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VOLUME 7

RESOURCE ACQUISITION STRATEGY SELECTION

THE EMPIRE DISTRICT ELECTRIC COMPANY

4 CSR 240-22.070

FILE NO. EO-2016-0223

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RESOURCE ACQUISITION STRATEGY SELECTION

4 CSR 240-22.070 Resource Acquisition Strategy Selection

PURPOSE: This rule requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

SECTION 1 PREFERRED RESOURCE PLAN

(1) The utility shall select a preferred resource plan from among the alternative resource plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060. The utility shall describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision-makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall provide the names, titles, and roles of the utility decision-makers in the preferred resource plan selection process. The preferred resource plan shall satisfy at least the following conditions:

(A) In the judgment of utility decision-makers, strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2);

(B) Invest in advanced transmission and distribution technologies unless, in the judgment of the utility decision-makers, investing in those technologies to upgrade transmission and/or distribution networks is not in the public interest;

(C) Utilize demand-side resources to the maximum amount that comply with legal mandates and, in the judgment of the utility decision-makers, are consistent with the public interest and achieve state energy policies; and

(D) In the judgment of the utility decision-makers, the preferred plan, in conjunction with the deployment of emergency demand response measures and access to short-term and emergency power supplies, has sufficient resources to serve load forecasted under extreme weather conditions pursuant to 4CSR 240-22.030(8)(B) for the implementation period. If the utility cannot affirm the sufficiency of resources, it shall consider an alternative resource plan or modifications to its preferred resource plan that can meet extreme weather conditions.

1.1 Preferred Plan Selection Criteria

All of the IRP analyses and the objectives of the IRP Rule were considered by Empire's decision makers during the preferred plan selection process. The preferred plan represents a balance between the planning objectives, planning risks, resource diversity, rate impacts, and financial measures that were examined using the information generated by the deterministic, stochastic, and risk analyses of this IRP. As reviewed by the Empire IRP team, the following summarizes the preferred plan selection guidance as supplied by the IRP Rule.

- Provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies
- Analyze demand-side, renewable energy, and supply-side resources on an equivalent basis (subject to legal mandates)
- Minimize the present worth of long-run utility costs as the *primary criterion* in selecting a preferred plan
- Identify, analyze, and document other considerations to the preferred plan selection such as risks associated with the critical uncertain factors, risks associated with new or more stringent legal mandates, and rate increases
- Strike an appropriate balance between the various planning objectives
- Invest in advanced T&D technologies unless not in the public interest
- Utilize demand-side resources to the maximum amount that comply with legal mandates, and are consistent with the public interest and achieve state energy policies

1.2 Preferred Plan Selection Process

ABB was retained by Empire to provide analytical services in support of the 2016 IRP. ABB and Empire undertook a detailed analysis of the performance of the resource plans. Multiple alternative resource plans with demand-side and supply-side "build outs" were developed with the Capacity Expansion Model (CEM). All plans were then subjected to full financial modeling including the calculation of net present value of revenue requirements (PVRR) in the Strategic

Planning model powered by MIDAS Gold (MIDAS). Additionally, all plans were evaluated in the decision analysis phase, represented by a decision tree in the MIDAS model. From this modeling, a detailed risk analysis was performed for each of the 19 plans.

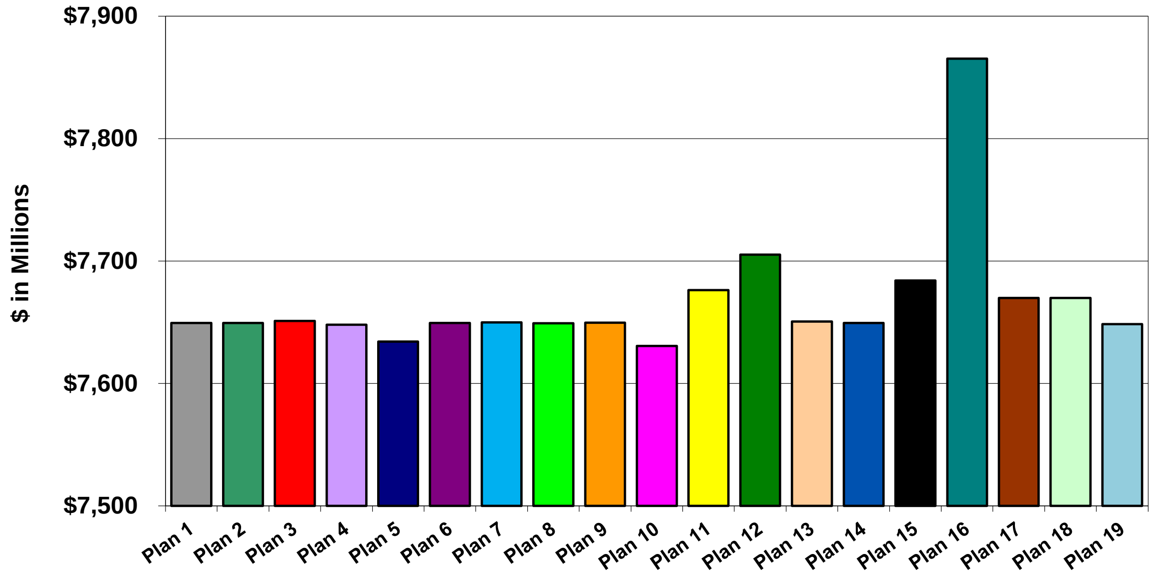
This process can be considered as a three-phase approach. Both candidate demand-side and supply-side resources were considered as available resources in the IRP's integration process. During Phase 1 (capacity expansion modeling), specific optimized resource plans were developed based on the lowest present value of revenue requirements (PVRR) for each of different scenarios with a capacity expansion model. Each set of resources was developed specifically to perform the best under the assumptions made about the possible future for each plan. These plans may not be directly comparable since the assumptions about the future may vary significantly between the plans.

In Phase 2 (deterministic analysis), each plan that was developed during Phase 1 was evaluated against the base case assumptions. Hourly dispatch of the units and full financial modeling was performed over the planning horizon. Deterministic PVRRs were calculated to compare plans against each other. In Phase 3 (stochastic/risk analysis), each plan was subjected to decision analysis (with the critical uncertain factors), again, with full financial modeling over the planning horizon. These stochastic runs generated 48 endpoints for each of the plans analyzed (High and low gas prices with correlated market prices were used only for the No CO_2 environmental future which made the decision tree asymmetric for the gas and market price branches. Only base gas and correlated market prices were developed for the other three levels of CO_2 futures). The results from this phase were used to develop risk profiles and tornado charts across all plans. ABB performed risk analyses to evaluate Empire's portfolio under varying conditions, identifying a wide range of possible outcomes. All of these analyses and the objectives of the IRP Rule were considered by Empire's decision makers during the development of the preferred plan. The preferred plan represents a balance between the planning objectives, planning risks, and financial impacts examined using the deterministic, stochastic, and risk analyses.

The demand-side inputs were supplied to ABB from Applied Energy Group (AEG). ABB developed load shapes for distributing energy savings for the integration modeling. The demand-side programs are essentially a modification to the load forecast inputs. The CEM model did not optimize demand-side resources. CEM optimized supply-side resources around the demand-side resource modified load. In addition to demand-side energy and coincident peak savings, AEG also provided all program costs and the information required to calculate a net shared benefit. The costs associated with the demand-side resources, including the net shared benefit, were input into the MIDAS model and assumed to be recovered in a timely manner through customer rates.

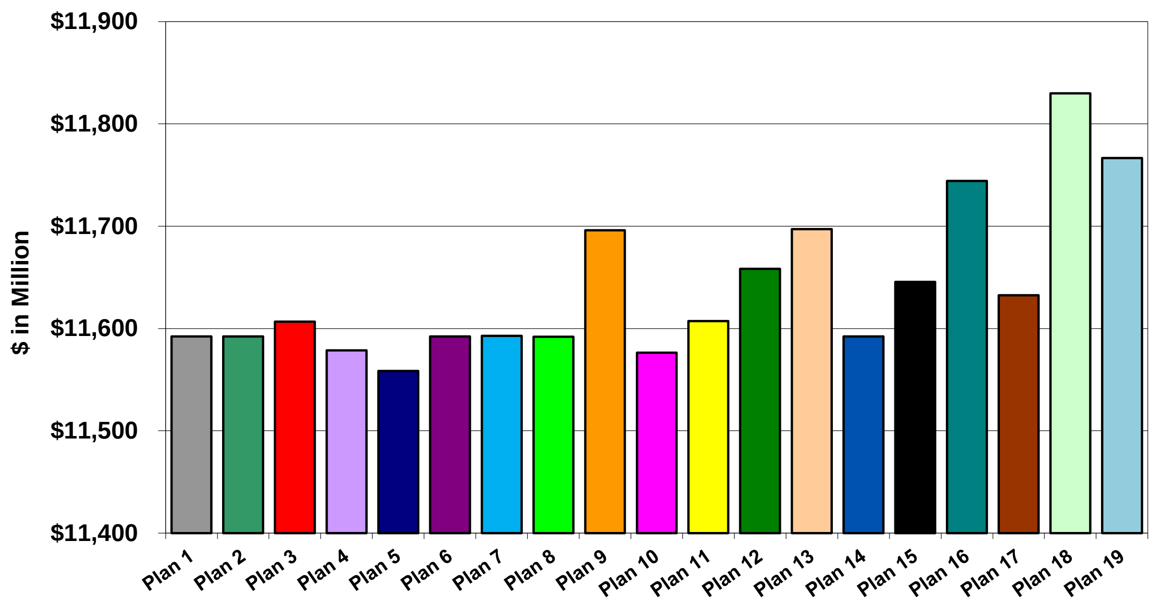
1.3 Present Value of Revenue Requirements

Minimization of PVRR is a primary criterion for the selection of the preferred plan. *Figure 7-1* displays the PVRR of all 19 plans *utilizing the base assumptions* prior to introducing uncertainty represented by the decision tree (the deterministic case) for the twenty-year planning period of the IRP. Because so many resource decisions happen near the end of that twenty-year horizon, end effects were examined for a succeeding twenty years. The PVRR of all of the plans as expected over the 40 years (2016-2055) are shown in *Figure 7-2.*



(Source: ABB Advisors)

