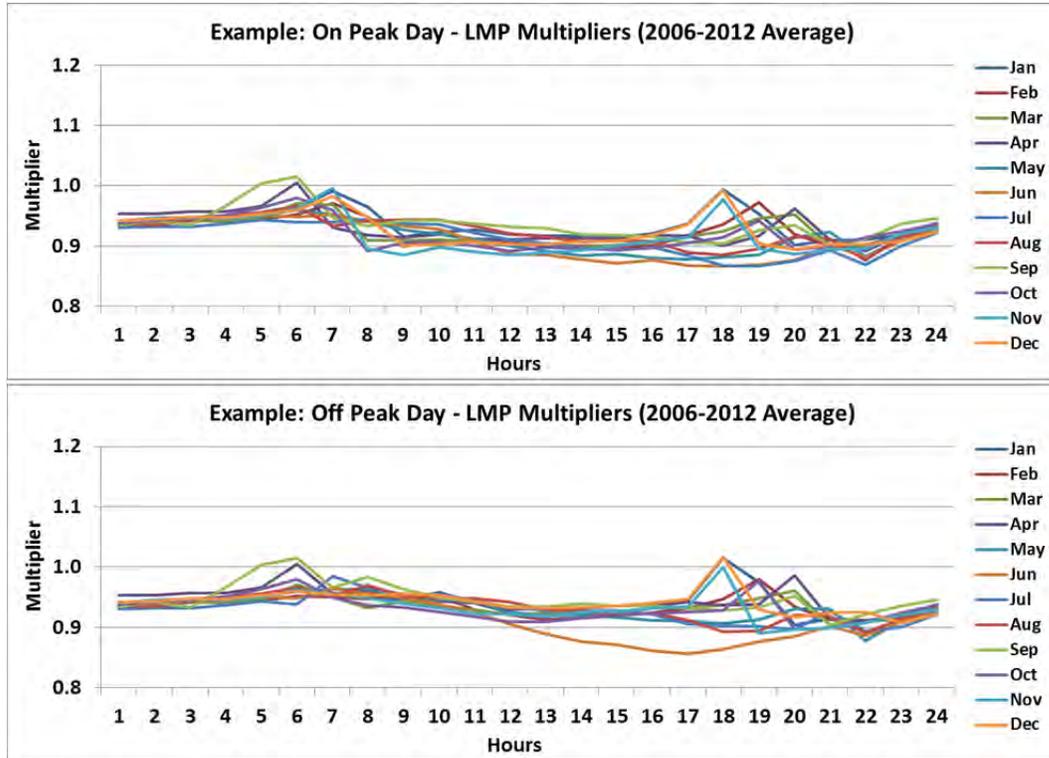
Source: IMPA

10.2 HORIZONS INTERACTIVE – DETERMINISTIC PROCESS

The formation of market energy and capacity prices begins with a reference case to reflect baseline assumptions for fuel, loads, transmission, congestion, environmental policy, retirements, etc. The reference case is also commonly referred to as the deterministic case. In this report, all forecasts are in current ("nominal") dollars. The study period is defined as 2014-2033.

Sources

IMPA's database uses a mix of publicly available forecasted information and IMPA proprietary information from a variety of sources.

Table 11 Data Sources

Source Title	Publishing Address
Annual Energy Outlook 2012 *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants April 2013*	U.S. Energy Information Administration Office of Communications, EI-40 Forrestal Building, Room 1E-210 1000 Independence Avenue, S.W. Washington, DC 20585
Velocity Suite Database	Ventyx 1495 Canyon Blvd, Suite 100 Boulder, CO 80302
SNL Database	SNL Financial LC One SNL Plaza PO Box 2124 Charlottesville, Virginia 22902
Planning Year 2011 LOLE Study *Multi Value Project Portfolio*	Midcontinent ISO (MISO) 701 City Center Drive Carmel, IN 46032
PJM's Reliability Pricing Model	The Brattle Group 1850 M Street NW, Suite 1200 Washington, DC 20036
2012 Long-Term Reliability Assessment	North America Electric Reliability Corporation (NERC) 3353 Peachtree Road NE, Suite 600 North Tower Atlanta, GA 30326
North American Gas and Power Scenarios	IHS CERA 55 Cambridge Parkway Cambridge Massachusetts 02142
GenHub Database	PennWell Corporation 1455 West Loop, Suite 400 Houston, TX 77027

Forward View Approach

IMPA created a forward view of the MISO and PJM electricity markets. The forward view is a proprietary perspective of the future based on public or commercial information and IMPA's experience in working in electricity markets. This fundamental approach relies on first identifying the basic components of electricity price: supply, transmission and demand, and, using best available sources, projecting the components over time and geography.

The following figure shows the electricity zones and their interconnections.

Figure 19 MISO-PJM Centric Zonal Topology
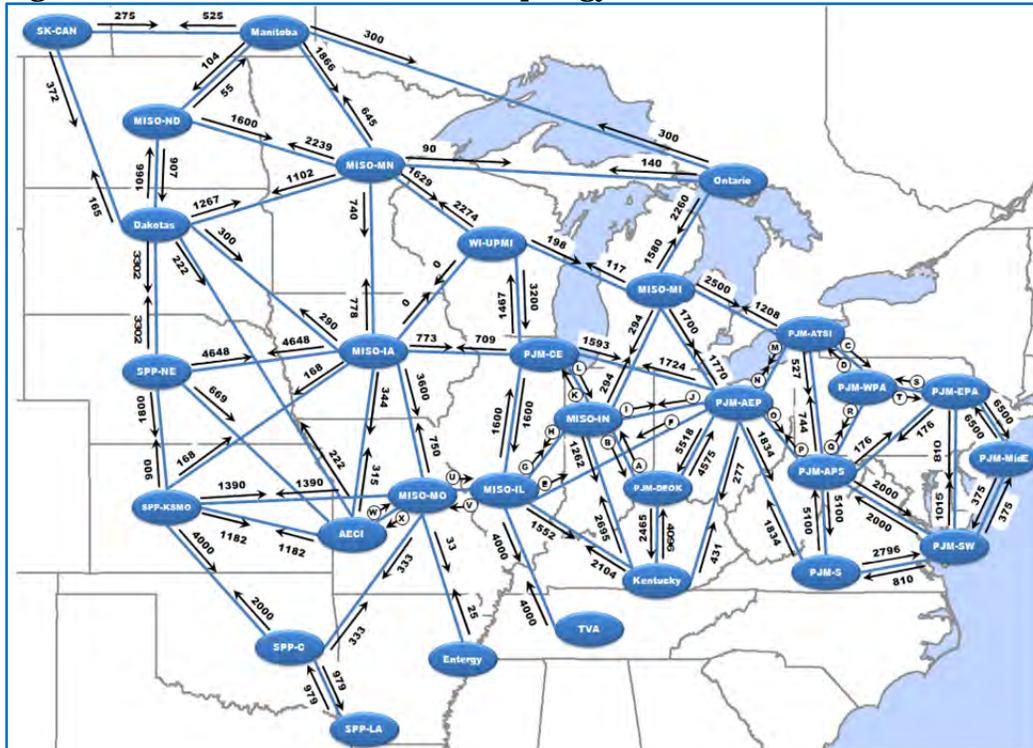
Source: Horizons Interactive

Natural Gas

IMPA generated a natural gas price forecast that was representative of the then current NYMEX pricing (April 29, 2013) and blended to EIA's AEO2012 forward view.

Table 12 Natural Gas Outlook

Forecast Phase	Period Length	Data Source	Forecast Technique
Futures Driven	First 77 Months (Jan 2014 - May 2020)	NYMEX Henry Hub futures (April 29, 2013)	Calculated Henry Hub and liquid market center differentials
Long-term Trend	Remaining forecast period (to 2033)	EIA AEO2012	EIA fundamental supply and demand analysis using the NEMS forecasting model

To derive the burner-tip forecasts used, IMPA examined regional prices and basis swaps at a number of trading hubs. Using this historical data, IMPA developed a differential price between the appropriate market center nearest to the power plant and the Henry Hub.

Figure 20 Natural Gas Market Centers

Source: Horizons Interactive

Burner-tip gas price for each gas-fired generation plant in a region is developed by taking the hub price and adding a regional transportation adder. This amount depends on the plant's location relative to the basins or hubs, and the economics of transporting gas, including compressor fuel used and pipeline tariffs/discounts, to the plant's burner-tip. The commodity and transportation components of natural gas burner-tip prices are forecast separately and then assembled to derive the prices paid by generation plants appropriate to their geographic location.

Table 13 Average Delivered Natural Price ($/MMBtu)

	Henry Hub	MichCon Gate	Chicago	Lebanon	Ventura	Dominion South
2014	REDACTED					
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						

Source: IMPA

The EIA2012 reference case projects natural gas price to escalate at 4.5 percent per year.

**Figure 21 Natural Gas Henry Hub History/Forecast**
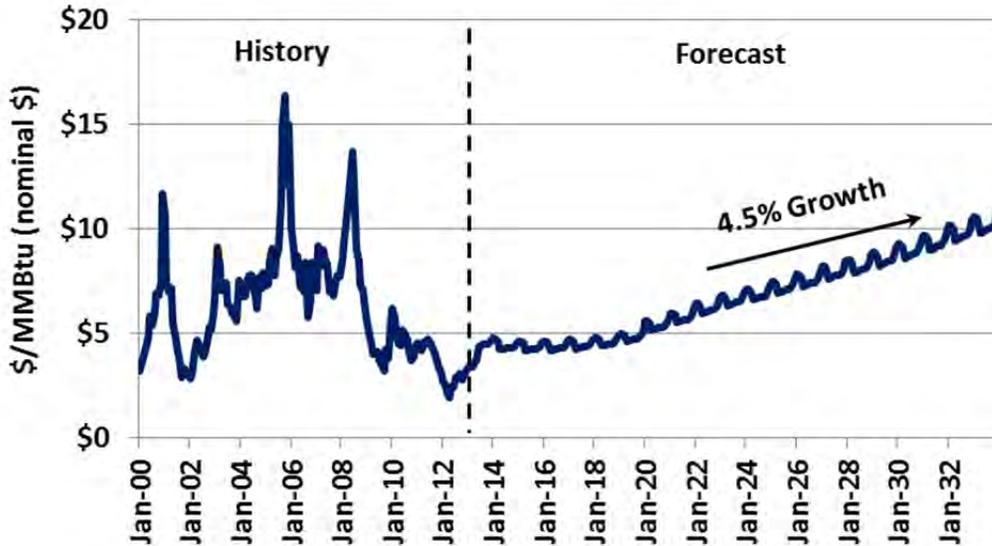
Source: IMPA

As shown by the historical portion of the graph, natural gas has proven to be a highly volatile commodity. If U.S. natural gas exports increase due to new LNG facilities, there will likely be an upward pressure on natural gas price as the "world price" of natural gas is on the order of 4 times higher than the present U.S. price. Shown below are the proposed and potential North America LNG terminals.

Figure 22 Proposed/Potential LNG Terminals

|	
1 Robbinston	2 Astoria
3 Corpus Christi	4 Offshore NY
5 Freeport	6 Corpus Christi
7 Coos Bay	8 Lake Charles
9 Hackberry	10 Cove Point
11 Astoria	12 Lavaca Bay
13 Elba Island	14 Sabine Pass
15 Lake Charles	16 Plaquemines
17 Sabine Pass	18 Kitimat
19 Douglas Islnd	20 Kitimat
21 Brownsville	22 Pascagoula
23 Cameron	24 Ingleside
25 Cameron	26 Cameron
27 Gulf of Mex	28 Goldboro
29 Prince Rupert	30 Melford
31 Prince Rupert	32 Prince Rupert
33 Squamish	
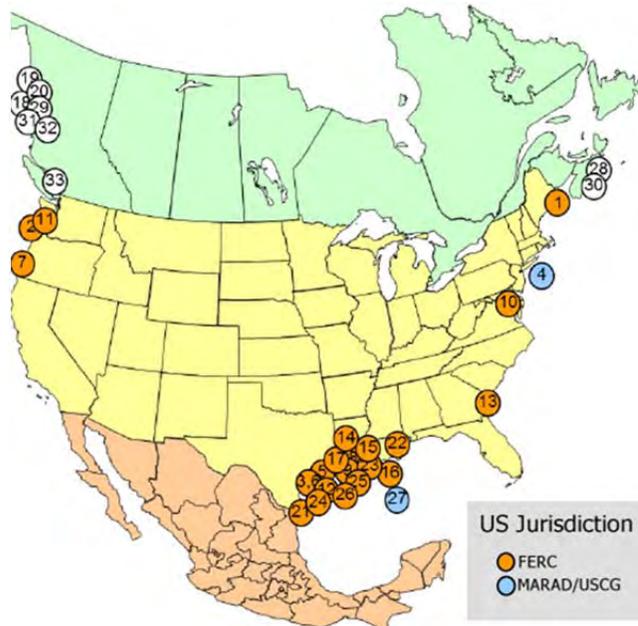
Source: FERC (as of July 25, 2013)

Horizons Interactive Loads

Monthly peak load and energy forecasts are projected for each balancing authority based on historical values and assumed growth from a variety of public and private sources.

The graph below shows the forward view of U.S. electricity demand.

Figure 23 U.S. Electricity Demand (Energy)
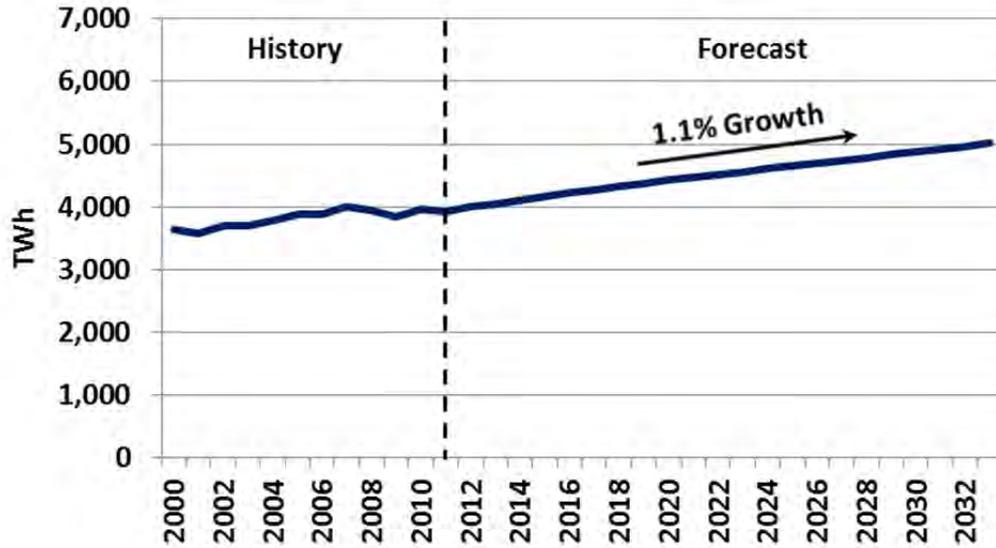
Source: Horizons Interactive

Coal Retirements

It is expected a significant amount of coal-fired generation will be retired over the study period largely due to the capital investment required to comply with the EPA Mercury and Air Toxics Standards (MATS).

The map below identifies the location of the assumed retirements over the study period in which 18% of the coal capacity (56 GW) will be retired by 2033. A large share of the retirements is concentrated in two North American Electric Reliability Corporation (NERC) regions: the SERC Reliability Corporation (SERC), which covers the Southeast region and the Reliability First Corporation (RFC), which includes most of the Mid-Atlantic and Ohio Valley region.
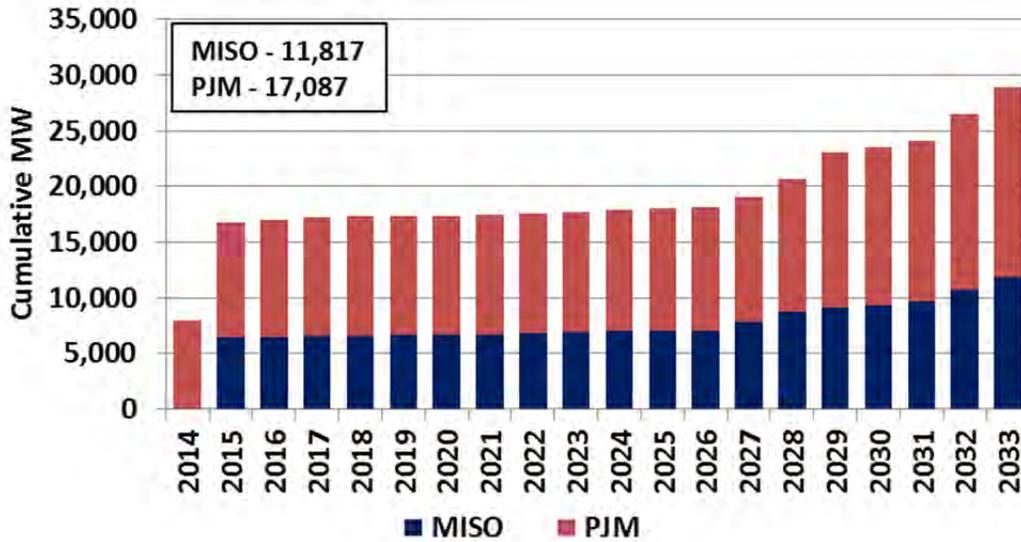
Figure 24 Projected Coal Retirements (2014-2033)

Source: Horizons Interactive

The following figure illustrates the assumed coal-fired generation retirements (29 GW) in the MISO/PJM RTOs. This figure represents about 20% of the current coal fleet.

**Figure 25 MISO/PJM Coal Retirements**

Source: IMPA

Resource Expansion

Announced new generating units plus generic units that were selected by the Horizons Interactive market-based resource expansion algorithm are shown in the graph below for the MISO/PJM RTOs. The units were added to replace retiring coal units and meet projected load growth. The renewable units (wind and solar) were added to meet state-level RPS standards.

Figure 26 MISO/PJM Resource Expansion
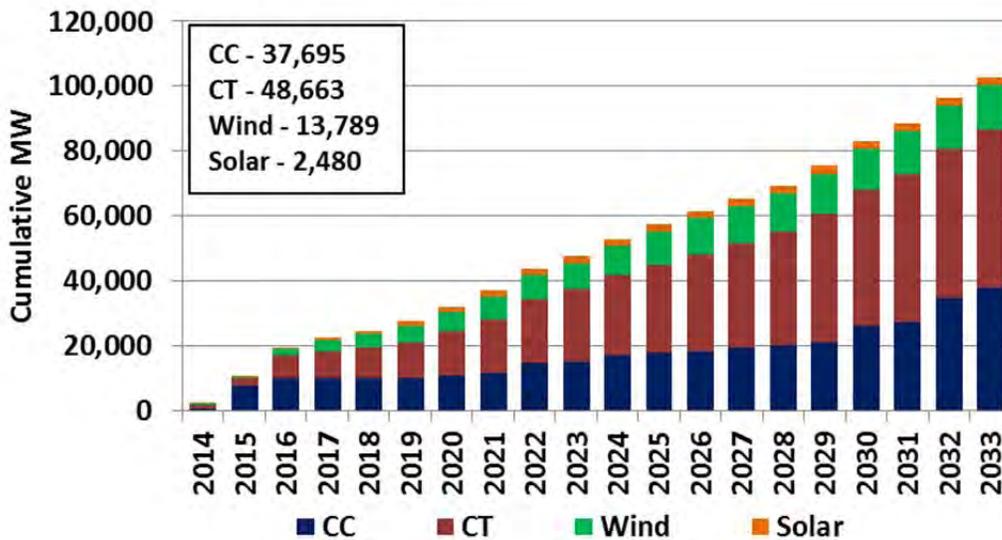
Source: IMPA

Transmission

The transmission transfer capability between Zones is determined from the most recent AC load flow studies. Likely transmission additions such as the MISO MVP are added to the database to incorporate their impact on the transmission transfer capability and energy and capacity prices.
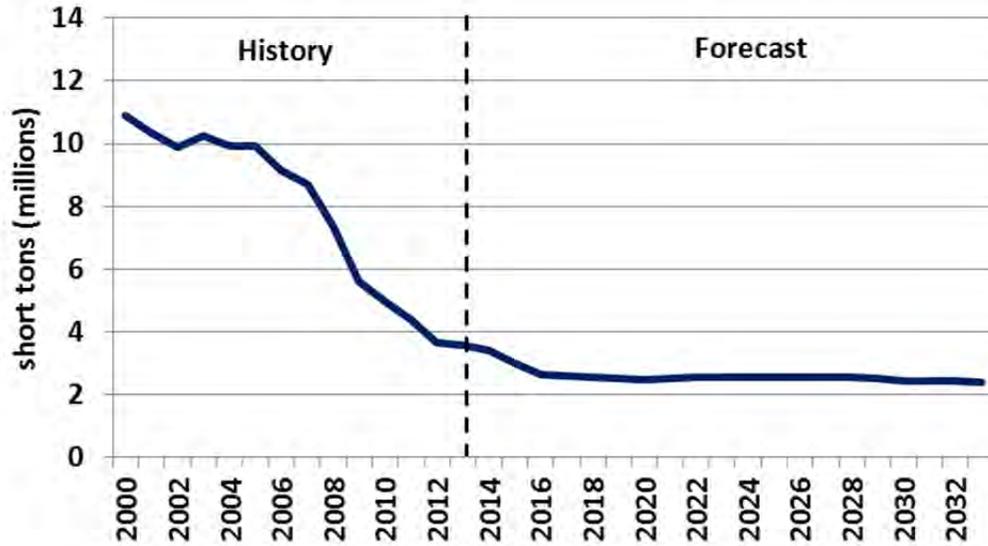
Figure 27 MISO MVP Portfolio
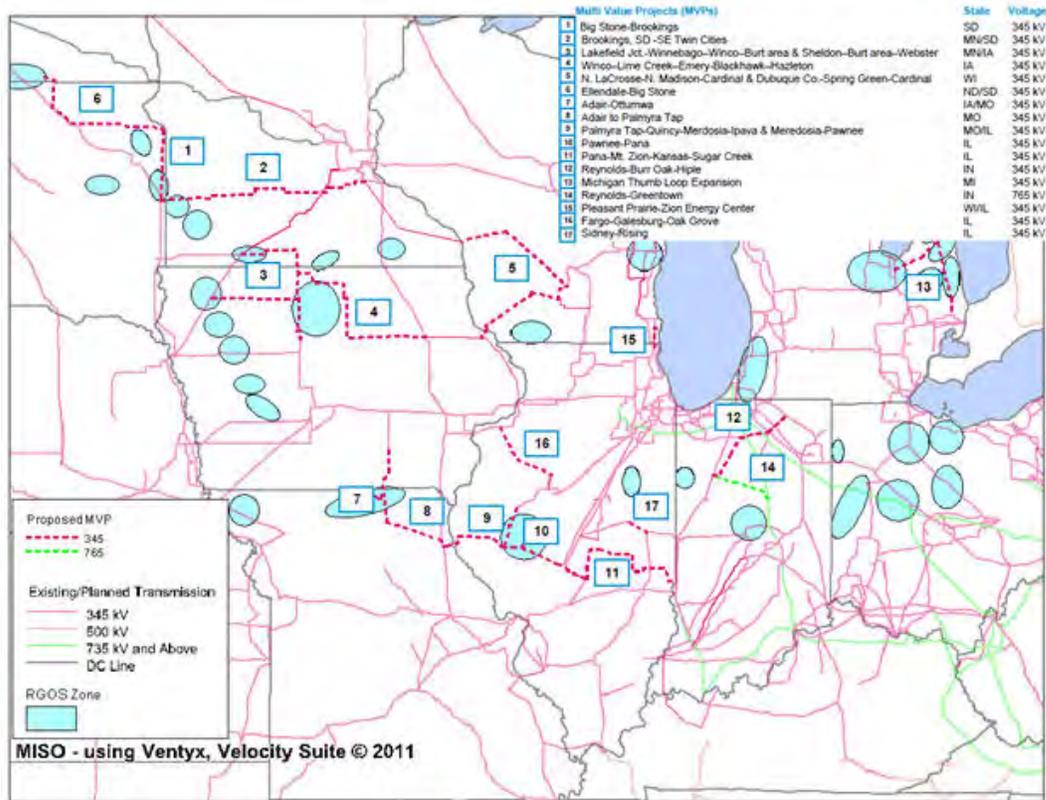
Source: MISO

10.3 HORIZONS INTERACTIVE – DETERMINISTIC RESULTS

SO$_2$ Emissions

U.S. SO$_2$ emissions are projected to be significantly lower as a result of coal-fired capacity retirements and the installation of pollution control equipment.

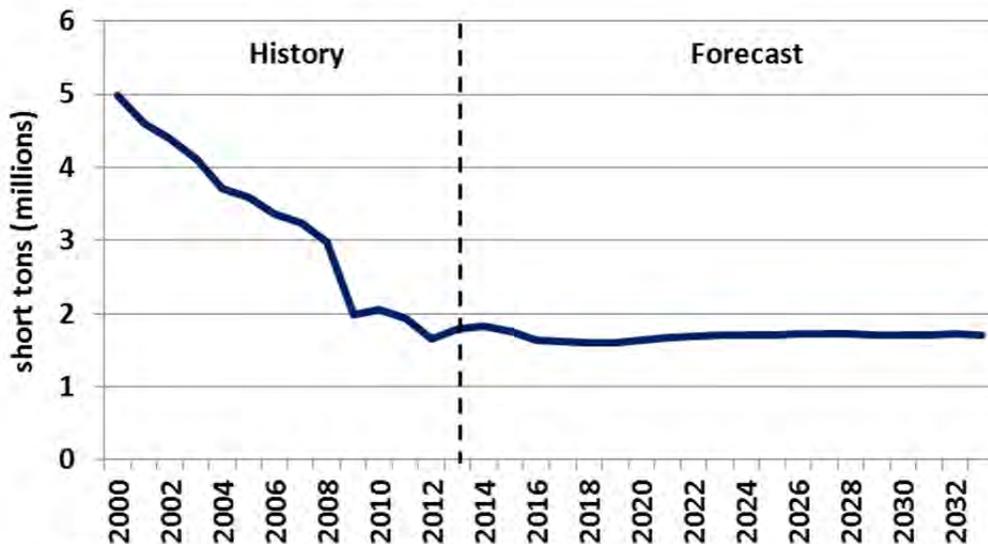**Figure 28 U.S. Power Sector SO$_2$ Emissions**

Source: IMPA

U.S. NO$_x$ Emissions

U.S. NO$_x$ emissions are projected to drop slightly as a result of coal-fired capacity retirements.

Figure 29 U.S. Power Sector NO$_x$ Emissions

Source: IMPA

U.S. CO_2 Emissions

By the end of the study period, CO_2 emissions are projected to rise by 8.4% over 2005 levels which the Obama administration has used as the base year CO_2 emission level. While the overall long-term coal burn declines due to coal-fired generation retirements and is replaced by combined cycle gas generation which emits approximately 63% less CO_2 compared to the retired coal units, the overall emission level increases primarily due to load growth.

Figure 30 U.S. Power Sector CO_2 Emissions
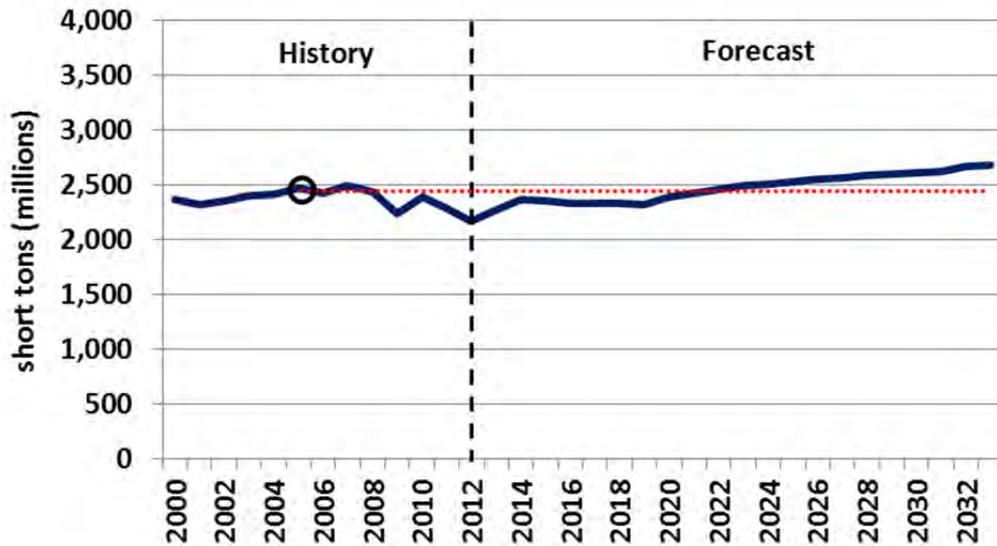
Source: IMPA

Electric Wholesale Prices
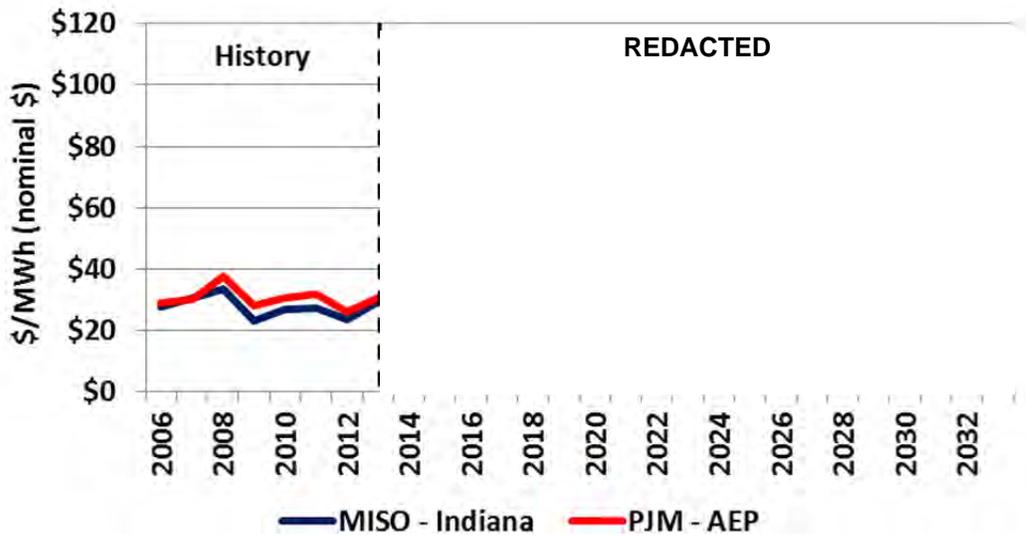
On peak and off peak wholesale prices are expected to _____ and _____ espectively, which is _____ the projected natural gas _____. The growth differential is attributable to the shift from coal towards natural gas as the marginal fuel.

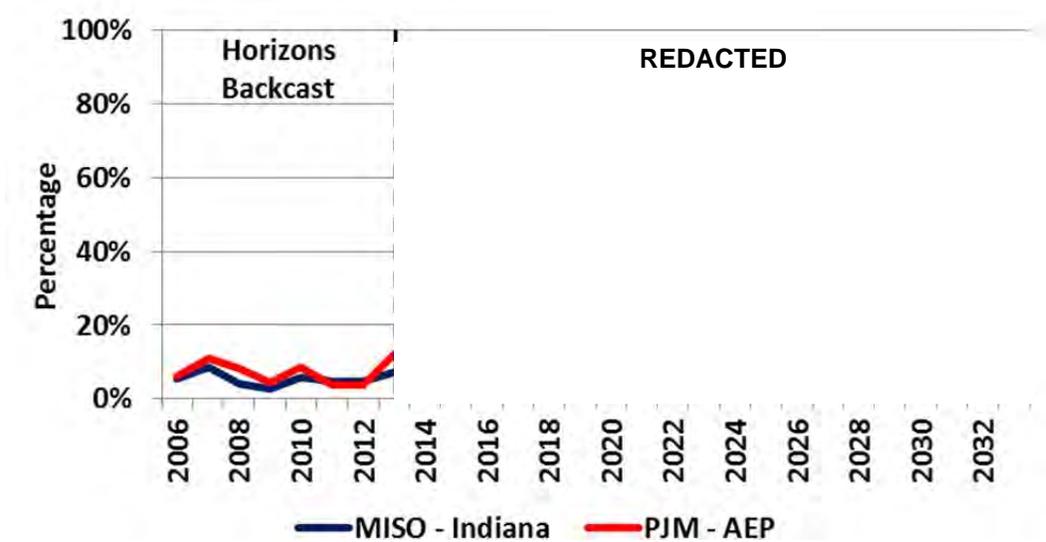**Figure 31 MISO - Indiana and PJM – AEP 5x16 Market Prices**
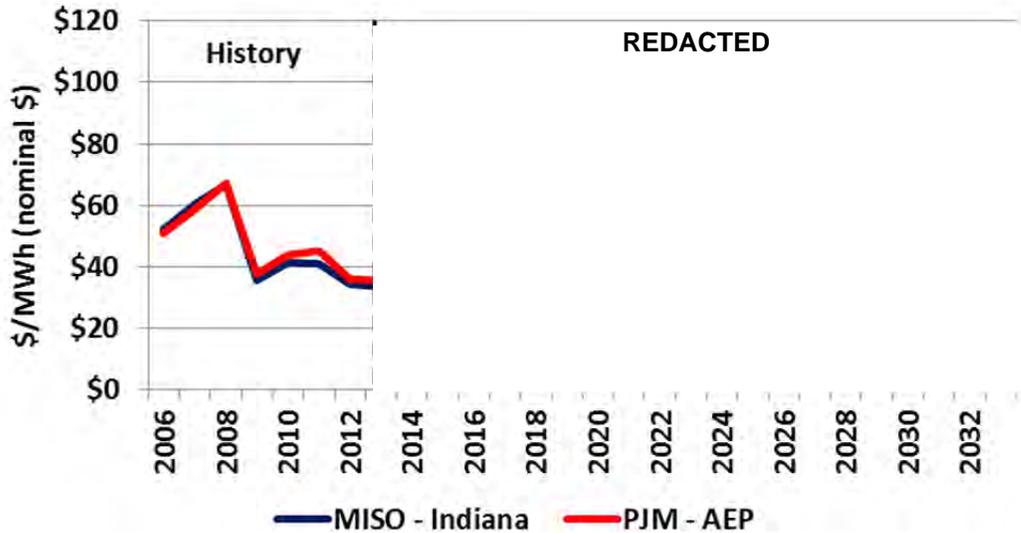
Source: IMPA

Figure 32 MISO - Indiana and PJM – AEP Wrap Market Prices

Source: IMPA

As coal-fired generation is retired and is replaced by natural gas, it is projected that more natural gas will be on the margin.

