The Brattle Group

Integrated System Nodal Study: Costs & Revenues of ISO Membership

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Acknowledgements and Disclaimer
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EXECUTIVE SUMMARY

The purpose of this study is to evaluate the potential benefits if Basin Electric, Heartland, and WAPA (collectively, the "IS Companies" or the "Companies") join MISO or SPP markets. To calculate these benefits, we analyzed the energy-related costs and revenues of the IS Companies for the study years 2013 and 2020 under three configurations: Stand-Alone, Join-MISO, and Join-SPP. The scope of our study is limited to production cost modeling of the wholesale energy markets in order to measure changes in fuel and other variable costs, but excludes any potential benefits or costs associated with resource adequacy, transmission cost allocation, resource expansion, and ISO tariff charges and revenues.

Our analysis reflects the base expectations as well as the sensitivities around key drivers such as gas prices, hydro conditions, and renewable generation expansion, which could affect the IS Companies' energy-related variable costs and revenues.

The standard metric used in the industry to measure the net energy-related costs of serving load is adjusted production costs ("APC"). It reflects the production costs of the generators adjusted for market-based purchases and revenues. The calculation of APC is based on a number of simplifying assumptions and does not consider certain features that may ultimately affect the IS Companies' net costs. These additional features include the explicit accounting of cost-based versus market-based transactions, loss refunds, and FTR revenues. Therefore, we developed the enhanced APC ("E-APC") metric to keep track of each of these features. We calculate the E-APC metric for each of the three companies (Basin, Heartland, and WAPA) and separately for the IS region and the remote load areas in the MISO and SPP regions. We compare the E-APC metric in Stand-Alone, Join-MISO, and Join-SPP cases to estimate the potential savings of different ISO membership configurations. In addition to the E-APC metric, we present several other metrics including physical loss percentages, marginal loss charges, loss refunds, gross and net congestion costs, FTR revenues, and off-system sales for each company, region, and ISO membership configuration.

Our study shows that joining SPP or MISO could provide small to moderate savings in energy-related costs. Figure 1 summarizes the estimated E-APC savings under the base assumptions and various sensitivities analyzed. We estimate that, by joining SPP, the IS Companies could save about [redacted] using the base assumptions. The amount of savings varies depending on the sensitivity considered, ranging from [redacted]. We estimate that joining MISO could provide about [redacted], but could result in about [redacted]

[redacted] using the base assumptions. The estimated savings range from [redacted]. The results in both the Join-SPP and Join-MISO cases are relatively sensitive to WAPA's hydro generation, gas prices, and also assumed loss refunds. Reducing the assumed loss refunds from 50% to 30% in SPP and from 30% to 20% in MISO would eliminate most of the savings in the Join-SPP case, and it would amplify the cost increases in the Join-MISO case.

Figure 1
Summary of E-APC Savings Relative to Stand-Alone Case[1]

	Basin		Heartland		WAPA		Grand Total	
	Join-MISO ($m/yr)	Join-SPP ($m/yr)	Join-MISO ($m/yr)	Join-SPP ($m/yr)	Join-MISO ($m/yr)	Join-SPP ($m/yr)	Join-MISO ($m/yr)	Join-SPP ($m/yr)
2013								
Base	[redacted]	[redacted]	[redacted]	[redacted]	($3.3)	$0.9	[redacted]	[redacted]
High Hydro	[redacted]	[redacted]	[redacted]	[redacted]	$9.6	$15.6	[redacted]	[redacted]
Low Hydro	[redacted]	[redacted]	[redacted]	[redacted]	($5.8)	($3.8)	[redacted]	[redacted]
Optimized Hydro	[redacted]	[redacted]	[redacted]	[redacted]	$2.1	$6.6	[redacted]	[redacted]
High Hurdle Rate	[redacted]	[redacted]	[redacted]	[redacted]	($2.5)	$1.8	[redacted]	[redacted]
Low Hurdle Rate	[redacted]	[redacted]	[redacted]	[redacted]	($4.5)	($0.7)	[redacted]	[redacted]
Low Refund	[redacted]	[redacted]	[redacted]	[redacted]	($6.1)	($4.7)	[redacted]	[redacted]
2020								
Base	[redacted]	[redacted]	[redacted]	[redacted]	($10.0)	$3.3	[redacted]	[redacted]
High Hydro	[redacted]	[redacted]	[redacted]	[redacted]	($14.8)	$7.5	[redacted]	[redacted]
Low Hydro	[redacted]	[redacted]	[redacted]	[redacted]	($2.7)	$3.1	[redacted]	[redacted]
High Gas Price	[redacted]	[redacted]	[redacted]	[redacted]	($16.9)	$3.9	[redacted]	[redacted]
High Wind Generation	[redacted]	[redacted]	[redacted]	[redacted]	($10.3)	$2.4	[redacted]	[redacted]
Low Refund	[redacted]	[redacted]	[redacted]	[redacted]	($13.2)	($2.3)	[redacted]	[redacted]

It should be noted that several key modeling limitations would tend to understate the actual cost savings under the Join-MISO and Join-SPP cases.

- The analysis focuses on variable production cost impacts and does not consider other costs and benefits of ISO-membership (such as resource adequacy, transmission cost allocation, and administrative costs).