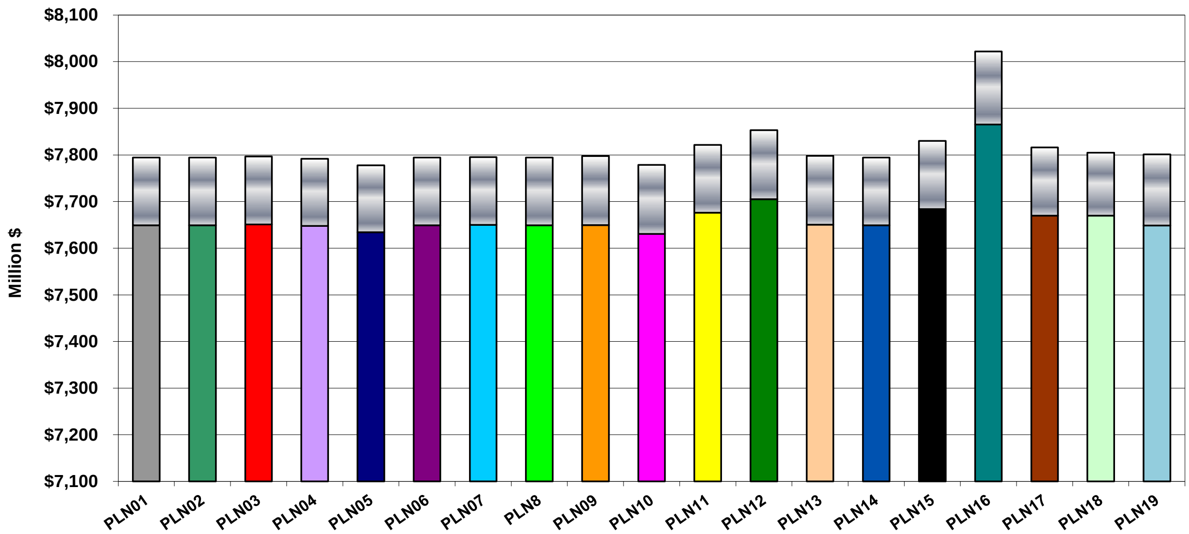
Figure 7-1 - Deterministic PVRR for All Plans (2016-2035)



(Source: ABB Advisors)

Figure 7-2 - All Plans with End Effects – 40-Year Deterministic PVRR (2016-2055)

The results of decision analysis (using the critical uncertain factors) provides the uncertainty range in addition to the PVRR for each of the alternative resource plans, as shown in *Figure 7-3.*



(Source: ABB Advisors)

Figure 7-3 - PVRR with Risk Value for All Plans (2016-2035)

1.5 Preferred Plan Selection

Since finding a low cost plan is a primary-*but not the only*-objective, Empire focused on a set of low cost plans that were variations of the base case plan and included a wide range of demand-side portfolios (RAP, RAP - DSM, RAP + DSM, and no DSM) as shown in the *Figure 7-4* for the base plans listed in *Table 7-1.*

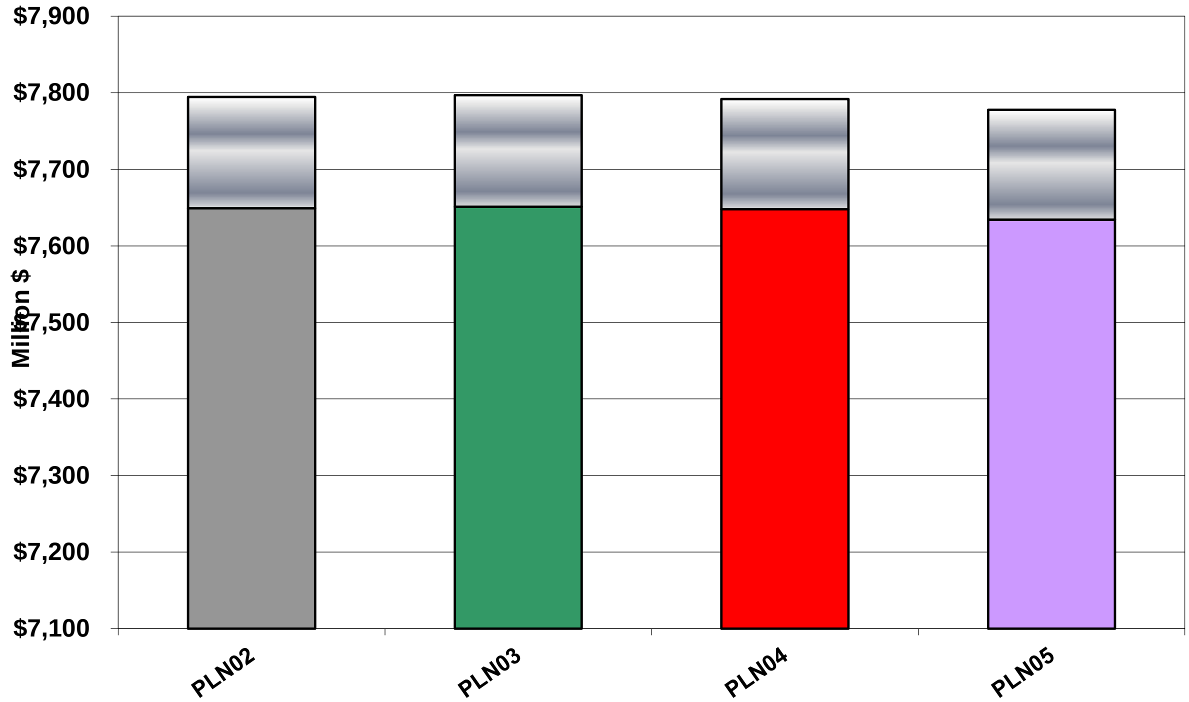
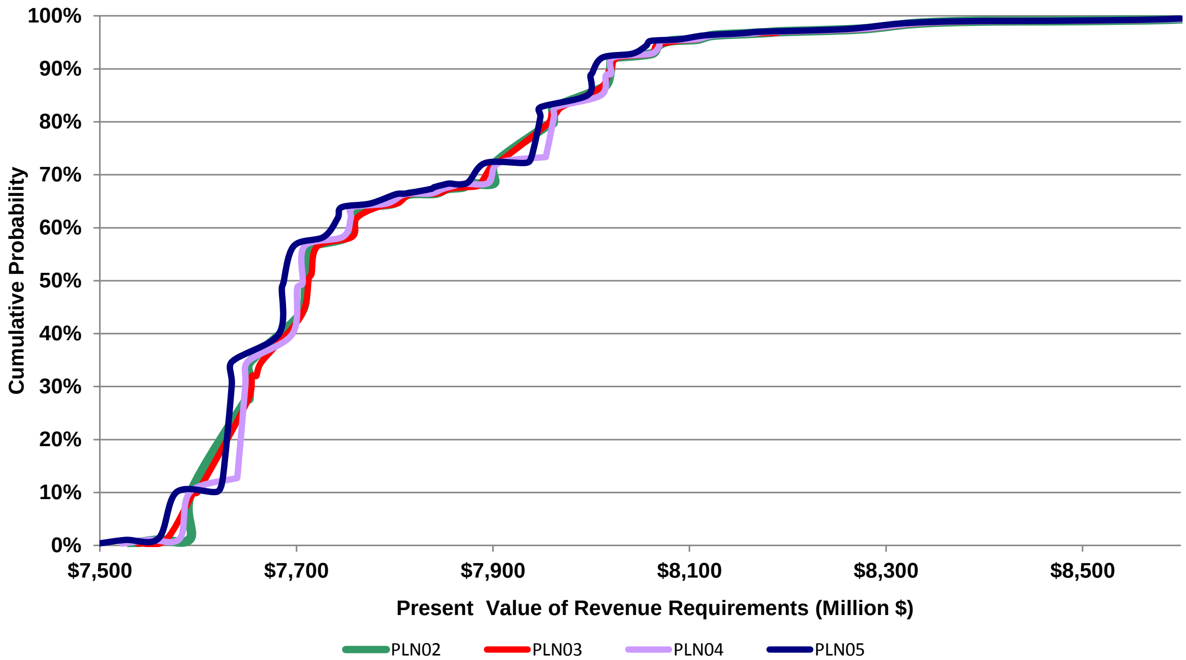


Figure 7-4 – 20-Year PVRR (Deterministic and Stochastic) of Base Plans
(Source: ABB Advisors)

Plan	Base Plan Description
2	Base Case (meet RPS)
3	RAP + DSM
4	RAP - DSM
5	No DSM

Table 7-1 - Base Plans List

Empire looked at the difference in the 20-year PVRR among these base plans as well as the 40-year PVRR basis to aid in its selection of the preferred plan. Plans 2, 3 and 4 are all very close with regard to PVRR, but Plan 5 has a lower PVRR. Therefore, considering all of the preferred plan selection criteria, and attempting to strike a balance over all of the planning objectives, Empire has selected the lowest cost base plan, Plan 5, the no DSM Scenario, as the preferred plan. The risk profile graphic for the base plans considered is shown *Figure 7-5.*



(Source: ABB Advisors)

Figure 7-5 - Risk Profiles of Base Plans

1.6 Preferred Plan Description

Empire's decision makers have selected Plan 5 as the Preferred Plan. Plan 5 contains no Missouri DSM portfolio and supply-side resources are not added until the latter part of the study period.

1.6.1 Supply-Side Resources in the Preferred Plan

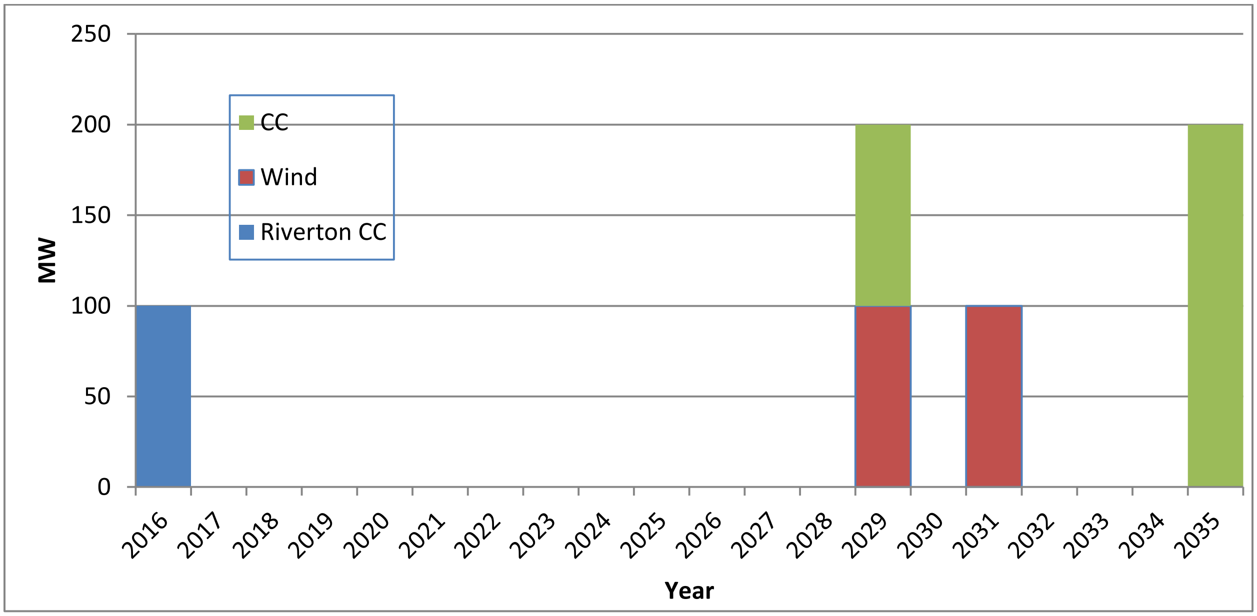
By mid-2016, the conversion of Riverton 12 to combined cycle should be complete with a resulting gain of approximately 100 MW for the system. This project was already in progress before this IRP was developed. For planning purposes, the Preferred Plan assumes the 82-MW Energy Center 1 will be retired in 2023 and Energy Center 2 will be retired in 2026 (see *Table 7-2*). Each unit represents a net loss in capacity of about 82 MW. As also shown in *Table 7-2*, Riverton units 10 and 11 are assumed to retire in 2033 (net loss of about 33 MW total); and Asbury is assumed to retire in 2035, with a net loss to the system of about 194 MW.