Figure 33 Natural Gas Marginal Fuel Percentage

Source: IMPA

Electric Capacity Prices

Historic and projected capacity prices for the MISO and PJM zones are shown in the graph below. The MISO auction commits capacity 1-year ahead (2013/2014) while the PJM auction commits capacity 3-years ahead (2016/2017). The purpose of the IMPA capacity market forecast is to provide the direction and magnitude of capacity prices, but the outcome in specific years is subject to great uncertainty due to the timing of retirements, additions, participant bid behavior and regulatory uncertainty.

Figure 34 MISO-IN (LRZ6), PJM-RTO, MISO-IL (LRZ4) Capacity Prices
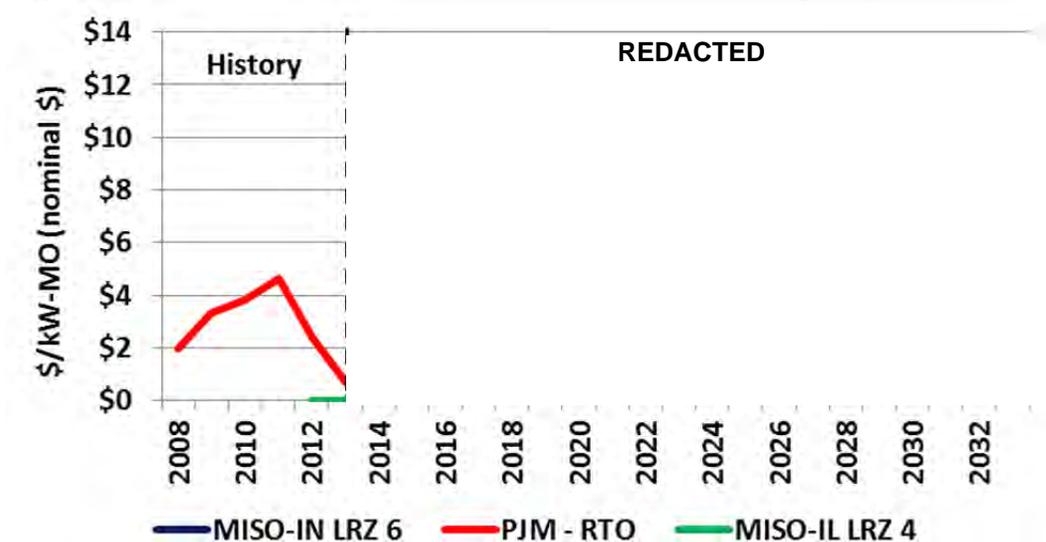
Source: IMPA

10.4 HORIZONS INTERACTIVE – STOCHASTIC PROCESS

Horizons Interactive is an integrated market model which uses a structural approach for forecasting prices that captures the uncertainties in regional electric demand, resources and transmission, and provides a solid basis for decision-making. Using a stratified Monte Carlo sampling program, which is referred to as the Latin Hypercube, Horizons Interactive generates regional forward price curves across multiple stochastic futures (draws). The draws are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, unit availability, hydro output, capital expansion cost, transmission availability, reserve margin, emission price, weather, etc.) and take into account statistical distributions, correlations, and volatilities.

Stratified sampling can be thought of as "smart" Monte Carlo sampling. Instead of drawing each sample from the entire distribution – as in Monte Carlo sampling – the sample space is divided into equal probability ranges and then a sample is taken from each range.

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

- Quantifies the uncertainties that drive market price through a Stratified Monte Carlo sampling model (Latin Hypercube);
- Puts the uncertainties into a decision tree;
- Evaluates multi-region, hourly market price for a set of consistently derived futures using Horizons Interactive; and
- Accumulates the information into expected forward price and volatility of the marketplace.

The uncertainty drivers were developed for the IMPA specific zones of interest (MISO-Indiana, MISO-Iowa, MISO-Illinois, PJM-AEP, and PJM-DEOK) as well as all of the other zones in the Horizons Interactive market model.

Uncertainty Variables

For the price trajectories, IMPA examined the impact of load, fuel price, emissions, and supply on regional spot market energy and capacity prices. Specifically, the following uncertainties were evaluated:

Demand
- Long-Term Electricity Demand Growth
- Mid-Term Peak Demand
- Mid-Term Energy
- Reference Load Shape Year

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

Emissions
- Long-Term CO_2 Price

Supply
- Long-Term Capital Costs

- Mid-Term Coal Unit Availability

Congestion

- Mid-Term Congestion

Horizons Interactive – Stochastic Simulation Time

For its stochastic process, IMPA creates 50 stochastic futures. Fifty (50) trajectories strike a balance between the number of stochastic futures required for a comprehensive solution and a manageable number of simulations.

IMPA's technique for creating stochastic market prices is very resource intensive because the hourly zonal market price for each future is computer simulated, not mathematically estimated. While the Horizons Interactive market model is widely considered one of the fastest commercial software models for zonal market price simulation, the simulation time to create 50 stochastic futures including the nodal algebraic model (NAM) simulation for creating LMPs takes nearly eight (8) days using a desktop PC workstation with 12 GB of RAM, 64-bit operating system, and a 3.2GHz clock speed.

Figure 35 Horizons Interactive Stochastic Process
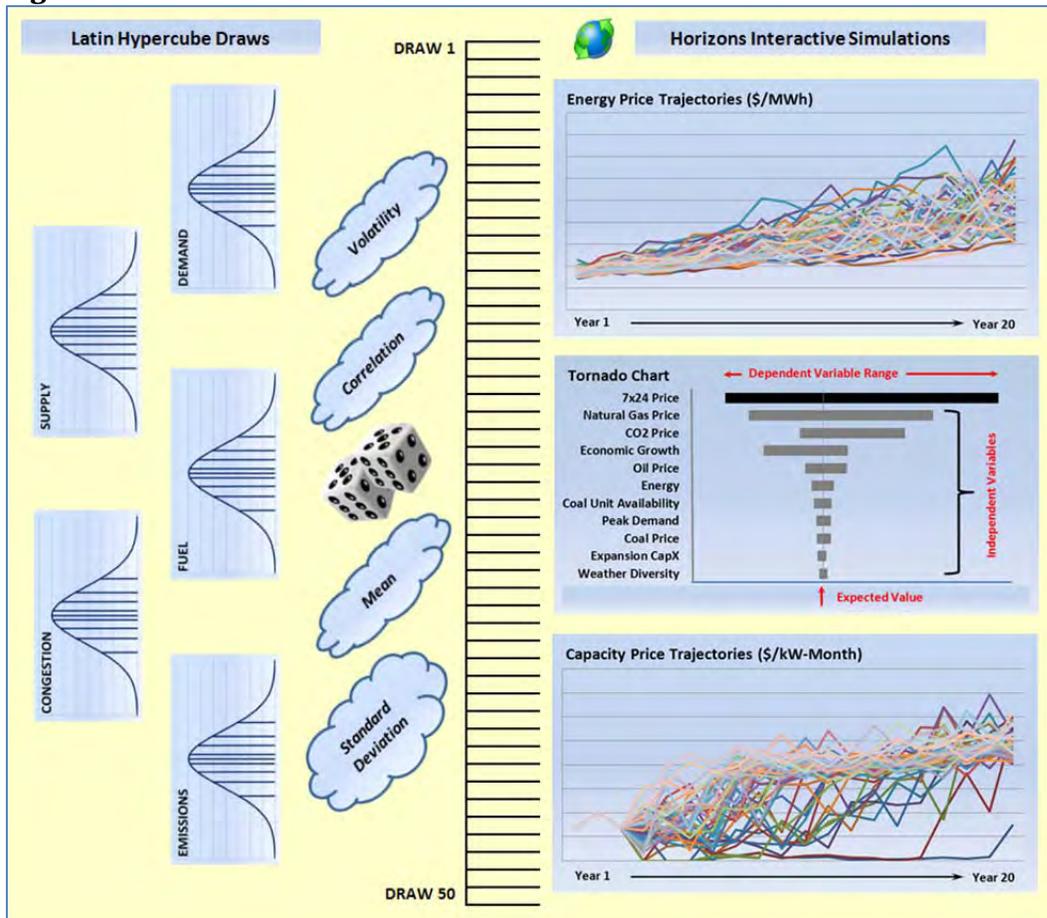
Source: IMPA

10.5 LONG-TERM UNCERTAINTIES

IMPA built its long-term stochastic draws based on the underlying projections of the *EIA Annual Energy Outlook 2012* (AEO2012). The EIA projections provide the key input drivers of electricity price such as fuel price and demand which supplement IMPA's proprietary assumptions and projections.

EIA Annual Energy Outlook 2012

The National Energy Modeling System Projections in the AEO2012 are generated using the NEMS, developed and maintained by the Office of Energy Analysis of the U.S. Energy Information Administration (EIA). The projections in NEMS are developed with the use of a market-based approach, subject to regulations and standards. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and 8 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs).

NEMS is organized and implemented as a modular system shown in the figure below.

Figure 36 EIA National Energy Modeling System (NEMS)

Source: U.S. Energy Information Administration. Office of Energy Analysis. eia
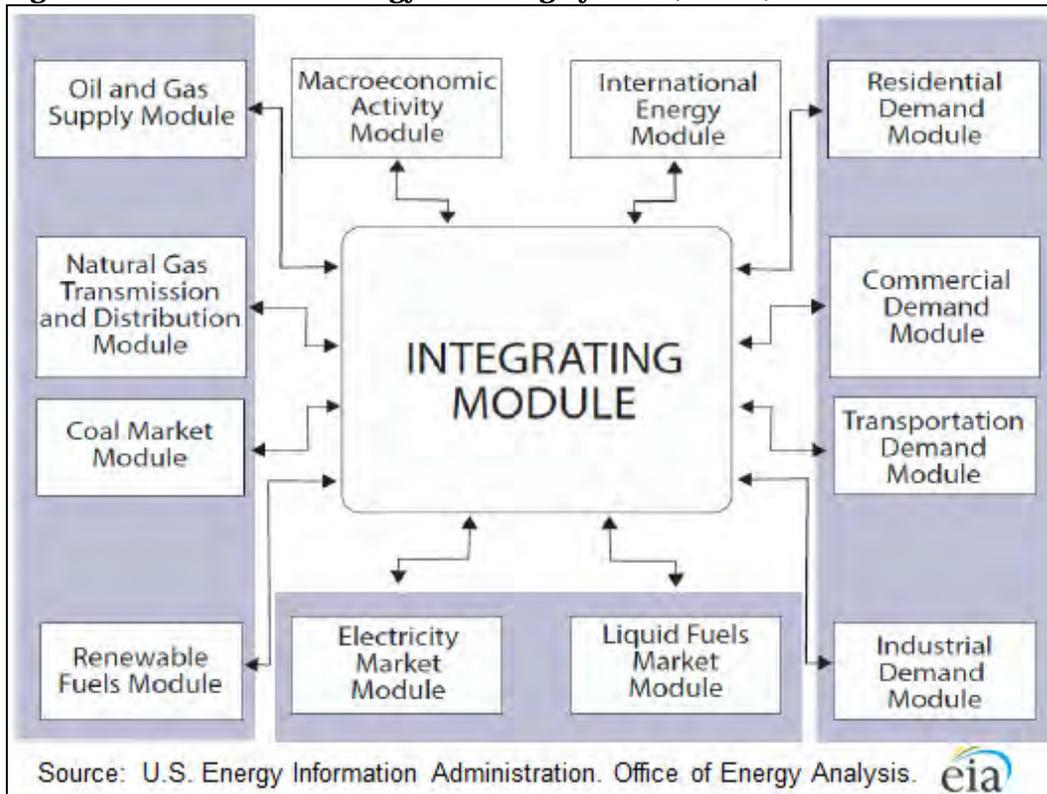
Source: EIA

The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users.

The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors for each year. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence. Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury from the electricity generation sector.

EIA2012 Cases

Projections by the EIA are not statements of what will happen but of what might happen, given the assumptions for any particular case. To that end, the EIA developed a reference case (business as usual estimate) and 29 additional cases for Annual Energy Outlook 2012.

The 30 EIA cases are briefly described below.

Table 14 EIA Annual Energy Outlook 2012 – 30 Cases

Reference	HDV NG Potential	Low Coal Cost
Low Economic Growth	Low Nuclear	High Coal Cost
High Economic Growth	High Nuclear	2011 Demand Tech
Low Oil Price	Reference 05	Best Demand Tech
High Oil Price	Low Gas Price 05	High Demand Tech
No Sunset	Low Renew Tech Cost	2011 Technology
Extended Policies	Petroleum: LFMM	High Technology
CAFE Standards	Low EUR	No GHG Concern
High Technology Battery	High EUR	GHG15
HDV NG Reference	High TRR	GHG25

Source: EIA

1. Reference: Business as usual (BAU)
2. Low Economic Growth: Real GDP grows at an average annual rate of 2.0 percent.
3. High Economic Growth: Real GDP grows at an average annual rate of 3.0 percent.
4. Low Oil Price: Low prices result from a combination of lower demand for petroleum and higher global supply.

5. High Oil Price: High prices result from a combination of higher demand for petroleum and lower global supply.

6. No Sunset: Assumes extension of all existing energy policies and legislation and periodic updates of efficiency standards.

7. Extended Policies: Assumes extension of all existing energy policies and legislation and periodic updates of efficiency standards as well as new standards for products not yet covered.

8. Transportation - CAFE Standards: Assumes proposed EPA and NHTSA Corporate Average Fuel Economy (CAFE) standards are implemented changing the vehicle sales mix.

9. Transportation - High Technology Battery: Explores the impact of significant improvement in vehicle battery cost and performance.

10. Transportation - HDV NG Reference: Market acceptance of heavy duty vehicles (HDV) powered by natural gas (NG).

11. Transportation - HDV NG Potential: Market acceptance of heavy duty vehicles (HDV) powered by natural gas (NG) and assumed expansion of the natural gas refueling infrastructure.

12. Electricity - Low Nuclear: Assumes all nuclear plants are limited to a 60-year life.

13. Electricity - High Nuclear: Assumes all nuclear plants are life-extended beyond 60 years.

14. Electricity - Reference 05: Reduced environmental investment recovery to meet MATS.

15. Electricity - Low Gas Price 05: Reduced environmental investment recovery to meet MATS combined with an estimated ultimate recovery (EUR) which is 50 percent higher than the Reference Case.

16. Renewable Fuels – Low Renewable Technology Cost: Costs for new non-hydropower renewable technologies start 20 percent lower in 2012 and decline to 40 percent lower by 2035.

17. Petroleum - LFMM: Changes in EIA's liquid fuels market module redefining the refining regions on the basis of market potential and available feedstocks.

18. Oil and Gas - Low EUR: The estimated ultimate recovery (EUR) is 50 percent lower than the Reference Case.

19. Oil and Gas - High EUR: The estimated ultimate recovery (EUR) is 50 percent higher than the Reference Case.

20. Oil and Gas – High Technically Recoverable Resources (TRR): The technically recoverable reserves (TRR) allow for more wells per square mile and the estimated ultimate recovery (EUR) is 50 percent higher than the Reference Case.

21. Coal - Low Coal Cost: Mining productively is 2.8 percent higher than the Reference Case and mining expenses are 21 and 25 percent lower.

22. Coal - High Coal Cost: Mining productively is 2.8 percent lower than the Reference Case and mining expenses are 25 and 27 percent higher.

23. Integrated 2011 Demand Technology: Assumes future equipment purchases in the residential and commercial sectors are based on what was available in 2011.

24. Integrated Best Available Demand Technology: Assumes all future equipment purchases in the residential and commercial sectors are made from only the most efficient models available.

25. Integrated High Demand Technology: Assumes earlier availability of lower cost, higher efficiency equipment for the residential and commercial sectors.

26. Integrated 2011 Technology: Combination of Integrated 2011 Demand Technology with assumption costs of new power plants do not improve.
27. Integrated High Technology: Combination of Integrated High Demand Technology and the Low Renewable Technology Cost case.
28. No GHG Concern: No GHG emissions policy is enacted.
29. $15 GHG: Applies a price for CO_2 emissions starting at $15 per metric ton in 2013 rising by 5 percent per year.
30. $25 GHG: Applies a price for CO_2 emissions starting at $25 per metric ton in 2013 rising by 5 percent per year.

IMPA 50 Long-Term Stochastic Draws

To capture long-term uncertainty for its IRP, IMPA extrapolated the trends from the 30 EIA Cases into 50 long-term stochastic draws which were coupled with IMPA's medium-term and short-term proprietary stochastic draws.

Long-Term Uncertainty – Electricity Demand Growth

The upper bound of the long-term electricity demand growth is tied to the *High Economic Growth* case in which real GDP grows at an average annual rate of 3.0 percent. The lower bound is tied to the *Integrated Best Available Demand Technology* case where all future equipment purchases in the residential and commercial sectors are made from only the most efficient models available. The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

**Figure 37 Long-Term Electricity Demand Growth – 50 Draws**
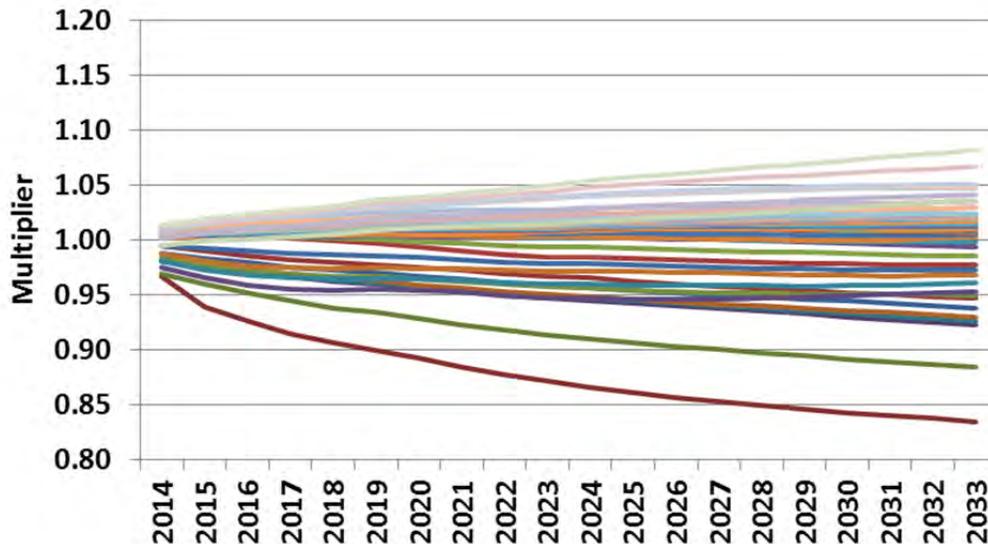
Source: EIA/IMPA

Long-Term Uncertainty – Natural Gas Price

The upper bound of the long-term natural gas price growth varies over time and is tied to three EIA cases. The initial upper bound is tied to the *$25 GHG* case where the price for CO_2 emissions starts at $25 per metric ton in 2013 and rises by 5 percent per year resulting in increased natural gas consumption. In 2026, the *$25 GHG* case is replaced by the *Low EUR* case where the EUR of

natural gas is 50 percent lower than the Reference Case resulting in decreased natural gas supply. In 2032, the *Low EUR* case is replaced by the *Low Economic Growth* case where real GDP grows at an average annual rate of 2.0 percent. While the last case is somewhat counterintuitive in terms of higher natural gas price, in EIA's view the macroeconomic effect of a lower real GDP disrupts the natural gas supply and consumption balance resulting in higher natural gas prices. The biggest driver is that the first two cases decline over time whereas the last case steadily increases over time.

The lower bound is tied to the *High TRR* case where the TRR allow for more wells per square mile and the EUR is 50 percent higher than the Reference Case. The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

Figure 38 Long-Term Natural Gas Price – 50 Draws
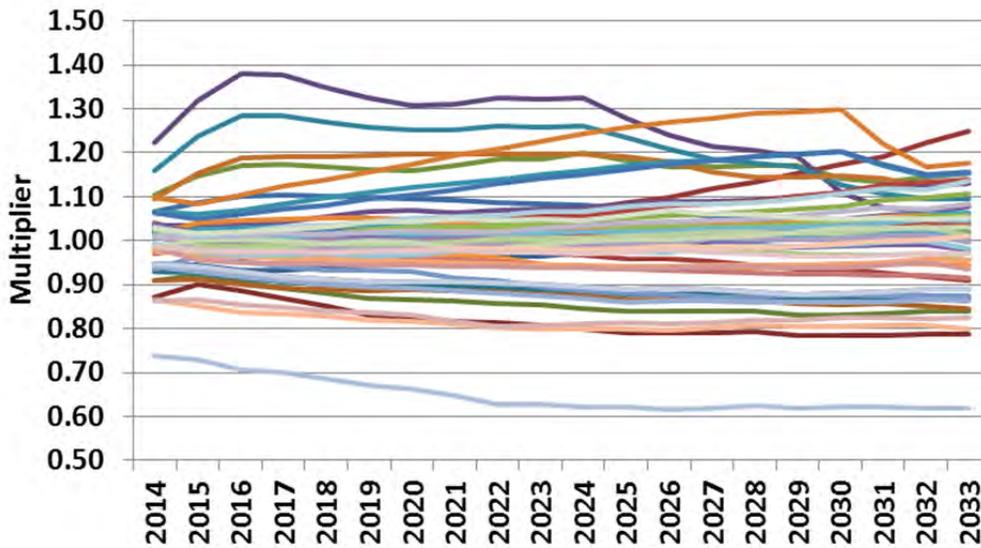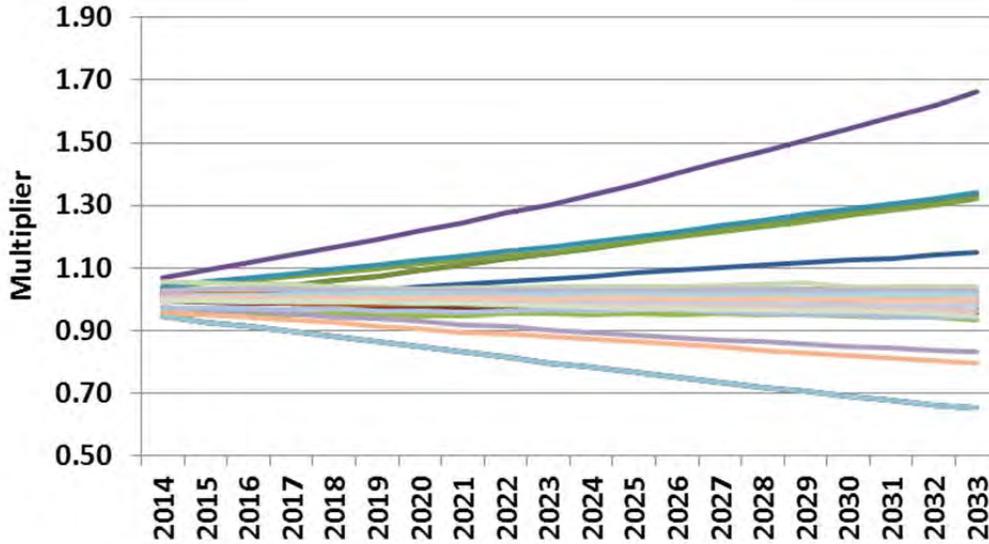

Source: EIA/IMPA

Long-Term Uncertainty – Coal Price

The upper bound of the long-term coal price growth is tied to the *High Coal Cost* case where the mining productivity is 2.8 percent lower than the Reference Case and mining expenses are 25 and 27 percent higher. The lower bound is tied to the *Low Coal Cost* case where the mining productivity is 2.8 percent higher than the Reference Case and mining expenses are 21 and 25 percent lower. The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

**Figure 39 Long-Term Coal Price – 50 Draws**

Source: EIA/IMPA

Long-Term Uncertainty – Oil Price

The upper bound of the long-term oil price growth is tied to the *High Oil Price* case where high prices result from a combination of higher demand for petroleum and lower global supply. The lower bound is tied to the *Low Oil Price* case where low prices result from a combination of lower demand for petroleum and higher global supply. The distribution is an extrapolation of the standard deviation of the 30 EIA cases into 50 stochastic futures.

**Figure 40 Long-Term Oil Price – 50 Draws**
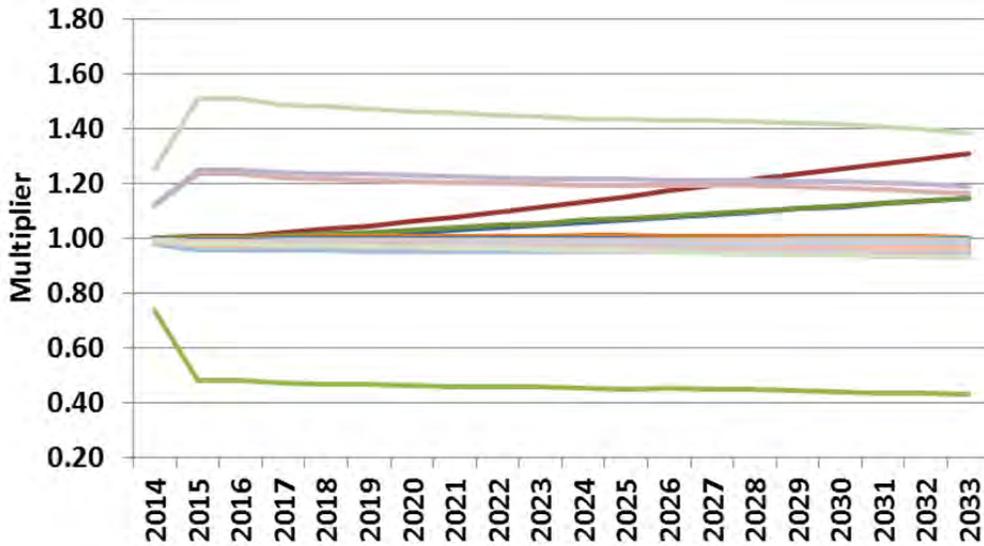
Source: EIA/IMPA

Long-Term Uncertainty – CO$_2$ Price

The upper bound of the long-term CO$_2$ price is tied to the $25 GHG case which applies a price for CO$_2$ emissions starting at $25 per metric ton in 2013 rising by 5 percent per year. The lower bound is tied to the *No GHG Concern case* where no GHG emissions policy is enacted. As shown in the graph below, IMPA delayed the EIA upper boundary as the $25 per metric ton isn't realistic as early as 2013. The full impact of $25 per metric ton ($31.92 per short ton) was achieved in 2020. A distribution was created by extrapolating the three EIA cases (*$25 GHG, $15 GHG, No GHG Concern*) into 50 stochastic futures.

**Figure 41 Long-Term CO$_2$ Price – 50 Draws**
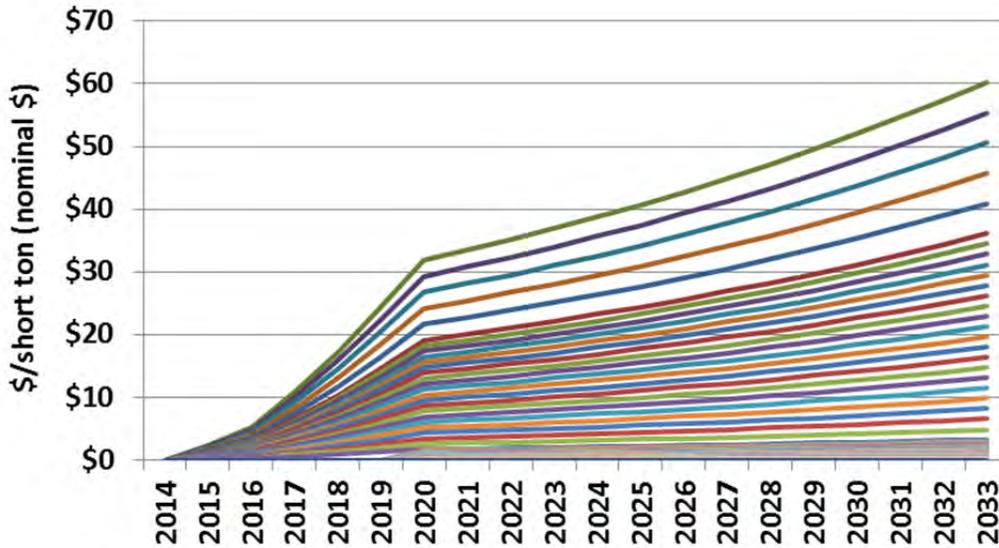
Source: EIA/IMPA

Long-Term Uncertainty – Capital Cost

For new power plant construction, an EPC (engineering, procurement and construction) cost is assigned for each new technology. Because construction costs can vary significantly, they are best thought of as ranges that reflect variability due to a variety of uncertainties. For new power capital cost uncertainty, IMPA assumed a uniform distribution of uncertainty which varied from 0.95 to 1.25 with a mean of 1.0.

Figure 42 Long-Term Expansion CapX – 50 Draws
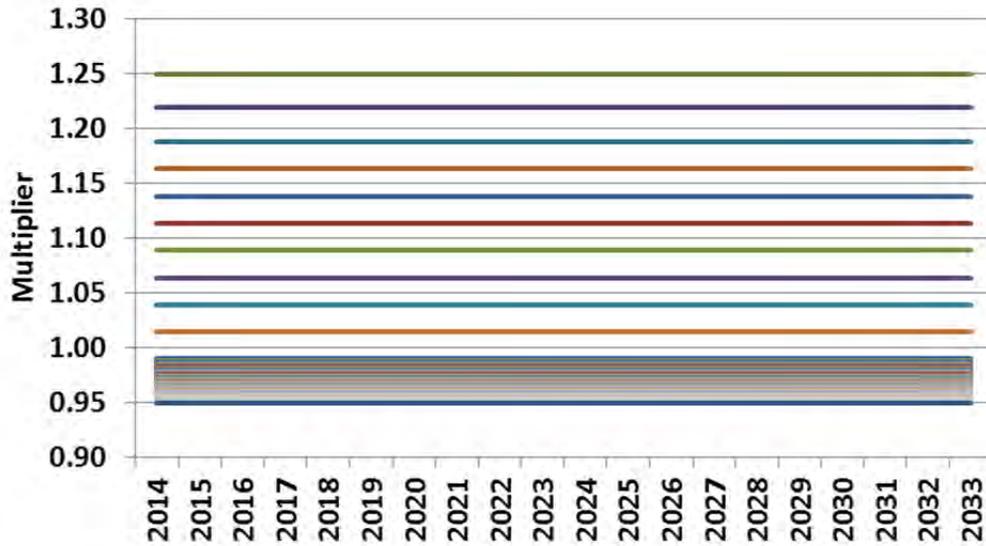
Source: IMPA

10.6 MID-TERM UNCERTAINTIES

IMPA built its mid-term stochastic draws based on historical volatiles, standard deviations, and correlations.

Mid-Term Uncertainty – Peak and Energy

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

The table below shows typical monthly normalized standard deviations for monthly peak and energy uncertainty variables. The correlation coefficients are also included.