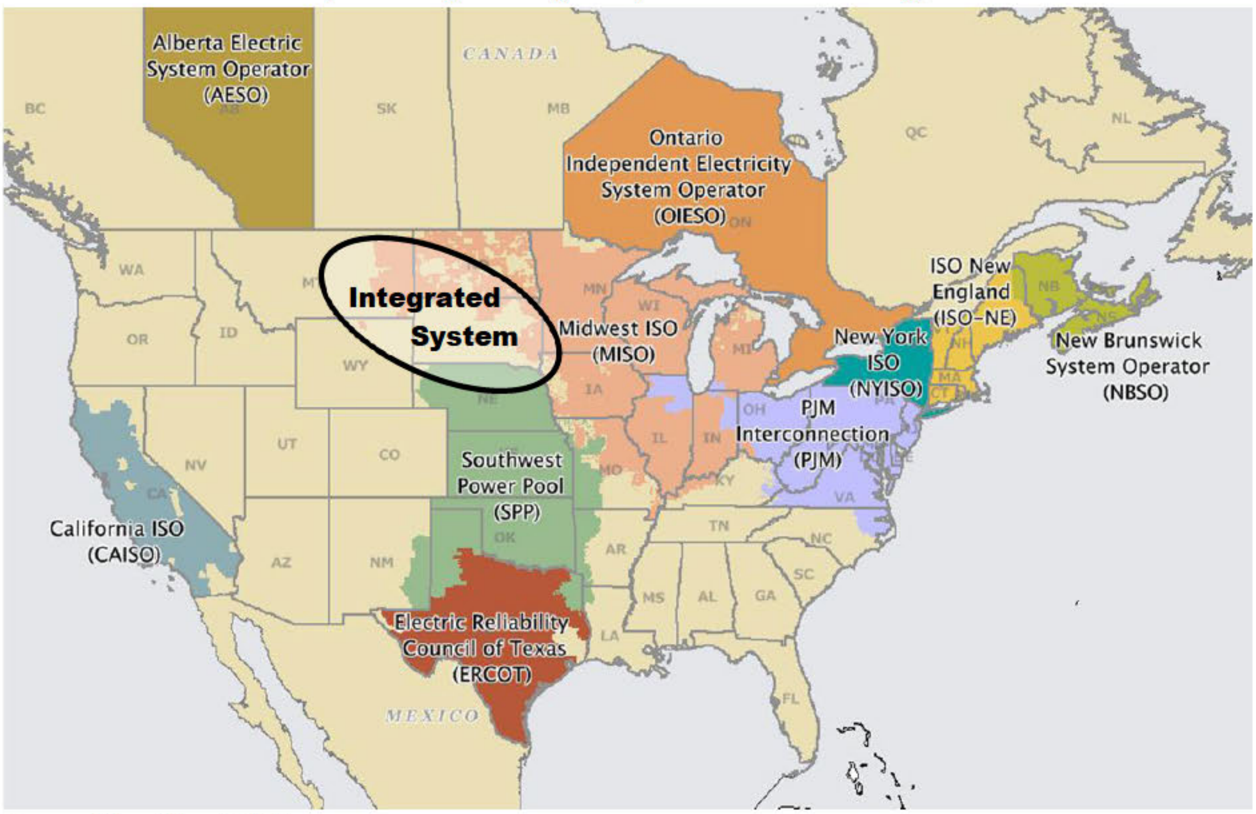
[1] Assumes that the IS Companies' loss refunds are equal to 30% of the marginal loss charges in MISO and 50% of the marginal loss charges in SPP under base assumptions and all other sensitivities except for the *Low Refunds* sensitivity. The results for the *Low Refunds* sensitivity are based on loss refunds of 20% in MISO and 30% in SPP.

- Inefficiencies of TLR-based and non-market congestion management (as currently used in the IS region and also applied to energy schedules between the IS region and the neighboring ISO regions) are not modeled.
- Production cost simulations are deterministic, hence assuming perfect foresight under normal system conditions without transmission outages or challenging market conditions.
- WAPA's hydro dispatch is assumed to be constant across all cases, hence our simulations do not capture the potential benefits from optimizing the hydro dispatch in response to changing price patterns in the Join-MISO and Join-SPP cases.
- The impact of the IS Companies' ISO membership on ancillary services markets in MISO or SPP is not modeled explicitly.

I. INTRODUCTION AND BACKGROUND

Integrated System of Basin Electric, Heartland, and WAPA (collectively, the "IS Companies" or the "Companies) are currently evaluating the costs and benefits of alternative ISO-membership configurations, and asked *The Brattle Group* ("*Brattle*") to provide a nodal analysis to estimate the potential energy-related savings if they join MISO or SPP markets. The scope of our study is limited to production cost modeling of the wholesale energy markets. Therefore, it only covers fuel and other variable production costs and does not address other categories of costs and benefits under ISO-membership that are related to resource adequacy, transmission cost allocation, administrative costs, ancillary service prices, and ISO tariff charges and revenues.

Figure 2
Map of Integrated System, MISO and SPP Regions



Source: Adopted from FERC.

A. The IS Companies

Basin Electric is a not-for-profit generation and transmission cooperative serving 133 member electric cooperatives in nine states (Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming), serving 2.8 million customers. While a large portion of Basin Electric's electric load is located in the IS region, some of its customers are located in the MISO and the SPP regions. [redacted]

Heartland is a not-for-profit Consumers Power District organized under South Dakota statute. Heartland provides wholesale electric power and energy to 27 municipal electric systems in South Dakota, Minnesota and Iowa, six state institutions and a cooperative in South Dakota, and a joint action agency in Iowa.[3] Heartland's customers are located in the IS region and the MISO region. [redacted]

WAPA is one of four power marketing administrations within the U.S. Department of Energy, receiving generation (mostly hydroelectric), and owning transmission facilities in 15 states in Central and Western U.S.[4] WAPA receives about 2,675 MW of generation capacity and serves about 2,000 MW of electric load in the Eastern and Western Interconnect.

B. MISO AND SPP

MISO manages the reliable operation of the transmission system and markets for energy, financial transmission rights, and operating reserves. The MISO region covers all or parts of 11 U.S. states (Michigan, Indiana, Kentucky, Illinois, Missouri, Iowa, Wisconsin, Minnesota, North Dakota, South Dakota, and Montana) and the Canadian province of Manitoba. The energy markets include day-ahead and real-time markets where spot prices are calculated every five minutes for more than 1,900 pricing nodes on the system. The MISO region has more than 140,000 MW of generation capacity and about 100,000 MW of peak load.

SPP operates the power transmission system covering all or parts of 9 states (Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.). SPP currently has an Energy Imbalance Service market, and is planning to implement the Integrated Marketplace (including day-ahead and real-time energy markets, operating reserves market, and financial congestion rights) starting in 2014. The SPP region has more than 70,000 MW of generation capacity and about 55,000 MW of peak load.

[redacted]

3 http://www.hcpd.com/Customers/

4 http://ww2.wapa.gov/sites/Western/about/Pages/default.aspx

II. METHODOLOGY

A. Overall Approach

Our analysis largely relies on the simulation of nodal electricity markets in three different configurations of the IS system relative to the surrounding markets: (1) maintain the current configuration of the IS system as a stand-alone entity, (2) join MISO as a member, and (3) join SPP as a member. We developed a metric that reflects the net energy-related cost of serving load for each of the IS Companies and compared the results among the three configurations to estimate the potential impact of alternative ISO-memberships.