All other existing Empire generating units are presumed to continue operations throughout the planning horizon. However, the 105-MW Meridian Way 20-year wind purchased power agreement (PPA) will expire in December 2028, and the 150-MW Elk River 20-year wind PPA will expire in 2030 with a 5-year extension assumed for Elk River.

The Preferred Plan will satisfy future capacity needs with combined cycle additions and Wind PPAs. Combined cycle units were installed in 2029 (100 MW) and 2035 (200 MW). Renewable resources were added in the form of a 100-MW wind resource in 2029 and a 150 MW wind resource in 2031. The Plan 5 supply-side additions are further illustrated in *Figure 7-6*.

Year	Common to All IRP Plans (Applies to Preferred Plan)	Plan 5 (Preferred Plan)
2016	By Mid-2016, Riverton 12 begins combined cycle operation (100 MW addition to the Empire system)	
2017		
2018		
2019		
2020		
2021		
2022		
2023	Energy Center Unit 1 assumed to retire for IRP purposes (82 MW loss)	
2024		
2025		
2026	Energy Center Unit 2 assumed to retire for IRP purposes (82 MW loss)	
2027		
2028	Meridian Way 105 MW Wind PPA expires (19 MW loss)	
2029		100 MW Combined Cycle, 100 MW Wind Resource
2030	Elk River 150 Wind PPA expires after 5-year extension (17 MW loss)	
2031		150 MW Wind Resource
2032		
2033	Riverton Units 10 and 11 assumed to retire for IRP purposes (33 MW loss)	
2034		
2035	Asbury Unit 1 assumed to retire for IRP purposes (194 MW loss)	200 MW Combined Cycle

Table 7-2 - Preferred Plan Highlights



NOTE: The Riverton 12 conversion results in a net gain to the system of approximately 100 MW. Riverton 12 will be rated at approximately 250 MW after the conversion.

Figure 7-6 - Preferred Plan Supply-Side Additions

1.6.2 Demand-Side Programs in the Preferred Plan

Empire's 2016 IRP assumed that no additional Missouri DSM programs will be implemented.

1.6.3 Resources in the Preferred Plan

Table 7-3 and *Table 7-4* present the required forecasts of capacity balance for the Preferred Plan (Plan 5) and provide more detail about the timing of the resources planned to meet Empire's loads while complying with current legal mandates based on the planning assumptions. *Table 7-3* shows the capacity balance for the summer season (utilizing summer peaks and summer unit ratings) and *Table 7-4* shows the capacity balance for the winter season (utilizing winter peaks and winter unit ratings).

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Table 7-3 - Plan 5 Preferred Plan – Summer Peak

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Table 7-4 - Plan 5 Preferred Plan – Winter Peak

1.6.4 Advanced Transmission and Distribution Technologies in the Preferred Plan

Empire is a member of the Southwest Power Pool (SPP) and relies on SPP's determination of transmission line expansion projects and their schedules throughout the SPP region. Empire is assigned its membership cost allocation for all lines that are built within SPP. Therefore, to the extent that SPP incorporates advanced transmission technologies into projects, Empire is also a participant.

Operation Toughen Up is a long-term $100 million initiative currently in progress to strengthen the transmission and distribution (T&D) delivery system. Since reliable service is important for customers, Empire has established long-term goals to address two primary factors – interruption frequency and interruption duration. These factors are measured by the reliability indices SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). Empire is continuing a variety of upgrades to physical assets in the T&D areas to improve system performance. The objective is to improve the reliability of Empire's electrical delivery system by reducing the number of outages and shortening outage duration. Empire's goal is to achieve a SAIFI of no greater than 1.00 and a SAIDI of no more than 100.

Table 7-5 provides a description and schedule for the Operation Toughen Up projects that Empire has completed or has planned for the next few years.

Project Type	In Service Date	Description
Transmission Breakers	April of 2013	Install transmission breakers between Joplin 5th street (#284) and Joplin 10th street (#64) Substations, impacting Joplin downtown customers.
Automated Transfer Scheme	May of 2013	Install at Webb City - Cardinal Substation (#436) impacting Webb City customers.
Automated Transfer Scheme	May of 2013	Install at Nixa - North Substation (#114) impacting Nixa area customers.
Transmission Breakers	2014	Engineer two transmission breakers at Neosho-West Substation (#56) impacting customers in the Neosho and Seneca areas.

Project Type	In Service Date	Description
Transmission Breakers	2014	Engineer two transmission breakers at Wentworth-West Substation (#205) impacting customers in the Wentworth, Sarcoxie and Pierce City areas.
Transmission Breakers	2014	Engineer two transmission breakers at Diamond-H.T. Substation (#131) impacting Diamond and Granby customers.
Transmission Breakers	2014	At Fairgrove South Substation (#397), this project adds a third 69-kV breaker as well as replaces the existing line relay panels. A differential relay panel and communications panel will also be added.
Automated Transfer Scheme	2014	Engineer transfer scheme at Joplin 2nd Street and Division Substation (#372) impacting Joplin area customers.
Re-closer Control Replacement	2014	Three-Phase Recloser Control Replacement: Replace approx. 15 outdated controls on distribution reclosers throughout system. This project will provide sequence coordination of downstream reclosers; it will also provide better data collection and fault finding capabilities to help reduce SAIDI.
Automated Transfer Scheme	2014	Engineer transfer scheme at Sarcoxie - Southwest Substation (#362) impacting Sarcoxie area customers.
Reconductor	2014	Replace 0.27 miles of #6 CU rotten three phase to 336 ACSR along Knox Avenue from Evergreen to Texas Avenue on Hollister East (#387-2) (this has 336 ACSR on both sides).
Reconductor	2014	Replace 0.6 miles of #6/#8 solid CU 3ph conductor with 1/0 ACSR along 12th Street between Euclid and State Line Road in Galena, Kansas.
Reconductor	2014	Replace 0.54 miles of 8 X rotten single-phase conductor to 1ph 1/0 ACSR along FR82 on Greenfield (#614-2) (2 miles north of Greenfield).
Reconductor	2014	Replace 0.54 miles of 6 X rotten single-phase conductor to 1ph 1/0 ACSR along FR142 on South Greenfield (#614-1).
Reconductor	2014	Replace 0.17 miles of overhead 3ph deteriorated conductor with 3ph 1/0 ACSR along Johnson Drive in Neosho, Missouri.
Reconductor	2014	Replace 3 miles of 8A overhead single-phase deteriorated conductor with 1ph 1/0 ACSR along Base Line Boulevard (Missouri Highway N) from CR120 to CR90 SE of Jasper, Missouri.
Transmission Breakers	2015	At Fairland West Substation (#363), this project adds 2 69-kV breakers and associated relay panels. The addition of a 2nd motor operator and 69-kV auto throw-over relay scheme will further increase reliability to the area. Line Work: Install 300' of new conductor to tie Shell Substation into existing 69-kV line. Reroute the incoming and outgoing line segments to allow the breakers to be installed. Additional line rerouting may be required to protect the (#261) Fairland shell tap protection. Line rerouting may not be as severe, with the moving of a switch and some bus work inside of the substation to serve Fairland shell (#261).
Transmission Breakers	2015	At Republic Hines Street Substation (#451), this project adds another 69-kV dead end structure, 2 69-kV breakers, and associated relay panels. Line Work: Install 300' of new 69-kV line and remove existing transmission switches.

Project Type	In Service Date	Description
Transmission Breakers	2015	At Republic Hines Street Substation (#451), this project adds another 69-kV dead end structure, 2 69-kV breakers, and associated relay panels. Line Work: Install 300' of new 69-kV line and remove existing transmission switches.
Reconductor	2015	Replace 0.14 miles of #6 CU rotten 3ph conductor to 3ph 1/0 ACSR in downtown alley between Church Street and College Avenue (East of Jefferson Park) in Aurora on Aurora Circuit (#124-2).
Automated Transfer Scheme	2016	Engineer transfer scheme at Brighton - East substation (#323) impacting Brighton area customers.
Rebuild	2016	At Baxter Springs West Substation (#271), this project replaces identified B.O. porcelain on switches, bus supports, and D.E. insulators. Line Work: ***2014:*** Construct Phase 1 of 69-kV rebuild from Welch-North (#186) to Chetopa-Twin Valley (#388). ***2014:*** Engineer and purchase RIghts-of-way for Phase 2 of 69-kV rebuild from Welch-North Substation (#186) to Chetopa-Twin Valley Substation (#388). ***2015:*** Construct Phase 2 of 69-kV rebuild from Welch-North Substation (#186) to Chetopa-Twin Valley Substation (#388).
Automated Transfer Scheme	2016	Install at Sub# 372 in downtown Joplin area. Presently a load tap between existing breakers. Will allow for much reduced outage times during contingency events
Automated Transfer Scheme	2016	Install at Sub# 362 Tap in Sarcoxie area. Presently a load tap between existing breakers. Will allow for much reduced outage times during contingency events
Transmission Breakers	2016	At Joplin-Fir Road Substation (#417), this project adds 2 161-kV breakers, a control enclosure, and associated relay panels. This work is the first of a 5 part project involving 5 distribution serving substations as well as addressing protection issues at Asbury. The overreaching project will better sectionalize the transmission circuits in/out of the Asbury generation plant as well as insulate customers served from any of the 5 distribution substations from the extended exposure present. At Joplin Oronogo Junction Substation (#110), this project replaces the existing line relay panel on the line to Asbury (breaker #16154).
Transmission Breakers	2016	Substation Work (completed): At Columbus S.E. Substation #94, this project adds 5 69-kV breakers in a ring-bus configuration, a control enclosure, and associated relay panels. At Columbus Tennessee St. Substation (#282), this project adds a motor-operated, auto throw-over switch scheme. Line Work (work to be completed in 2016): Existing lines will need to be rerouted to allow for the substation expansion and inclusion of 69-kV breakers. Provisions should be made for a fifth new line segment exiting the substation to serve the current Columbus tap.