**Table 15 Peak and Energy Standard Deviations**

	Peak Standard Deviation	Energy Standard Deviation	Peak - Energy Correlation
Jan	0.035	0.025	0.800
Feb	0.035	0.025	0.950
Mar	0.035	0.025	0.800
Apr	0.035	0.025	0.750
May	0.035	0.025	0.500
Jun	0.035	0.025	0.700
Jul	0.035	0.025	0.950
Aug	0.035	0.025	0.950
Sep	0.035	0.025	0.600
Oct	0.035	0.025	0.550
Nov	0.035	0.025	0.550
Dec	0.035	0.025	0.700

Source: IMPA

These parameters are used by the stratified Monte Carlo sampling program to develop a statistically consistent set of uncertainty multipliers. The resulting monthly peak and energy multipliers are then used to modify the input market-area forecasts.
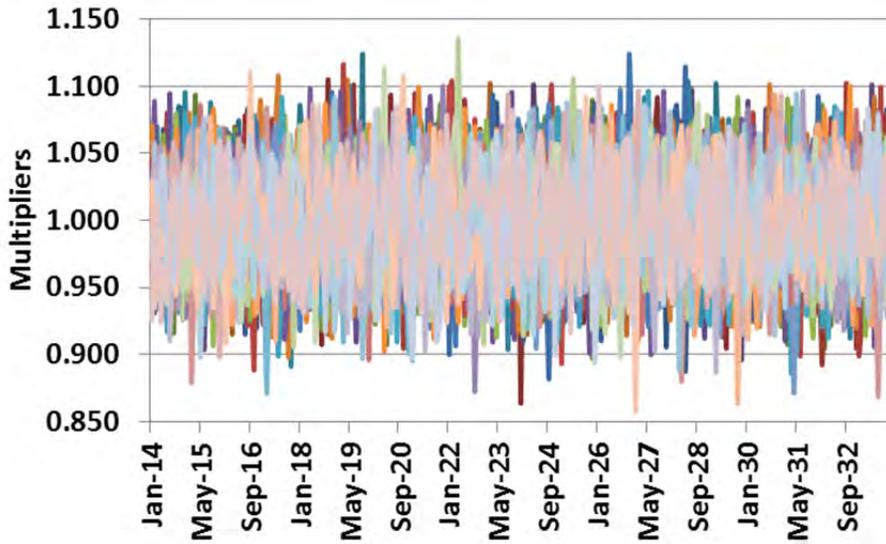
MISO - Indiana and PJM - AEP peak and energy multipliers are shown following figures. The figures illustrate 50 draws per month for 20 years (50 x 12 x 20 = 12,000 data points).

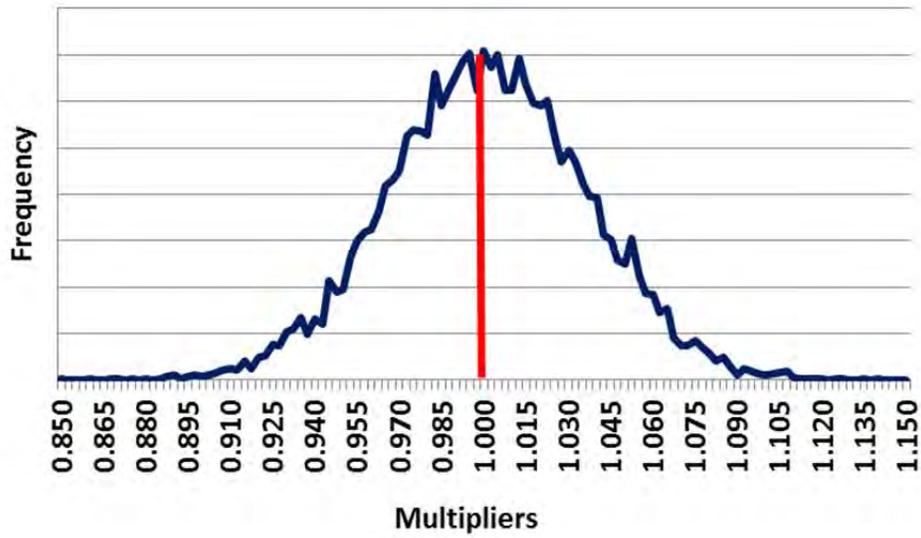**Figure 43 MISO - Indiana Peak Multipliers**
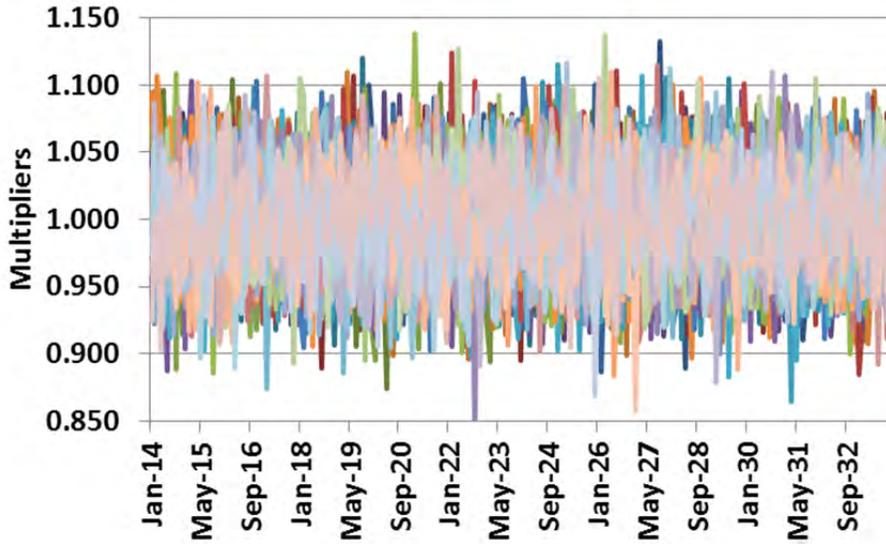
Source: IMPA

Figure 44 PJM - AEP Peak Multipliers
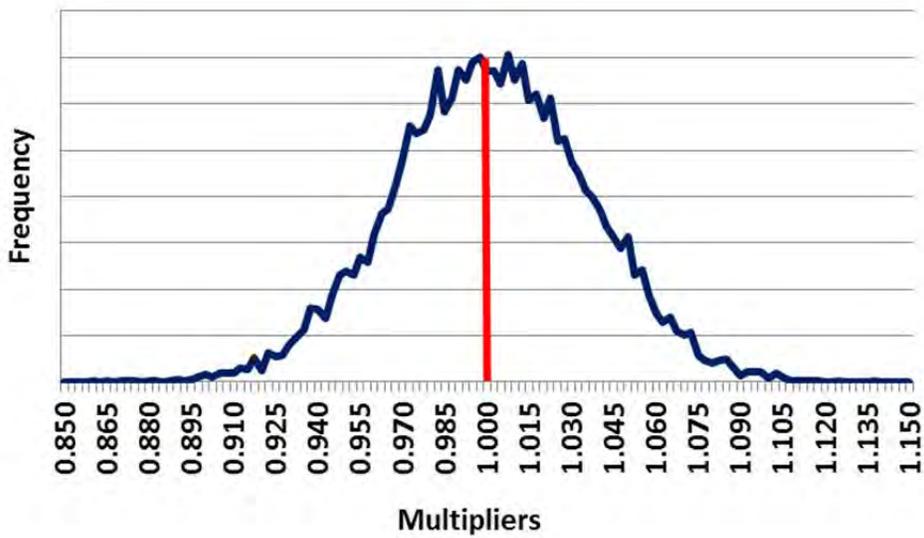

Source: IMPA

Figure 45 MISO - Indiana Peak Distribution
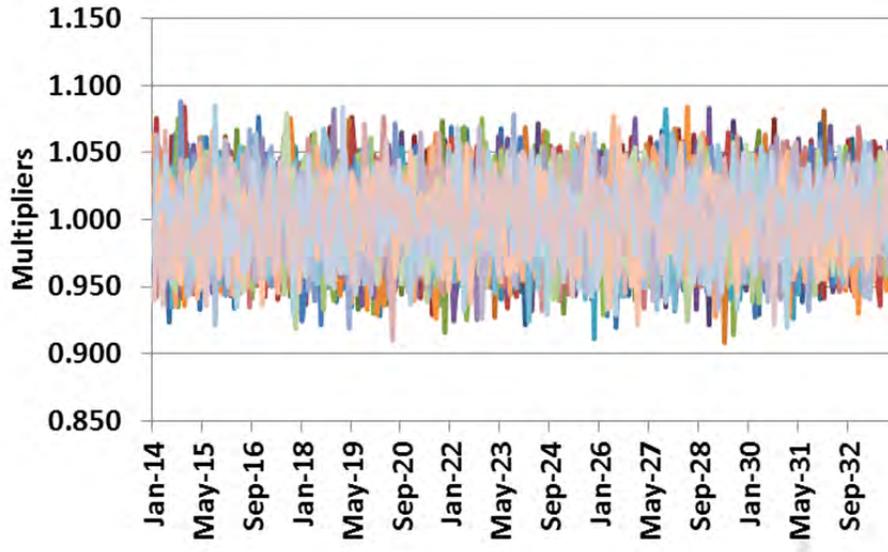

Source: IMPA

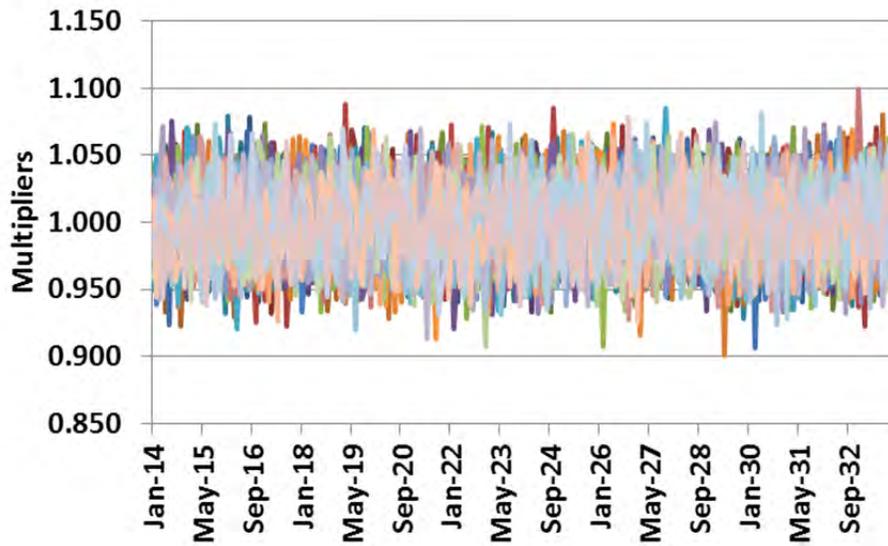**Figure 46 PJM - AEP Peak Distribution**

Source: IMPA

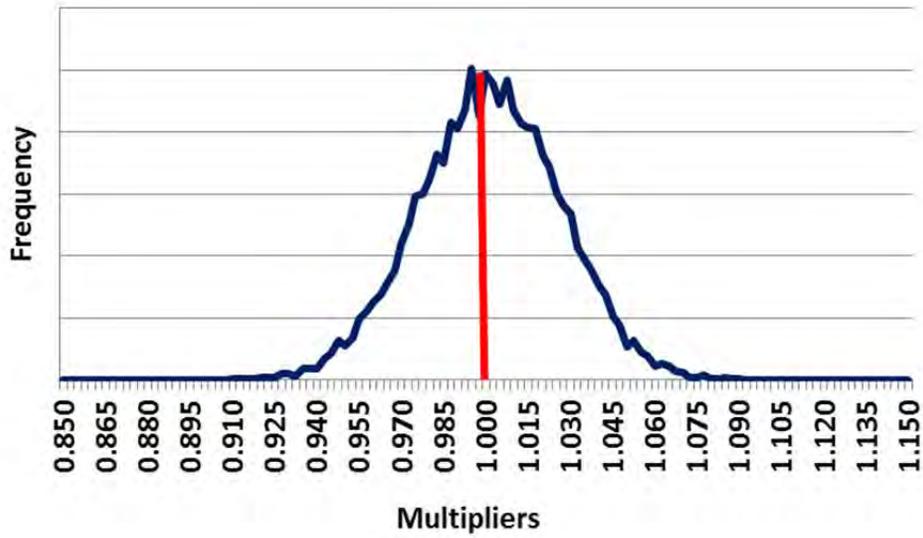**Figure 47 MISO - Indiana Energy Multipliers**

Source: IMPA
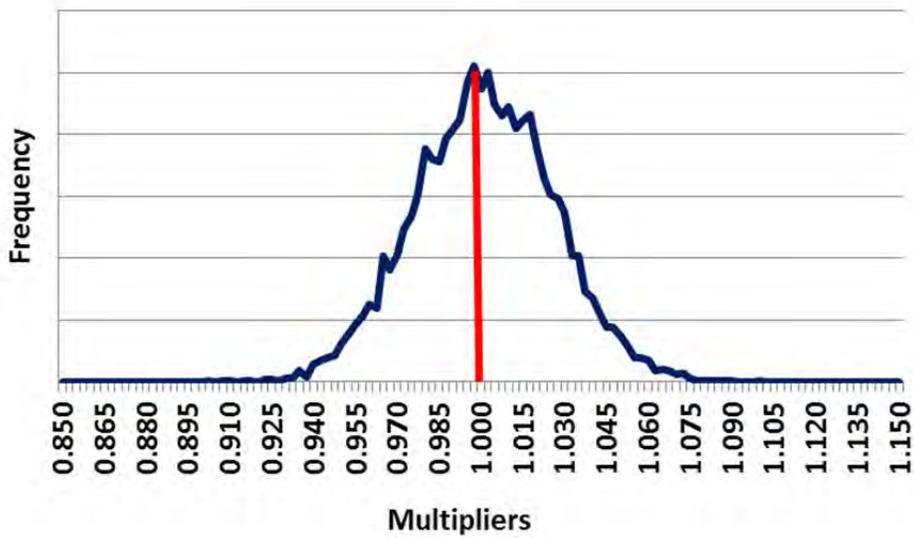
Figure 48 PJM - AEP Energy Multipliers

Source: IMPA

Figure 49 MISO - Indiana Energy Distribution

Source: IMPA

Figure 50 PJM - AEP Energy Distribution

Source: IMPA

Mid-Term Uncertainty – Reference Load Shape Year

The Horizons Interactive market model maintains a library of historical hourly load shapes for each of the 192 balancing authorities in its database. For each year of a given stochastic future (draw 1, draw 2, etc.), a load-shape year is drawn from the years 2007-2011 using a uniform distribution. By randomizing the load-shape year for each draw, consideration is given to the various weather patterns and temperatures that exist across the geographic regions of the market model. The graphs below illustrate IMPA's weather normalized load shapes for the years 2007-2011 and the Indiana statewide temperatures.

Figure 51 IMPA Historical Normalized Load Shapes
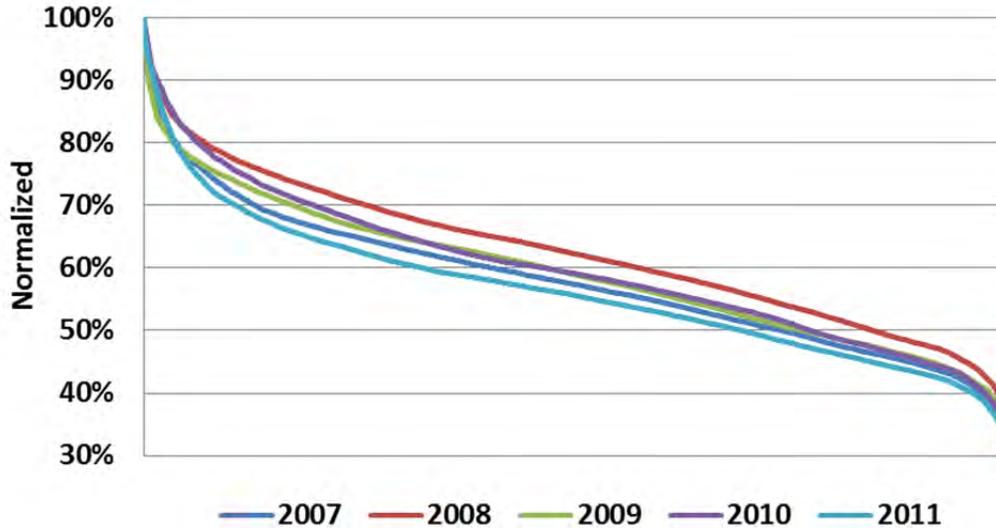
Source: IMPA

Mid-Term Uncertainty – Natural Gas Price

As shown in the graph below, mid-term natural gas price exhibits a mean reverting random walking behavior. That is, over some definable period of time, the price of the commodity tends to move back toward the mean value. To capture mid-term natural gas price uncertainty, IMPA combines monthly volatility with a mean reversion time. Natural gas volatility is month specific as the volatility is greater during the injection and withdrawal winter heating season and less during the summer season.

Figure 52 Mid-Term Natural Gas Volatility (1994-2012)
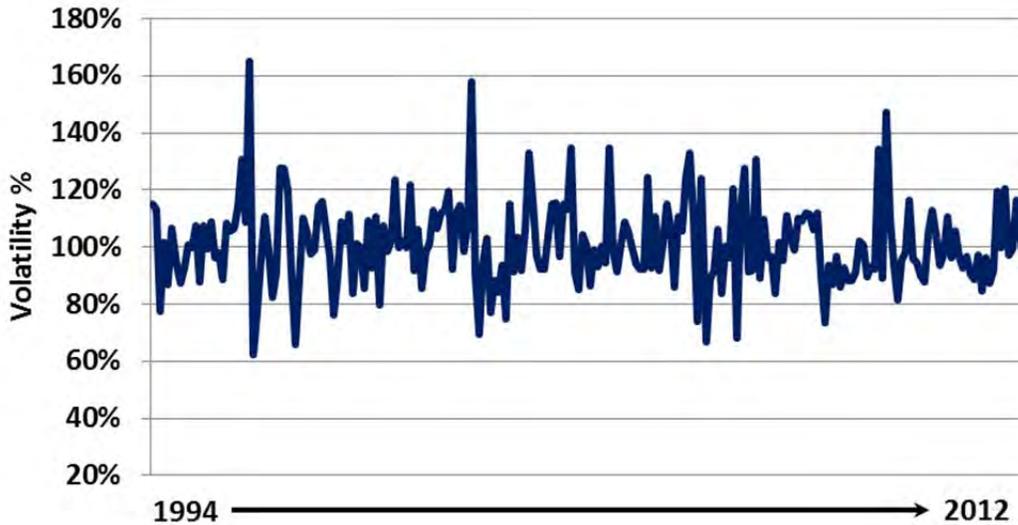
Source: IMPA

Figure 53 Mid-Term Natural Gas Volatility (Monthly)
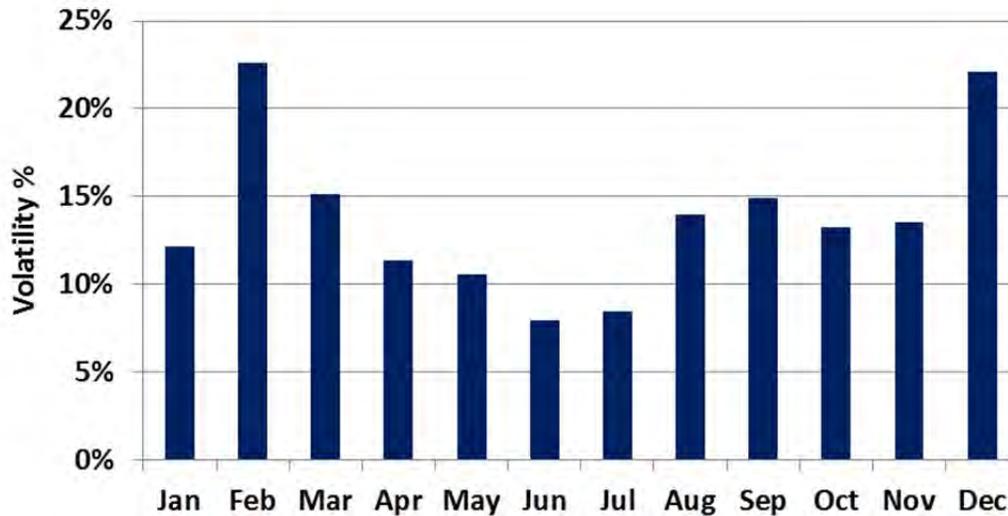
Source: IMPA

As shown by the graph below, the distribution of mid-term natural gas price follows a lognormal distribution. The distribution is asymmetric, positively skewed, and as a lognormal distribution assumes that natural gas prices cannot be negative.

Figure 54 Mid-Term Natural Gas Lognormal Distribution

Source: IMPA

Mid-Term Uncertainty – Coal Unit Availability
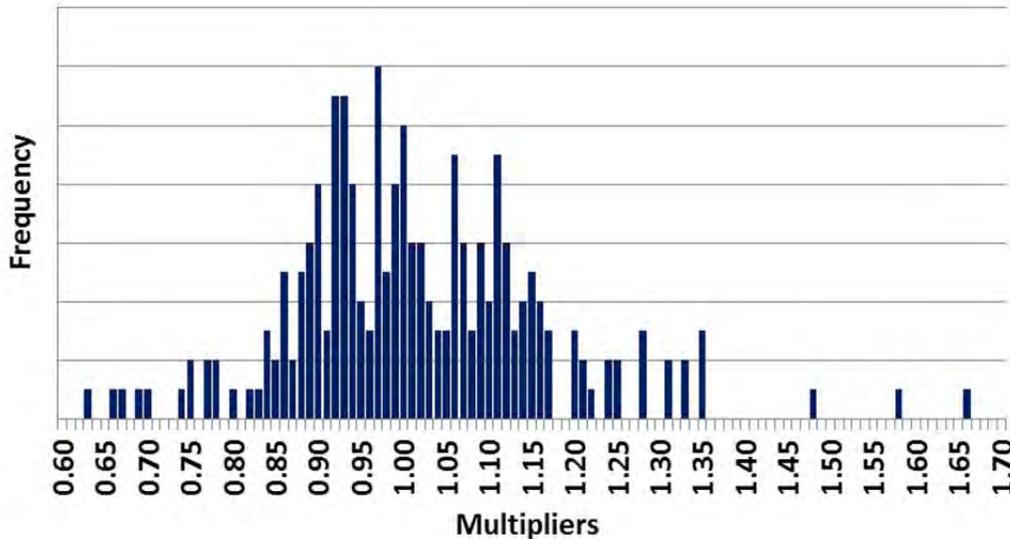Coal unit forced and planned outages are modeled as unit derates in the Horizons Interactive market model. The aggregated coal unit availability within any single zone is a function of the forced and planned outages of each individual unit and the number of units in the zone. So if there is a single coal unit in a zone, then the coal unit availability would be very volatile. Conversely, if there are many coal units in the zone, then the availability would be less volatile as the risk is spread across many units.

IMPA calculates the historical coal availability exhibited by each zone. Since it is impossible to know the planned outage schedule of all coal units in the market model, the monthly volatility provides a reasonable assumption of when forced and planned outages may occur.

The graph below illustrates the monthly expected availability and range of uncertainty of coal units in the MISO – Indiana zone. This zone represents nearly 15,000 MW of coal generation.

Figure 55 Mid-Term Coal Unit Availability (MISO - Indiana Zone)
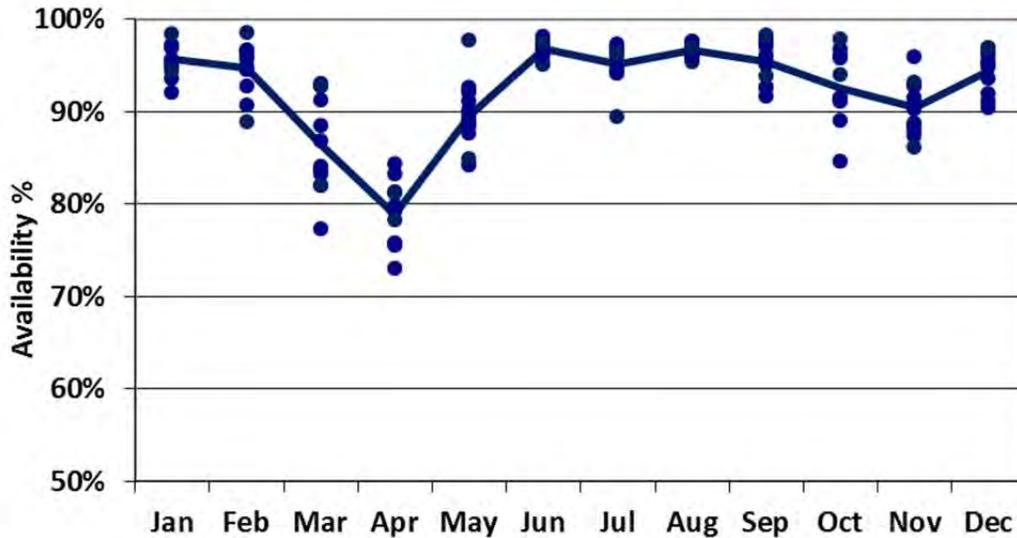
Source: IMPA

The following graph illustrates the monthly expected availability and range of uncertainty of coal units in the PJM - AEP zone. This zone represents slightl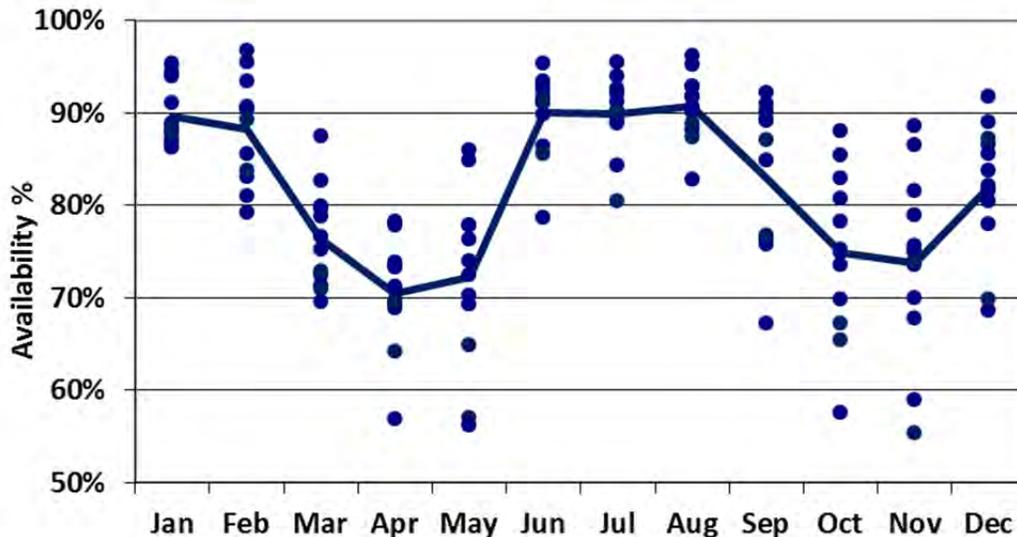y over 28,000 MW of coal generation, but the availability of the PJM – AEP coal units is not as great as is the MISO – Indiana coal units.

Figure 56 Mid-Term Coal Unit Availability (PJM - AEP Zone)

Source: IMPA

## 10.7 HORIZONS INTERACTIVE – STOCHASTIC RESULTS

Introduction
As described earlier, IMPA creates 50 stochastic futures and simulates each future in the Horizons Interactive market model. IMPA is interested in hourly zonal and nodal electricity prices as well as monthly capacity prices which will be utilized in the MIDAS Gold portfolio model. From the market model, IMPA is also interested in the market fundamentals which drive price as well as the fuel usage, emissions, transmission flows, new builds, etc. as they provide insight into future market conditions, opportunities, and risk.

Tornado Charts
To understand the risk of the market drivers, IMPA creates tornado charts to determine the sensitivity of the various fundamental drivers of price. As shown in the figure below, the 7x24 price (black bar) is the dependent variable and the remaining ten (10) drivers are independent variables (gray bars).

The length of the black bar is the uncertainty range of the 7x24 price for a selected time frame. The lengths of the gray bars illustrate each independent variable's impact on the 7x24 price; the longer the bar, the greater the impact. The expected value is signified by the vertical line. When a gray bar is off-set to the left that means that independent variable puts downward pressure on price. Conversely, if the gray bar is off-set to the right, then the independent variable puts upward pressure on price.

Figure 57 Tornado Chart Example
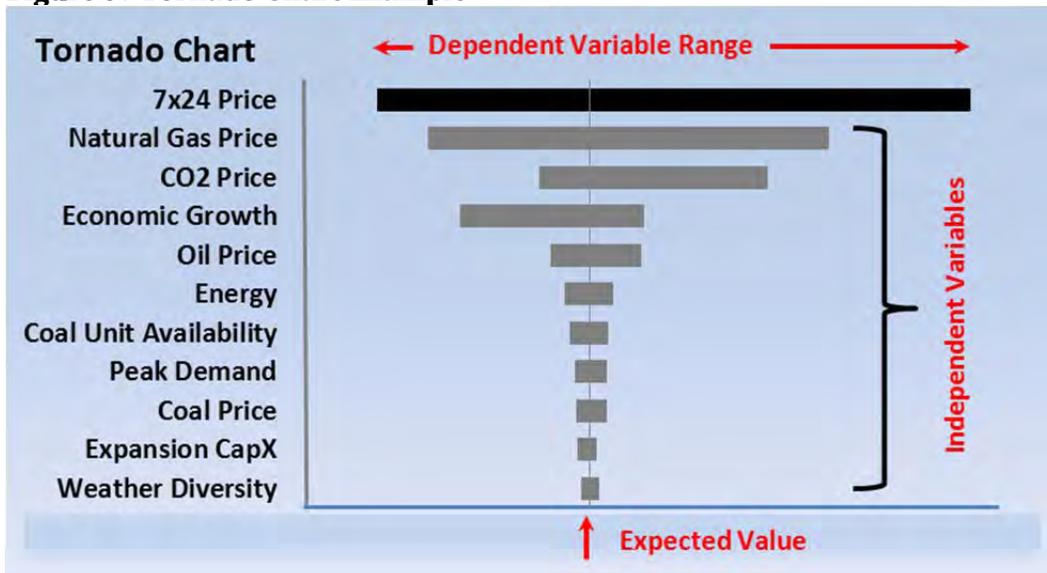
Source: IMPA

The MISO – Indiana 7x24 zonal price   The average stochastic price is higher than the deterministic price due to the impact of CO₂ legislation which isn't in the business as usual deterministic case.

Figure 58 MISO - Indiana Annual 7x24 Market Prices

Source: IMPA

Over the 20 year planning horizon, natural gas price has the highest impact on the MISO – Indiana 7x24 price as natural gas becomes the marginal fuel a greater percentage of the time. CO₂ legislation and economic growth have very similar impact; however, CO₂ legislation provides upwards pressure on price while economic growth provides downward pressure.

Figure 59 MISO - Indiana Annual 7x24 Tornado Chart (2014-2033)

Source: IMPA

The PJM - AEP 7x24 zonal price   The average stochastic price is slightly higher than the deterministic price due to the impact of CO₂ legislation which isn't in the business as usual deterministic case.
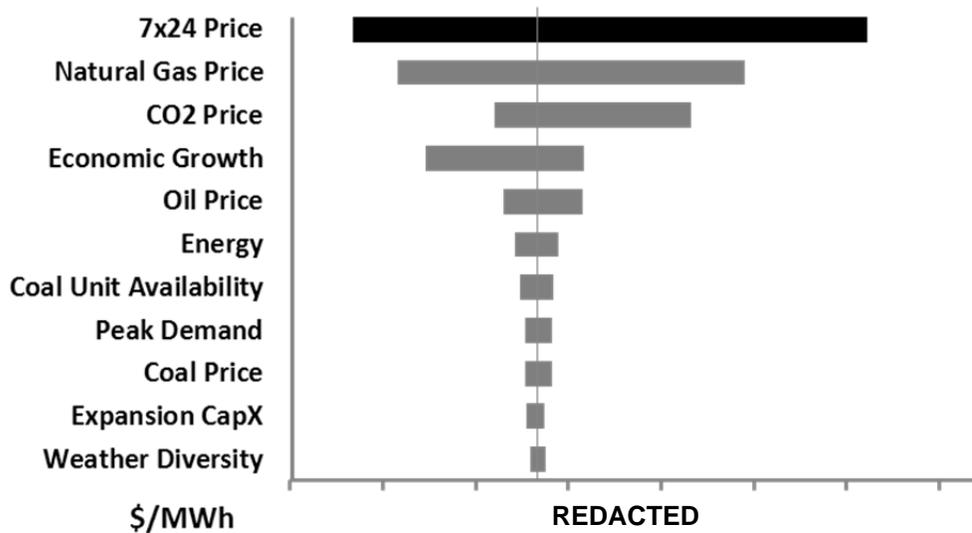
Figure 60 PJM - AEP Annual 7x24 Market Prices
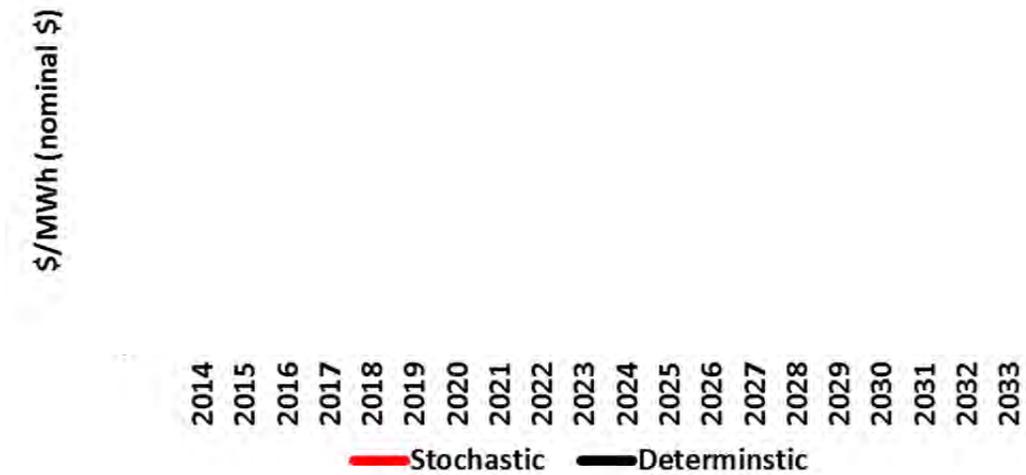
Source: IMPA

Over the 20 year planning horizon, natural gas price has the highest impact on the PJM - AEP 7x24 price as natural gas becomes the marginal fuel a greater percentage of the time. CO₂ legislation has the next highest impact providing upward pressure on price. Economic growth isn't as significant in PJM as in MISO due to the different resource mix between the two RTOs and which fuel type is on the margin.