Specifically, we developed three separate cases for two study years (2013 and 2020):

1. **"Stand-Alone"** case reflects expected market conditions and system topology where the current configuration of the IS system as a stand-alone entity is maintained;
2. **"Join-MISO"** case simulates the market conditions assuming that the IS Companies will join MISO as new members; and
3. **"Join-SPP"** case simulates the market conditions assuming that the IS Companies will join SPP as new members.

The main difference between the Stand-Alone case and the Join-MISO and Join-SPP cases is the assumed "hurdle rates" that are imposed on any exchange of energy between the IS region and its neighboring regions. The hurdle rates impact the cost of transferring energy between power pools as a financial threshold that must be overcome to allow economic interchanges. To simulate the three cases, we made two types of changes to the hurdle rate assumptions:

- First, we assumed in the Stand-Alone case that energy transfers to serve market load between the IS region and each of the MISO and SPP regions are subject to a $8.0/MWh hurdle rate to account for the uncoordinated commitment and dispatch decisions between regions, and also to model inefficient congestion management for transmission flowgates outside each pool. In the Join-MISO case, we eliminated the hurdle rate between the IS and MISO regions to model the centralized commitment and dispatch of all resources to serve combined load in these two regions by MISO. Similarly, we eliminate the hurdle rate between the IS and SPP regions in the Join-SPP case.
- Second, we assumed a special hurdle rate of $2/MWh in the Stand-Alone case for the IS Companies to serve their remote load in the MISO and SPP regions from their resources located in the IS region. This hurdle rate reflects the assumed average transmission loss charge of approximately $2.0/MWh in the IS region. In contrast, in the Join-MISO and Join-SPP cases, the transactions to serve the IS Companies' remote loads from the IS

region are expected to face drive-out transmission rates charged by MISO and SPP. We estimated that the hurdle rate to serve the IS Companies' remote load in the SPP region from the resources in the IS region would be $8.0/MWh in the Join-MISO case, and the hurdle rate to serve the IS Companies' remote load in the MISO region from the resources in the IS region would be $6.7/MWh in the Join-SPP case.

In the production cost simulations, the generation units owned by the IS Companies are treated the same as any other generation unit in the model. To the extent imported energy from neighboring regions (after accounting for the hurdle rate) is cheaper than IS generation, IS generation would not be dispatched. Similarly, IS generation would be dispatched for exporting a portion of energy to neighboring regions (after accounting for the hurdle rates) if it is more economic. The only exception is that WAPA's hydro generation has a fixed hourly schedule in the model, and hence does not respond to market price signals.

We used the PROMOD® model (hereafter referred to as "PROMOD") to perform the nodal market simulations. Ventyx consultants conducted the model runs with guidance from the *Brattle* team. Basin Electric, Heartland, and WAPA staff provided the inputs needed to calibrate the PROMOD model to accurately represent the transmission elements and operation of generation facilities within the IS region and neighboring areas.

PROMOD is a widely used simulation tool for analyzing electricity markets to support market impact analyses and system planning processes. The users of the model include MISO, PJM, and SPP. The model simulates the hourly operations of the electric system and wholesale electricity market by emulating how ISOs would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints. Simulation outputs include hourly locational marginal prices ("LMPs") for each system node, generation dispatch levels, operating costs and emissions of each generating unit, flows on each transmission line, costs of transmission congestion, and system-wide production costs. These simulations provide a useful starting point for estimating how system conditions change in the future as new generators or transmission projects are added or market seams are reduced or eliminated—as would happen if the IS Companies became a member of the MISO or SPP market.

In addition to comparing the results of the Stand-Alone, Join-MISO, and Join-SPP cases under base projections of normalized market conditions, we also performed sensitivity analyses to capture the effects of key uncertainties. Specifically, we simulated *low hydro* and *high hydro* conditions to test the impact of the generation output from WAPA's hydro plants; a *high gas price* future that would affect energy prices and price differentials among IS, MISO, and SPP regions; and a *high wind generation* future in which significantly more new wind resources owned by entities other than IS Companies are added within the IS region. We also ran additional sensitivities to test the impacts of our assumptions on hydro dispatch, hurdle rates, and loss refunds.

B. STUDY LIMITATIONS

PROMOD is a standard tool that is widely used by ISOs for their planning studies. However, it is important to recognize the limitations of these types of tools, as they may impact the overall results and estimated benefits. Some of these limitations are discussed below.

1. **The analysis focuses on production cost impacts and does not consider other costs and benefits of ISO-membership**

   As mentioned before, the scope of our study is limited to variable production cost impacts. Therefore, it does not include any operational benefits such as the automatic provision of replacement power during plant outage hours (as opposed to using the trading desks to seek replacement power through bilateral deals). It also does not capture any costs or benefits under ISO-membership related to resource adequacy, transmission cost allocation, administrative costs, and ISO tariff charges and revenues.

2. **The inefficiencies of TLR-based congestion management are not modeled**

   One of the main limitations of the PROMOD model is that it does not capture the inefficiencies of TLR-based congestion management, as it simulates economic commitment and dispatch under Day-2 LMP markets. In the past, MISO evaluated the effectiveness of the TLR process to manage congestion, and found that almost three times as many transactions were curtailed as the quantity of generation that would be economically re-dispatched under a Day-2 LMP market.[5]

   The non-market, non-centralized nature of congestion management could result in under-utilization of flowgate limits. For example, a U.S. Department of Energy ("DOE") study of standard market design benefits assumed that improved congestion management and internalization of power flows by ISOs result in a 5-10% increase in the total transfer capabilities on transmission interfaces.[6] Similarly, a study by Ronald McNamara compared the MISO Day-2 LMP markets to a non-market based congestion management system in

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5 Midwest ISO 2002 State of the Market Report.

6 U.S. Department of Energy, *Report to Congress, Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*, April 30, 2003. ("DOE Study")

which available transfer capabilities are de-rated by 7.7% to reflect under-utilization of flowgates during TLR events.[7] The PROMOD simulations do not fully capture such under-utilization of flowgates during TLR events in the "Stand-Alone" case.

Overall, the inefficiency of TLR-based congestion management means transmission is utilized less optimally, and it could potentially lead to incremental curtailments of transactions in the IS region under the "Stand-Alone" case, which is not simulated in PROMOD model runs. This likely understates the related production costs for the IS Companies in the Stand-Alone case, and results in lower benefits shown from joining MISO or SPP markets.

3. **Market simulations assume a deterministic model of the system**

   The commitment and dispatch decision of generators are simulated in a deterministic way, assuming perfect foresight under normal system conditions without transmission outages or challenging market conditions (*e.g.*, no extreme regional weather differences). As a result, this may understate the amount of congestion in the system and any benefits that could be attributed to more effective congestion management under ISO membership.