Project Type	In Service Date	Description
Transmission Breakers	2017	Install (4) 69kV breakers to upgrade existing protections for better Co-ordination between 69kV & 34.5kV networks. Sectionalize 69kV transmission system. Protect associated assets within the substation and Improve coordination on the 34.5kV sub-network.
Transmission Breakers	2017	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Carl Jct. #366. In conjunction with 2016 project at Fir Road #417, this project will allow for further sectionalization of the transmission paths in/out of the Asbury generation substation by way of building on gains from 2016 project. Total project will benefit 5 different substations
Automated Transfer Scheme	2017	Install transfer scheme at Jasper West #403 impacting Jasper, MO area customers.
Automated Transfer Scheme	2018	Install transfer scheme at Commerce #381 impacting Commerce and Quapaw area customers.
Automated Transfer Scheme	2018	Install transfer scheme at Galena #278 impacting Galena area customers.
Transmission Breakers	2018	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Purcell #421. In conjunction with 2016 project at Fir Road #417, this project will allow for further sectionalization of the transmission paths in/out of the Asbury generation substation by way of building on gains from 2016 project. Total project will benefit 5 different substations
Transmission Breakers	2018	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Hollister #387. This project will allow for further sectionalization of the transmission paths on the southern loop of the Branson area service territory. This will eliminate the load tap present on the 161kV system and lower the exposure to customers in the Hollister/Branson areas.
Transmission Breakers	2018	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Carthage #395. In conjunction with 2016 & 2017 projects at Fir Road #417 & Carl Jct., this project will allow for further sectionalization of the transmission paths in/out of the Asbury generation substation by way of building on gains from 2016 project. Total project will benefit 5 different substations
Automated Transfer Scheme	2018	Install transfer scheme at Joplin NW #341 impacting Joplin, MO area customers.
Transmission Breakers	2019	Install (2) 69kV breakers, a control enclosure, and associated relay panels at Neosho #398 to improve sectionalization of area transmission system. Presently 3 separate substations are load taps on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Neosho area served customers.

Project Type	In Service Date	Description
Transmission Breakers	2019	Install (2) 69kV breakers, a control enclosure, and associated relay panels at Anderson #322 to improve sectionalization of area transmission system. Presently 2 separate substations are load taps on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Noel/Anderson area served customers.
Transmission Breakers	2019	Install (2) 161kV breakers, a control enclosure, and associated relay panels at Oakland #432 to improve sectionalization of area transmission system. Present substation is load tap on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Joplin/Webb City area served customers.
Transmission Breakers	2019	Install (2) 69kV breakers, a control enclosure, and associated relay panels at Golden City #251 to improve sectionalization of area transmission system. Presently 2 separate substations are load taps on the line section in consideration. Additional breakers will allow for line faults to be isolated and improve service to the Jasper/Boston/Lockwood area served customers.

Table 7-5 - Operation Toughen Up Project Schedule

1.6.5 Extreme Weather Capability

Empire examined the sufficiency of the Preferred Plan resources to serve the load forecasted under extreme weather conditions pursuant to 4 CSR 240-22.030(8)(B). For reference, the extreme weather conditions load forecast is developed in Volume 3 - Load Analysis and Load Forecasting at section 8.2, Estimate of Sensitivity of System Peak Load Forecasts to Extreme Weather. This sensitivity analysis determined that the summer peak temperatures in the extreme weather case (see *Figure 7-7*) would increase system peak loads to levels envisioned in two of the higher load growth plans such as Plan 12 (High-High Load) and Plan 15 (Aggressive Electric Vehicle). The first new resource required in either Plan 12 occurs in 2026 and the first new resource required in Plan 15 occurs in 2023, as compared to the Preferred Plan, where the first new resource is required in 2029 based on the IRP assumptions.

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Figure 7-7 - Base, Mild and Extreme Weather Scenario - System Annual Peak

1.7 Utility Decision Makers

The Empire 2016 IRP Team contains 16 members, and is composed of executives, directors, managers and specialists who were involved in the IRP development. To fulfill the requirements of 4 CSR 240-22.070, the names, titles, and roles of the utility decision makers and the team members are provided in *Table 7-6.*

Name	Title	Primary IRP Function
Kelly Walters	Vice President & COO-Electric	Executive staff - utility decision maker
Blake Mertens	Vice President - Energy Supply & Delivery Ops	Executive staff - utility decision maker
Laurie Delano	Vice President - Finance & CFO	Executive staff - utility decision maker
Brent Baker	Vice President – Cust Service/ Transmission Eng	Executive staff - utility decision maker
Rob Sager	Controller & Asst Treasurer/Asst Secretary	Financial
Todd Tarter	Manager of Strategic Planning	IRP Project Manager
Scott Keith	Director Planning & Regulatory	Director in charge of IRP
Bryan Owens	Assistant Director Planning & Regulatory	Assistant Director in charge of IRP
Tim Wilson	Director of Energy Supply Services	Supply-Side, Environmental, Renewable Energy
Drew Landoll	Manager of Strategic Projects	Supply-Side, Environmental, Renewable Energy
Rick McCord	Director of Supply Management	Energy Supply, Energy Trading, Next Day Market
Terry Wright	Manager Market Operations	Energy Supply, Energy Trading, Next Day Market
Nate Morris	Manager of System Planning & Protection Eng	Transmission and Distribution
Nate Hackney	Energy Efficiency Coordinator	Demand-Side
Josh Eckerman	Planning & Fuel Analyst	Supply-Side
Steve Williams	Planning-Eng Efficiency Analyst	Load forecasting

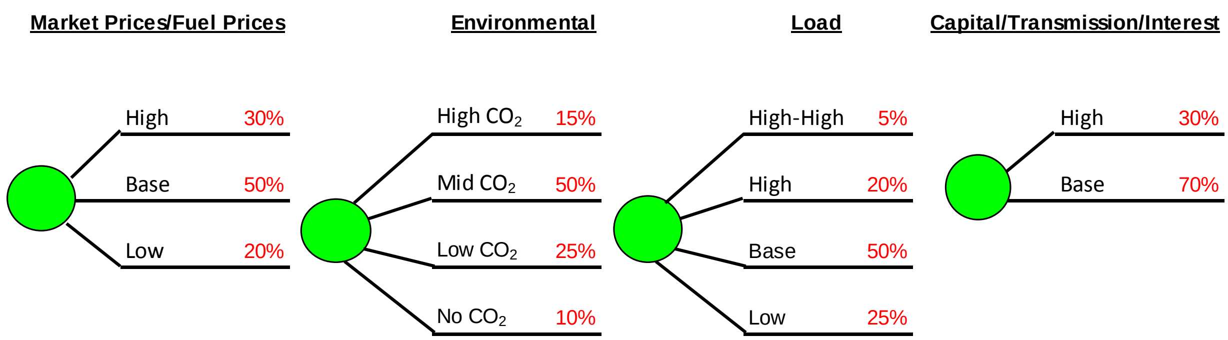
Table 7-6 - Empire 2016 IRP Team

SECTION 2 RANGES OF CRITICAL UNCERTAIN FACTORS

(2) The utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate and explain how these limits were determined. The utility shall also describe and document its assessment of whether, and under what circumstances, other uncertain factors associated with the preferred resource plan could materially affect the performance of the preferred resource plan relative to alternative resource plans.

2.1 Critical Uncertain Factors

A critical uncertain factor is any uncertain factor that is likely to materially affect the outcome of the resource planning decision. The critical uncertain factors that Empire has identified include environmental costs, market prices/fuel prices, load, and capital/transmission/interest costs. As part of the normal course of business, these factors are monitored very closely by Empire personnel in coordination with senior management. It is important to consider how variations in these factors impact the plans. These critical uncertain factors form the nodes of the decision tree in *Figure 7-8.*



(Source: ABB Advisors)

Figure 7-8 - Critical Uncertain Factor Decision Tree

2.2 Ranges of Critical Uncertain Factors

Planning for future resources in the electric utility industry involves the consideration and evaluation of many uncertainties. For this IRP, Empire developed 19 alternate plans. Five of these plans are "base" plans, three are plans required by the IRP Rule and the remaining eleven plans can be considered contingency plans. Of the contingency plans, one examines a future with an aggressive penetration of electric vehicles, another considers the early retirement of a coal unit and the remaining contingency plans were developed to examine changes to the critical uncertain factors. One of the base plans, Plan 5, which was the lowest cost plan on a PVRR basis, was selected as the Preferred Plan. An analysis of the range of outcomes for the critical uncertain factors is required to determine the limits within which the Preferred Plan is judged to be appropriate and explain how these limits were determined. However, while undertaking this task, it is appropriate to note that based on this IRP, there are no resources added in the next few years for any of the alternate plans since Empire does not have a capacity need until the latter part of the study period. Additionally, the composition of the expansion plans do not vary significantly for the nineteen plans considered.

The ranges or combinations of outcomes for the critical uncertain factors are calculated by finding the value at which the critical uncertainty must change in order for the Preferred Plan to no longer be the preferred plan. The PVRRs for the Preferred Plan and the eleven contingency plans are compared and ranked by isolating the extreme critical uncertainty variables in *Table 7-7* and *Table 7-8* for both No CO_2 and High CO_2 futures. Once a critical uncertain variable is determined, the range is calculated by finding the crossover point where the Preferred Plan is no longer the lowest cost plan.

PVRR (Mil$)	Expected Value	Ranking	High CO2	Ranking	High/High Load	Ranking	Low Load	Ranking	High Market/Gas Price	Ranking	Low Market/Gas Price	Ranking
PLN05	7,777.880	1	7,783.225	1	7,944.851	1	7,719.319	1	7,783.225	1	7,783.225	1
PLN06	7,794.465	4	7,808.562	4	7,967.736	3	7,745.347	3	7,808.562	4	7,808.562	4
PLN07	7,795.108	6	7,808.971	6	7,967.744	5	7,746.033	6	7,808.971	6	7,808.971	6
PLN08	7,794.391	3	7,808.315	3	7,967.187	2	7,745.388	5	7,808.315	3	7,808.315	3
PLN09	7,797.351	7	7,811.982	7	7,969.974	6	7,749.358	7	7,811.982	7	7,811.982	7
PLN10	7,778.694	2	7,802.556	2	7,970.160	7	7,736.544	2	7,802.556	2	7,802.556	2
PLN11	7,821.704	9	7,823.218	9	7,974.746	9	7,761.114	9	7,823.218	9	7,823.218	9
PLN12	7,853.118	11	7,846.042	11	7,990.933	11	7,784.767	11	7,846.042	11	7,846.042	11
PLN13	7,798.004	8	7,812.728	8	7,970.840	8	7,749.911	8	7,812.728	8	7,812.728	8
PLN14	7,794.465	4	7,808.562	4	7,967.736	3	7,745.347	3	7,808.562	4	7,808.562	4
PLN15	7,830.103	10	7,825.118	10	7,975.172	10	7,763.153	10	7,825.118	10	7,825.118	10
PLN16	8,021.632	12	7,983.604	12	8,127.540	12	7,924.377	12	7,983.604	12	7,983.604	12

(Source: ABB Advisors)

Table 7-7 Risk Scenario PVRRs and Rankings for High CO_2

Table 7-7 illustrates that the Preferred Plan is the lowest cost plan for all uncertain factors under the High CO_2 scenario. That is, even when 100% probability is assigned to the uncertain factors in the table, the Preferred Plan is still the lowest cost plan.