Figure 61 PJM - AEP Annual 7x24 Tornado Chart (2014-2033)
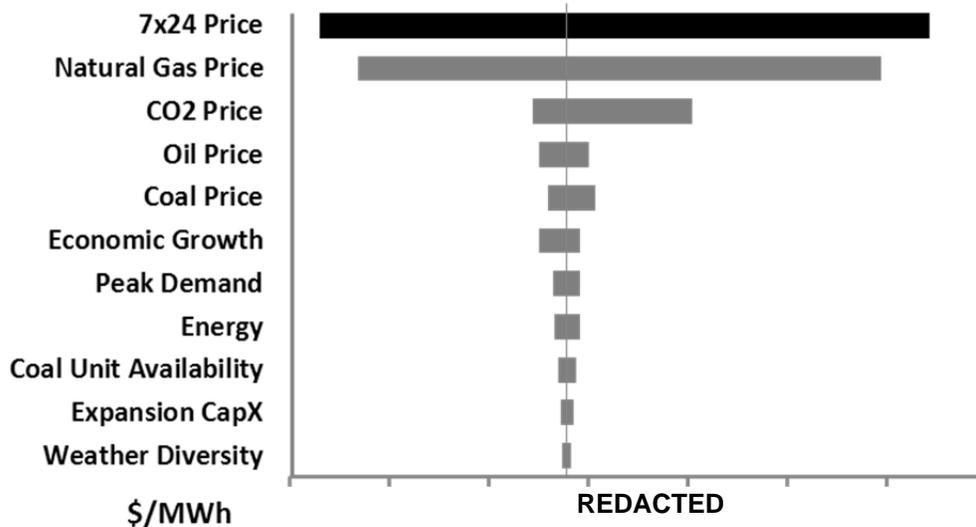
Source: IMPA

Horizons Interactive simulates the MISO cost of new entry (CONE) and a resource adequacy requirements (RAR) curve. For the MISO RTO, IMPA is interested in MISO – Illinois (LRZ4) and MISO – Indiana (LRZ6) capacity prices.

Figure 62 MISO-IL (LRZ4) Capacity Market

REDACTED
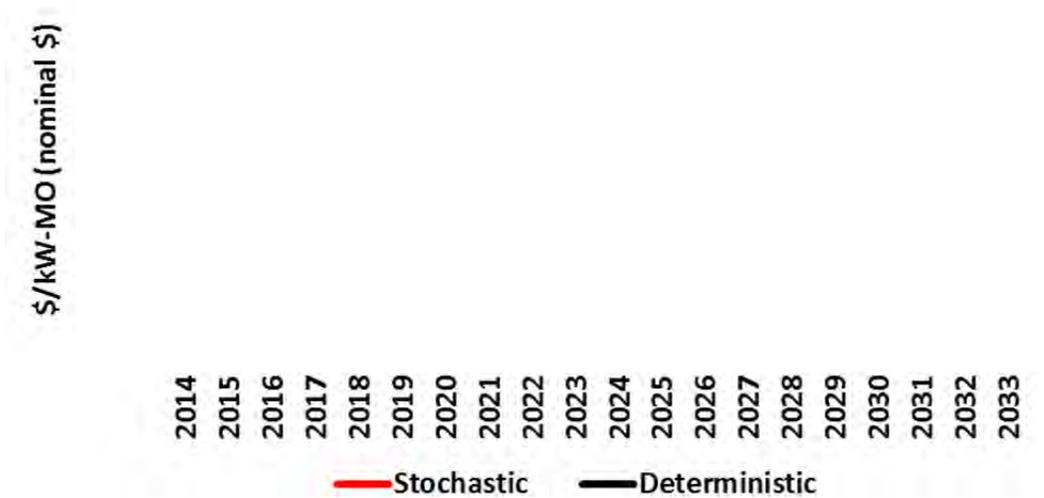
Source: IMPA

Figure 63 MISO-IN (LRZ6) Capacity Market

REDACTED
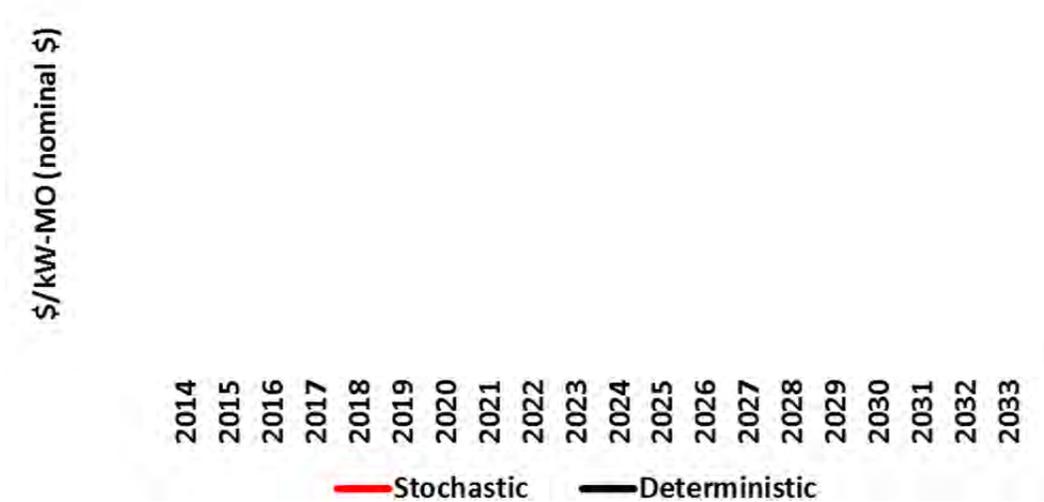
Source: IMPA

Horizons Interactive simulates the PJM cost of new entry (CONE) and a variable resource requirement (VRR) curve. For the PJM RTO, IMPA is interested in PJM-RTO capacity prices.

Figure 64 PJM-RTO Capacity Market

REDACTED

$/kW-MO (nominal $)

2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033

——Stochastic ——Deterministic
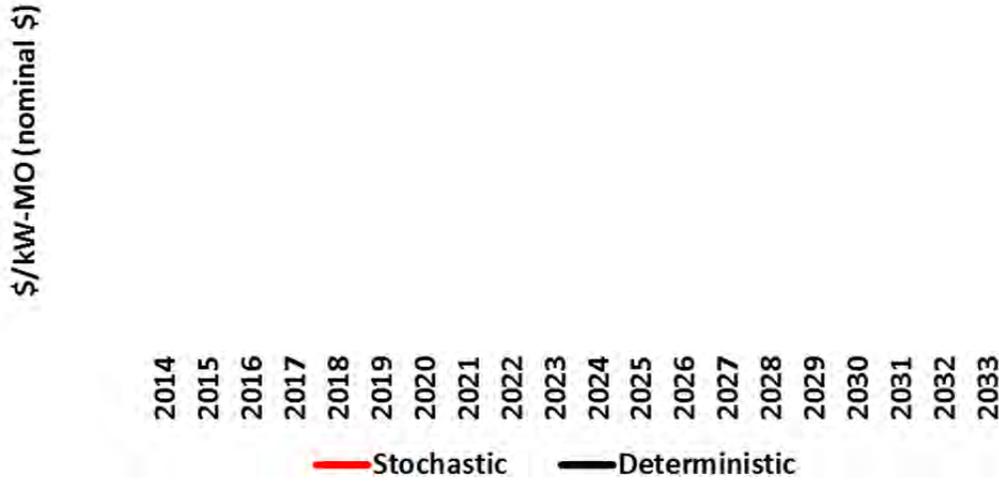
Source: IMPA

10.8 HORIZONS INTERACTIVE – SCENARIO PROCESS

Scenario planning is a proven tool to better anticipate and respond to future risks and opportunities by providing a powerful compliment to the stochastic analysis described earlier. Whereas stochastic analysis uses quantitative techniques to describe an uncertainty (e.g. behavior of natural gas prices), scenario analysis is used to answer "what if" questions (e.g. carbon legislation implemented).

Scenario planning works by iteratively building plausible alternative views of the future given different economic, regulatory, and technical driving forces. Properly implemented, the process should challenge participants' mental maps, check over-optimism, provide strategic insights, and lead to better decision-making.

IMPA identified three scenarios with distinct themes which are expected to have the greatest impact on the future energy business environment over the next 20 years.

Figure 65 Scenario Narratives

The "green" scenario:
- Triggered by climate concerns.
- Strict policies slow global GHG emissions growth and reduces U.S. GHG emissions dramatically.
- Comes at a high cost.

The "compromise" scenario:
- Triggered by political compromise between carbon and non-carbon advocates.
- Steady movement towards sustainable energy as a larger percentage of the power supply.
- Intentions exceed results.

The "traditional" scenario:
- Triggered by global competitiveness and reliability concerns.
- Shift back towards traditional low cost, non-intermittent resources.
- Improves U.S. competitive position on the world stage.

Source: IMPA

The objective of the IMPA scenario building process is to produce forward-looking robust alternate future business environments that challenge our existing perspectives on the future and eliminate hindsight and personal bias. The workflow of the scenario building process and how it feeds into the Horizons Interactive market model is illustrated in the figure below.

Figure 66 Horizons Interactive Scenario Workflow
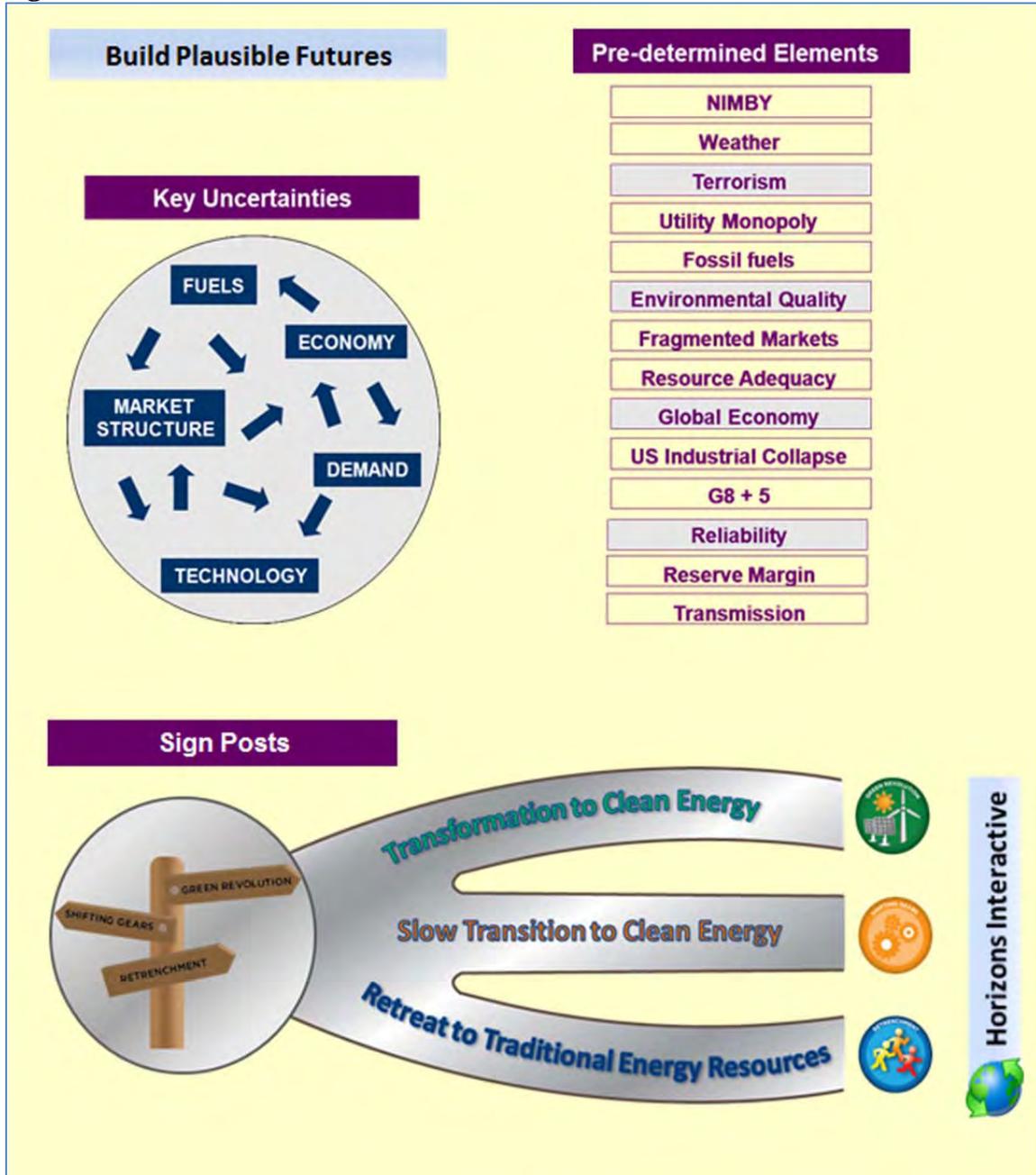
Source: IMPA

Scenario Descriptions and Key Drivers

Power Demand Policy
Reference Scenario
- The US Department of Energy (DOE) is in the process of implementing new energy efficiency standards for electric appliances, lighting products and equipment, as well as updated standards, driven by EPAct 2005, EISA 2007, and earlier legislation. Twenty-four new and updated standards will take effect by 2015 and an additional 54 standards could take effect by 2025.
- Twenty-six of the contiguous United States require electric utilities to invest in demand-side energy efficiency measures in an attempt to reduce electricity consumption by a certain future percentage. Some targets attempt to slow demand growth; the majority aim to flatten or reverse it.
- The US government is promoting the adoption of electric vehicles through corporate average fuel economy requirements and vehicle tax credits.

Green Revolution
- DOE adheres to its statutory schedule for issuing new and revised standards.
- State implementation of complementary measures and eligibility of energy efficiency under a federal Clean Electricity Standard (CES), allow most existing state efficiency targets to be met.
- Other states follow suit and enact their own state efficiency targets.
- Electric vehicles grow to represent 13.8% of new sales and 7.6% of the US light-duty fleet by 2035.

Shifting Gears
- DOE continues to roll out new and revised appliance standards, albeit on a delayed basis when compared to their statutory schedule.
- Although some state efficiency targets are met, a majority go unmet owing to insufficient incentive and penalty measures.
- Electric vehicles grow to represent about 6% of new sales and 3% of the US light-duty fleet by 2035.

Retrenchment
- DOE accumulates a backlog of unrevised appliance standards.
- State efficiency targets are largely unenforced owing to cost concerns.
- Electric vehicles stall, taking until after 2030 to exceed current hybrid electric vehicle sales levels.

Conventional Pollutant Policy
Reference Scenario
- The US EPA is in the process of implementing several major non-carbon environmental regulations, including: the MATS rule, the CCR rule, and the Cooling Water Intake Structures (CWIS) Rule.
- CSAPR has been struck down and MATS faces its own legal challenges. EPA is taking longer than initially expected to issue final CCR and CWIS rules, owing in part to a large volume of public comments.

Green Revolution
- EPA pursues an aggressive regulatory agenda.
- A CSAPR replacement takes effect in 2017 and resembles the "Direct Control" approach proposed when the draft Transport Rule was released.
- CCRs are designated a "special waste" and regulated similar to hazardous waste.
- EPA uses various Clean Air Act provisions (i.e., National Ambient Air Quality Standards, Regional Haze Rule, New Source Review, etc.) to impose increasingly stringent SO_2 and NO_x emission reduction requirements at the unit-level.

Shifting Gears
- Other than CSAPR, the other major rules move forward with some delay.
- Final rules are more measured and flexible than initially conceived, driven by concerns over costs and reliability impacts.
- A CSAPR replacement takes effect in 2018.
- States are liberal in granting 4th year compliance extensions under MATS, and EPA makes full use of risk management procedures to grant additional time.
- EPA regulates coal ash as nonhazardous waste.

Retrenchment
- EPA regulations are delayed and pared back considerably, owing to legal challenges, legislative intervention, and reduced agency capacity.
- A comprehensive CSPAR replacement is never promulgated. Instead EPA addresses Section 126 petitions on a case-by-case basis.
- MATS is delayed by Congress until 2018.
- EPA cedes significant CWIS and CCR regulatory authority to the states.
- CCR regulations allow for the continued operation of ash ponds.

Federal Climate Change and Clean Energy Policy

Reference Scenario
- The United States is on a regulatory path, as the economic and political climate does not favor major new laws.
- EPA is currently pursuing a two-track approach for regulating greenhouse gases (GHG) from the power sector.
- Despite a recent proposal to introduce a carbon tax, there has been no significant federal legislative momentum on GHGs since Waxman-Markey passed the House in 2009.
- A CES is a more likely cornerstone program (than carbon cap-and-trade) of any federal legislation in the near term, but continues to face challenges. The most recent CES proposals put natural gas, nuclear, and carbon capture and storage (CCS) in the mix.
- The Wind production tax credit (PTC) is scheduled to expire at the end of 2013, and the solar investment tax credit (ITC) to drop from 30% to 10% at the beginning of 2017.

Green Revolution
- Ambitious and increasingly targeted policies are pursued.
- EPA promulgates aggressive GHG performance standard requirements for existing units.
- High oil prices drive the passage of a 2015 law that includes a CES, $10 billion in funding for CCS, and loan guarantees for 20 new nuclear plants.
- The PTC and ITC are extended/lowered commensurate with technology cost declines.
- Congress replaces EPA regulations with CO_2 performance standards for existing power plants that takes effect in 2025 and provides more funding for CCS and nuclear.

Shifting Gears
- Moderate policy momentum that balances ambition and cost.
- Congress replaces EPA GHG regulations with a cap-and-trade program in 2017, which takes effect in 2021.
- A federal CES fails to gain traction.
- The PTC lapses but then gets extended through 2015 only. ITC reverts back to 10% in 2017.
- Additional targeted funding is limited.

Retrenchment
- Policy momentum wanes due to poor economic conditions.
- EPA regulations are light-handed and pressure to curb their authority fades.
- The PTC expires in 2013 and the ITC reverts back to 10% in 2017.
- Climate reemerges as a policy priority late in the scenario and a modest carbon tax is implemented in 2030.

State Climate Change and Clean Energy Policy

Reference Scenario
- The Regional Greenhouse Gas Initiative (RGGI) CO_2 cap-and-trade program entered the second of three compliance periods in 2012. The first of two interim program reviews are underway to determine what, if any, changes should be made to the program. 2011 emissions (121,000 tons) were 35% below the current program cap (188,000 tons) and 30% below the program's terminal cap in 2018 (170,000 tons).
- The California GHG cap-and-trade program is slated to go into effect in 2013 and will ultimately cover 85% of the state's GHG emissions. Initially (2013–14), the cap covers all major industrial sources and electricity, and declines by 2%. Beginning in 2015, distributors of transportation fuels, natural gas, and other fuels become subject to the cap, and the cap declines 3% per year.
- Twenty-nine states plus DC have binding RPS policies in place. Collectively, they call for approximately 400 TWh of renewable supply by 2020, compared to roughly 190 TWh of available supply today.

Green Revolution
- During RGGI's 2015 program review the cap is revised downward significantly and the program is extended indefinitely.
- CA's program produces a politically unpalatable allowance price. The program is revised in 2018 and a mechanism is introduced to manage prices to a tolerable level, albeit a higher one than in Shifting Gears.
- State RPS policies become more ambitious and increasingly target technologies and initiatives that exploit local resources.

Shifting Gears
- RGGI remains structurally oversupplied allowances and eventually is rolled into the national CO_2 program in 2021.
- CA's program takes effect in 2013 but produces a politically unpalatable allowance price. The program is revised in 2018 and a mechanism is introduced (such as a price cap) to manage prices to a tolerable level.
- RPS' are fortified where industry is established and/or wind resources are good, whereas other states introduce additional flexibility in the late 2010s.

Retrenchment
- RGGI is dissolved at the end of the third and final compliance period in 2018.
- Legal challenges prevent CA's program from ever going into effect.
- No new state RPS policies are introduced and some are weakened or rolled back.

Transmission Policy

Reference Scenario
- Several utility companies have or are in the process of realigning their RTO memberships, and the RTOs have continued to change their market rules to address issues raised by various stakeholders and the US Federal Energy Regulatory Commission (FERC).
- FERC issued its Order 1000 in July 2011 to address regional planning and transmission cost allocation issues it felt had not been adequately addressed in Order 890. Order 1000 focused on two major areas, regional and interregional project planning and transmission project cost allocation.

Green Revolution
- The balance of power in transmission planning shifts toward the federal government as federal energy policy becomes more ambitious.
- There is a strong push for interregional integration of large-scale renewables projects.
- A "Super RTO" evolves from PJM Interconnection, Mid-Continent ISO, Southwest Power Pool, and neighboring entities to facilitate regional transmission development and allow delivery of renewable energy from the upper Midwest and Plains states to the relatively renewable energy–deficient areas in the Southeast.

Shifting Gears
- Depending on the region, reliability and renewable resources are the investment drivers for transmission development.
- In the West, access to renewables is the main driver.
- In the Northeast and Southeast it is reliability and congestion relief.
- FERC continues to provide rate-of-return incentives for transmission projects.
- The states continue to experiment with cost allocation formulas to minimize rate impacts.

Retrenchment
- The focus of state and federal transmission policy shifts toward local reliability needs rather than interregional grid integration projects.
- This shifts the responsibility for transmission planning back toward the states and utility transmission owners.
- FERC's policy related to National Interest Electric Transmission Corridors loses steam in large part because the push for interregional renewables projects do not materialize until late in the scenario.

Scenario Signposts and Roadmap

Signposts and roadmap play a key role in determining the relevance of any one scenario and an early warning system of possible events to follow. The external environment must be continuously monitored to identify signposts and determine their meaningfulness in pointing to a given scenario. The more credible signposts identified for any given scenario, the greater the likelihood that the scenario and its associated strategic implications will be relevant.

Figure 67 Plausible Future Energy and Environmental Policies

Source: IMPA

10.9 HORIZONS INTERACTIVE – SCENARIO RESULTS

Introduction
The following key drivers of electricity price from the aforementioned scenario narratives are quantified for the Horizons Interactive market model.
- CO_2 Emission Trajectories
- CO_2 Price
- Natural Gas Price
- Load Forecast
- Capacity Retirements
- Capacity Additions
- Capital Expenditures

Scenarios
The three scenarios are:
- Green Revolution: transformation to clean energy
- Shifting Gears: slow transition to clean energy
- Retrenchment: retreat to traditional energy resources

Scenario CO_2 Emission Trajectories
As illustrated in the graph below, Green Revolution produces the largest CO_2 reduction. Green Revolution retires 88% of the coal fleet and replaces it with nuclear, renewable, and combined cycle units. Post 2025, all new combined cycle units are outfitted with carbon capture and sequestration removing 75% of their carbon emissions. Green Revolution reduces CO_2 emissions by 43% from 2005 levels which the Obama administration has used as the base year CO_2 emission level. By 2036, all coal units will have been retired in this scenario. Shifting Gears reduces CO_2 emissions by 9% while the Retrenchment and Reference scenarios increase CO_2 emissions by 12% and 8% respectively.

Figure 68 Scenario Power Sector CO_2 Emission Trajectories
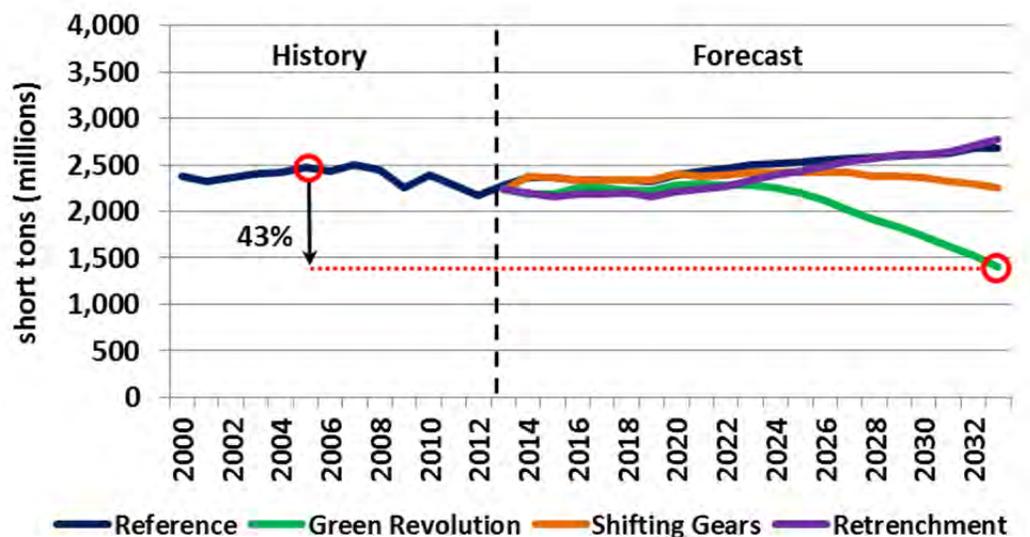
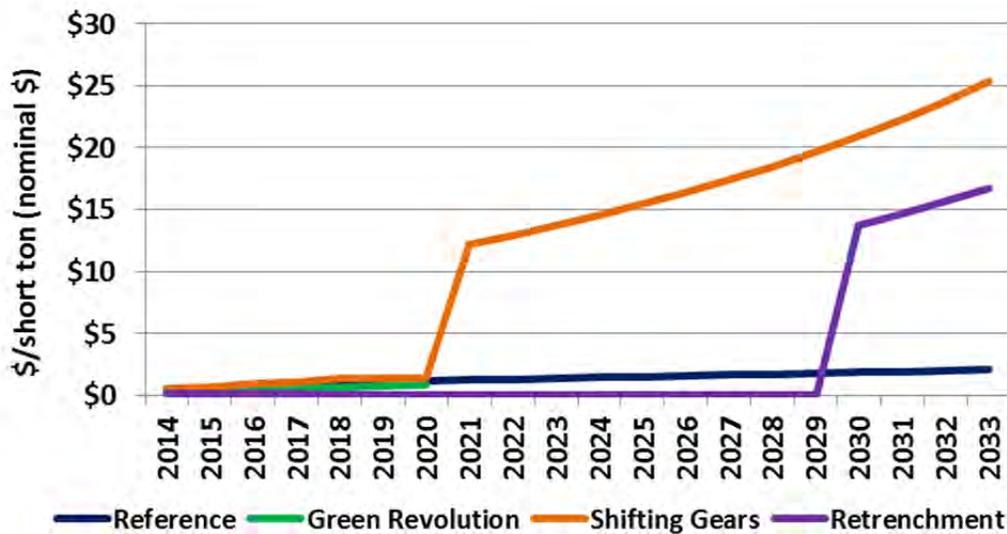

Source: IMPA

Scenario CO$_2$ Price

In Reference, Shifting Gears, and Retrenchment scenarios, a cap and trade market structure is utilized for CO$_2$ emission trading. These scenarios model the existing Regional Greenhouse Gas Initiative (RGGI) and California AB32 carbon markets. Later, a nationwide carbon market is implemented in the Shifting Gears and Retrenchment scenarios in 2021 and 2030 respectively.

Green Revolution does not utilize a cap and trade structure, but rather implements a federal clean energy investment recovery mechanism based on a regulated return. To recover the large capital investment associated with replacing the coal fleet with nuclear and renewable energy, a clean energy transition charge (CETC) is levied on retail load. The CETC is analogous to the allowed return on rate base currently afforded to investor-owned utilities. In the case of the CETC, the return on investment is applied on a federal level. The CETC is calculated as the recovery of the levelized cost difference (capital expenditures and fixed O&M) between clean energy resources and conventional resources. This quasi-market structure maintains the efficiencies of RTO free markets while equitably recovering the clean energy investment from all end users, providing a proper CO$_2$ price signal for energy efficiency and conservation.

**Figure 69 Scenario CO$_2$ Price**

Source: IMPA

Scenario Natural Gas Prices

The Retrenchment scenario assumes high technically recoverable reserves which allow for more wells per square mile as well as a high estimated ultimate recovery rate. In contrast, the Green Revolution scenario assumes more stringent regulations are imposed on the natural gas industry increasing the cost of production.
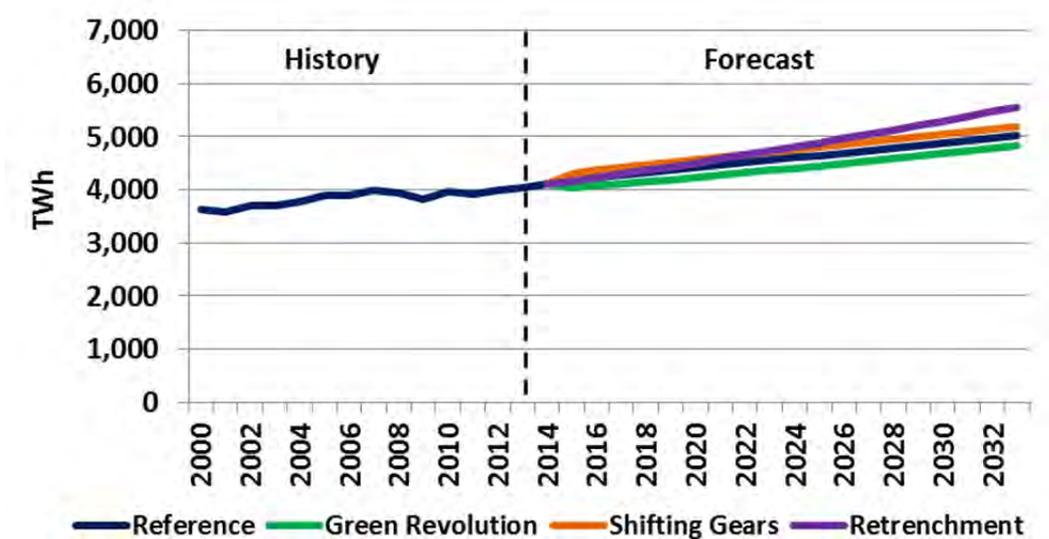
Figure 70 Scenario Natural Gas Prices

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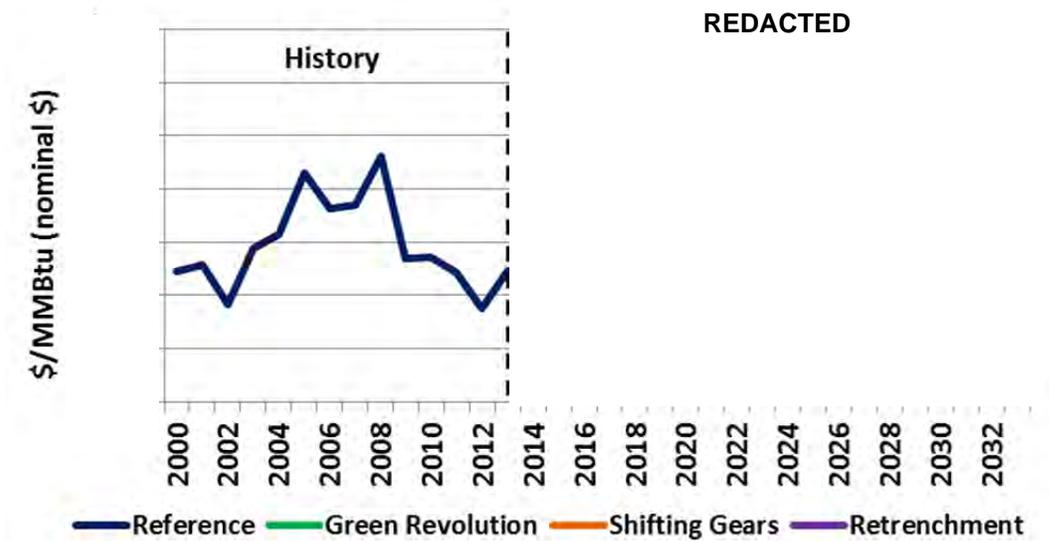
Source: IMPA

Scenario Load Forecast

The load growth is highest in the Retrenchment scenario due to the price elasticity of lower energy prices. Green Revolution has the low load growth due to higher energy prices and more energy efficiency.

Figure 71 Scenario Load Forecast (Energy)

Source: IMPA

Scenario Capacity Retirements

Green Revolution retires 322 GW (88%) of the coal fleet by 2033. In this scenario, all of the steam-gas units (116 GW) and the oil units (45 GW) are retired by the end of the study. Shifting Gears is less aggressive as 145 GW (37%) of the coal fleet is retired by 2033. In this scenario, the same steam-gas and oil retirements take place as in Green Revolution. Retrenchment retires 80 GW (21%) of the coal fleet to comply with MATS or due to age.