4. **WAPA's hydro dispatch is assumed to be constant across all cases**

   Our analysis assumes that the dispatch of WAPA's hydroelectric plants would be the same in all three simulated cases. While this simplifying assumption keeps the results comparable across cases, it rules out the potential to optimize hydro dispatch in response to price patterns observed and to increase the LMP revenues from hydro generation in the Join-MISO or Join-SPP cases. We performed a sensitivity run to test the approximate impact of an optimized schedule of hydro output, and showed that the additional savings could be $6 million per year in 2013 under the normal hydro conditions.

5. **The impact of the IS Companies' ISO membership on ancillary services markets in MISO or SPP is not modeled explicitly**

   Our analysis does not consider the impact of the IS Companies' ISO membership on the ancillary service markets in MISO or SPP regions. As a result, it does not capture the IS Companies' costs and revenues associated with the ancillary service markets in the Join-MISO and Join-SPP cases. Using historical prices as a proxy, we estimated that WAPA

[7] Affidavit of Ronald McNamara in Docket ER04-691-000 filed before FERC on June 25, 2004 (McNamara Study) at page 45.

could get a net revenue of about $8 million per year by selling regulation service into the MISO or SPP markets.

C. Measuring the Production Cost Benefits of ISO Membership

The standard industry metric used to measure the net energy-related costs of serving loads is adjusted production costs ("APC"). It reflects the production costs of the generators adjusted by market-based purchases and revenues. The calculation of APC is based on a number of simplifying assumptions and does not consider certain features that may ultimately affect the IS Companies' net costs. These additional features include explicit accounting of cost-based versus market-based transactions, loss refunds, and FTR revenues. Therefore, we developed the enhanced APC ("E-APC") metric to keep track of each of these features.

In addition to the E-APC metric, we also report physical losses, marginal loss charges, loss refunds, gross and net congestion costs, FTR revenues, and off-system sales. While these additional metrics do not reflect any benefits incremental to the E-APC metric, we believe that they could be useful to the IS Companies' in their decision-making process.

D. Description of E-APC Calculations

The E-APC metric is the sum of variable production costs and LMP-based charges, net of the total LMP-based revenues, FTR revenues, loss refunds, and loss adjustments.

We calculate the E-APC metric for each of the three companies (Basin, Heartland, and WAPA) and separately for the IS region and remote load areas in the MISO and SPP regions. For a given scenario and study year, we compare the E-APC metric in Stand-Alone, Join-MISO, and Join-SPP cases to estimate the potential savings of different ISO membership configurations on energy-related net costs.

The components of the E-APC metric are described below:

(+) Variable Production Costs

This includes the fuel, variable O&M, and emission costs associated with the units owned or contracted by the companies. We assumed the production costs for renewable generation (*e.g.*, hydro, wind) to be zero.

(+) Cost-Based Purchases

This corresponds to energy purchases under bilateral contracts. The purchase quantities and related costs remain constant across the three cases compared, *except for* the purchases from Rapid City and Stegall DC-ties and the cost-based purchases from WAPA in the IS region to serve remote load in MISO and SPP. Therefore, we keep track of the purchase quantities as they affect the amount of market-based transactions, but we set the purchase costs to "zero" as they do not drive the relative savings under different ISO membership configurations.

On the other hand, the purchase quantity through Rapid City and Stegall DC-ties depends on market conditions; therefore, the costs may change under different cases analyzed. As a result, we include the cost of purchases from Rapid City and Stegall DC-ties in our E-APC calculations. We use historical average monthly purchase prices to estimate costs under the Stand-Alone case, and hourly LMPs at the delivery points to estimate costs under the Join-MISO and Join-SPP cases.

(–) Cost-Based Sales

This corresponds to energy sales under bilateral contracts. The sales quantities and related revenues remain constant across the three cases compared, except for the cost-based sales from WAPA in the IS region to serve remote load in MISO and SPP. Therefore, we keep track of the sales quantities as they affect the amount of market-based transactions, but we set the sales revenues to "zero" as they do not drive the relative savings under different ISO membership configurations.

(+) LMP-Based Charges

This is the LMP-based charges to be paid to ISOs.

For the IS Companies under the Stand-Alone case, these charges include only those for market-based purchases. We estimate the quantity of market-based purchases on an hourly basis as the amount of additional energy needed (incremental to the total generation from owned or contracted resources) to meet each company's obligations for load and cost-based sales. Then, we use average load LMPs to estimate the charges associated with these market-based purchases.

The LMP-based charges for remote load areas in the Stand-Alone case include the charges to be paid to the ISO's for total obligations for load and cost-based sales. We use the average load LMPs to estimate the charges for the load (served by either internal generation or energy purchases). For the cost-based sales, we apply average generation LMPs if the sales are within the ISO, and border LMPs otherwise.

We estimate the LMP-based charges in Join-MISO and Join-SPP cases similar to those for the remote load areas in the Stand-Alone case. As a result, the IS Companies pay for their *total* obligations for load and cost-based sales, not only for the portion associated with market-based transactions.

(–) LMP-Based Revenues

This is the LMP-based revenues collected from the ISOs.

For the IS companies under the Stand-Alone case, these revenues include only those for market-based sales. We estimate the quantity of market-based sales on an hourly basis as the amount of excess generation (from owned or contracted resources) available after meeting obligations for load and cost-based sales. Then, we use average generation LMPs to estimate the revenues associated with these market-based sales.

The LMP-based revenues for remote load areas in the Stand-Alone case include the revenues to be received by generators, as well as cost-based purchases. We use the average generation LMPs to estimate the revenues collected by generators and cost-based purchases within the ISO.[8] For the cost-based purchases from outside of the ISO, we apply border LMPs to determine associated revenues.[9]

We estimate the LMP-based revenues in the Join-MISO and Join-SPP cases similar to those for the remote load areas in the Stand-Alone case. As a result, the IS Companies receive LMP-based revenues for their *total* generation and cost-based purchases, not only for the portion associated with market-based transactions.

8 LMP-based revenues for purchases from Boswell 4 and Cooper were estimated based on the LMPs associated with the unit-specific buses.

9 We defined two custom hubs for the borders between IS – MISO and IS – SPP. We first identified the branches that cross from the IS to MISO or SPP. We calculated average border prices based on the buses on either side of these branches. LMP-based revenues for purchases from the western side of Stegall and Rapid City DC-ties were estimated based on the LMPs associated with their dispatchable coal generation.