PVRR (Mil$)	Expected Value	Ranking	No CO2	Ranking	High/High Load	Ranking	Low Load	Ranking	High Market/Gas Price	Ranking	Low Market/Gas Price	Ranking
PLN05	7,777.880	1	7,963.622	1	8,090.495	1	7,914.916	2	8,416.537	2	7,624.489	1
PLN06	7,794.465	4	7,985.066	3	8,111.007	4	7,936.666	3	8,428.886	4	7,656.422	3
PLN07	7,795.108	6	7,986.216	7	8,111.853	8	7,938.049	6	8,429.479	6	7,658.229	8
PLN08	7,794.391	3	7,985.352	5	8,110.932	3	7,937.131	5	8,428.772	3	7,657.301	7
PLN09	7,797.351	7	7,986.130	6	8,111.297	6	7,938.224	7	8,430.772	7	7,656.643	6
PLN10	7,778.694	2	7,965.066	2	8,099.401	2	7,913.324	1	8,410.105	1	7,635.230	2
PLN11	7,821.704	9	8,017.252	9	8,133.845	9	7,970.173	9	8,460.080	9	7,689.592	9
PLN12	7,853.118	11	8,053.960	11	8,163.587	11	8,007.666	11	8,495.716	11	7,727.444	11
PLN13	7,798.004	8	7,986.449	8	8,111.746	7	7,938.236	8	8,431.398	8	7,656.499	5
PLN14	7,794.465	4	7,985.066	3	8,111.007	4	7,936.666	3	8,428.886	4	7,656.422	3
PLN15	7,830.103	10	8,028.380	10	8,142.997	10	7,981.665	10	8,470.686	10	7,701.314	10
PLN16	8,021.632	12	8,234.431	12	8,343.077	12	8,189.271	12	8,672.574	12	7,910.696	12

(Source: ABB Advisors)

Table 7-8 Risk Scenario PVRRs and Rankings for No CO2

Table 7-8 illustrates that Plan 5, the Preferred Plan, and Plan 10 (low load), a contingency plan, are the lowest cost plans under different risk scenarios. The uncertain factors that may cause the company to modify the Preferred Plan are under the No CO_2 scenario for both low load and high market/gas prices.

2.2.1 Critical Uncertainty Factor: CO_2

As seen in *Table 7-7* and *Table 7-8,* the projected High CO_2 and No CO_2 prices do not cause any of the contingency plans to out-perform the Preferred Plan.

2.2.2 Critical Uncertainty Factor: Load

Table 7-9 summarizes the uncertain factor range calculation. At a lower than mid load growth forecast, with low CO_2, contingency Plan 10 becomes the lower cost plan than the Preferred Plan. As the load approaches the low forecast, contingency Plan 10 becomes a lower cost plan than the Preferred Plan.

Load		
Plan	Mid	Low
Plan 5	7,963.622	7,914.916
Plan 10	7,965.066	7,913.324
Percent	from Low	
Lower %	45%	
Crossover Point	7,941.98	

(Source: ABB Advisors)

Table 7-9 Load Uncertain Factor Range

2.2.3 Critical Uncertainty Factor: Market/Gas Prices

As the gas and market prices become higher than the mid natural gas and market price scenario, contingency Plan 10 becomes the lower cost plan than the Preferred Plan, under the No CO_2 scenario. *Table 7-10* summarizes the uncertain factor range calculation.

Natural Gas/Market Prices		
Plan	Mid	High
Plan 5	7,963.622	8,416.537
Plan 10	7,965.066	8,410.105
Percent	from High	
Upper %	94%	
Crossover Point	7,992.41	

(Source: ABB Advisors)

Table 7-10 Natural Gas and Market Price Uncertain Factor Range

SECTION 3 BETTER INFORMATION

(3) The utility shall describe and document its quantification of the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by the present value of utility revenue requirements. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities.

3.1 Expected Value of Better Information

Suppose Empire had the opportunity to conduct a research study that would evaluate each of the four critical uncertainties identified in the Risk Section of Volume 6, which included market and fuel prices, loads, environmental costs, and capital costs. Such a study could help by improving the probability assessments that were assigned to each of these outcomes. However, if the cost of obtaining the research information exceeds its value, Empire should not conduct the study.

To determine the maximum possible value that Empire should pay for better information, it was assumed Empire could obtain perfect information regarding the states of nature, that is, Empire could determine with certainty which state of nature will occur, as provided in *Table 7-11*. To make use of perfect information, a payoff table was developed which is shown in *Table 7-12*. The payoff table illustrates the optimal resource alternative given perfect knowledge of the future.

States of Nature - PVRR ($000,000)

Decision	Market (Power & Fuel) High	Market (Power & Fuel) Base	Market (Power & Fuel) Low	Environmental High	Environmental Base (Mid)	Environmental Low	Environmental No	Load Levels High-High	Load Levels High	Load Levels Base	Load Levels Low	Capital Costs High	Capital Costs Base
PLN02	7838.847	7780.982	7761.601	7808.562	7748.544	7801.609	7985.066	7946.412	7847.011	7788.214	7734.541	8011.061	7701.638
PLN04	7836.702	7778.365	7758.561	7796.102	7748.309	7800.655	7981.718	7941.841	7843.535	7786.015	7732.395	8011.752	7697.685
PLN05	**7823.171**	**7764.270**	**7743.967**	**7783.225**	**7735.279**	**7785.577**	**7963.622**	**7931.342**	**7831.470**	**7771.248**	**7717.579**	**7997.726**	**7683.660**
PLN11	7865.987	7808.241	7788.938	7823.218	7776.718	7832.547	8017.252	7964.529	7872.195	7816.517	7763.120	8043.505	7726.646
PLN12	7897.293	7839.673	7820.466	7846.042	7807.991	7867.280	8053.960	7988.846	7903.341	7848.273	7795.483	8081.260	7755.342
PLN13	7842.499	7784.505	7765.009	7812.728	7752.757	7804.286	7986.449	7949.163	7850.631	7791.669	7738.341	8021.372	7702.275
PLN14	7838.847	7780.982	7761.601	7808.562	7748.544	7801.609	7985.066	7946.412	7847.011	7788.214	7734.541	8011.061	7701.638

Optimal Decision with Perfect Information - PVRR ($000,000)

Decision	Market (Power, Fuel, Wind) High	Market (Power, Fuel, Wind) Base	Market (Power, Fuel, Wind) Low	Environmental High	Environmental Base	Environmental Low	Environmental No	Load Levels High-High	Load Levels High	Load Levels Base	Load Levels Low	Capital Costs High	Capital Costs Base
Lowest PVRR	7823.171	7764.270	7743.967	7783.225	7735.279	7785.577	7963.622	7931.342	7831.470	7771.248	7717.579	7997.726	7683.660
Optimal Decision	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05	PLN05

(Source: ABB Advisors)

Table 7-11 - EPVI States of Nature

For this IRP, Plan 5 (No DSM) wins in all cases for the study period 2016-2035, so the tree was built using Plan 4 (RAP-) for comparison as it was the next best plan. By taking the probabilistic expected value of Plan 5 and subtracting the expected value with perfect information, ABB determined the expected value of perfect information (EVPI) as shown in *Table 7-12* and *Figures 7-9* through *7-12*. EVPI represents the theoretical maximum amount of money Empire could spend to obtain additional information about the states of nature, as provided in *Table 7-11.*

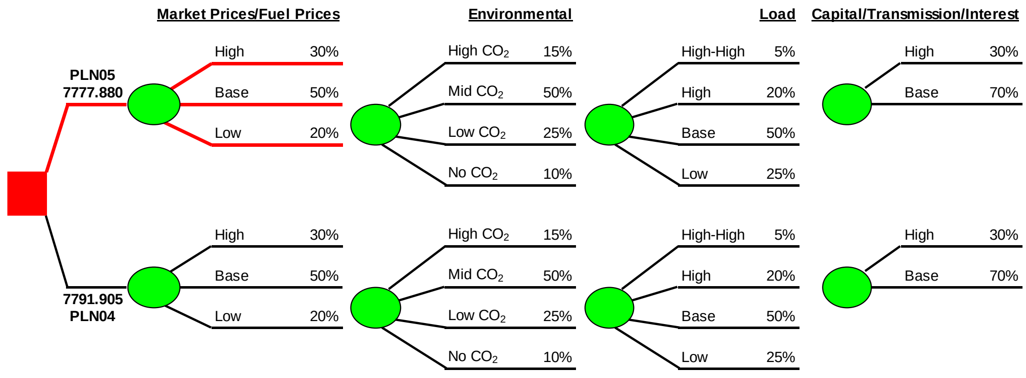
Expected Values	**Market Mil $**	**Load Mil $**	**Environmental Mil $**	**Capital Mil $**
Expected Value of Best Decision	$ 7777.88	$ 7777.88	$ 7777.88	$ 7777.88
Expected Value of Decision Strategy Using Perfect Information	$ 7777.88	$ 7777.88	$ 7777.88	$ 7777.88
Expected Value of Better Information	$ 0	$ 0	$ 0	$ 0

(Source: ABB Advisors)

Table 7-12 - Summary of the Expected Values of Better Information

The results of this analysis indicated that it would probably not be worthwhile for Empire to spend time and money pursuing better information than it currently possesses for the critical uncertain factors. However, spending large sums on sophisticated analyses and forecasts, would not guarantee they are any more accurate or likely than those that Empire already uses.