Figure 72 Scenario Capacity Retirements
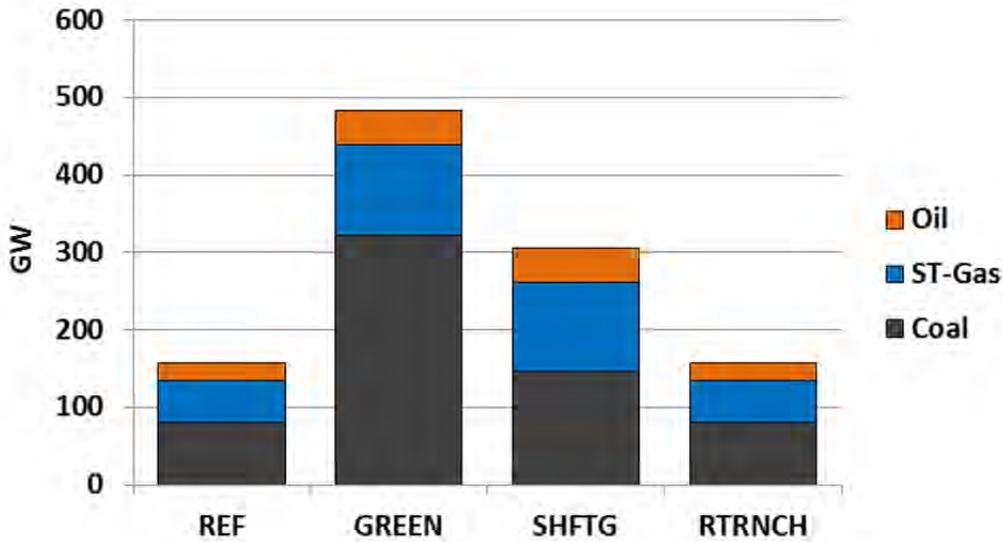
Source: IMPA

Scenario Capacity Additions

In Green Revolution, the U.S. adds 186 GW of wind plus another 176 GW of biomass, geothermal, landfill gas and solar. By 2033, 27% of the U.S. electricity usage is provided by renewable energy. Green Revolution adds 70 GW of nuclear energy bringing the total U.S. nuclear fleet to 171 GW by 2033. Beginning in 2025, all new combined cycle units must be equipped with carbon capture and sequestration. Green Revolution also adds high voltage direct current (HVDC) transmission lines to move the wind energy from the high wind areas to the load centers. The estimated capital investment of this scenario is nearly $2.8 trillion.

The Shifting Gears scenario adds 112 GW of wind and 52 GW of biomass, geothermal, landfill gas and solar. By 2033, 16% of the U.S. electricity usage is provided by renewable energy. The Retrenchment scenario adds 52 GW of renewable resources providing 8% of the U.S. electricity usage. The estimated capital investment of the Shifting Gears and Retrenchment scenarios is $1.2 trillion and $0.6 trillion respectively.

Figure 73 Scenario Capacity Additions
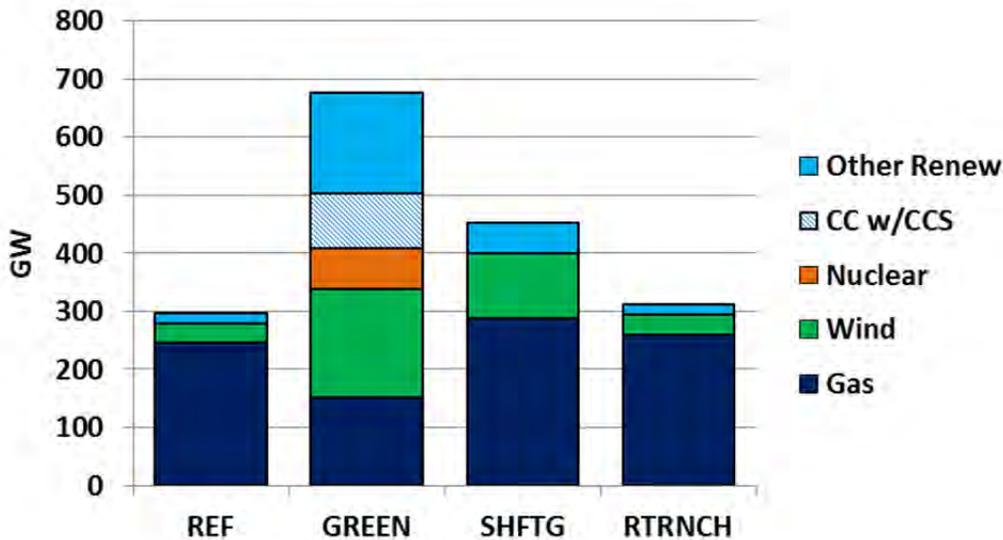
Source: IMPA

Clean Energy Transition Charge (CETC)

As discussed earlier, Green Revolution recovers the large capital investment associated with replacing the coal fleet with nuclear and renewable energy via a clean energy transition charge (CETC). As shown in the graph below, the CETC is applied as a cent per kWh adder to retail load. Prior to 2020, the adder is very small to cover the HVDC transmission investment. As the investment in nuclear, renewables, and CC with CCS increases, the CETC grows exponentially.

The CETC represents the levelized difference between clean energy resources and conventional energy resources.

**Figure 74 Clean Energy Transition Charge (CETC)**
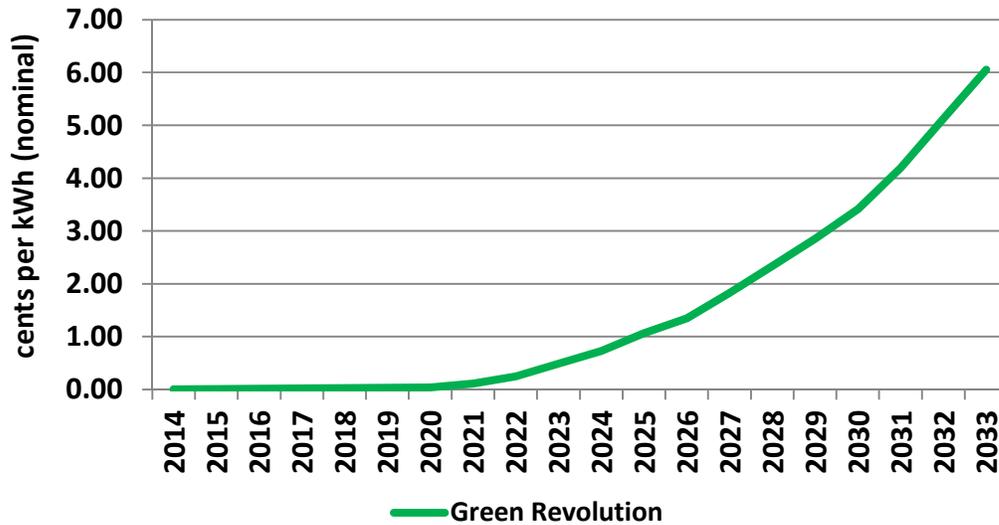
Source: IMPA

Scenario Electric Wholesale Prices

By 2033, annual wholesale prices are projected to be 17% higher in Shifting Gears and 34% higher in Green Revolution compared to the Retrenchment scenario. The effect of the carbon cap and trade on the Retrenchment scenario is evident by the jump in wholesale prices beginning in 2030.

**Figure 75 Scenario 7x24 Annual Market Prices**

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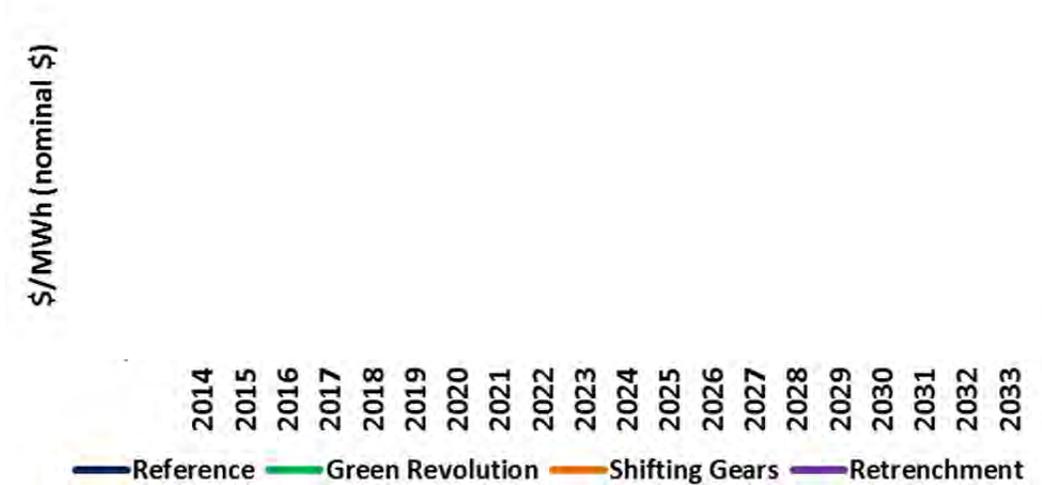
Source: IMPA

Scenario Capacity Prices

The weighted average capacity price for the MISO–IN (LRZ6) and PJM-RTO zones are shown in the graph below. The purpose of the IMPA capacity market forecast is to provide the direction and magnitude of capacity prices, but the outcome in specific years is subject to great uncertainty due to the timing of retirements, additions, participant bid behavior and regulatory uncertainty.

Figure 76 Scenario Capacity Prices

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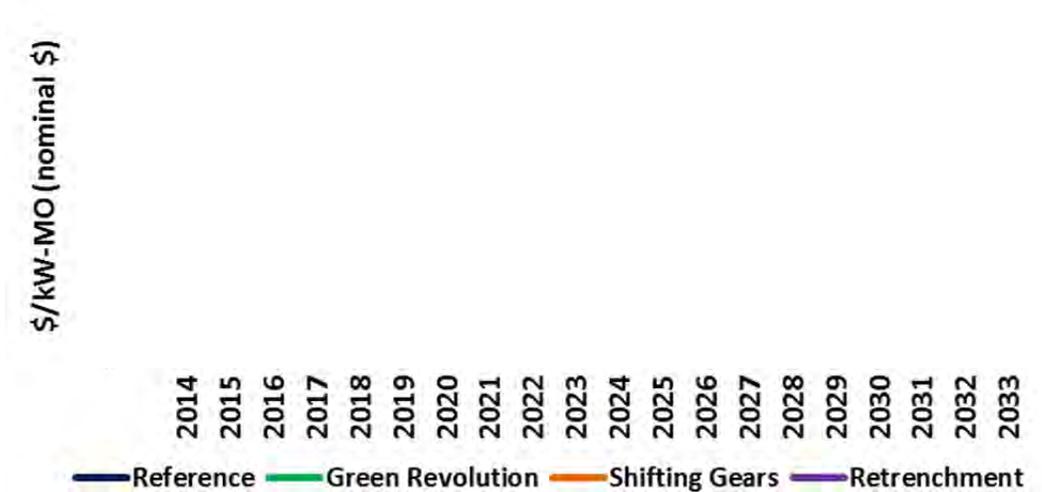
Source: IMPA

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11 RESOURCE OPTIMIZATION

11.1 NEW SUPPLY-SIDE OPTIONS

Existing Supply-Side Resources

All IMPA-owned units were given the opportunity to retire in the capacity expansion runs. This is performed by allowing the expansion model to opt to retire an existing resource and replace it with other alternatives. When a unit is retired in this manner, all future capital expenditures, O&M and fuel costs disappear, however, all remaining bond obligations associated with the facility remain. Given that none of IMPA's existing resources require substantial capital investment in the study period, no IMPA-owned units were selected for retirement. A relative comparison of the incremental capital and operating costs of IMPA's existing resources at various load factors is shown below. See Appendix E for detailed existing unit data.

Figure 77 Retirement Screening Curve

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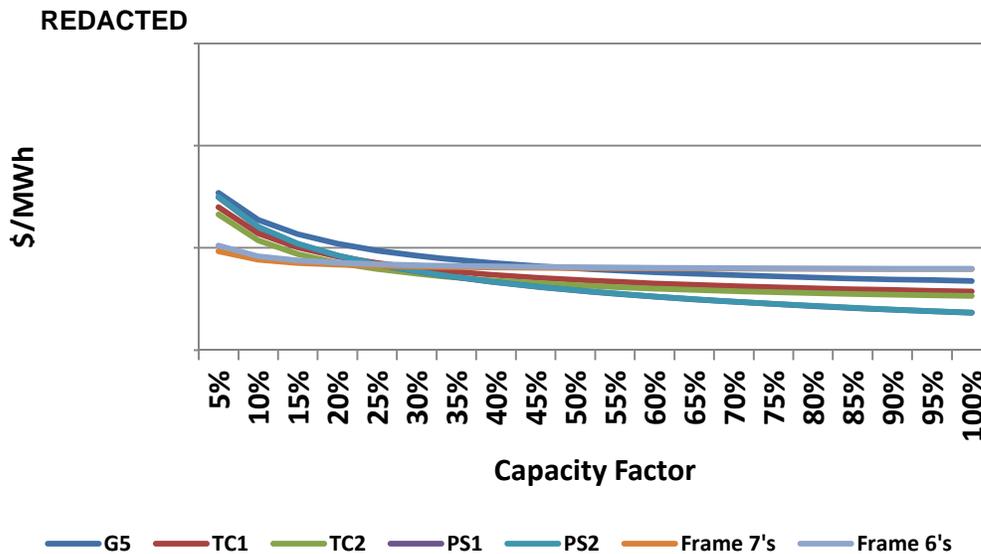
Source: IMPA

New Supply-Side Resources

The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit type and model. For example, IMPA does not screen various brands and models of CTs against each other to determine the generic CT for use in the IRP expansion. CT pricing is sufficiently compressed that one CT brand over another will not cause the expansion model to select a CT when a CT is not needed or vice versa. The selection of the actual brand and model to construct would be determined in the bid and project development process.

The traditional generating resources considered in this study include:

- Nuclear (100 MW from a 1100 MW unit)
- Coal-fired steam generation (100 MW from a 750 MW unit)
- Integrated Gasification Combined Cycle (IGCC) (100 MW from a 600 MW unit)
- Advanced combined cycle (CC) units (100 MW from a 400 MW unit)
- Advanced gas-fired combustion turbines (CT) (185 MW)
- Aero Derivative combustion turbine (100 MW)
- Gas-fired high efficiency internal combustion (IC) units (10 MW units in multi-unit sets of 50 MW)

Capital costs, operating costs and operating characteristics for these sources were taken from Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, US Energy Information Administration, April, 2013. See Appendix F for detailed expansion unit data.

A comparison of expansion alternatives at various load factors is shown below.

Figure 78 Thermal Screening Curve
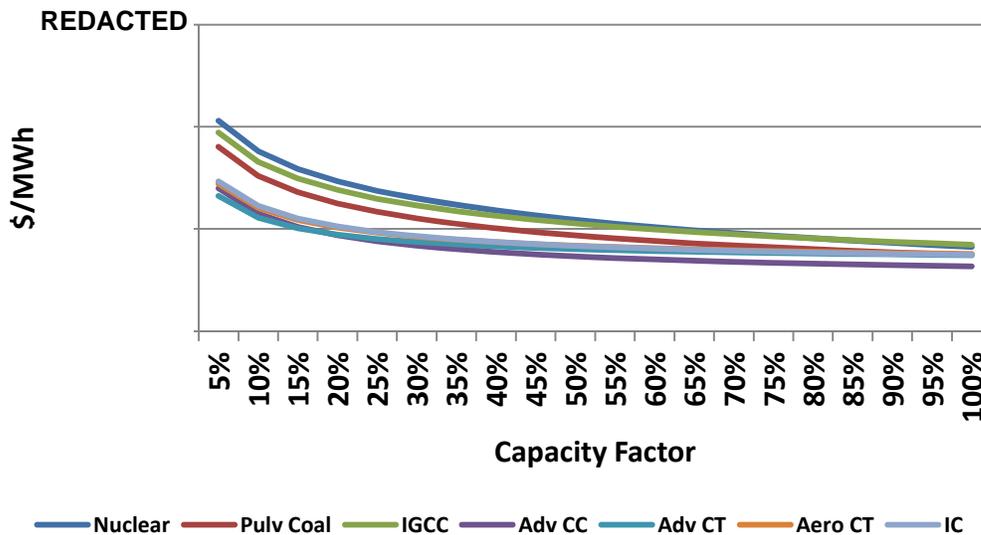
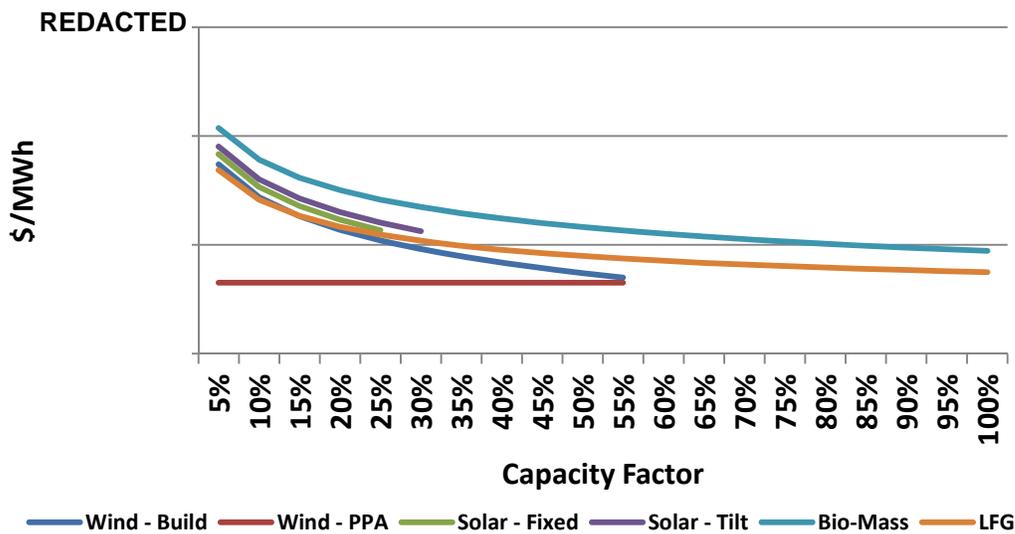Source: IMPA

<u>**New Renewable Resources**</u>

In addition to the traditional resources discussed above, the expansion model was allowed to pick from a variety of renewable resources as well. The renewable alternatives included in the expansion analysis are shown below.

- Wind - Build (50 MW)
- Wind - PPA (50 MW)
- PV Solar (small facilities at member locations)
- Bio Mass (25 MW)
- LFG (2.5 MW units in sets of 10 MW)

Pricing for all of the renewable alternatives was based on indicative market quotes from renewable energy providers or industry documentation of installed and operating costs.

A comparison of renewable alternatives at various load factors is shown below.

Figure 79 Renewable Screening Curve

Source: IMPA

<u>**Retail Customer-Owned Generation**</u>

As stated previously, other than emergency generators, IMPA has very little customer owned generation connected to its member systems. There are approximately six (6) net metering installations, all less than 10 kW.

IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. A review of the EPA industrial boiler database reveals approximately 15 industrial boiler installations in IMPA member communities. At this point, IMPA is uncertain of the size or condition of these facilities.

Since a CHP or customer owned generation system is a very site specific resource, IMPA did not model an expansion unit to represent these systems. Most systems are very small and would have

little effect on the long term build plan. Going forward, IMPA will work with its members and their customers to investigate the addition of CHP or renewable systems at customer locations.

New Demand-Side Resources

As described in the *Resource Options Section* of this report, IMPA's long-term strategic plan includes an aspirational energy efficiency target of 10% reduction in projected demand and energy requirements by 2020 through cost effective energy efficiency programs. Energizing Indiana, the state-wide core program, is still relatively new but early indicators suggest reaching the 10% target by 2020 through cost effective programs may not be realistic as the technology, economics, and market-acceptance potential may not allow such a target to be achieved.

It is important to recognize that even if IMPA does not provide the direct funding for energy efficiency, it does not mean that energy efficiency isn't occurring. It is. As IMPA works with its member's customers, it has become evident that many businesses and residential customers have already embraced energy efficiency and energy conservation. These are energy savings IMPA does not count towards its goal, but nonetheless the energy savings are real. IMPA sees the impact of energy efficiency in its long-term load forecast which is expected to grow at less than 1% per year and likely includes organic energy efficiency implemented by customers without incentives or subsidies from IMPA.

In the stochastic section of this report, considerable discussion centers on supply-side resource cost and performance uncertainty. Demand-side programs are also very uncertain. For future demand-side programs, potential and feasibility studies are often performed to understand what levels of savings are possible from technical, economic, and market-acceptance perspectives. IMPA's participation in Energizing Indiana essentially performs these studies with "real data" allowing IMPA to gain insight into which futures programs might work best.

For the IRP, two demand-side management penetration levels (Base-EE and High-EE) were designed from the list of individual programs shown below. The Base-EE forecast reflects the expected savings by 2020 garnered from IMPA's experience with Energizing Indiana, while the High-EE forecast reflects IMPA's aspirational target of 10% by 2020.

- C&I Prescriptive Rebates
- Residential Home Lighting
- Low Income Weatherization
- Home Energy Audits
- School Audits and Education
- Commercial and Industrial Customized Audits
- High Efficiency Residential Appliances
- HVAC and Home Envelope
- Refrigerator Turn In
- New Construction
- Commercial and Industrial Demand Response

**Figure 80 Cumulative Energy Efficiency Savings Targets**
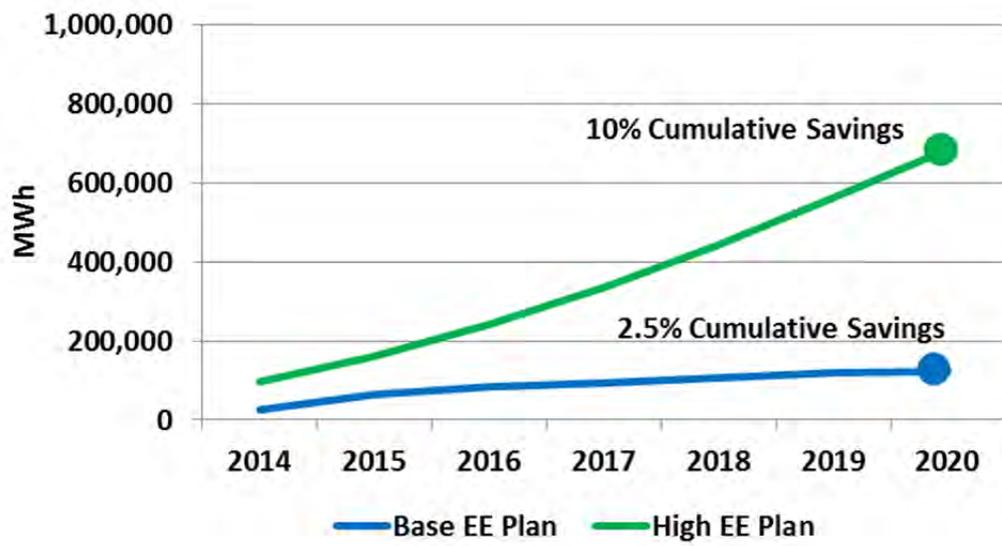
Source: IMPA

11.2 CAPACITY EXPANSION MODULE

Utilities create an IRP to provide a framework for prudent future actions required to ensure continued reliable and least cost electric service to their customers. An important part of this exercise is to evaluate the future resource needs to meet growing demand, and present a balanced and responsible resource strategy to the stakeholders and the state regulatory bodies that meets system reliability requirements, is fiscally sound, promotes environmental stewardship, and balances risks and costs.

The Capacity Expansion Module (CEM) is a long-term portfolio optimization model for automated screening and evaluation of decisions for supply-side capacity expansion and retirement options, contract transactions, and demand-side management programs.

Figure 81 Capacity Expansion Module Cut Sheet
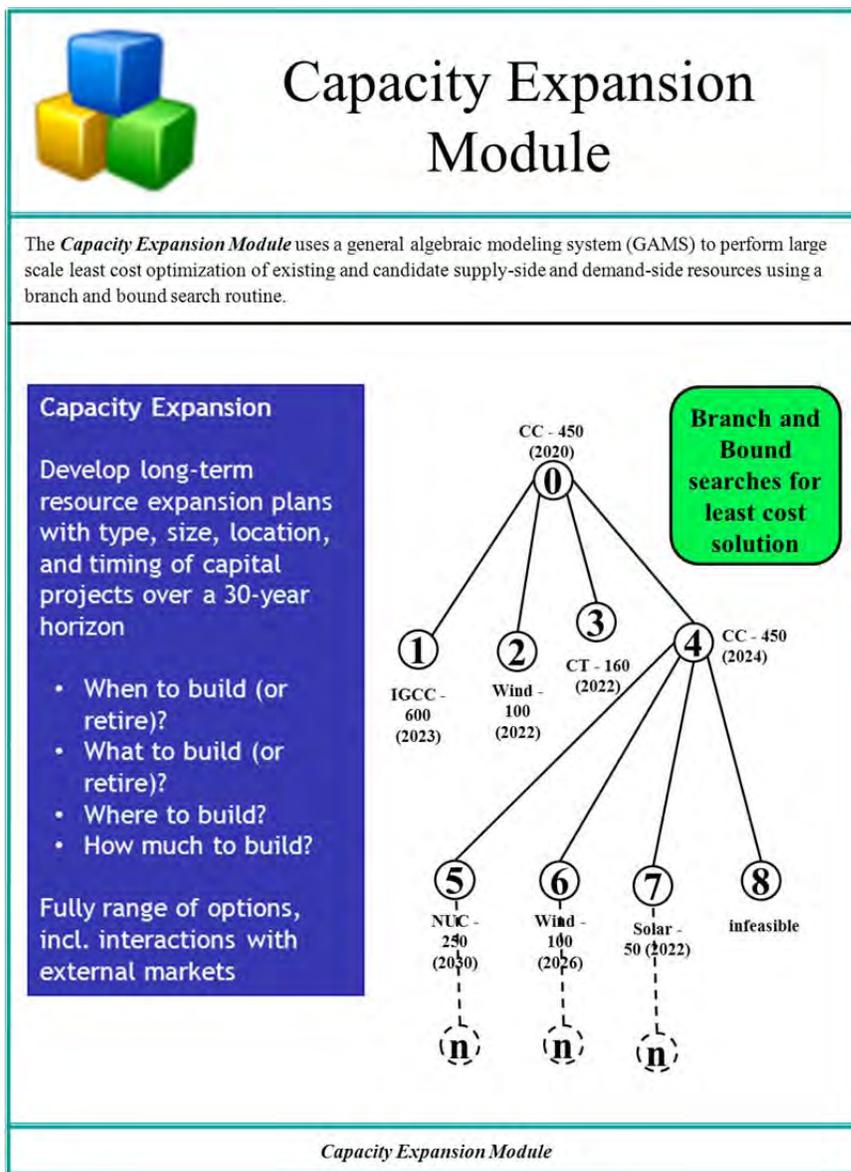
Source: Ventyx

Capacity Expansion Module – Objective Function

The optimal resource expansion strategy is based on an objective function subject to a set of constraints. The goal of the CEM is to minimize the net present value cost of supply-side and demand-side projects, contract and spot market transactions, and generating station decommissioning costs subject to load balance, reliability, and investment constraints. Thus, the criterion for evaluation is minimization of the net present value of revenue requirements (PVRR).

The CEM answers the key investment decisions of:
- What to build (or retire)?
- When to build (or retire)?
- Where to build?
- How much to build?

The CEM is a mixed integer linear program (MILP) in which the objective is minimization of the sum of the discounted costs of supplying customer loads in each area with load obligations. The model includes all existing and proposed plants in a utility system. Binary integer variables are used in the MILP to represent discrete decisions regarding whether to build or retire generation or enter into a particular contract transaction. General integer variables are used to represent how many discrete units of generation to add.

The CEM solves for the "optimal" resource plan, considering the cost effectiveness of the specific resource options, including their scale and timing to meet a target reserve margin. Decisions on generation additions or retirements are made on an annual basis. Decisions on contract transactions and demand-side management programs are made once for each potential contract's delivery period.

Capacity Expansion Module – Simulation Time

Capacity expansion planning models have very long time horizons (typically 20+ years). To remain practical in computer memory requirements and execution speed, time is represented in buckets larger than individual hours. The CEM uses the "representative hours" approach, in which average generation and load values in each representative time of use period in a week are scaled up appropriately to span all hours of the week and days of the month. IMPA utilizes powerful desktop PC workstations with 12 GB of RAM, 64-bit operating system, and a 3.2GHz clock speed to run the CEM simulations.

Despite the considerable advantages of using the CEM for resource capacity planning, it is only intended for use as a preliminary screening tool for quickly and objectively narrowing the choice set from an extremely large number of possible resource plans down to a few "good" alternatives for more detailed production, rate, and financial simulation analysis using the MIDAS Gold module.

11.3 DESCRIPTION OF RESOURCE EXPANSION ALTERNATIVES

For this IRP, IMPA developed a series of ten plans to optimize in the CEM module. The ten plans are summarized below.

Plan01 – Hedge thru 2023

In this plan, IMPA utilizes a series of contracts for capacity and energy to delay the construction of any physical assets until the 2024 time frame. Current market prices for capacity and energy are at historic low levels and there is great interest in taking advantage of this opportunity. Starting in 2024, the model is allowed to add resources. Renewables are at the base level of solar discussed previously. Energy efficiency is based on IMPA's continuing involvement and growth in the Energizing Indiana program.

Plan02 – Base Case Build

Traditional build plan. The assumption in all build plans is that 2016 is the soonest that IMPA could bring a new resource online. In these runs, greater amounts of market capacity are allowed in the early years. Renewables and EE are at the base levels discussed previously.

Plan03 – Low Load Build

The same as Plan02 except the expansion plan is run for the low load forecast. Renewables and EE are at the base levels discussed previously.

Plan04 – High Load Build

The same as Plan02 except the expansion plan is run for the high load forecast. Renewables and EE are at the base levels discussed previously.

Plan05 – High EE/Base Renew

In this plan, EE levels equal to IMPA's aspirational target are assumed. Renewables and EE are at the base levels discussed previously.

Plan06 – High EE/High Renewable

In this plan, EE levels equal to IMPA's aspirational target are assumed. Additionally, renewable energy is increased to approximately 10% of IMPA's pre EE energy needs. This is met with solar and wind resources.

Plan07 – High Renewable

In this plan, renewable energy is increased to approximately 10% of IMPA's pre EE energy needs. This is met with solar and wind resources. EE is at the base levels discussed previously.

Plan08 – Hedge thru 2020

Same as Plan01 except the hedges go through 2020. Renewables and EE are at the base levels discussed previously.

Plan09 – No Renewable

Plan02 without the solar projects. EE is at the base levels discussed previously.

Plan10 – Gibson #5 Retires in 2023

Gibson #5 retires in 2023 and IMPA cannot find a near term CC partner. Renewables and EE are at the base levels discussed previously.

11.4 SELECTED RESOURCE EXPANSION PLANS

IMPA ran the ten plans discussed above in the CEM module to develop ten different expansion plans. The resulting plans are shown in the table on the following page. It is interesting to note that every plan installs new capacity in the 2016-2017 time frame. This is due to the loss of approximately 200 MW of capacity between 2014 and 2020. Even the high EE cases which contain virtually no growth between 2014 and 2020 require the installation of additional peaking capacity.

Table 16 Expansion Results – 10 Plans

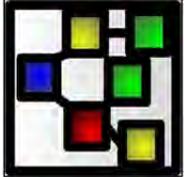|	Plan01	Plan02	Plan03	Plan04	Plan05	Plan06	Plan07	Plan08	Plan09	Plan10
Load	BASE	BASE	LOW	HIGH	BASE	BASE	BASE	BASE	BASE	BASE
EE	BASE	BASE	BASE	BASE	HIGH	HIGH	BASE	BASE	BASE	BASE
RENEW	BASE	BASE	BASE	BASE	BASE	HIGH	HIGH	BASE	NONE	BASE
Other	Hedge 2023							Hedge 2020		G5 23, no CC
2014	3 S	3 S	3 S	3 S	3 S	3 S	3 S	3 S	3 S	3 S
2015	3 S	3 S	3 S	3 S	3 S	6 S, 100 W	6 S, 100 W	3 S		3 S
2016	3 S	3 S, 185 CT	3 S, 185 CT	3 S, 185 CT	3 S, 185 CT	6 S, 185 CT 50 W	6 S, 185 CT 50 W	3 S	185 CT	3 S, 185 CT
2017	3 S	3 S, 100 CC	3 S	3 S, 100 CC	3 S	6 S	6 S	3 S	100 CC	3 S, 185 CT
2018	3 S	3 S	3 S, 100 CC	3 S	3 S, 100 CC	6 S	6 S, 100 CC	3 S		3 S
2019	3 S	3 S	3 S	3 S	3 S	6 S	6 S	3 S		3 S
2020	3 S	3 S	3 S	3 S, 100 CC	3 S	9 S	9 S	3 S		3 S
2021						9 S	9 S	100 CC, 185 CT		
2022								100 CC	100 CC	
2023		100 CC								
2024	200 CC, 185 CT									100 CC
2025										
2026							100 CC			
2027										
2028										100 CC
2029				100 CC						
2030						100 CC				
2031			100 CC							
2032										
2033										
Natural Gas Additions – ICAP	385	385	385	485	285	285	385	385	385	570
Wind Additions – ICAP	0	0	0	0	0	150	150	0	0	0
Solar Additions – ICAP	21	21	21	21	21	51	51	21	21	21
UCAP Added	370	370	370	464	276	314	401	370	370	546

CC = Advanced Combined Cycle
CT = Advanced Combustion Turbine
W = Wind
S = Solar

12 PLAN EVALUATION

12.1 MIDAS GOLD MODULE

Once the price trajectories have been simulated using the Horizons Interactive module and the optimal resource plans have been identified using the Capacity Expansion module, the MIDAS Gold (MIDAS) module is used to perform IMPA specific portfolio analysis.