(–) FTR Revenues

This includes the revenues associated with Auction Revenue Rights ("ARRs") that are allocated to the market participants within the ISOs. ARRs can be converted to Financial Transmission Rights ("FTRs") that can be used to hedge against congestion charges.

We set the FTR revenues in the IS region to zero for the Stand-Alone case. For both in MISO and SPP regions, we assume that allocated ARRs would hedge 85% of the congestion charges estimated based on the *difference* between the marginal congestion components ("MCC") of the LMPs.

Specifically, we apply the difference between IS load MCC and generation MCC to calculate the congestion charges associated with the load served by internal generation and cost-based purchases within the ISO. For the cost-based purchases from outside of the ISO, we use the difference between load MCC and border MCC.

(–) Loss Refunds

This corresponds to the loss refunds received from the ISOs that are associated with over-collected loss charges.

We set the loss refunds in the IS region to zero for the Stand-Alone case, which does not model marginal losses. Marginal losses are modeled in the Join-MISO and Join-SPP cases, and we assume that the loss refunds would be equal to 30% of the net loss charges in MISO and 50% of the net loss charges in SPP, estimated based on the marginal loss component ("MLC") of the LMPs.[10] The assumed percentages for loss refunds in MISO and SPP are based on our review of the market rules and MISO experience to date with the loss refunds. Section II.F of this report provides further detail on the loss refund methodologies in MISO and SPP.

Specifically, we apply load MLC to estimate loss charges for internal load and cost-based sales within the ISO, and border MLC for cost-based sales to outside of the ISO. We use generation MLC to estimate loss credits to generators and cost-based purchases within the ISO, and border MLC for loss credits to cost-based purchases from outside of the ISO. We estimate the net loss charges on an hourly basis, by subtracting the total loss credits from the

[10] In addition to these base assumptions, we also performed a low refund percentage sensitivity where the IS Companies collect 20% of the marginal loss charges in MISO and 30% in SPP.

total loss charges. We then calculate the loss refunds to be a share of the net loss charges (30% in MISO, 50% in SPP) during the hours when the net loss charges are positive.

(–) Loss Adjustment

In PROMOD, the load is "grossed up" for average transmission losses to simplify the simulations and make run-times of the simulations manageable. We calculate the LMP-based charges paid by the load using this grossed up load estimate and, therefore, overstate them compared to the actual charges to be paid at the meter. To account for this, we make a downward adjustment equal to static losses (4%) multiplied by the load quantity and load LMPs. This adjustment does not apply to the IS companies in the Stand-Alone case, because they are not exposed to any LMP-based charges to meet their internal load.

E. DESCRIPTION OF OTHER METRICS

In addition to the E-APC, we also present several other metrics including physical losses, marginal loss charges, loss refunds, gross and net congestion costs, FTR revenues, and off-system sales for each company, region, and ISO membership configuration. While these metrics do not reflect any benefits incremental to the E-APC metric, they were requested by the IS Companies to be reported for a more detailed understanding of the operations in LMP-based markets.

1. Physical Losses

Physical losses correspond to the average electric losses in the transmission system, expressed as a percent of annual load that needs to be served by each company.

We assume that the average losses are equal to the marginal losses divided by 2 (based on the quadratic approximation of the loss function). We do not simulate the marginal losses for the IS region under the Stand-Alone case. Therefore, we use the static loss factor (4%) that Basin, Heartland, and WAPA provided as a proxy for the physical losses in the IS region under the Stand-Alone case.

In the MISO and SPP regions, and also in the IS region under the Join-MISO and Join-SPP cases, we take the difference between the marginal loss components (MLC) of the load and the generation LMPs on an hourly basis, first dividing it by two and then dividing it by the energy component of the LMPs to estimate the physical losses associated with the load served by internal generation and cost-based purchases within the ISO. For the cost-based purchases from outside of the ISO, we use instead the difference within the load MLC and border MLC.

2. Net Marginal loss Charges

Net marginal loss charges include the marginal loss charges and credits associated with generation and load owned/served by each of the three companies as well as their cost-based sales and/or purchases.

We set the marginal loss charges in the IS region to zero for the Stand-Alone case since the IS region does not implement marginal losses in system dispatch and for market settlements.

In the MISO and SPP regions, and also in the IS region under the Join-MISO and Join-SPP cases, we apply the MLC at the load buses to estimate charges for internal load and cost-based sales within the ISO, and the MLC at the border points for cost-based sales to outside of the ISO.[11] We use the MLC at the generation buses to estimate credits to generators and cost-based purchases within the ISO, and the MLC at the border points for credits to cost-based purchases from outside of the ISO. We estimate *total* net marginal loss charges by summing the difference between the total loss credits and the total loss charges across all hours of the year.

3. Loss Refunds

Loss refunds include the loss refunds received from the ISO that are associated with over-collected loss charges.

The loss refunds are calculated to be a share of net marginal loss charges (30% in MISO, 50% in SPP) during hours when the net marginal loss charges are positive. A description of loss refund methodologies in MISO and SPP is provided in Section II.F.

4. Gross Congestion Charges

Gross Congestion Charges correspond to the difference in the congestion charges paid by the load and the congestion charges received by the generation.

We set the gross congestion costs in the IS region to zero for the Stand-Alone case since the IS region currently does not implement a market-based congestion management system in dispatching resources and in market settlements.

In the MISO and SPP regions, and also in the IS region under the Join-MISO and Join-SPP cases, we estimate the congestion charges based on the difference between the marginal congestion components (MCC) of the LMPs. Specifically, we apply the difference between the MCC at the load buses and the MCC at the generation buses to calculate the gross congestion charges associated with the load served by internal generation and cost-based purchases within the ISO. For the cost-based purchases from outside of the ISO, we use the difference between the MCC at the load buses and the MCC at the border.

5. FTR Revenues

Financial Transmission Right (FTR) revenues include the revenues associated with Auction Revenue Rights (ARRs) that are allocated to the market participants within ISOs. These FTR revenues act as hedges against congestion charges in the day-ahead energy markets. ARRs can be converted to the FTRs used to hedge against congestion charges. At the beginning of the planning year, each of the three companies would be assigned ARRs to cover the cost of purchasing FTRs at the auction for serving its load from the expected source points. The amount of ARRs allocated is pre-determined based on the expected peak load for the planning year and is not a result of the actual market outcome. In addition, the amount of ARR allocations to load is typically less than the total load as a result of the projected transmission constraints in the system.