NP



Expected Value of Perfect Information - Market

Payoff Table for Market (perfect knowledge of outcomes)

	Market Levels		
Decision	High	Base	Low
PLN05	**7823.171**	**7764.270**	**7743.967**
PLN04	7836.702	7778.365	7758.561

Optimal Decision Strategy with Perfect Information

If High Market Prices occur, then Plan 5
If Base Market Prices occur, then Plan 5
If Low Market Prices occur, then Plan 5

1. Expected Value of Decision Strategy using Perfect Information = (If High, then Plan5; If Base, then Plan5; If Low, then Plan5)
{(7823.171 * 0.30 +7764.27 * 0.50 +7743.967 * 0.20)}
7777.880

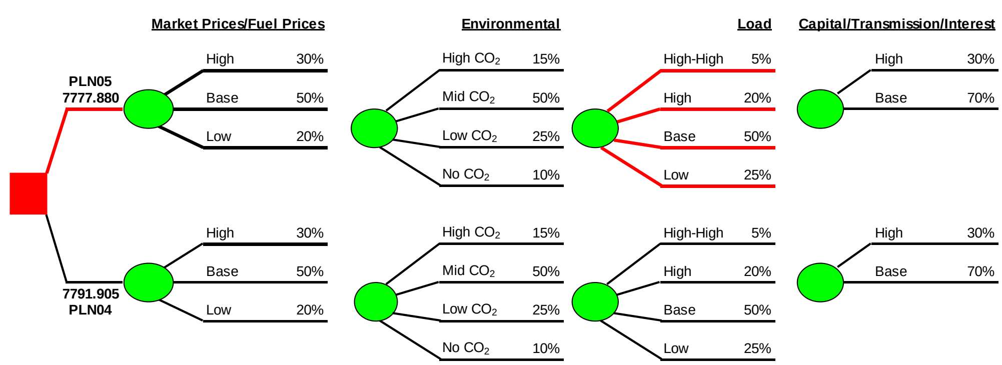
2. Expected Value of Best Decision (Plan 5) **7777.880**

3. Expected Value of Perfect Information (EVPI) Expected Value of Best Decision - Expected Value using Perfect Information
7777.88-7777.88
$0.000 million

(Source: ABB Advisors)

Figure 7-9 - EVPI - Market Prices and Fuel Prices

Load **Risk Assessment From: 2016 - 2035**



Expected Value of Perfect Information - Load

Payoff Table for Load (perfect knowledge of outcomes)

	Load Levels			
Decision	High-High	High	Base	Low
PLN05	**7931.342**	**7831.470**	**7771.248**	**7717.579**
PLN04	7941.841	7843.535	7786.015	7732.395055

Optimal Decision Strategy with Perfect Information

If High-High Load occur, then Plan 5
If High Load occur, then Plan 5
If Base Load occur, then Plan 5
If Low Load occur, then Plan 5

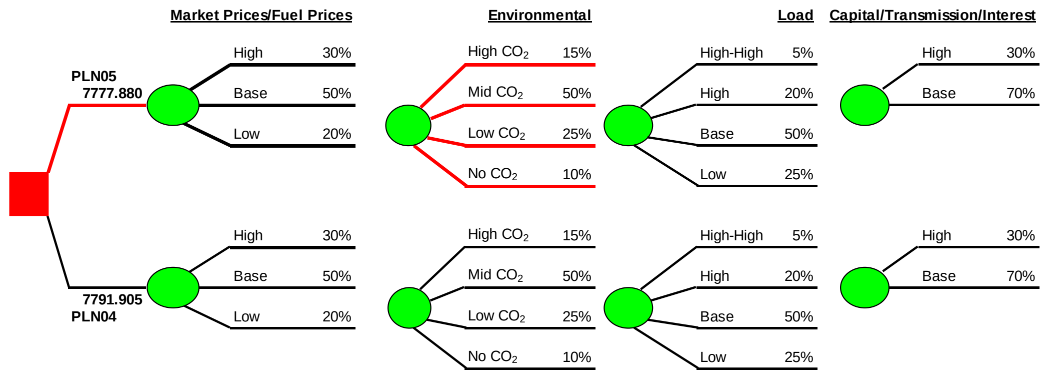
1. Expected Value of Decision Strategy using Perfect Information = (If High-High then Plan 5; If High, then Plan 5; If Base, then Plan5; If Low, then Plan 5)
{(7931.324 * 0.05 + 7831.47 * 0.20 + 7771.248 * 0.50 + 7717.579 * .25)}
7777.880

2. Expected Value of Best Decision (Plan 5) **7777.880**

3. Expected Value of Perfect Information (EVPI) Expected Value of Best Decision - Expected Value using Perfect Information
7777.88-7777.88
$0.000 million

(Source: ABB Advisors)

Figure 7-10 - EVPI - Loads



Expected Value of Perfect Information - Environmental

Payoff Table for Environmental (perfect knowledge of outcomes)

Decision	Environmental High	Moderate	Low	Base (No)
PLN05	**7783.225**	**7735.279**	**7785.577**	**7963.622**
PLN04	7796.102	7748.309	7800.655	7981.718

Optimal Decision Strategy with Perfect Information

If High Environmental Prices occur, then Plan 5
If Moderate Environmental Prices occur, then Plan 5
If Low Environmental Prices occur, then Plan 5
If No Environmental Prices occur, then Plan 5

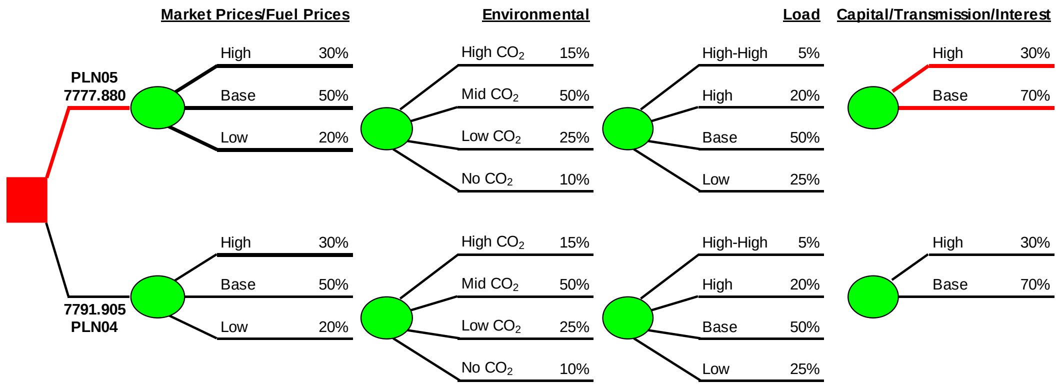
1. Expected Value of Decision Strategy using Perfect Information = (If High, then Plan 5; If Base, then Plan 5; If Low, then Plan 5; If No, then Plan 5)
{(7783.225 * 0.15 + 7735.279* 0.50 +7785.577 * 0.25 + 7963.622 * .10)}
7777.880

2. Expected Value of Best Decision (Plan 5) **7777.880**

3. Expected Value of Perfect Information (EVPI) Expected Value of Best Decision - Expected Value using Perfect Information
7777.88-7777.88
$0.000 million

(Source: ABB Advisors)

Figure 7-11 - EVPI - Environmental Costs



Expected Value of Perfect Information - Capital Costs

Payoff Table for Capital Costs (perfect knowledge of outcomes)

	Capital Costs	
Decision	High	Base
PLN05	**7997.726**	**7683.660**
PLN04	8011.752	7697.685

Optimal Decision Strategy with Perfect Information

If High Capital Cost occur, then Plan 5

If Base Capital Cost occur, then Plan 5

1. Expected Value of Decision Strategy using Perfect Information = (If High, then Plan 5 If Base, then Plan 5)
{(7997.726 * 0.30 + 7683.66 * 0.70)}
7777.880

2. Expected Value of Best Decision (Plan 5) **7777.880**

3. Expected Value of Perfect Information (EVPI) Expected Value of Best Decision - Expected Value using Perfect Information
7777.88-7777.88
$0.000 million

(Source: ABB Advisors)

Figure 7-12 - EVPI - Capital Costs

SECTION 4 CONTINGENCY RESOURCE PLANS

(4) The utility shall describe and document its contingency resource plans in preparation for the possibility that the preferred resource plan should cease to be appropriate, whether due to the limits identified pursuant to 4 CSR 240-22.070(2) being exceeded or for any other reason.

4.1 Contingency Resource Plans

The 19 alternative resource plans were described in detail in Volume 6 - Integrated Resource Plan and Risk Analysis, Section 3. For reference, *Table 7-13* provides a summary of each of the 19 plans.

Plan	Plan Description	Plan Type	DSM Portfolio	RPS	Carbon Costs for DSM Screening
1	Base Scenario	Base Plan	RAP Portfolio	None	Weighted
2	Base Scenario With RPS	Base Plan	RAP Portfolio	15 to 20% by 2021	Weighted
3	RAP + DSM	Base Plan	RAP + DSM	15 to 20% by 2021	Weighted
4	RAP – DSM	Base Plan	RAP – DSM	15 to 20% by 2021	Weighted
5	No DSM	Base Plan	None	15 to 20% by 2021	NA
6	Federal Renewable Incentives	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
7	High Environmental DSM	Contingency Plan	High Environmental	15 to 20% by 2021	High
8	Low Environmental DSM	Contingency Plan	Low Environmental	15 to 20% by 2021	Low
9	No Environmental DSM	Contingency Plan	No Environmental	15 to 20% by 2021	None
10	Low Load	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
11	High Load	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
12	High-High Load	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
13	Low Fuel	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
14	High Fuel	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
15	Aggressive Electric Vehicle	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
16	Early Asbury Retirement	Contingency Plan	RAP Portfolio	15 to 20% by 2021	Weighted
17	Highly Aggressive DSM	Required Plan	MAP Portfolio	15 to 20% by 2021	Weighted
18	Aggressive Capacity DSM	Required Plan	Aggressive Capacity Portfolio	15 to 20% by 2021	Weighted
19	Aggressive Renewable	Required Plan	None	Only renewables utilized	NA

Table 7-13 - Alternative Resource Plans

There are five base plans (1, 2, 3, 4 and 5). Plans 17, 18, and 19 exist for planning purposes only. They were required by specific rules or prior agreements and are not considered contingency plans. Plans 6 through 16 are considered contingency plans. Most of these plans result in alternate resource plans addressing differing futures for loads, fuel prices, and environmental costs. Plans 15 and 16 examine the early retirement of a coal unit and a future with a high penetration of electric vehicles, respectively. Plans 11, 12 and 16 require a new resource at an earlier point in the future than does the Preferred Plan. Empire will be monitoring its loads and other factors; filing annual updates; and filing Triennial Integrated Resource Plans with plenty of advance notice should a new resource be required earlier than expected in this 2016 IRP preferred plan.

(A) The utility shall identify as contingency resource plans those alternative resource plans that become preferred if the critical uncertain factors exceed the limits developed pursuant to section (2).