Figure 82 MIDAS Gold Module Cut Sheet

Source: Ventyx

MIDAS Gold – Operations
MIDAS allows for detailed operational characteristics of IMPA's portfolio. The generation fleet, contracts, and load are dispatched competitively against the LMP market prices created by Horizons Interactive.

The generation fleet dispatch and unit commitment logic allows for unit specific parameters for:
- Heat rates
- Fuel costs
- FO/MO rates
- VOM and FOM
- Emissions
- Ramp rates
- Minimum/maximum run times
- Startup costs

The decision to commit a unit is based on the economics including the cost of shutdown and restarting at a later time. Forced outages may be modeled as Monte-Carlo or frequency and duration with detailed maintenance scheduling.

MIDAS Gold – Rates and Financing
MIDAS creates pro forma financial statements (income statement, balance sheet, cash flow statement) using a middle-up income driver tied to IMPA's debt service coverage (DSC) ratio.

MIDAS Gold – Risk Analyst Tools
The Risk Analyst tools and techniques provide assessment of the contributors of risk.
- Risk Profiles
- Tornado Charts
- Deterministic and Stochastic Bar Charts
- Trade-Off Diagrams
- Dominance Charts
- Risk Confidence Band Charts
- Efficient Frontier

MIDAS Gold – Simulation Time
The simulation and processing time for running each of the ten (10) plans through the deterministic and stochastic draws is approximately an hour per plan using a desktop PC workstation with 12 GB of RAM, 64-bit operating system, and a 3.2GHz clock speed. In total, 510 20-year portfolio simulations were performed.
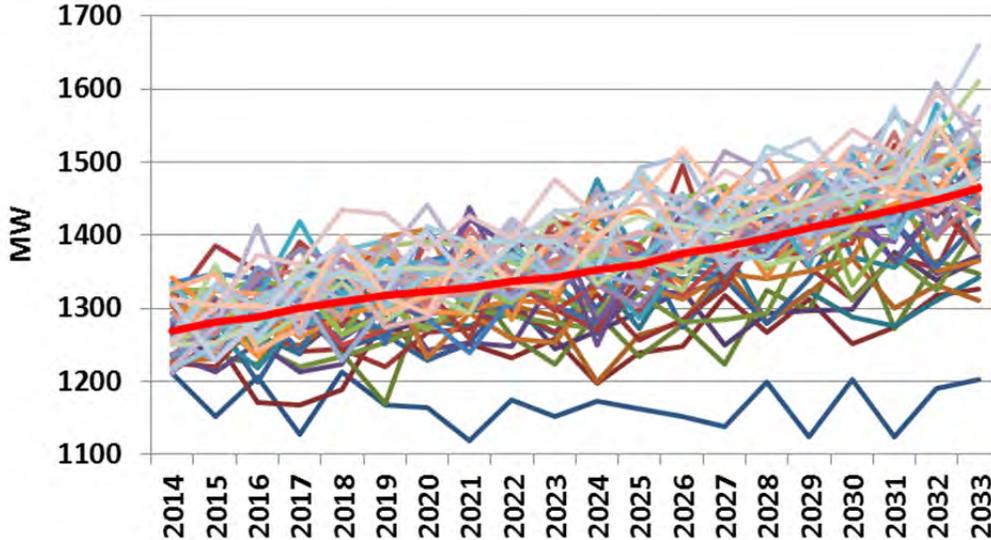
Figure 83 MIDAS Gold Stochastic Process
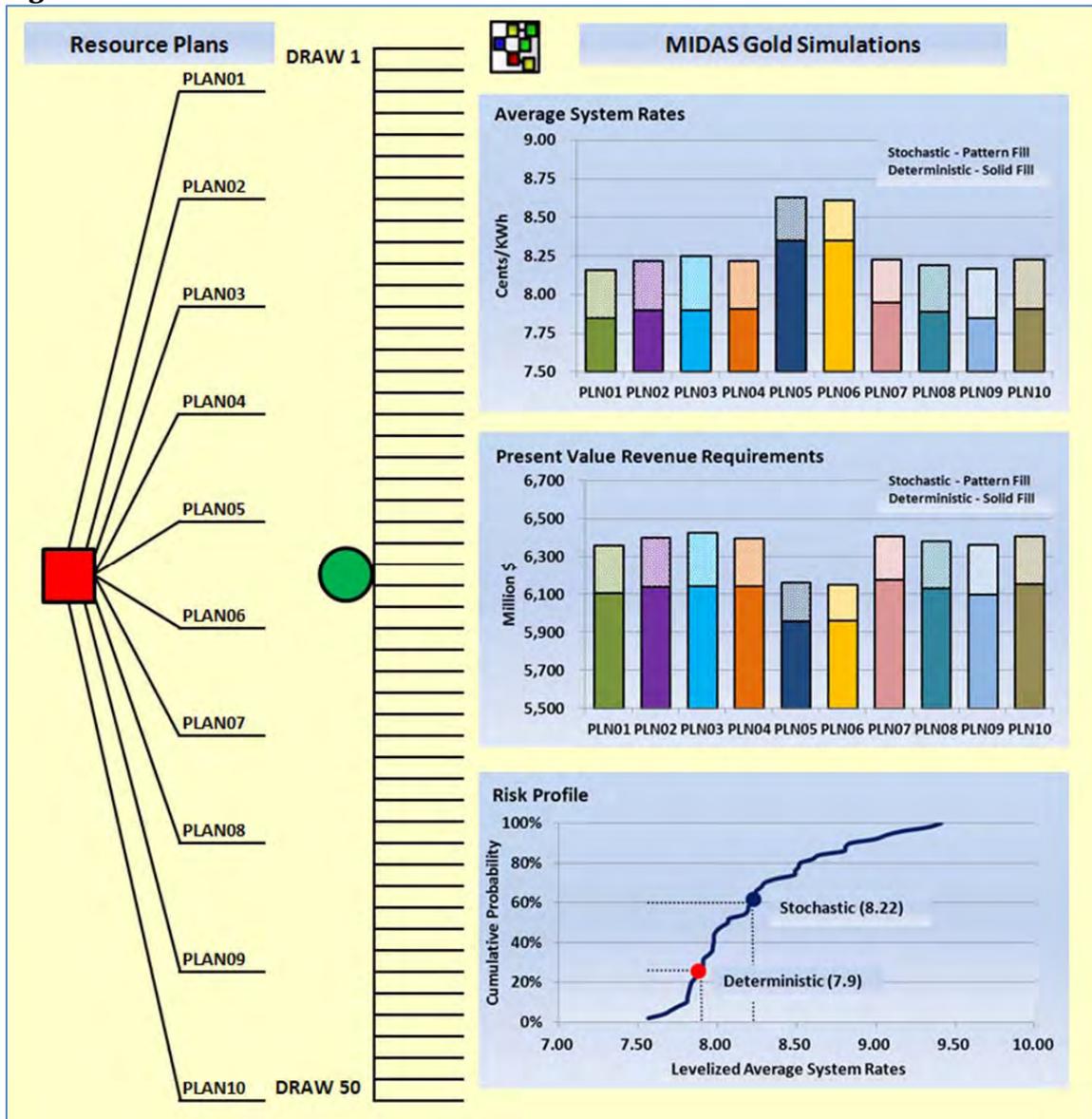
Source: IMPA

IMPA Stochastic Peak Demand

IMPA's peak demand uncertainty is driven by the long-term economic growth combined with the medium-term weather driven peak demand uncertainty.

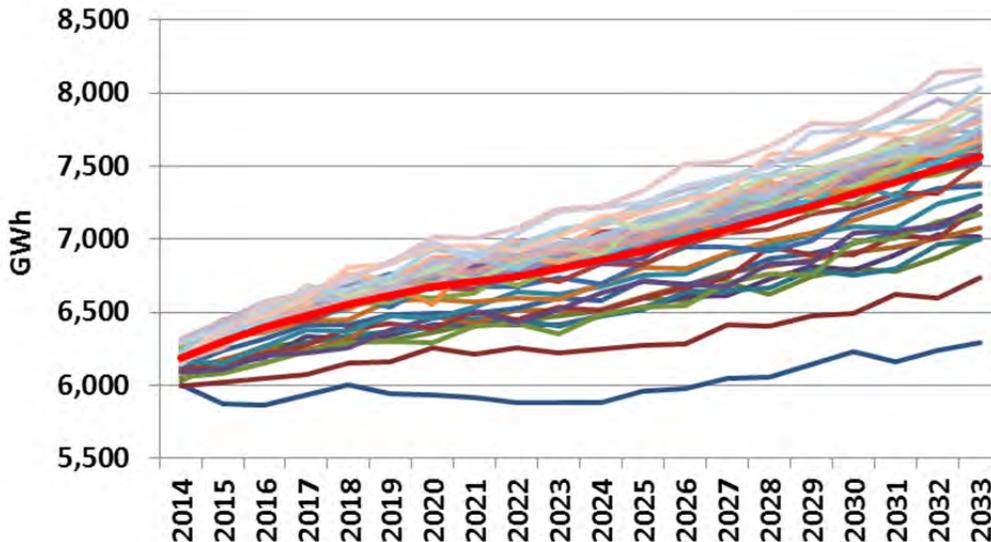**Figure 84 IMPA Peak Demand – 50 Stochastic Futures**

Source: IMPA

IMPA Stochastic Energy

IMPA's annual energy uncertainty is driven by the long-term economic growth and energy efficiency cases combined with the medium-term weather driven energy uncertainty.

Figure 85 IMPA Annual Energy – 50 Stochastic Futures

Source: IMPA

IMPA Stochastic Natural Gas Price

IMPA's natural gas forecast is driven by long-term gas exploration and recovery combined with medium-term volatility driven by usage, storage and weather.

Figure 86 IMPA Natural Gas Price – 50 Stochastic Futures
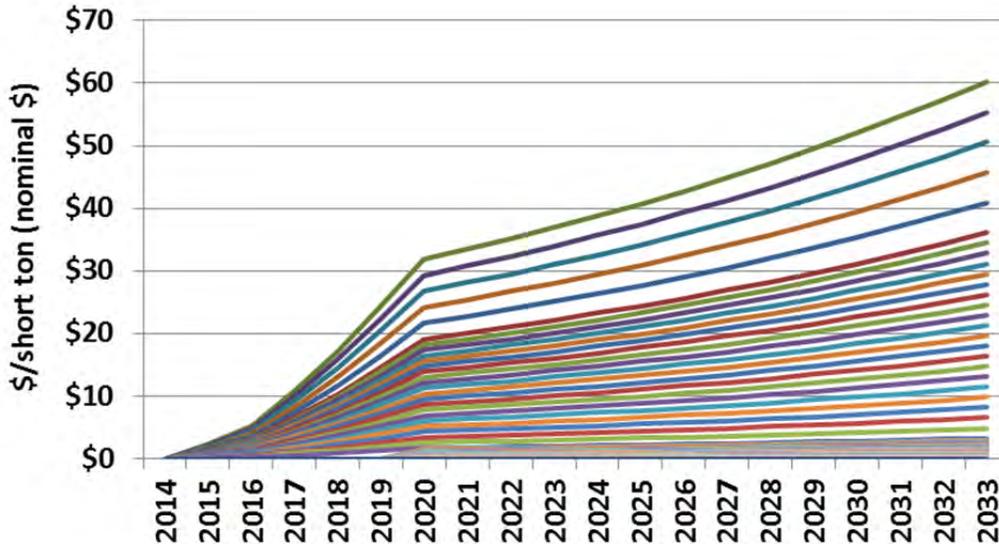

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Source: IMPA

IMPA Stochastic CO_2 Expense

IMPA's CO_2 expense is driven by CO_2 price exposure and the assumed number of CO_2 allowances.

**Figure 87 IMPA CO_2 Price – 50 Stochastic Futures**

Source: IMPA

IMPA Coal Fleet Availability

IMPA's coal fleet consists of joint-ownership in five (5) large coal units. To capture the uncertainty of one or more of the coal units experiencing a forced outage, IMPA created a frequency of availability curve shown below. The curve illustrates the frequency of availability for the entire IMPA coal fleet based on data from 100+ similar sized units from the NERC's Generating Availability Data System (GADS) database. The skewed-left lognormal distribution is applied to the Monte Carlo draws of the coal fleet depicting the probabilistic range of availability.

Figure 88 IMPA Coal Fleet Availability
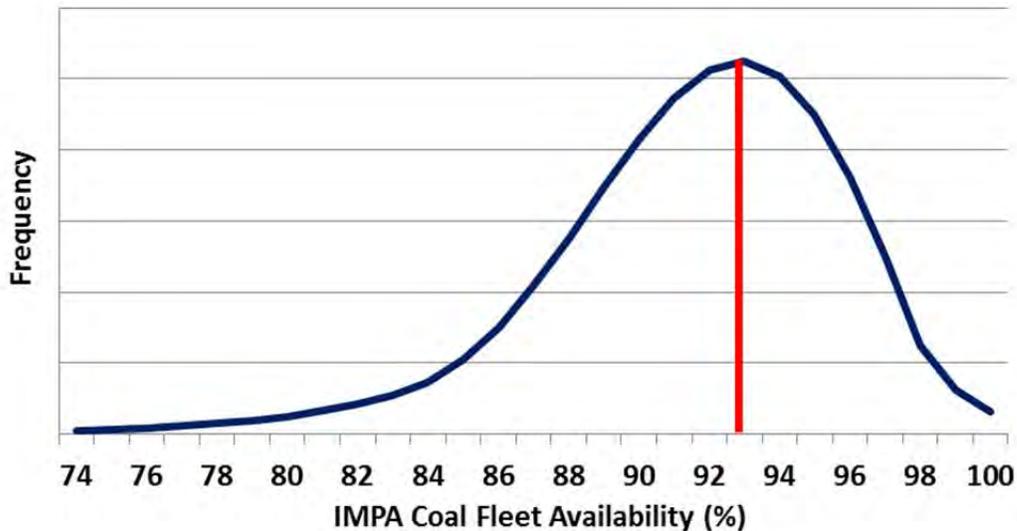
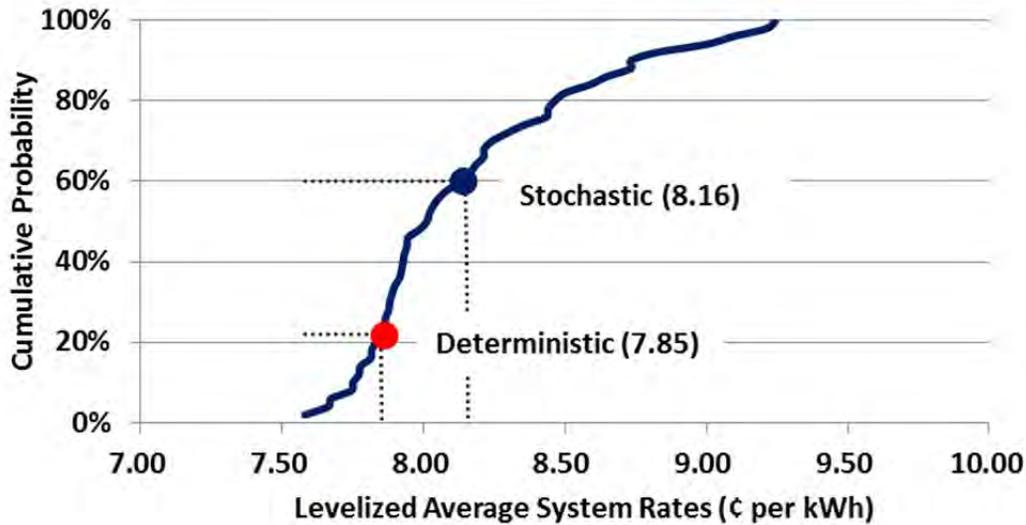Source: IMPA

Risk Profiles Explained

The risk profiles created for each plan provide valuable insight into the risk of a particular plan. The x-axis (levelized average system rate) shows the range of possible outcomes, in this case IMPA plots the outcome of fifty (50) stochastic draws. The y-axis is the cumulative probability of the occurrence of each outcome between 0% and 100%. For example, if the far left point is 7.6 ¢/kWh and the far right point is 9.25 ¢/kWh, then there is 100% confidence that the rate will be between those two points. The narrower the range, the less risk. To manage risk, risk managers look for ways to minimize the "fat tails" of a risk profile often trading upside opportunity for downside risk. A risk averse profile would be a vertical line, but achieving a risk free vertical line likely moves the entire profile far to the right. Think of it as buying far more insurance than is necessary and laying off the risk on the insurance company. IMPA recognizes there is inherent risk in the electric utility business so a balance is drawn between risk and reward using tools such as a risk profile.

The risk profiles are labeled with two points. The deterministic point is the reference case outcome (base case assumptions). The stochastic point is the average of all 50 uncertain outcomes. The difference between the points is a measure of the overall risk added to the deterministic simulation.

12.2 PLAN01 RESULTS

In this plan, IMPA utilizes a series of contracts for capacity and energy to delay the construction of any physical assets until the 2024 time frame. Current market prices for capacity and energy are at historic low levels and there is great interest in taking advantage of this opportunity. Starting in 2024, the model is allowed to add resources. Renewables and EE are at the base levels discussed previously.

Figure 89 Plan01 Risk Profile

Source: IMPA

Figure 90 Plan01 Tornado Chart
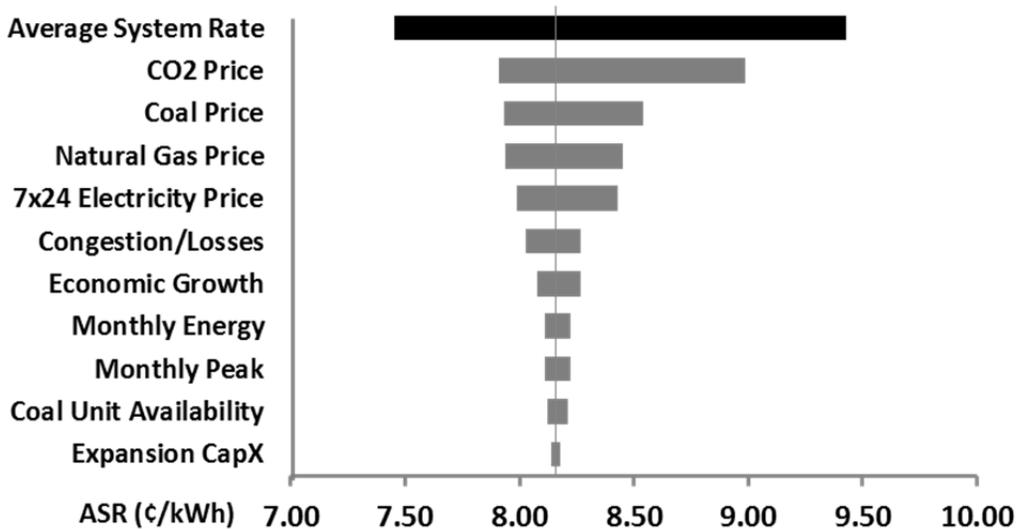
Source: IMPA

12.3 PLAN02 RESULTS

Traditional build plan. The assumption in all build plans is that 2016 is the soonest that IMPA could bring a new resource online. In these runs, greater amounts of market capacity are allowed in the early years. Renewables and EE are at the base levels discussed previously.

Figure 91 Plan02 Risk Profile

Source: IMPA

Figure 92 Plan02 Tornado Chart

Source: IMPA

12.4 PLAN03 RESULTS

The same as Plan02 except the expansion plan is run for the low load forecast. Renewables and EE are at the base levels discussed previously.

Figure 93 Plan03 Risk Profile
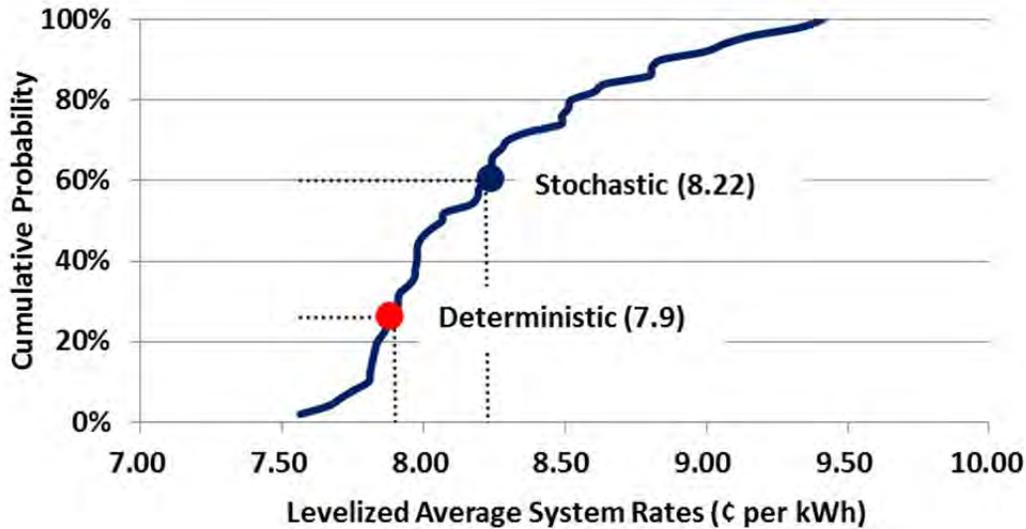

Source: IMPA

Figure 94 Plan03 Tornado Chart

Source: IMPA

12.5 PLAN04 RESULTS

The same as Plan02 except the expansion plan is run for the high load forecast. Renewables and EE are at the base levels discussed previously.

Figure 95 Plan04 Risk Profile

Source: IMPA

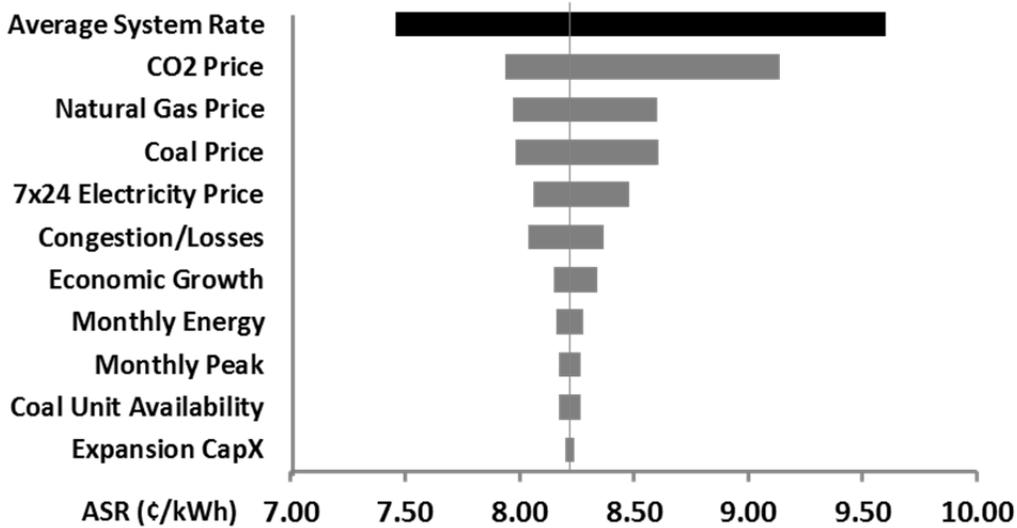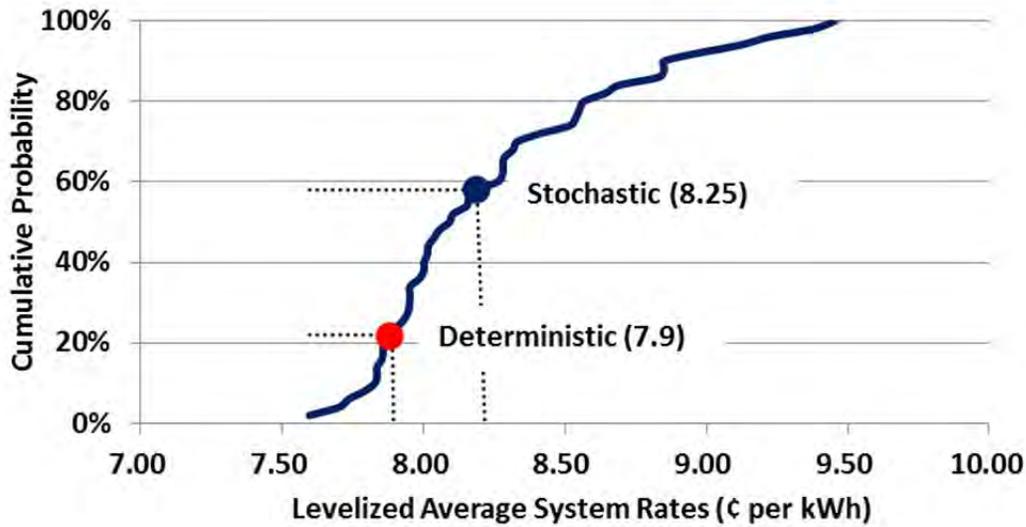**Figure 96 Plan04 Tornado Chart**
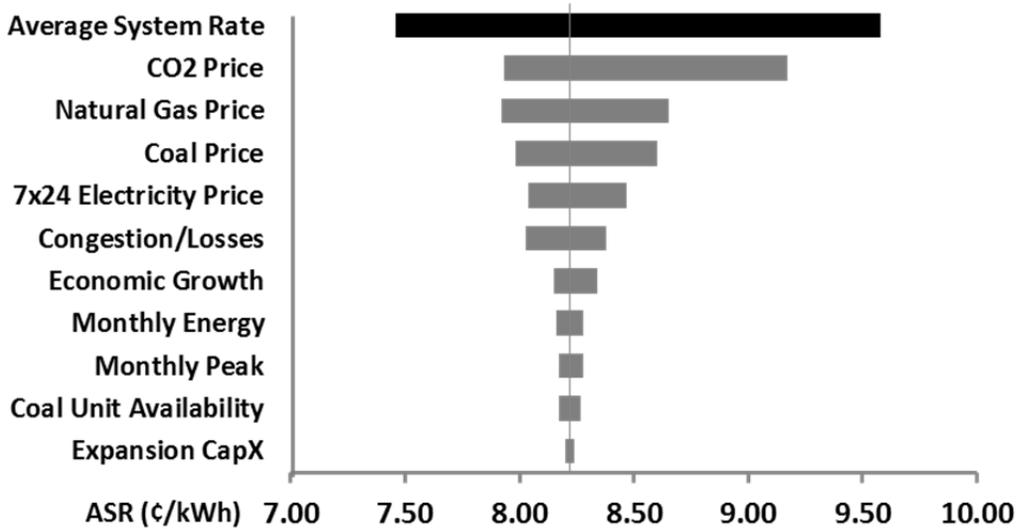
Source: IMPA

12.6 PLAN05 RESULTS

In this plan, EE levels equal to IMPA's aspirational target are assumed. Renewables are at the base level of solar discussed previously.

Figure 97 Plan05 Risk Profile

Source: IMPA

Figure 98 Plan05 Tornado Chart
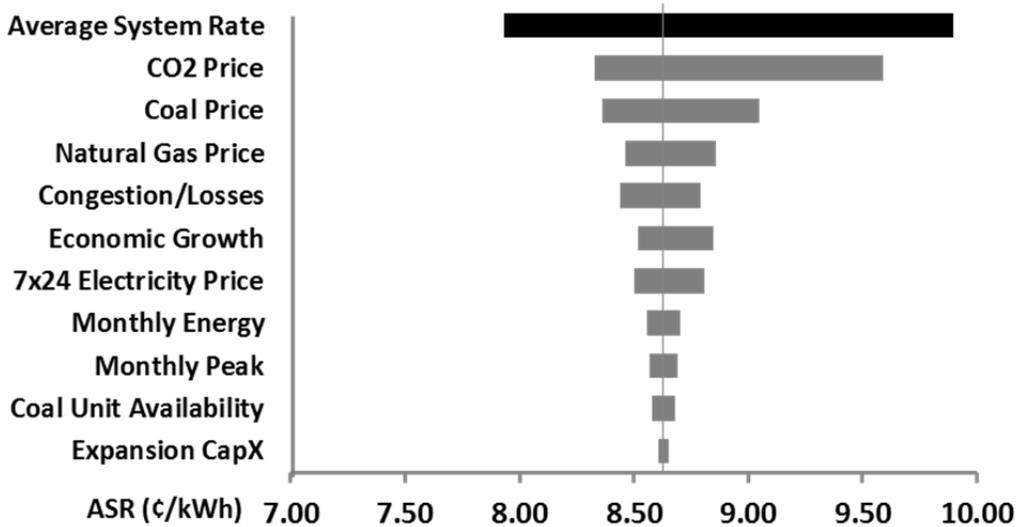
Source: IMPA

12.7 PLAN06 RESULTS
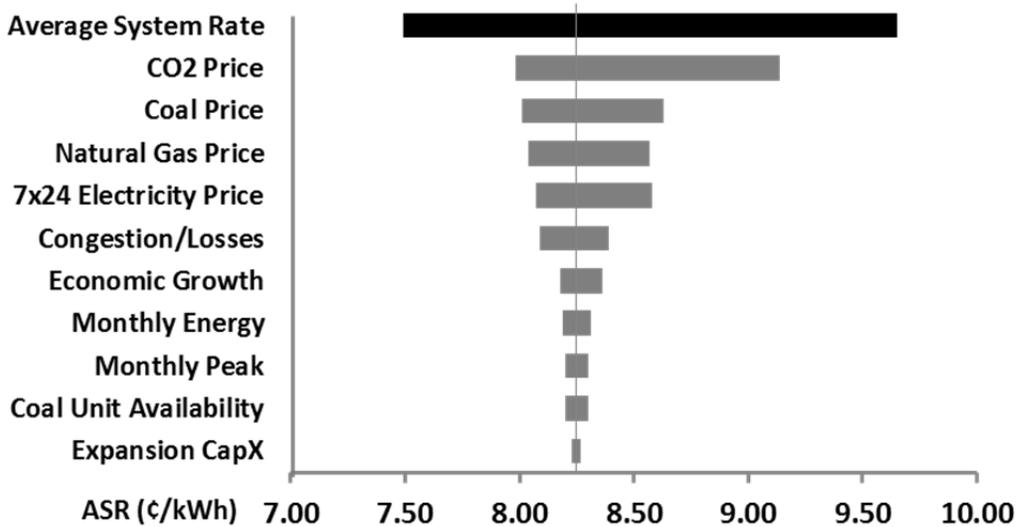
In this plan, EE levels equal to IMPA's aspirational target are assumed. Additionally, renewable energy is increased to approximately 10% of IMPA's pre EE energy needs. This is met with solar and wind resources.

Figure 99 Plan06 Risk Profile

Source: IMPA

Figure 100 Plan06 Tornado Chart
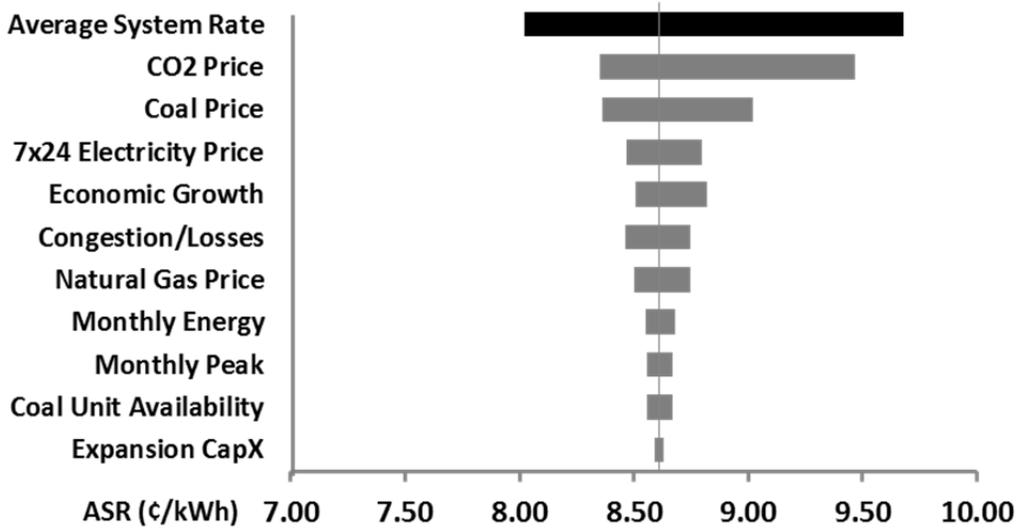
Source: IMPA

12.8 PLAN07 RESULTS

In this plan, renewable energy is increased to approximately 10% of IMPA's pre EE energy needs. This is met with solar and wind resources.