We set the FTR revenues in the IS region to zero for the Stand-Alone case. For both the MISO and SPP regions, we assume that allocated ARRs would hedge 85% of the congestion charges estimated based on the difference between the marginal congestion components (MCC) of the LMPs at load buses and generation buses. A description of ARR allocation methodologies in MISO and SPP is provided in Section II.G.

Specifically, we multiply the gross congestion charges by 85% across all hours of the year to calculate the *total* hedged FTR revenues.

6. Net Congestion Costs

We estimate the *total* net congestion charges for each company by subtracting total hedged FTR revenues from total gross congestion costs associated with that company.

7. Net Off-System Sales

Net off-system sales correspond to the amount of net revenues generated from selling the excess generation from owned/contracted resources that is available after meeting obligations for load and cost-based sales.

Specifically, on an hourly basis we estimate the quantity of market-based sales for each company as the amount of generation from owned or contracted resources in excess of its obligations for load and cost-based sales. Similarly, we estimate the quantity of market-based purchases as the amount of additional generation needed (incremental to the total generation from owned or contracted resources) to meet the company's obligations for load and cost-based sales, if positive. We use the average generation LMPs to estimate the revenues associated with the market-based sales, and apply average load LMPs to estimate the costs associated with the market-based purchases. We then estimate the *total* net off-system sales by subtracting the market-based purchases from the market-based revenues.

8. Transmission Constraints

Transmission constraints include the list of major binding transmission constraints. We report all the flowgates modeled in the IS, MISO, and SPP regions. We filter them based on how much they contribute to congestion costs, and show the ones with an annual congestion cost of $10 million or more.

9. Reference Bus LMPs

Reference bus LMPs reflect the energy component of the LMPs for those buses located in a given pool. We report them for the IS, MISO, and SPP regions. By definition, all of the buses within a pool would have the same reference bus LMPs.

10. System-Wide Loss Payments and Over-Collections

System-wide loss payments and over-collections include a summary of the total marginal loss charges paid by load, the loss credits received by generators, and the estimated over-collections in the MISO and SPP regions. We report this metric only for the Stand-Alone case in 2013 and 2020.

We estimate the loss charge as the system-wide load multiplied by average MLC across all of the load buses. Similarly, we estimate the loss credits as the system-wide generation multiplied by the average MLC across all of the generation buses. Then, we calculate the net loss payments as the difference between the loss charges and credits. Finally, as explained below, the over-collections are set to be 30% of the net loss payments in MISO, and 50% of the net loss payments in SPP.

F. ALLOCATION OF OVER-COLLECTED LOSSES (LOSS REFUNDS)

MISO

Rules[12]

MISO allocates the total "marginal losses surplus" ("MLS," or over-collected loss) first to loss pools, then to asset owners ("AOs") within those loss pools. A "loss pool" is defined as a collection of local balancing authorities ("LBAs"). The relationships between LBAs and loss pools may change over time.

Certain types of load get special treatment in MISO in terms of how much marginal loss refunds they get. In particular, "Carve-Out GFA" load (where GFA represents Grandfathered Agreements) receives 100% rebate for the cost of losses, and "GFA Option B" load receives 50% rebate for the cost of losses. No special treatment applies to GFA Option A and GFA Option C transactions.

The MLS is calculated each hour for the MISO region as the difference between total marginal loss charges and the average losses. It is then distributed to loss pools on a *pro rata* basis, based on their share of costs for supplying losses to load (excluding Carve-Out GFA and GFA Option B loads).

The cost for supplying losses to load in a loss pool is equal to:

- (+) charges for marginal losses by *load* in the loss pool
- (–) credits for marginal losses by *generation* in the loss pool
- (–) average cost of marginal losses for the *energy imported into the MISO system*

If the cost for supplying losses to load in a loss pool is negative, then no MLS rebate is allocated to that loss pool in that hour. The following diagram illustrates the allocation of over-collected losses in MISO.

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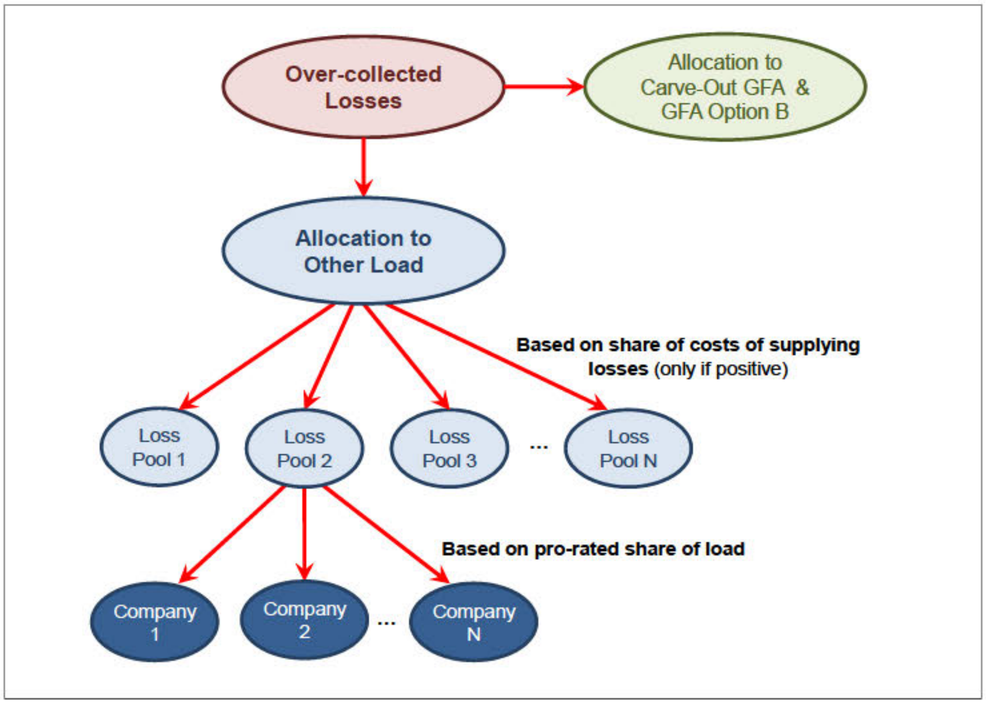
12 Source: MISO Business Practices Manual — Market Settlements, Manual No. 005, Section 2.16.