The IRP is a snap shot of the forecasts, loads, and resources over the planning horizon as they appear at this time. But given the continual refocus and ongoing nature of this planning process; the fact that at this time, Empire does not need any uncommitted capacity in the near future; and Empire has just completed a triennial filing with 19 alternate plans, makes Empire well positioned to develop contingency plans if the critical uncertain factors change enough to warrant a different course of action. For example, should higher load levels than contemplated in the Preferred Plan occur, Empire could adjust its planning to a course similar to Plan 11 or Plan 12 which was used in this IRP process to determine the potential impact of higher than expected load growth. Similarly, if load growth is slower or lower than contemplated, Empire could begin to adjust is planning course to the low load scenario contemplated in Plan 10. Also Plan 14 (High Fuel) and Plan 13 (Low Fuel) provide an indication of how Empire's planning could change in the event of higher or lower than forecast fuel process, based upon the information available at this time. Another key uncertainty that has been discussed many times in the IRP reports involves environmental issues, including the status of the Clean Power Plan (currently stayed). During development of this IRP, Empire looked at four different levels of carbon costs, including having no carbon costs during the study period and various levels of carbon costs should such rules be implemented.

In section 2.2 of this report, as required by rule, Empire has included an analysis of the range of outcomes for the critical uncertain factors to determine the limits within which the Preferred Plan is judged to be appropriate and explain how these limits were determined.

(B) The utility shall develop a process to pick among alternative resource plans, or to revise the alternative resource plans as necessary, to help ensure reliable and low cost service should the preferred resource plan no longer be appropriate for any reason. The utility may also use this process to confirm the viability of contingency resource plans identified pursuant to subsection (4)(A).

Much of the discussion in the previous section also applies to this issue. Empire is continually monitoring the critical uncertain factors and other factors, if any, that could impact the preferred plan. This may involve additional analyses. Empire updates its Missouri stakeholder group periodically through the filing of triennial IRPs and annual updates required under rule 4 CRS 240-22.080, so that the result of Empire's modeling and the effects upon its plans are researched, recalculated and documented for the Commission nearly every year. Additionally, if Empire's preferred plan has a material change, Empire would notify the Commission as required by 4 CSR 240-22.080(12). Because of the ongoing nature of the cycle, Empire is always focused on regulatory and industry developments and the Commission and the stakeholders are continually apprised of how these developments affect Empire's performance and plans.

(C) Each contingency resource plan shall satisfy the fundamental objective in 4 CSR 240-22.010(2) and the specific requirements pursuant to 4 CSR 240-22.070(1).

Each of the finalist Base Plans (2, 3, 4, and 5) and each of the Contingency Plans (6, 7, 8, 9, 10, 11, 12 13, 14, 15, and 16) satisfy the Missouri renewable energy standard mandates. The Base Plans, Plan 6 and Plans 10-16 also contain realistically achievable potential (RAP) levels of demand-side management (DSM) programs, except Plan 5, which contains no DSM. Each of these alternative resource plans was configured to satisfy the stated requirements.

SECTION 5 LOAD BUILDING PROGRAMS

(5) Analysis of Load-Building Programs. If the utility intends to continue existing load-building programs or implement new ones, it shall analyze these programs in the context of one (1) or more of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3) of this rule, including the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). This analysis shall use the same modeling procedure and assumptions described in 4 CSR 240-22.060(4). The utility shall describe and document-

(A) Its analysis of load building programs, including the following elements:

1. Estimation of the impact of load-building programs on the electric utility's summer and winter peak demands and energy usage;

2. A comparison of annual average rates in each year of the planning horizon for the resource plan(s) with and without the load-building program;

3. A comparison of the probable environmental costs of the resource plan(s) in each year of the planning horizon with and without the proposed load-building program;

4. A calculation of the performance measures and risk by year; and

5. An assessment of any other aspects of the proposed load-building programs that affect the public interest; and

(B) All current and proposed load-building programs, a discussion of why these programs are judged to be in the public interest, and, for all resource plans that include these programs, plots of the following over the planning horizon:

1. Annual average rates with and without the load-building programs; and

2. Annual utility costs and probable environmental costs with and without the load-building programs.

Empire does not have any load building programs in place at this time and does not contemplate adding load building programs during the 20-year planning horizon.

SECTION 6 IMPLEMENTATION PLAN

(6) The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the preferred resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain-
(A) A schedule and description of ongoing and planned research activities to update and improve the quality of data used in load analysis and forecasting;
(B) A schedule and description of ongoing and planned demand-side programs and demand-side rates, evaluations, and research activities to improve the quality of demand-side resources;
(C) A schedule and description of all supply-side resource research, engineering, retirement, acquisition, and construction activities, including research to meet expected environmental regulations;
(D) Identification of critical paths and major milestones for implementation of each demand-side resource and each supply-side resource, including decision points for committing to major expenditures;

6.1 Implementation Plan

The implementation plan contains the descriptions and schedules for the major tasks necessary to implement the preferred resource plan over the implementation period which is the time interval between the triennial compliance filings. The next triennial IRP filing is scheduled for 2019. Therefore, the implementation period is the period 2016-2019.

6.1.1 Demand-Side Implementation Plan

As previously mentioned, the preferred plan does not contain a Missouri demand-side portfolio. At this time, avoided energy costs are relatively low due in large part to historically low natural gas prices. Additionally, load growth has moderated as compared to past IRP assumptions. Empire has recently concluded a significant construction phase and does not have a near-term capacity need that could be offset by energy efficiency programs. In order for the utilization of additional demand-side resources to be in the public interest, it must be cost effective. The analysis in this IRP, which includes the financial impact of a demand-side investment mechanism, finds that Plan 5, the “No DSM” option is the least cost plan. Therefore, there is no short-term implementation plan for additional demand-side resources to report for the implementation period. Additionally, based on the IRP results, which did not support the inclusion of an updated demand-side portfolio in the preferred plan, the existing Missouri demand-side programs are planned to be discontinued as well. Empire will continue to monitor the factors related to demand-side management. Demand-side resources will be reevaluated during the next IRP currently scheduled for 2019. By that time, 2019, a statewide technical resource manual may be available in Missouri, which could help facilitate the analysis, reporting and evaluation of demand-side resources.

6.1.2 Supply-Side Implementation Plan

During the past few years, Empire has added generating capacity and has been working to complete its environmental Compliance Plan. During this period, Empire has completed several major projects. Plum Point and Iatan Unit 2 were added to the generation fleet in late 2010. Air Quality Control System (AQCS) additions were installed on Iatan Unit 1 and at Asbury in 2009 and 2014, respectively. Empire has recently retired the following small coal units: Asbury Unit 2 in December 2013, Riverton Unit 7 in June 2014 and Riverton Unit 8 in June 2015. Riverton Unit 9, a small gas turbine that utilized steam from either Riverton Unit 7 or Unit 8 for start-up, was also retired in June 2015. And finally, the conversion of Riverton Unit 12 to a combined cycle unit is nearing completion. This project is expected to add about 100 MW of capacity at the Riverton site.

As a result of the successful implementation of these projects, there are not any short-term supply-side projects related to capacity adjustments to address in this IRP. All of the supply-side resources from the preferred plan are outside the short-term implementation window through 2019. However, Empire will continue to evaluate opportunities for resource options between IRP filings as conditions warrant. This may include the evaluation of renewable resources not specifically required for capacity needs. Emerging technology changes, environmental changes, renewable incentive levels, renewable portfolio changes, pricing changes—particularly for renewable resources, and changing assumptions in general can impact resource planning. For example, during the development of this IRP, the EPA Clean Power Plan (CPP) moved from a proposal to a final rule to being stayed by the U.S. Supreme

Court. The long-term status of the CPP and resulting state and/or regional compliance plans are still unclear at this time. Also, near the end of the 2016 IRP process, verbal price quotes from wind developers created the need for high-level investigation and additional IRP runs. Further, various legislative actions and initiative petitions may pose a need to alter Empire's renewable portfolio in the future.

6.1.3 Preferred Plan Considerations Beyond the Short-Term Implementation Period

The Preferred Plan contains wind resources and combined cycle units in the latter part of the planning horizon. In fact, the Preferred Plan and nearly all contingency plans contain future wind resources beyond the short-term implementation period. The IRP refers to these future wind resources as wind purchased power agreements (PPA). However, this is based on the IRP modeling process and the engineering estimates for generic wind resources utilized for this IRP. Empire views these IRP wind resources as potential placeholders for future wind resources. If new wind resources are actually required in the future, Empire would issue a request for proposal (RFP) and consider all wind PPA and ownership options. Further analysis of ownership versus PPA would need to be completed once specific proposals are known. The location of a specific future wind resource—unknown to a generic twenty-year planning study—could have a significant impact on related transmission upgrade costs, for example. The transmission requirements for specific projects including non-firm versus firm transmission risks would need to be considered to determine the low cost option. Ownership in what appears to be a saturated wind market within SPP may have advantages when looking at PPA take-or-pay contracts especially when production tax credit (PTC) payments are considered. When turning this aspect of the plan into an actual project, Empire may need to run more in-depth modeling to reflect recent negative Day Ahead and Real-time prices seen in the SPP integrated marketplace during periods of high wind production. Other important factors will be the status of future PTC, fuel prices and possible carbon costs.

Another important consideration beyond the short-term implementation period that was brought to light by this IRP, concerns the future retirements of Energy Center Units 1 and 2.

These peaking units use natural gas as their primary fuel, but they can also burn fuel oil as a backup fuel if it is more economical or if natural gas is not available. Therefore, even though these units may not operate many hours, they exhibit a valuable reliability component due to their ability to operate on fuel oil during a natural gas curtailment. For IRP purposes, these units were assumed to retire in 2023 and 2026, but due to the positive capacity balance and the IRP model approach, the next new generation addition in the Preferred Plan was not added until after their retirement dates in 2029. However, the IRP capacity expansion modeling does not recognize the dual fuel reliability issue. While this planning approach does not violate any capacity reserve requirement, it could create a situation where Empire is exposed to a period of time without a historical level of fuel oil backup on its system. Additional IRP model runs were created to further assess this situation, but since this concern occurs outside the implementation period and the actual retirement dates of these units are unknown, the Preferred Plan and contingency plans were not adjusted. As the time to replace these units draws closer, future planning studies should consider dual fuel reliability issues along with fine tuning these units' retirement dates.

(E) A description of adequate competitive procurement policies to be used in the acquisition and development of supply-side resources;

6.2 Competitive Procurement Policies

Prior to issuing requests for proposals, Empire pre-screens potential bidders' qualifications and experience to confirm that those who are allowed to propose on projects are capable of completing the work safely and satisfactorily. Thereafter, as described above in subsection 6.4 in response to 22.070 (6) (C), Empire utilizes the competitive bidding process and performs rigorous evaluations of the proposals submitted to secure the best evaluated goods and services for implementing the development of its supply-side resources. This policy and procedure are in the best interests of Empire's rate payers and stockholders, the other stakeholders and the public at large.