Figure 101 Plan07 Risk Profile
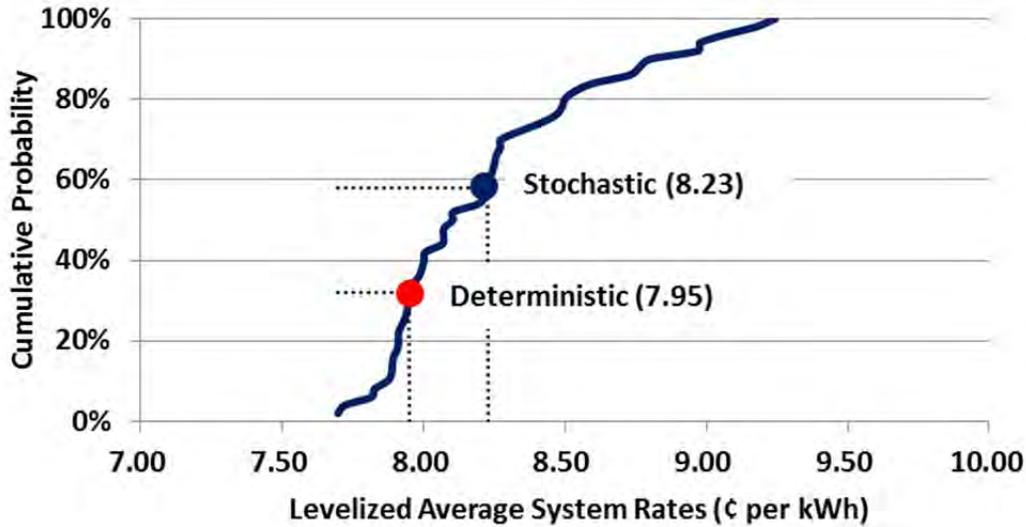
Source: IMPA

Figure 102 Plan07 Tornado Chart
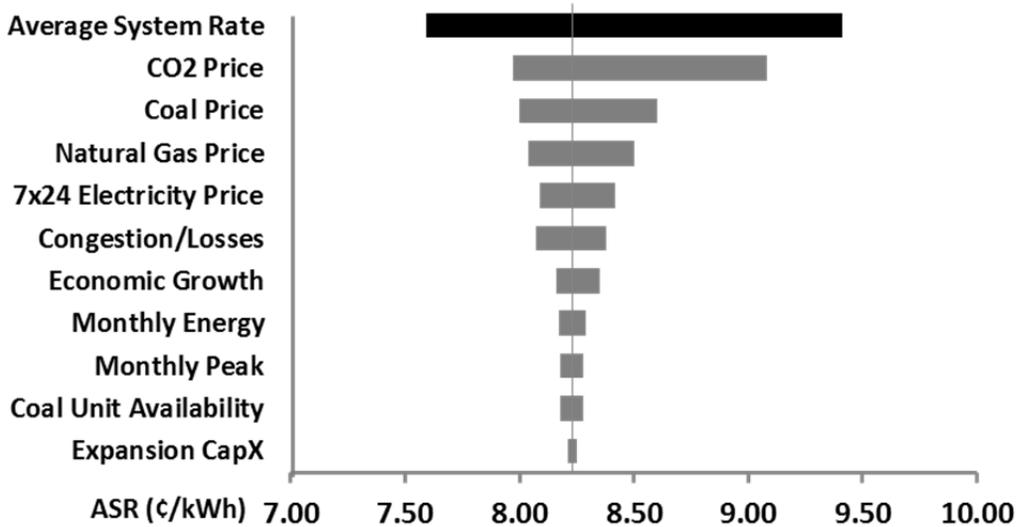
Source: IMPA

12.9 PLAN08 RESULTS

Same as Plan01 except the hedges go through 2020. Renewables and EE are at the base levels discussed previously.

Figure 103 Plan08 Risk Profile
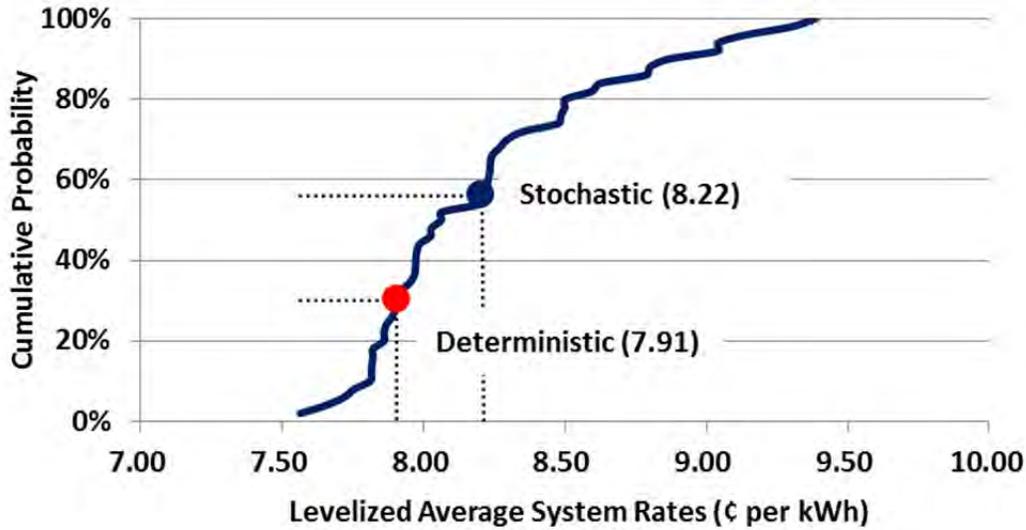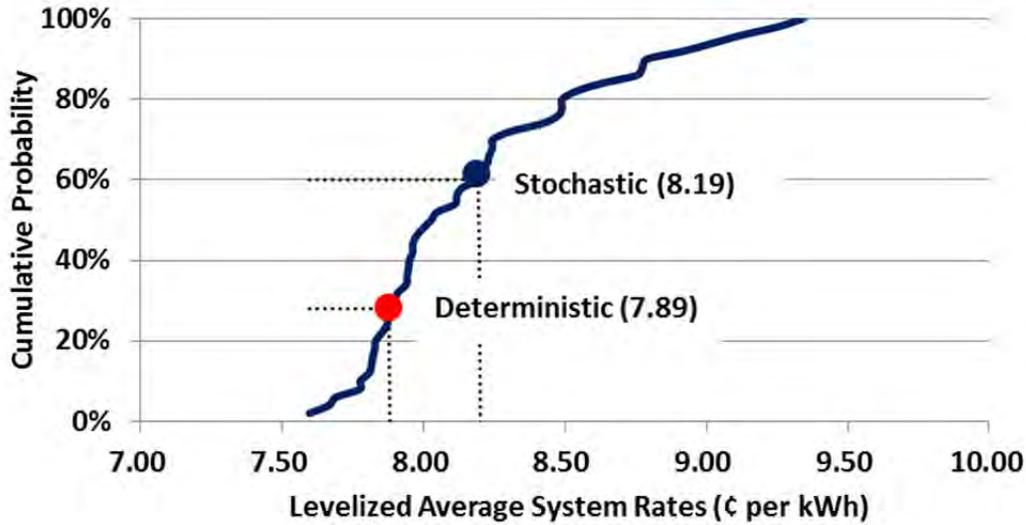

Source: IMPA

**Figure 104 Plan08 Tornado Chart**
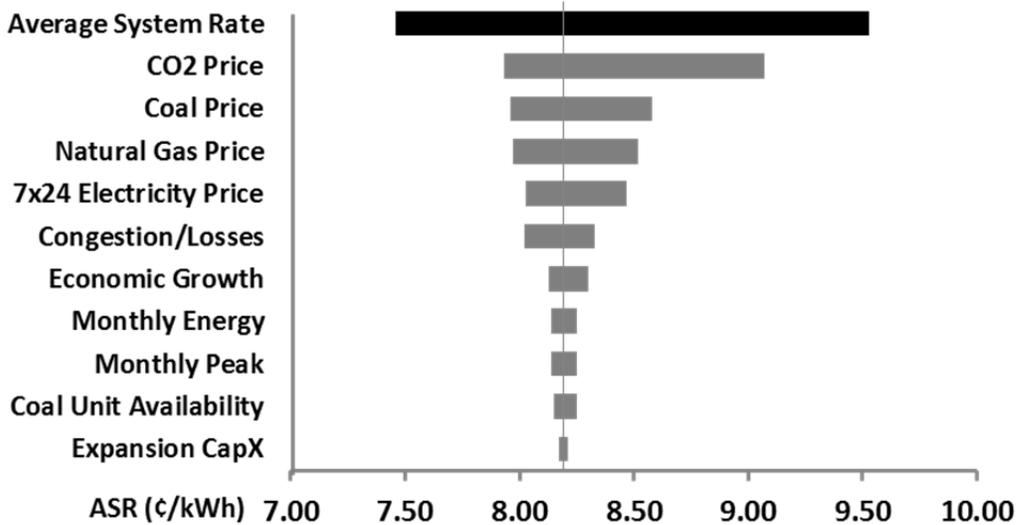
Source: IMPA

12.10 PLAN09 RESULTS

Plan02 without the solar projects.

Figure 105 Plan09 Risk Profile
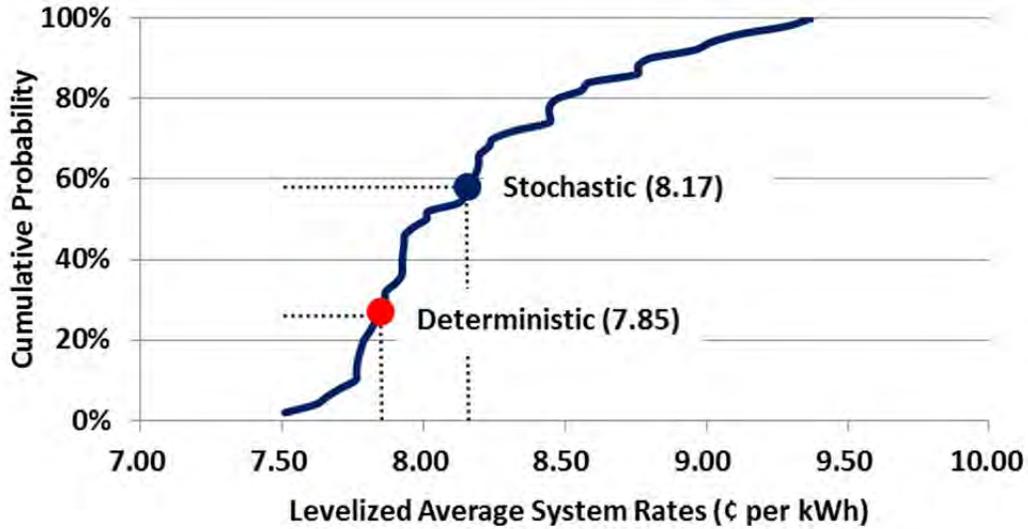
Source: IMPA

Figure 106 Plan09 Tornado Chart
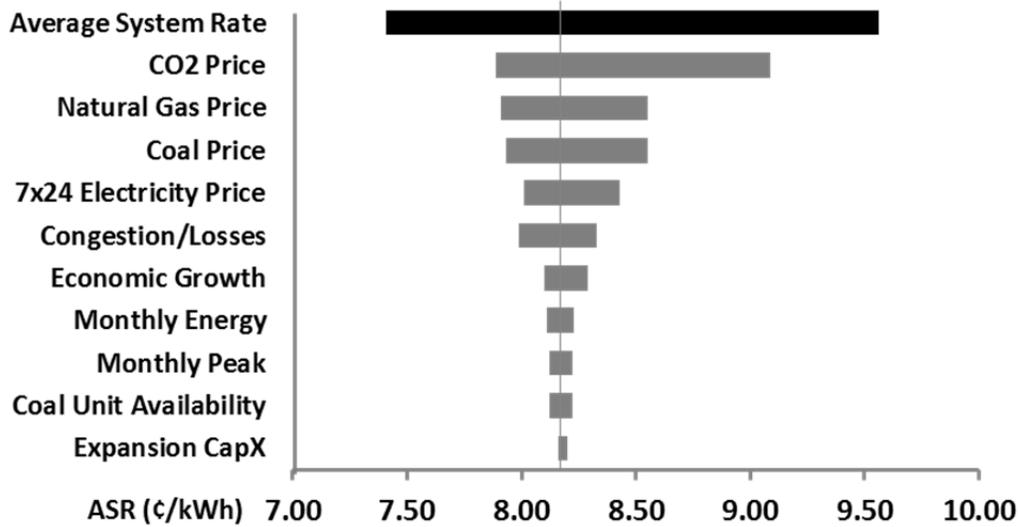
Source: IMPA

12.11 PLAN10 RESULTS

Gibson #5 retires in 2023 and IMPA cannot find a near term CC partner. Renewables and EE are at the base levels discussed previously.

Figure 107 Plan10 Risk Profile
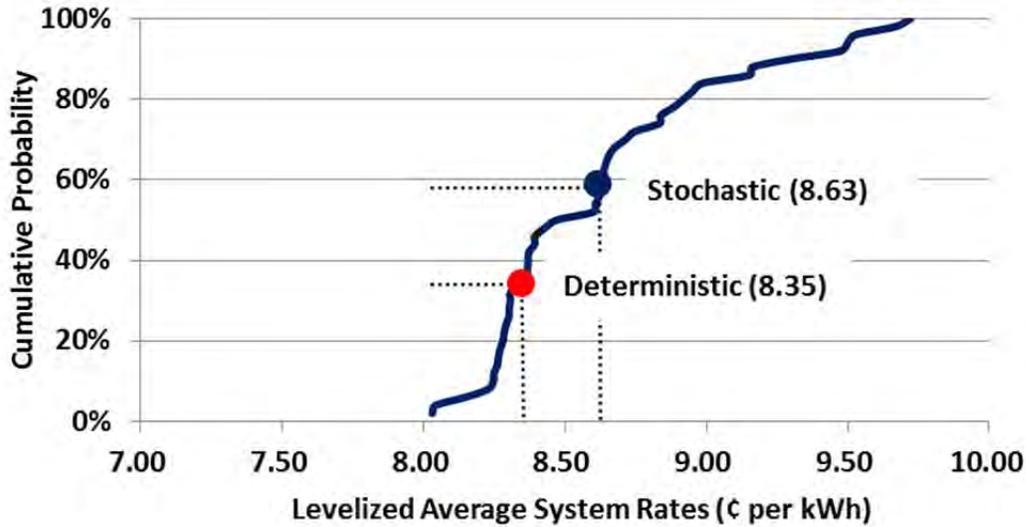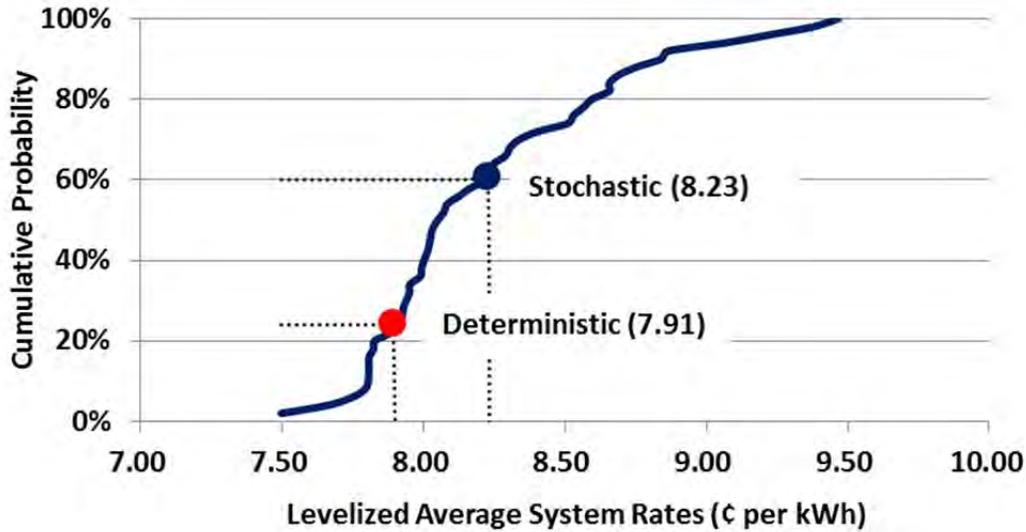

Source: IMPA

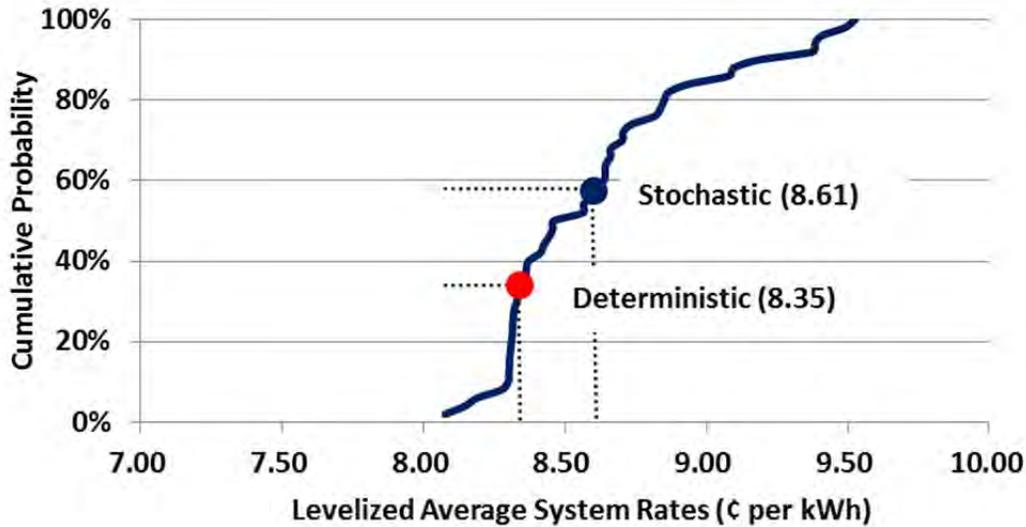**Figure 108 Plan10 Tornado Chart**
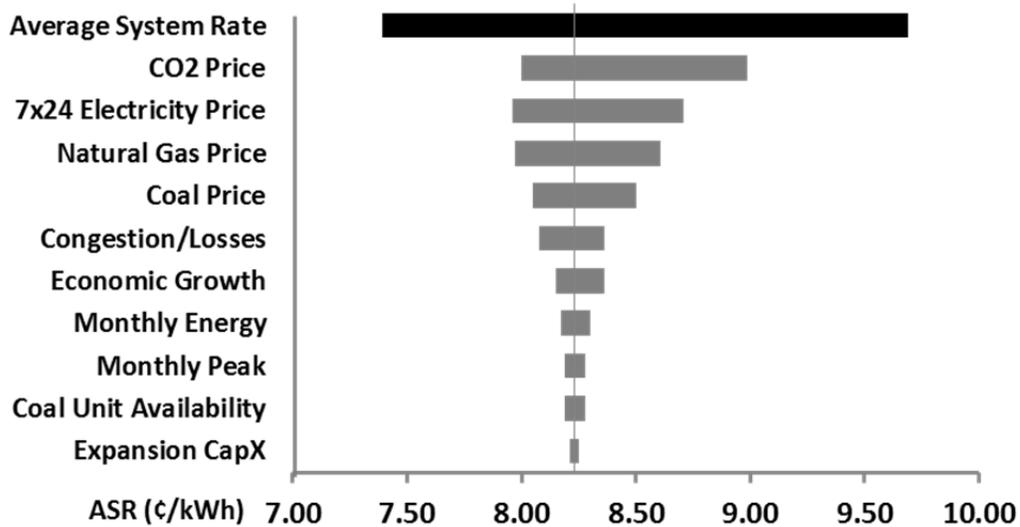
Source: IMPA

12.12 Average System Rates (ASR)

The following chart shows IMPA's levelized average system rate for the ten plans.

Figure 109 Average System Rates Chart
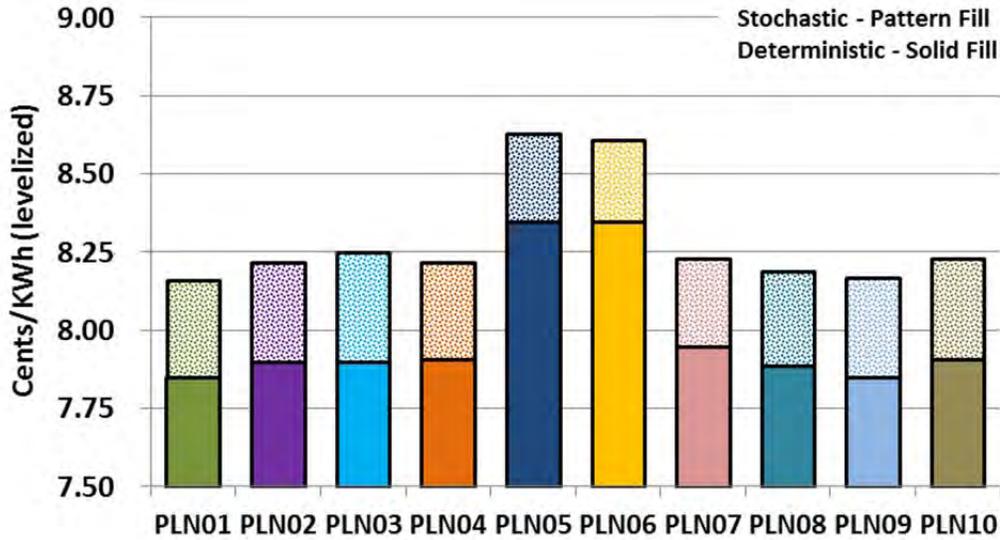
Source: IMPA

12.13 Present Value Revenue Requirements (PVRR)

The following chart shows IMPA's levelized present value revenue requirement for the ten plans.

Figure 110 Present Value Revenue Requirements Chart
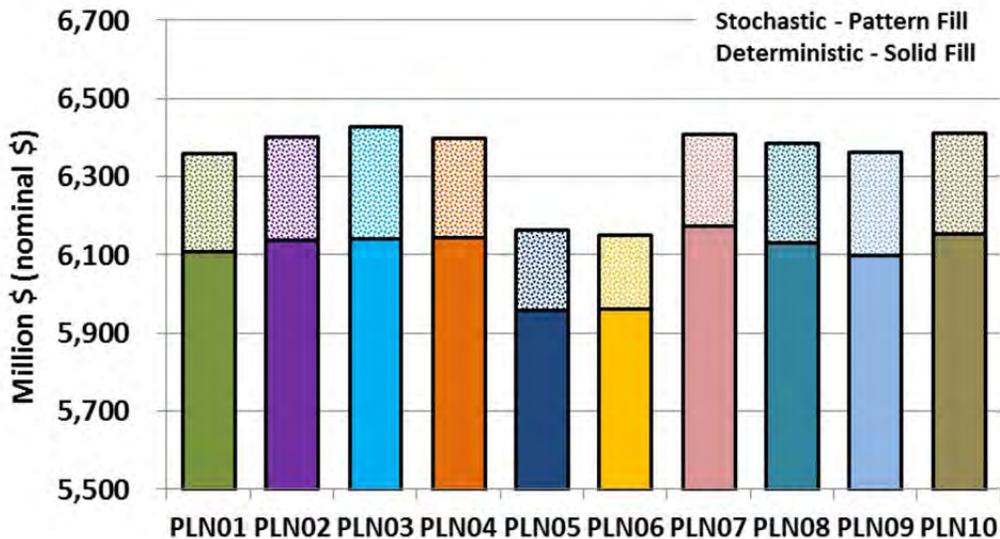
Source: IMPA

12.14 TRADE-OFF DIAGRAM

The following chart shows each plan's levelized PVRR plotted against the levelized rate per kWh. Viewing data in this manner allows a comparison of the relative tradeoff in different plans. For instance, the high EE plans (5 and 6) produce far lower PVRR, but increase IMPA rates by 5-6% compared to the cases with lower levels of EE.

Figure 111 Trade-Off Diagram
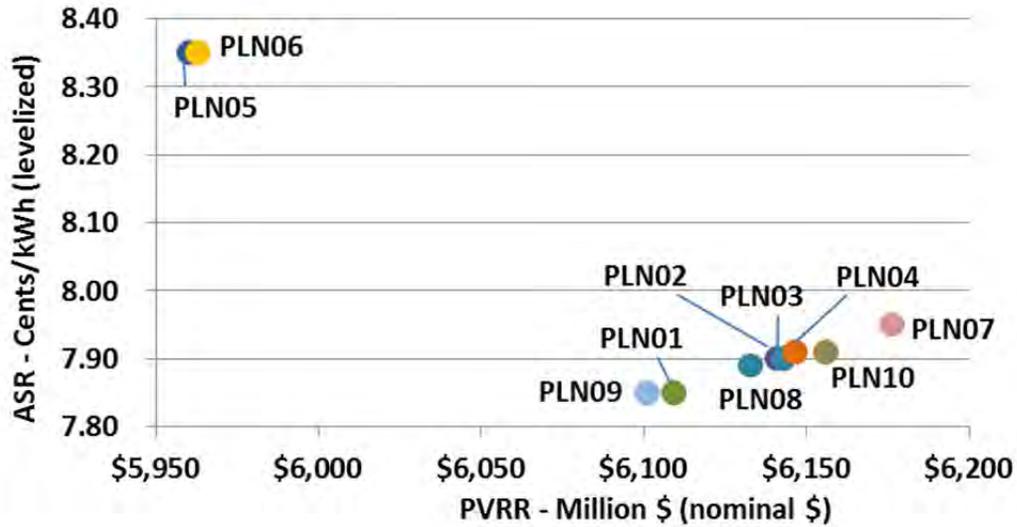
Source: IMPA

12.15 ASR Dominance Chart

The following charts measure how often a particular plan has the lowest ASR value for a given year and stochastic future. The charts are separated into two time frames. The top chart is from 2014-2023 and illustrates the hedge plans (PLN01 and PLN08) dominate. The bottom chart is from 2024-2033 and illustrates renewables and energy efficiency (PLN06 and PLN07) or less coal (PLN10) performs better as the potential for higher CO_2 prices increase in the later years.

Figure 112 ASR Dominance Charts
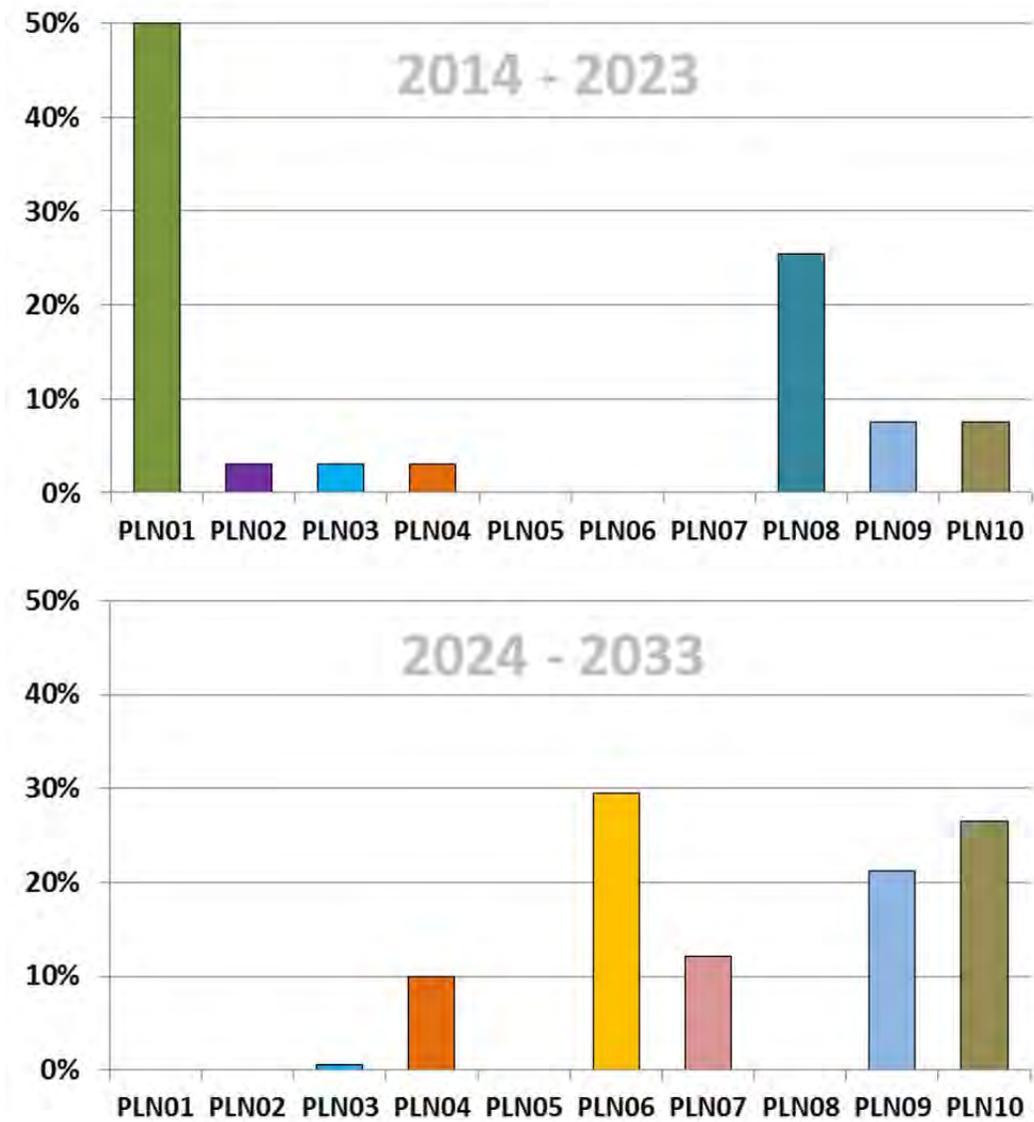
Source: IMPA

12.16 ASR RISK CONFIDENCE BANDS

The following chart identifies the risk confidence band of each plan where the green bar represents good outcomes relative to the mean and the red bar represents bad outcomes relative to the mean.

Figure 113 ASR Risk Confidence Bands Chart
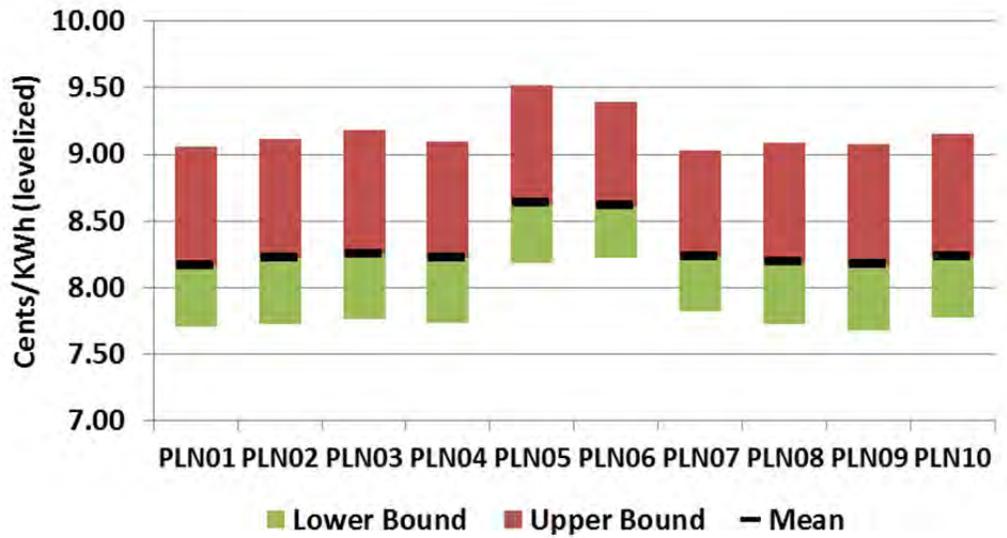
Source: IMPA

12.17 ASR EFFICIENT FRONTIER

The ASR efficient frontier graph provides a measurement of risk (standard deviation) versus reward (levelized average system rate). The optimal portfolio(s) lie in the lower left quadrant where risk and reward are both minimized. As illustrated by the graph, Plans 01 and 07 appear to be most optimal; however, Plan07 (high renewable) is highly dependent on an assumed favorable PPA that may not be available. Plan01 (long-term hedge) is highly dependent on an assumed favorable forward price, which like the renewable portfolio, also may not be available.