Figure 3
Illustration of Allocation of Over-Collected Losses in MISO



Historical Data

MISO provided information on system-wide MLS and average losses for the period 2005-2011. As shown in the table below, total MLS was $208 million in 2011 while the average costs of losses for load were $461 million in the day-ahead market and $457 million in the real-time (excluding Carve-Out GFA and GFA Option B load). This translates into a refund of about 45% of the average losses in 2011. Total marginal loss cost is the *sum* of average loss costs and loss refunds. Hence, it implies that loss refunds in 2011 corresponded to approximately 31% of the total marginal loss costs associated with the load, other than the Carve-Out GFA and GFA Option B load.[13] Based on these data, we use 30% to estimate the amount of loss refunds for our simulations. Note, however, that this reflects a system-wide average, and the individual companies' share of refunds may be different.

[13] Calculated as 45% ÷ (100% + 45%)

Figure 4
Summary of Historical Loss Charges and Refunds

(Data received from MISO)

Year	MISO Over-Collected Loss Rebate	Day-Ahead Loss Cost	OCL Rebate/ DA Loss Cost	Real-Time Loss Cost	OCL Rebate/ RT Loss Cost	DA GFA Carve-Out Rebate	RT GFA Carve-Out Rebate	DA GFA Option B Rebate	Total OCL Rebate	Total OCL Rebate/ DA Loss Cost	Total OCL Rebate/ DT Loss Cost
	[1]	[2]	[3]=[2]/[1]	[4]	[5]=[4]/[1]	[6]	[7]	[8]	[9]=[1]+[6] +[7]+[8]	[10]=[9]/[2]	[11]=[9]/[4]
	($m/yr)	($m/yr)	(%)	($m/yr)	(%)	($m/yr)	($m/yr)	($m/yr)	($m/yr)	(%)	(%)
2005	$149.1	$647.2	23.0%	$624.0	23.9%	$38.6	$2.6	$10.3	$200.6	31.0%	32.1%
2006	$322.2	$621.8	51.8%	$606.0	53.2%	$46.2	$6.5	$7.7	$382.5	61.5%	63.1%
2007	$352.6	$686.9	51.3%	$675.6	52.2%	$57.2	$8.3	$6.8	$425.0	61.9%	62.9%
2008	$326.2	$688.7	47.4%	$671.3	48.6%	$50.0	$1.7	$9.1	$387.0	56.2%	57.6%
2009	$171.9	$377.1	45.6%	$368.0	46.7%	$25.5	$1.0	$4.7	$203.1	53.9%	55.2%
2010	$221.7	$490.8	45.2%	$474.9	46.7%	$41.8	$1.5	$5.2	$270.2	55.1%	56.9%
2011	$207.7	$461.2	45.0%	$456.9	45.5%	$45.4	$1.7	$4.9	$259.7	56.3%	56.9%

SPP

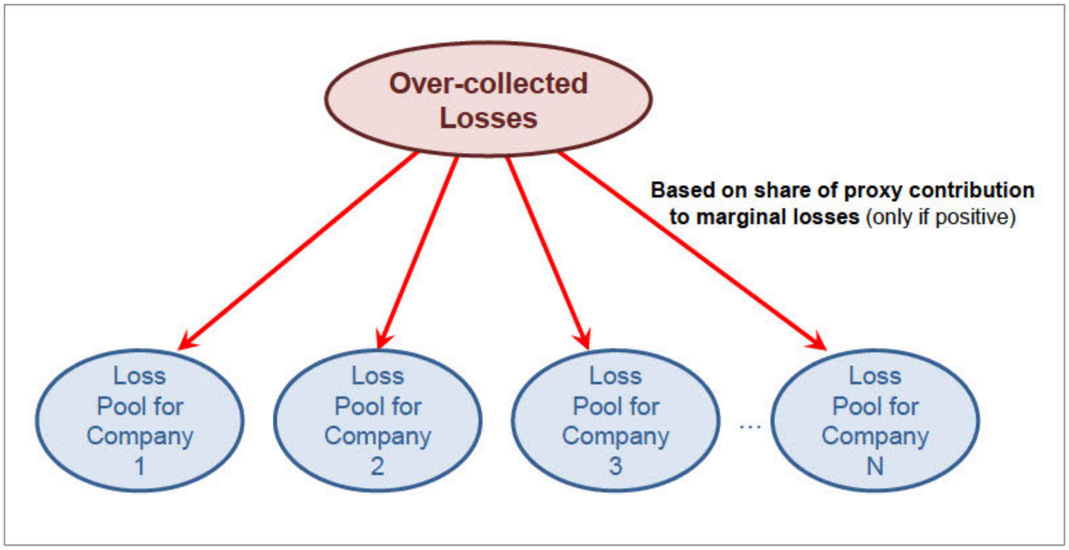
SPP currently does not have marginal loss pricing in its current energy markets. However, it plans to include marginal losses in its day-ahead markets under the proposed "Integrated Marketplace" design to start in 2014. As discussed in the testimony of Richard Dillon on behalf of SPP, the *marginal loss surplus* (*i.e.*, over-collected loss payments) will be refunded to market participants based on a proxy estimate of their contributions.[14] SPP's proposed method to refund over-collection of loss payments is similar to MISO's method, except that SPP's approach is more granular as it will employ hourly transactional activity and use "loss pools" that are specific to each asset owner (instead of balancing areas as in MISO's approach).

Under SPP's proposed approach, market participants' proxy contribution to the marginal loss surplus will be determined for each "settlement location" included in the market participants' loss pool (only if the total of all resources, load, virtual transactions, and interchange transactions results in a net withdrawal). The proxy will be calculated by using the differences between the marginal loss component (MLC) for market participants' *withdrawal* and the corresponding *injection* settlement locations. If a market participant has net market purchases in a given hour (*i.e.*, withdrawn quantity exceeds injections), then SPP will use the weighted-average of MLCs at injection points in other loss pools where the net injections remain positive. Each market participant's "loss pool" is defined as the set of settlement locations where the participant has

[14] Prepared Direct Testimony of Richard Dillon on Behalf of Southwest Power Pool, Exhibit No. SPP-3, dated February 29, 2012, pages 18-22.

transactional activity. The following diagram illustrates SPP's proposed method for allocating loss refunds.