6.3 Monitoring Critical Uncertain Factors

(F) A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency resource plans when the specified limits for uncertain factors are exceeded; and

6.3.1 Monitoring Environmental Costs

Empire personnel monitor environmental regulations and requirements to determine what actions need to be undertaken to ensure compliance and to determine the costs associated with that compliance. Among the environmental issues Empire is currently tracking are issues relating to ozone; sulfur dioxide (SO_2); nitrogen dioxide (NO_2); the Clean Air Interstate Rule (CAIR) and/or the Cross State Air Pollution Rule (CSAPR); water; particulate matter; the Coal Combustion Residuals (CCR) rule relating to ash; mercury and hazardous air pollutants (Hg/HAPS); and carbon dioxide (CO_2), especially the Clean Power Plan. The information gathered is shared through discussions with senior management.

Environmental issues are monitored by the Energy Supply Services department. Energy Supply Services department works with various other departments and management to monitor environmental costs and issues at Empire's generation facilities. Energy Supply Services provides management with the Annual NO_x Allocation Projection, the SO_2 Allowance Management Policy (SAMP) and the Greenhouse Gas Projections and Emissions Inventory. Empire also subscribes to JD Energy environmental forecasting services. The Energy Supply Services department provides management with a quarterly Environmental Key Issues Summary, as well. As important environmental issues develop, management is updated. Personnel from the Environmental staff are in regular contact with local, state and federal environmental agencies. They attend various environmental events. Empire is an active member of the Air and Waste Management Association, the EEI, the Regulatory Environmental Group for Missouri (REGFORM), the Missouri Electric Utilities Environmental committee (MEUEC), and various other state committees and organizations.

6.3.2 Monitoring Market and Fuel Prices

Power prices and fuel prices are regularly monitored by operational personnel. Both operational personnel and senior management are kept abreast of the processes and procedures being implemented in the Southwest Power Pool (SPP) that directly impact the availability and pricing of power. The price of natural gas is closely monitored. As documented in Volume 4, Empire implemented a natural gas risk management policy that has an objective of minimizing the impact of natural gas price volatility. The risk management policy includes monitoring of natural gas prices. The natural gas risk management policy is overseen and positions taken are approved annually by senior management.

Empire purchases fuel and power on a continuous basis. Each month, fuel and energy accountants prepare reports for management, such as reports known as the Summary of Fuel and Purchased Power Report, the Electric Fuel Report and the Power Report. The Summary of Fuel and Purchased Power Report compares generation, fuel costs, market revenue and purchase costs, actual to budget on a monthly, year-to-date and twelve-months-ended basis. The Electric Fuel Report contains detailed fuel usage and cost information by generating unit, plant and entire system on a monthly, year-to-date and twelve-months-ended basis. The Power Report is a detailed list of power purchases and sales for the month. Explanations for variances from budget are also reported to management. Empire's Electric Gas Position Report is supplied to management on a weekly basis. It reports detailed natural gas price and natural gas hedged amount information. This report contains a natural gas position summary, trading detail, market detail, storage balance and other information. It tracks both hedged and spot market natural gas activity. The market detail section lists current natural gas market futures prices and basis adjustment estimates for the next several years.

6.3.3 Monitoring Load Growth

Empire's load forecast is revised annually and close attention is paid to the levels of peak demand during the summer and winter months. Scheduled reviews on the load forecast are held with senior management. Each month, Empire prepares a variance report related to the demand and energy forecast and the actual results.

Each month the Planning and Regulatory Department prepares the Electric Sales and Revenue Variance Report for management. This report compares actual electric peaks, net system input (NSI) sales and revenue versus the forecast of each. It also provides an explanation of variance. This comparison and variance reporting is done at both the revenue class and total system level on a monthly, year-to-date, 12-months-ended and same month as last year basis. Each month, the Customer Report and Weather Report is prepared by the Planning and Regulatory department and distributed to management. The Customer Report exhibits the number of customers and the change in customer growth by Commercial Operation Area. Since weather is a key factor for the monthly peak, NSI, sales and revenue, a Weather Report shows how the current month's heating and cooling degrees compared to history. When the load forecasts are developed, input is provided from several areas of Empire including management, Industrial and Commercial Services, and the Commercial Operations areas.

6.3.4 Monitoring Construction/Transmission/Interest Rates

The capital costs associated with generation and transmission projects are monitored by Empire in a variety of ways. A project development team is formed for each major generation project with direct line reporting to a member of senior management. Finance personnel monitor the markets daily to track interest rates, are in frequent contact with the rating agencies, and are kept abreast of planned budgets for new projects. These efforts are coordinated with members of senior management.

Empire monitors the state of current estimates of construction costs for supply-side resources via industry periodicals such as Platt's and the EIA Annual Energy Outlook. Empire has contracted with engineering firms such as Black & Veatch, Burns and McDonnell, Sega, Inc., and others for construction cost estimates on an as needed basis. Empire has recent experience with several new generation construction projects with various technologies including combined-cycle, simple cycle combustion turbine, aeroderivative combustion turbine, wind turbines and coal plants. These types of construction projects are monitored by Project Managers. Energy Supply Services reports are provided to management on a monthly basis. Empire actively participates in the Southwest Power Pool Inc. regional transmission organization's (SPP RTO) transmission planning studies. SPP conducts several studies directly associated with transmission planning: the Balanced Portfolio Study, the Priority Projects Study, Aggregate Facilities Studies, the SPP Transmission Expansion Plan (STEP), and Integrated Transmission Plans (Near Term, 10-Year, and 20-Year Plans). A copy of each of these studies is provided in the appendices to Volume 4.5 – Transmission Distribution Analysis in response to rule 22.045(6). In addition to the aforementioned and attached studies, Empire, through its representation on various working groups, participates in any applicable High Priority and special case studies as deemed necessary by the respective overseeing working groups.

6.4 Monitoring Preferred Resource Plan

(G) A process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.

6.4.1 Preferred Plan Performance Measures

The performance measures of the preferred resource plan required by rule for each year of the planning horizon are presented below in *Table 7-14*. These measures include: estimated annual revenue requirement; estimated level of average retail rates and percentage of change from the prior year; and estimated company financial ratios. The annual results of the performance measures are illustrated in *Figures 7-13* through *7-20* that follow.

(Source: ABB Advisors)

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Table 7-14 - Preferred Plan Performance Measures

(Source: ABB Advisors)

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Figure 7-13 - Average System Rate Revenue

(Source: ABB Advisors)

****Highly Confidential in its Entirety****

Figure 7-14 - Preferred Plan Average Rate Change - Percent of Revenue

(Source: ABB Advisors)

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Figure 7-15 - Preferred Plan Cumulative Rate Increases

(Source: ABB Advisors)

****Highly Confidential in its Entirety****

Figure 7-16 - Preferred Plan Capital Forecast

(Source: ABB Advisors)

****Highly Confidential in its Entirety****

Figure 7-17 - Preferred Plan Capitalization Ratios

(Source: ABB Advisors)

****Highly Confidential in its Entirety****
Figure 7-18 - Preferred Plan Debt to Capital Ratio

(Source: ABB Advisors)

****Highly Confidential in its Entirety****
Figure 7-19 - Preferred Plan Pretax Interest Coverage Ratio

****Highly Confidential in its Entirety****

Figure 7-20 - Preferred Plan Net Cash Flow to Capital Expenditures

(Source: ABB Advisors)

SECTION 7 RESOURCE ACQUISITION STRATEGY

(7) The utility shall develop, describe and document, officially adopt, and implement a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by an officer of the utility who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:

Empire's resource acquisition strategy has been formally approved. A signed commitment to the Preferred Plan and the resource acquisition strategy was included with the Company's letter of transmittal, and it can be found attached to this volume as Appendix A.

7.1 Preferred Resource Plan

(A) A preferred resource plan selected pursuant to the requirements of section (1) of this rule;

The preferred Plan was described and documented in Section 1 above in response to rule 22.070 (1).

7.2 Implementation Plan

(B) An implementation plan developed pursuant to the requirements of section (6) of this rule; and

The Preferred Plan's implementation plan was described and documented in Section 6 above in response to rule 22.070 (6).

7.3 Contingency Resource Plans

(C) A set of contingency resource plans developed pursuant to the requirements of section (4) of this rule and identification of the point at which the critical uncertain factors would trigger the utility to move to each contingency resource plan as the preferred resource plan.

The contingency resource plans were described and their applicability was discussed in Section 4 above in response to rule 22.070 (4).

SECTION 8 EVALUATION OF DEMAND-SIDE PROGRAMS AND DEMAND-SIDE RATES

(8) Evaluation of Demand-Side Programs and Demand–Side Rates. The utility shall describe and document its evaluation plans for all demand-side programs and demand-side rates that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). Evaluation plans required by this section are for planning purposes and are separate and distinct from the evaluation, measurement, and verification reports required by 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7); nonetheless, the evaluation plan should, in addition to the requirements of this section, include the proposed evaluation schedule and the proposed approach to achieving the evaluation goals pursuant to 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7). The evaluation plans for each program and rate shall be developed before the program or rate is implemented and shall be filed when the utility files for approval of demand-side programs or demand-side program plans with the tariff application for the program or rate as described in 4 CSR 240-20.094(3). The purpose of these evaluations shall be to develop the information necessary to evaluate the cost-effectiveness and improve the design of existing and future demand-side programs and demand-side rates, to improve the forecasts of customer energy consumption and responsiveness to demand-side programs and demand-side rates, and to gather data on the implementation costs and load impacts of demand-side programs and demand-side rates for use in future cost-effectiveness screening and integrated resource analysis.

The evaluation plans and implementation plans for all *candidate* demand-side programs that were considered in the integration phase of this IRP are presented in IRP technical Volume 5: Demand-Side Resource Analysis. Additional information can be found in the appendices to Volume 5, specifically Appendix 5B – Energy Efficiency Program Design. However, there are not any Missouri demand-side programs or demand-side rates included in the Preferred Plan of this IRP.

APPENDIX A Commitment to the Preferred Plan Signed

THE EMPIRE DISTRICT ELECTRIC COMPANY
2016 INTEGRATED RESOURCE PLAN

COMMITMENT TO THE
APPROVED PREFERRED RESOURCE PLAN

FILE NO. EO-2016-0223

In accordance with Missouri Public Service Commission Rule 4 CSR 240-22, The Empire District Electric Company ("Empire") developed, described and documented, and now officially adopts for implementation the preferred resource plan and resource acquisition strategy contained in this filing.

As required, the adopted resource acquisition strategy consists of a preferred resource plan; an implementation plan; and a set of contingency resource plans. I hereby further commit to provide the notice called for by Commission Rule 4 CSR 240-22.080(12), if Empire should, between triennial compliance filings, decide to take actions materially inconsistent with the preferred resource plan.

Kelly S. Walters

Kelly S. Walters

Vice President and Chief Operating Officer – Electric

4/1/16

Dated