Figure 114 ASR Efficient Frontier
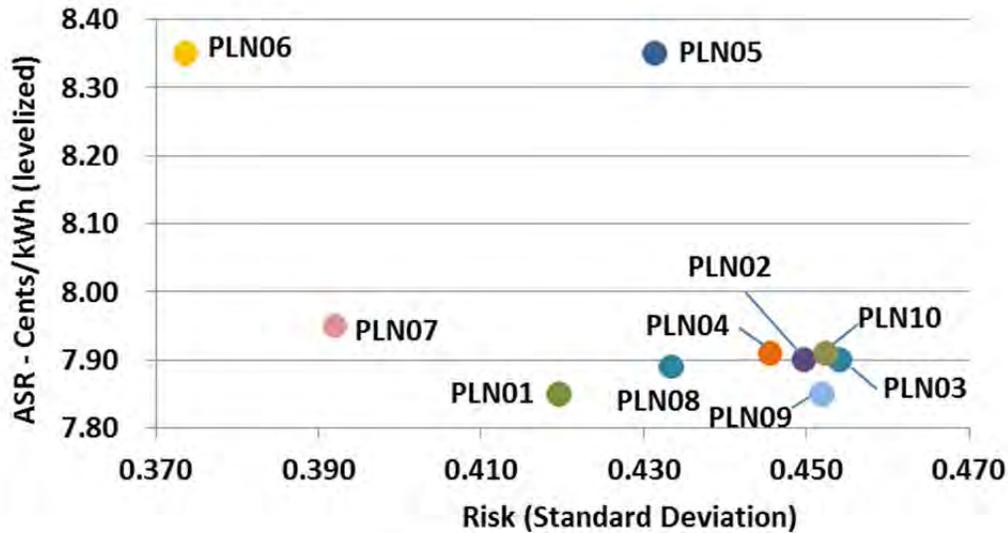
Source: IMPA

12.18 Scenario Results

Whereas stochastic analysis uses quantitative techniques to describe an uncertainty (e.g. behavior of natural gas prices), scenario analysis is used to answer "what if" questions (e.g. carbon legislation implemented). In addition to the stochastic simulation of the ten (10) plans, IMPA also quantified the robustness of the plans if a paradigm shift were to occur in the industry.

IMPA identified three scenarios with distinct themes which are expected to have the greatest impact on the future energy business environment over the next 20 years.

Figure 115 MIDAS Gold Scenario Process
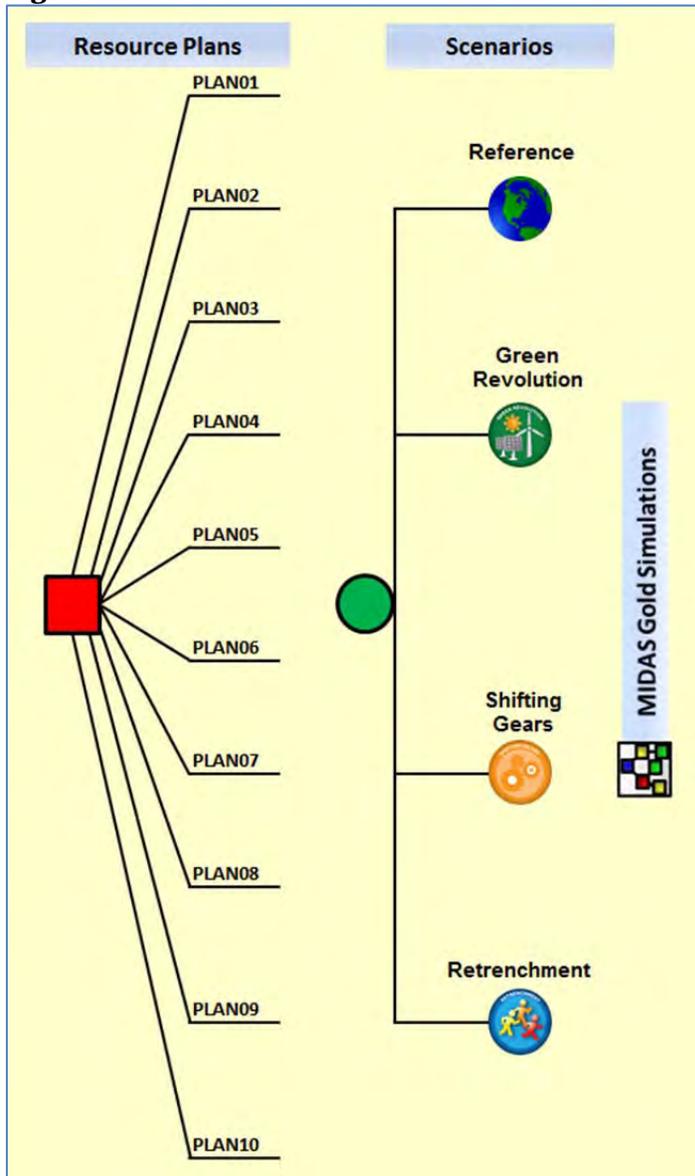
Source: IMPA

Scenario Results

The following charts show IMPA's levelized average system rate for the ten plans for each of the three scenarios.

Green Revolution Results

The "green" scenario:
- Triggered by climate concerns.
- Strict policies slow global GHG emissions growth and reduce U.S. GHG emissions dramatically.
- Comes at a high cost.

Figure 116 Green Revolution – ASR Chart
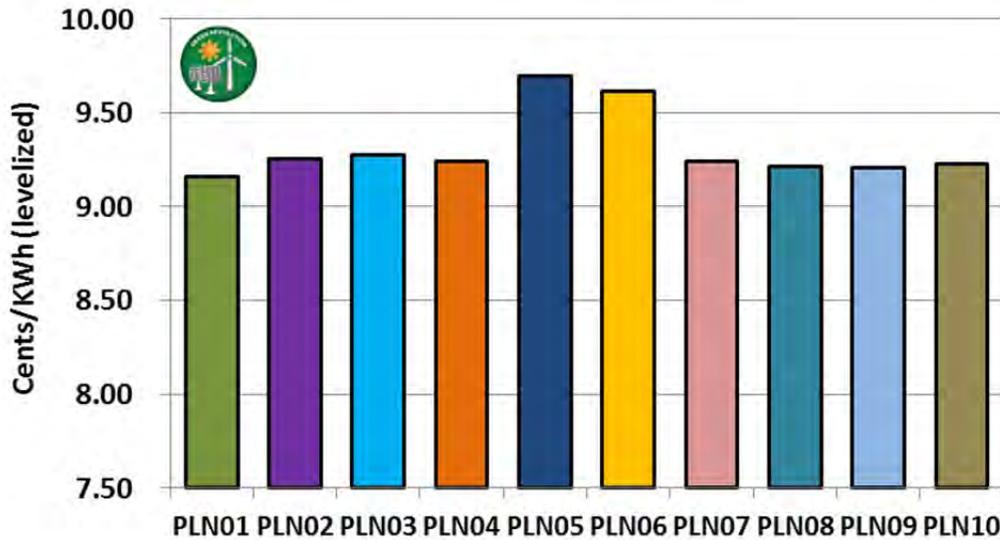
Source: IMPA

Shifting Gears Results

The "compromise" scenario:

- Triggered by political compromise between carbon and non-carbon advocates.
- Steady movement towards sustainable energy as a larger percentage of the power supply.
- Intentions exceed results.

Figure 117 Shifting Gears – ASR Chart
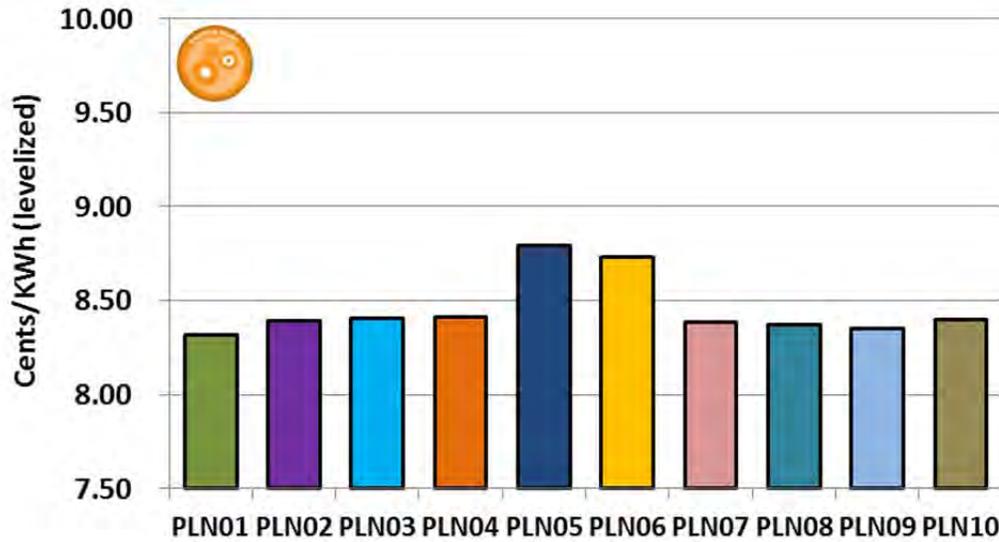
Source: IMPA

Retrenchment Results

The "traditional" scenario:

- Triggered by global competitiveness and reliability concerns.
- Shift back towards traditional low cost, non-intermittent resources.
- Improves U.S. competitive position on the world stage.

Figure 118 Retrenchment – ASR Chart
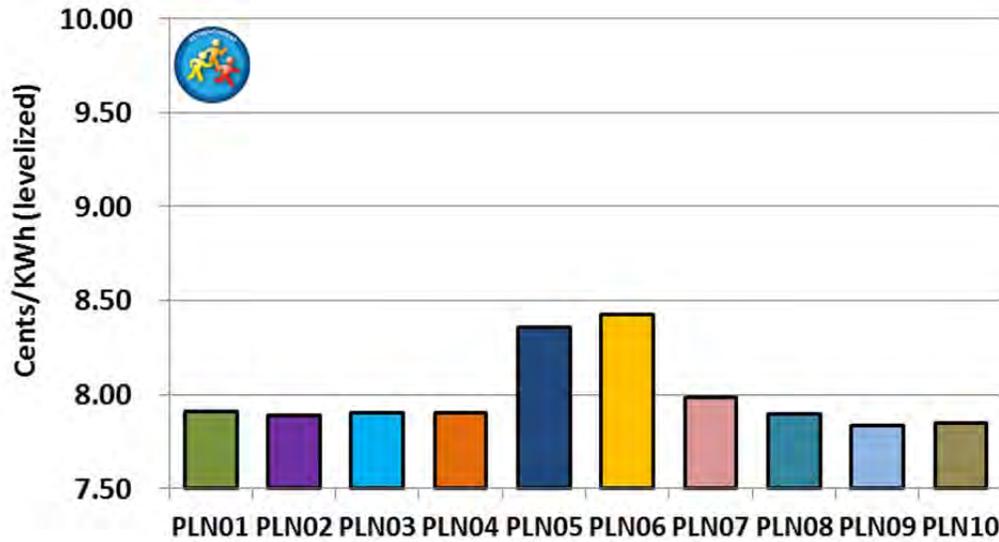
Source: IMPA

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13 PLAN SELECTION

13.1 PLAN SELECTION

As shown throughout this report, due to pending contract expirations, IMPA is losing approximately 200 MW of capacity in the next 7 years. Even assuming zero load growth, IMPA would still require additional resources to make up this deficit. This is proven by the fact that in every one of the ten plans IMPA ran for this study, capacity was added in the next 5 years, even the high EE cases.

The following table shows IMPA's load and capacity balance assuming no new resources are added in the future.

Table 17 Capacity Balance – Before Additions

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Requirements																				
Peak Load w/ EE	1,209	1,220	1,228	1,238	1,248	1,255	1,263	1,267	1,273	1,280	1,288	1,297	1,308	1,320	1,331	1,344	1,356	1,369	1,382	1,397
Resources																				
Gibson #5	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Gibson #5 Back-up	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trimble County #1	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Trimble County #2	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
Prairie State #1	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Prairie State #2	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Anderson #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #3	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
Georgetown #2	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Georgetown #3	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Richmond #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Richmond #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
AEP Cost Based	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Duke Cost Based	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Duke CB - New Members	22	22	18	9	9	9	9	-	-	-	-	-	-	-	-	-	-	-	-	-
Member Capacity	159	159	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Market Capacity	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Resources	1,369	1,345	1,285	1,226	1,176	1,176	1,176	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167
Reserves	160	125	57	(12)	(72)	(79)	(87)	(100)	(106)	(113)	(121)	(130)	(141)	(153)	(164)	(177)	(189)	(202)	(215)	(230)
Reserve Margin	13%	10%	5%	-1%	-6%	-6%	-7%	-8%	-8%	-9%	-9%	-10%	-11%	-12%	-12%	-13%	-14%	-15%	-16%	-16%

Source: IMPA

Based on the analysis described in this report, IMPA is proceeding with the general plan shown in Plan02. To allow flexibility and take advantage of current market conditions, the Plan may evolve into a version of Plan01 or Plan07 which both have similar underlying build plans over the long-term. These plans are not mutually exclusive so it is quite possible a hybrid of the plans will ultimately provide the optimal mix of resources and timing as the costs of the resources becomes clearer. The following decision tree illustrates the Plan Pursuit strategy:

Figure 119 Plan Pursuit Strategy (2014-2020)
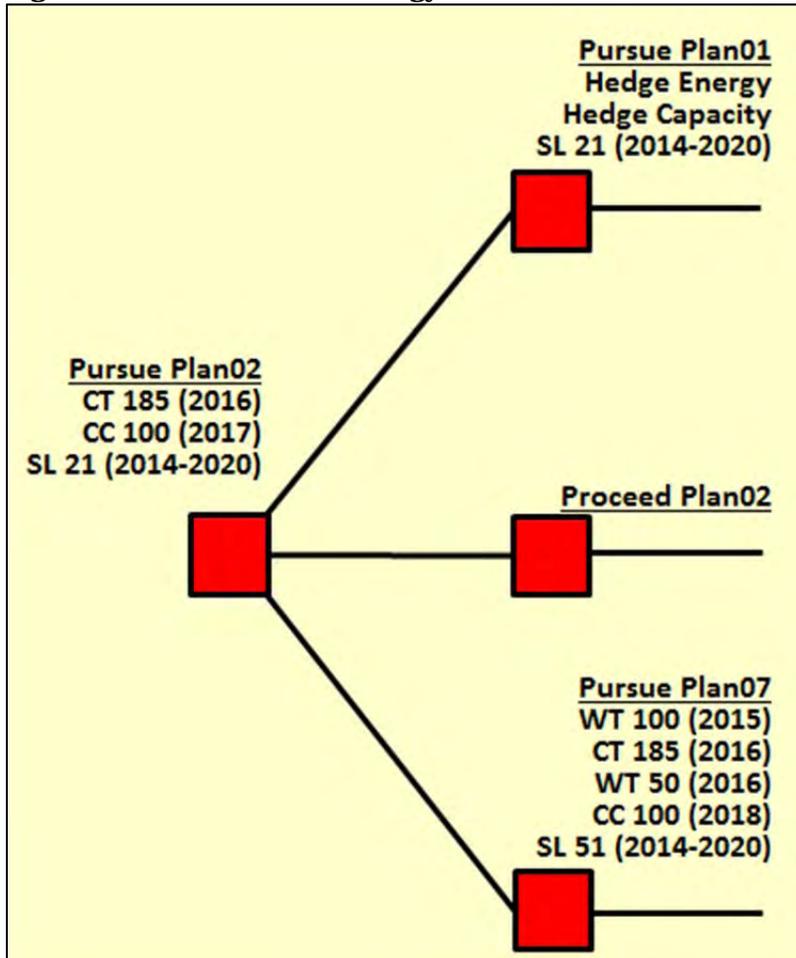
Source: IMPA

1. Plan01 assumes IMPA is able to enter into a market purchase at a lower cost than the build option. This plan would effectively build a virtual CC at a lower cost than IMPA would incur with a PPA or joint ownership of an actual facility. In the stochastic analysis, this plan was consistently the lowest cost plan in the early years of the study. Hedging this position until the 2020-2023 time frame allows IMPA to lock in attractive pricing while letting the regulatory, environmental and economic future shake out.

2. Plan07 is essentially the same as Plan02 except IMPA voluntarily adds additional renewable resources totaling approximately 10% of its energy requirements. The stochastic analysis shows that this plan performs well in the later years. The reasons are twofold, first, the added renewable sources benefit IMPA in the CO_2 cases through lower

emissions costs and second, the positions taken by locking into long term contracts hedge against the market price movements driven by CO_2 legislation.

The risk profile shown below compares the stochastic average system rates of Plans 01 and 07 against Plan02 using the defender/challenger approach. The graph assumes Plan02 is the defender and Plans 01 and 07 are the challengers. The ASR difference is displayed as the difference between the challengers and the defender (i.e. Plan01 minus Plan02, and Plan07 minus Plan02).

Figure 120 Plan02 Defender/Challenger ASR Analysis
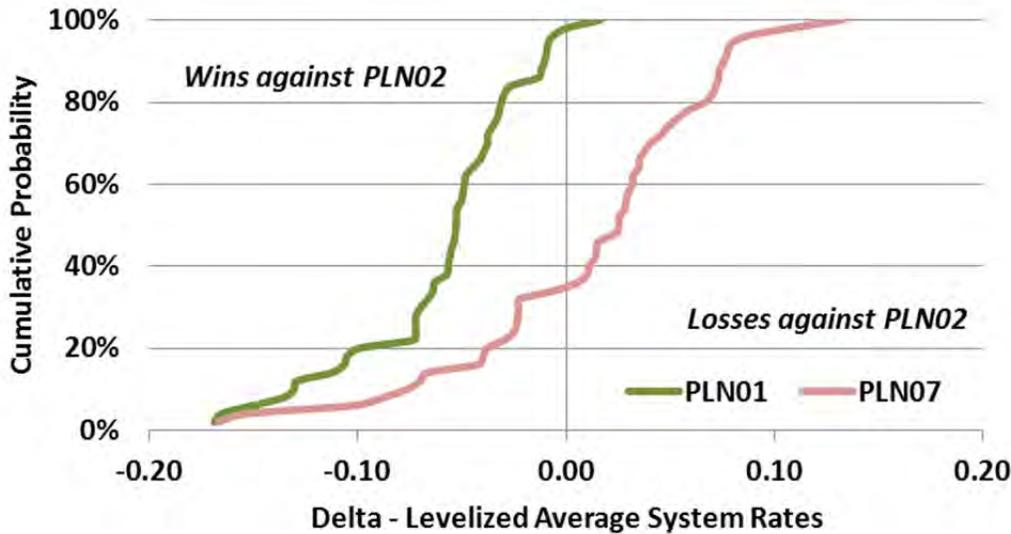
Source: IMPA

As shown in the graph above, Plan01 defeats Plan02 ninety-six (96) percent of the time, but it is important to note that this is highly dependent on an assumed hedge price which was the forward market price at the time the IRP analysis was performed. Plan07 defeats Plan02 thirty-four (34) percent of the time with the payoff highly dependent on possible future CO_2 legislation.

The following table shows IMPA's load and capacity balance assuming Plan02 new resources are added in the future.

Table 18 Capacity Balance – After Additions

|	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Requirements																				
Peak Load w/ EE	1,209	1,220	1,228	1,238	1,248	1,255	1,263	1,267	1,273	1,280	1,288	1,297	1,308	1,320	1,331	1,344	1,356	1,369	1,382	1,397
Resources																				
Gibson #5	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Gibson #5 Back-up	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trimble County #1	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Trimble County #2	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
Prairie State #1	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Prairie State #2	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Anderson #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Anderson #3	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
Georgetown #2	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Georgetown #3	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Richmond #1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Richmond #2	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
AEP Cost Based	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Duke Cost Based	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Duke CB - New Members	22	22	18	9	9	9	9	-	-	-	-	-	-	-	-	-	-	-	-	-
Member Capacity	159	159	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Market Capacity	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Gas			185	185	285	285	285	285	285	385	385	385	385	385	385	385	385	385	385	385
New Renewable	1	2	3	5	6	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Total Resources	1,370	1,347	1,473	1,415	1,467	1,468	1,469	1,460	1,460	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560
Reserves	161	127	245	177	219	213	206	193	187	280	272	263	252	240	229	216	204	191	178	163
Reserve Margin	13%	10%	20%	14%	18%	17%	16%	15%	15%	22%	21%	20%	19%	18%	17%	16%	15%	14%	13%	12%

Source: IMPA

IMPA's existing short position and future additions are graphically represented in the following figure.

Figure 121 Load/Capacity Balance Graph– Plan02
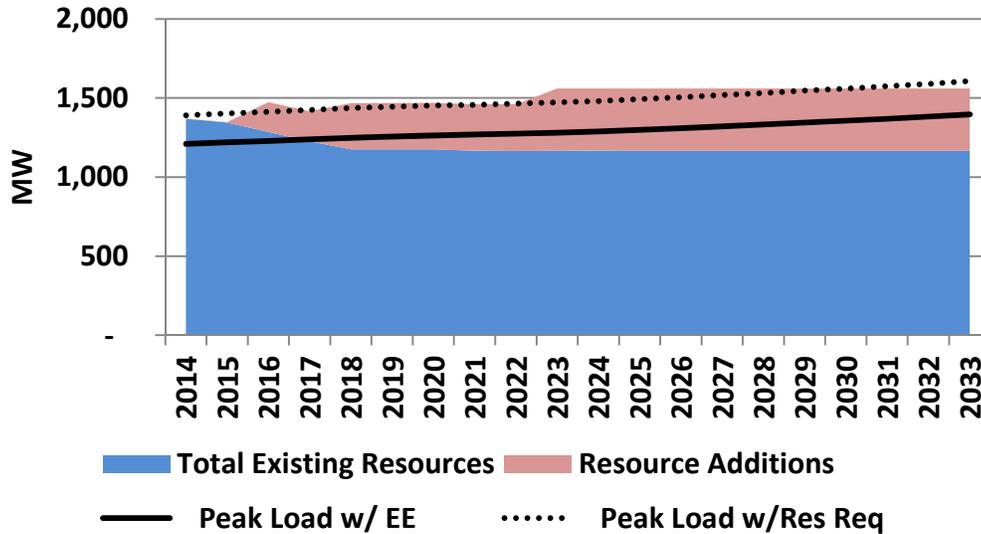
Source: IMPA

13.2 RISKS AND UNCERTAINTIES

As discussed elsewhere in this report, there are many uncertainties facing the electric power industry over the next decades. The following factors are just some of many that could greatly change the future of IMPA, Indiana and the nation:

- CO_2 legislation
- Generation retirements due to known EPA regulations
- New and Unknown EPA regulations
- Shale gas/LNG export
- State or Federal Renewable mandates
- Prolonged economic slump

IMPA's stochastic analysis, discussed in detail in sections 10-12, attempted to incorporate many of these risks and uncertainties. The tornado charts for all plans clearly show that the single biggest risk driver for IMPA is CO_2 legislation, followed by various commodities. IMPA believes that by continuing its long held corporate concept of resource diversity, the plan herein is able to weather these potential uncertainties. The key is that there is flexibility in the plan. By embarking on the process discussed above, IMPA can select the best option among those listed and still leave itself the flexibility to react to changes in political and market conditions.

Robustness Test

IMPA's approach is to consider the robustness of a particular plan using the following techniques:

- Deterministic: Outcome under expected conditions
  - Reference Case
- Stochastic: Sensitivity outcomes driven by key uncertainties
  - 50 Draws
- Scenario: Stress test under alternate views of the future
  - Green Revolution
  - Shifting Gears
  - Retrenchment

The following charts illustrate the ranking and robustness of the three selected plans.

Plan01 Robustness Test Results

In reviewing the results of Plan01 (long-term hedge), the plan ranks first in 4 of the 5 robustness measures. The plan ranks second in the Retrenchment scenario which assumes a higher load forecast and lower natural gas prices.
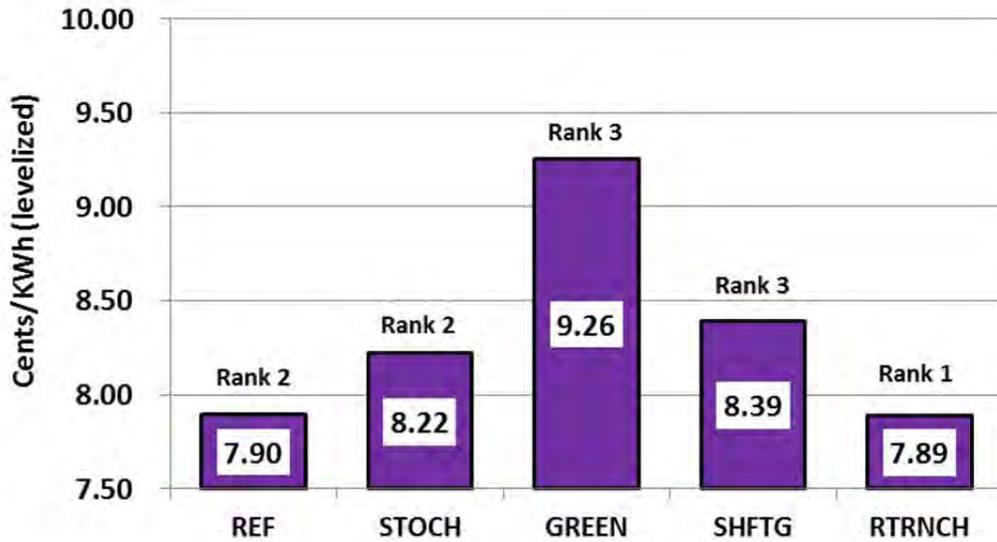
Figure 122 Plan01 Robustness Test - ASR Chart
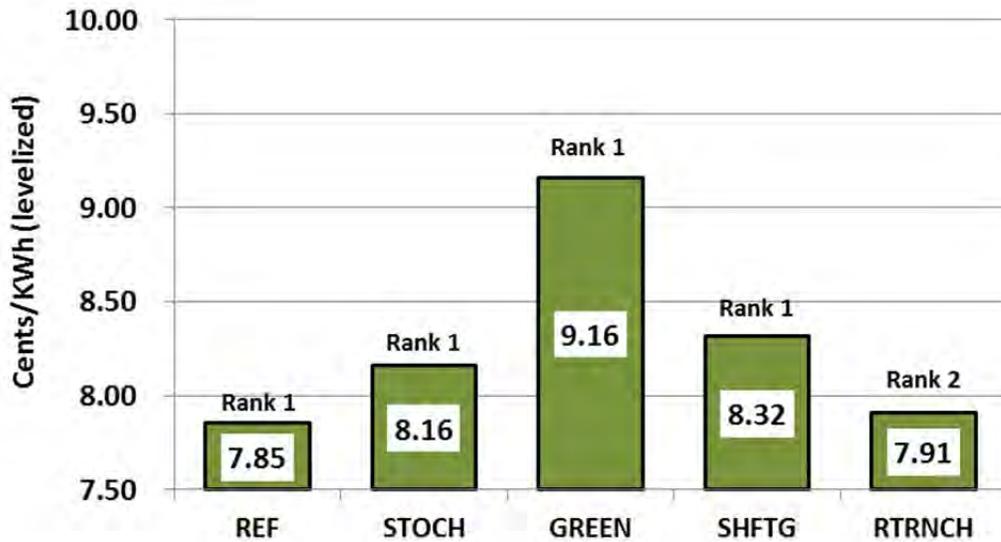
Source: IMPA

Plan02 Robustness Test Results

Plan02, which builds natural gas resources early in the planning horizon, ranks first in the Retrenchment scenario. Plan02 ranks third in both the Shifting Gears and Green Revolution scenarios, both of which place a high cost on CO_2 emissions.

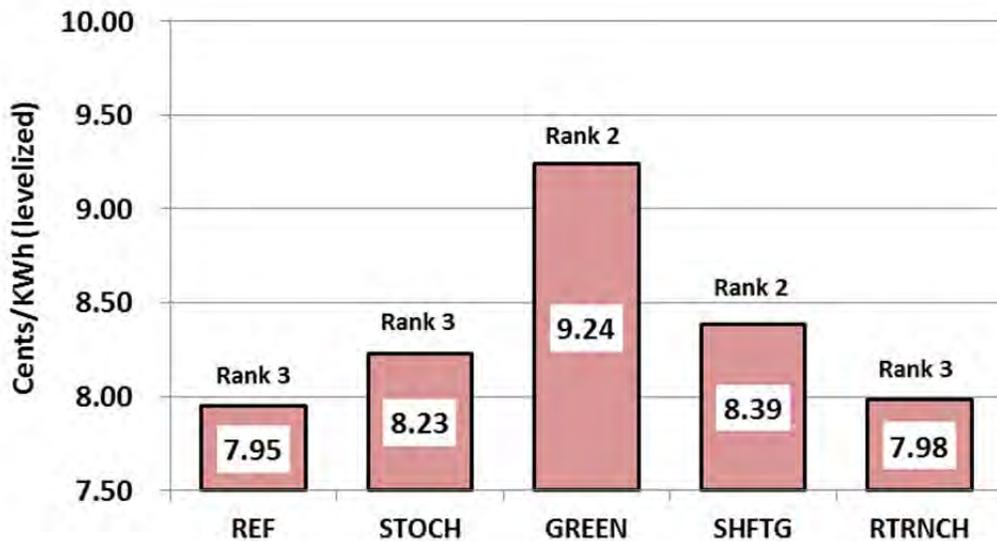**Figure 123 Plan02 Robustness Test - ASR Chart**

Source: IMPA

Plan07 Results

Plan07, which has more renewable energy than the other two plans, has an improved ranking under more stringent carbon futures.

Figure 124 Plan07 Robustness Test - ASR Chart

Source: IMPA

14 SHORT TERM ACTION PLAN

14.1 ACTION(S) REQUIRED TO IMPLEMENT THE PLAN

As discussed in the prior section, IMPA's preferred plan is Plan02, however, to allow flexibility and take advantage of current market conditions, the Plan may evolve into a version of Plan01 or Plan07 which both have similar underlying build plans over the long-term.

IMPA will embark on three simultaneous courses of action to implement this plan, or a hybrid variation thereof.

Plan02
- Begin the process to acquire/design/build/finance an F class style combustion turbine somewhere in the MISO footprint. Potential acquisition methods could include:
  - Self-build
  - Partnership
  - PPA
- Continue development/construction of municipal based solar projects
- Engage known developers on current Combined Cycle projects in the MISO footprint and determine likelihood of project completion

Plan01
- Issue an RFP for the acquisition of long term MISO ZRCs from interested counterparties
- Issue an RFP for the acquisition of long term MISO and PJM physical or financial purchased power swaps from interested counterparties
- Continue development/construction of municipal based solar projects

Plan07
- Begin the process to acquire/design/build/finance an F class style combustion turbine somewhere in the MISO footprint. Potential acquisition methods could include:
  - Self-build
  - Partnership
  - PPA
- Investigate the expanded development/construction of municipal based solar projects
- Engage known developers on current Combined Cycle projects in the MISO footprint and determine likelihood of project completion
- Pursue opportunities for cost effective long-term MISO and PJM Wind PPAs or ownership

Other
- Continue involvement in the Energizing Indiana program through 2014
- Acquire energy efficiency cost/benefit evaluation tools
- Evaluate benefits and costs of continued participation in the Energizing Indiana program compared to a slate of IMPA initiated programs.

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15 IRP GUIDELINES (170 IAC 4-7)

15.1 INDEX OF RULES AND REPORT LOCATION REFERENCE

Current Rule

170 IAC 4-7 Reference	Description	Reference
4.1	External data sources	Section 10.2 Appendix E Appendix F
4.2-4.6	Load Forecasting Matters	Section 4.3 Section 5 Appendix D
4.7-4.9	Miscellaneous planning criteria and practices	Section 3.3 Section 4.3 Section 7.1
4.10-4.15	Transmission Matters	Section 4.5 Section 8.1 Appendix H
4.16	Explanation of avoided cost calculation	Appendix G
4.17	Hourly System Demand of the most recent historical year	Appendix A
4.18	Description of public participation procedure, if used.	IMPA's IRP is presented to the IMPA Board of Commissioners on two occasions with formal approval taking place after initial Board input and a second presentation.
5	Analysis of historical and forecasted levels of peak demand. Forecast scenarios.	Section 4.2 Section 5 Appendix B
6	Resource Assessment	Section 4 Section 6 Section 7 Appendix E Appendix F Appendix G
7	Selection of Future Resources	Section 6 Section 7 Section 11 Section 12
8	Resource Integration	Section 12 Section 13

| 9 | Short-term Action Plan | Section 14 |

Proposed Rule (New Rule References)

4(a)	IRP Summary Document	Appendix J
4(b)10	Miscellaneous Transmission	N/A Section4.5 Appendix H
4(b)11	Contemporary Methods, Model Selection and Description	Sections 9-12
6(a)	Continued use of existing resource as a new resource alternative	Sections 6.1 & 11.1
8(a)	Candidate portfolios	Section 11.2
8(b)	Demonstrate how preferred resource portfolio balances cost-effective minimization with effective risk and uncertainty reduction.	Section 12 Section 13

16 APPENDIX

A. Hourly System Loads
B. Historic System Load Shapes
C. C1 - Hourly Market Prices – Indiana Hub
   C2 - Hourly Market Prices – AD Hub
D. IMPA Load Forecast
E. E1 - Existing Resource Data – Summary
   E2 - Existing Resource Data – Detailed
F. Expansion Resource Data
G. Avoided Costs
H. Statement on FERC Form 715
I. I1 - 2012 IMPA Annual Report
   I2 - 2012 IMPA Annual Report - Financials
J. IRP Summary Document