Figure 5
Illustration of Allocation of Over-Collected Losses in MISO



Note that the Federal Energy Regulatory Commission ("FERC") has recently issued an order criticizing SPP's proposed methodology as an "impermissible direct refund" since it concluded that the loss refunds for each company are proportional to the contribution to the loss surplus.[15] FERC asked SPP to explain how its proposal would not result in a direct reimbursement to customers. SPP made a filing at FERC on February 15, 2013 to explain with an example that its proposed methodology is not equivalent to direct reimbursement.[16]

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15 FERC, "Order Conditionally Accepting Tariff Revisions to Establish Energy Markets," 141 FERC ¶ 61,048, October 18, 2012, paragraphs 211-212.

16 Prepared Testimony of Richard Dillon on behalf of SPP, Docket No. ER12-1179, Exhibit No. SPP-10, February 15, 2013.

MISO vs. SPP Markets: Implications for the IS Companies

Load and generation of the Basin, Heartland, and WAPA companies are located across various balancing areas. The over-collected losses in MISO are allocated to loss pools (balancing areas) first, and then to companies within each pool based on a pro-rated share of load, which may result in a disconnect between the companies' exposure to marginal losses and their share of allocated loss refunds if they join MISO. This disconnect between exposure to marginal losses and allocated loss refunds has been also observed by FERC recently.[17]

In the light of this, we believe that the Basin, Heartland, and WAPA companies may get less than 31% of marginal loss charges (the historical system-wide average) as refunds if they join MISO, for two reasons:

1. Some of the Companies' generation assets are located to the west of the balancing areas where part of their load is located. For example, WAPA has substantial amount of load in the MISO region, while its generation to serve that load is in the IS region. The difference between the marginal loss components of LMPs at these generation and load locations could potentially be larger than the difference in loss components between all load and generation buses within the MISO balancing area where WAPA's load is located. Therefore, WAPA's load in that balancing area may get loss refunds that are relatively smaller as a share of its exposure to loss charges.

2. If the balancing areas where the Companies' load is located have generation and load that are close to each other, then they may not experience large marginal loss charges overall. Hence, their share of allocated loss refunds would be relatively small. In that case, the Companies' load in that balancing area would not receive much in loss refunds, even if they are exposed to substantial amounts of marginal loss charges between their generation located outside that balancing area and their load located in that balancing area.

In contrast, if the Companies join the SPP markets, then SPP's proposed methodology for allocating loss refunds would result in exposure to marginal loss charges to be more in line with the loss refunds that they would get. This means actual loss refunds should be close to the 50% theoretical refund amount since SPP proposes to use separate loss pools for each company. However, as mentioned before, the recent FERC order required SPP to re-evaluate its proposed

[17] *Ibid*.

mechanism for allocating loss refunds. This may result in changes to SPP's proposed methodology and a refund amount below 50%.

Even if SPP prevails with its proposed mechanism to allocate loss refunds, the resulting refunds in the Join-SPP case could still be less than the theoretical 50% of marginal loss charges. This is mainly due to the differences between day-ahead markets and real-time operations. For example, the unscheduled flows (*i.e.*, loop-flows) on the SPP system related to transactions in the surrounding regions may increase the actual losses in the real-time operations and reduce the difference between the day-ahead marginal loss payments and actual losses. In addition, changes between the day-ahead network model and real-time network conditions (*e.g.*, transmission outages) may result in higher average losses in the real-time than the levels projected in the day-ahead markets.

G. Allocation of Auction Revenues Rights (ARRs)

MISO

In MISO, ARRs are initially allocated to "market participants" based on firm historical usage of the transmission network (firm point-to-point and network transmission service, GFA Option A). Incremental ARRs may be allocated for Network Upgrades, and for new and replacement Network Resources. ARRs can be converted to FTRs in the annual FTR auction process.

ARR nominations are done in two main stages: In Stage 1, market participants can nominate up to 100% of their peak usage in three sub-stages (Stage 1A, Restoration, and Stage 1B) subject to simultaneous feasibility. In Stage 2, any unallocated nominations and new firm transmission service customers are awarded a share of excess FTR auction revenues (instead of allocating specific ARR paths).

MISO provided data on ARR allocations for the 2012/13 period. The allocation level in Stage 1 (A, Restoration, and B) is 91.8% of the nominated volumes in the East, and 90.8% of nominated volumes in the West. MISO indicated that only a few entities received less than 80% of their ARR nominations. No data is available on the dollar value of the nominated and allocated ARRs.

SPP

SPP's proposed mechanism to allocate ARRs is very similar to MISO's approach. It allows market participants to nominate candidate ARRs associated with their firm transmission reservations, including reservations under network, point-to-point, and GFAs. Nominated ARRs are awarded based on the submitted nominations, subject to simultaneous feasibility. The annual ARR allocation process consists of three rounds in which candidate ARRs may be nominated. Market participants holding ARRs may then either convert them into Transmission Congestion Rights ("TCRs") or hold the ARRs and receive a portion of the net revenue created in the annual TCR auction which occurs following completion of the annual ARR allocation. During the annual TCR auction, credit-qualified market participants may submit Bids to "purchase" TCRs, and TCRs are awarded based on submitted bids, subject to simultaneous feasibility.

In a conference call, SPP staff mentioned that the mock ARR allocation simulations conducted during 2012 resulted in SPP awarding 82-86% of the nominated ARRs for the months of April-May, and 66-78% of the nominated ARRs for the months of June-September in the first 2 rounds of the allocation process. SPP did not share any further information about the regional or company-specific results from the mock simulation. Similar to MISO, no data is available on the dollar value of the nominated and allocated ARRs.

III. STUDY ASSUMPTIONS

This section describes our study assumptions including hurdle rates, PROMOD inputs, and sensitivities.

A. HURDLE RATES

The hurdle rates impact the capability of a pool to transfer energy to other pools. They reflect a financial threshold that must be overcome to allow economic interchanges. The marginal price difference between pools should be greater than the assumed hurdle rate for the pools to interchange energy.

Figure 6 below summarizes the hurdle rates used in the PROMOD simulations, developed based on inputs provided by the Basin, Heartland, and WAPA teams.

Figure 6
Hurdle Rate Assumptions in PROMOD

	Stand Alone	Join MISO	Join SPP
Within IS region	$0.0	$0.0	$0.0
From IS to remote load in MISO	$2.0	$0.0	$6.7
Between IS and rest of MISO	$8.0	$0.0	$8.0
Within MISO	$0.0	$0.0	$0.0
From IS to remote load in SPP	$2.0	$8.0	$0.0
Between IS and rest of SPP	$8.0	$8.0	$0.0
Within SPP	$0.0	$0.0	$0.0
Among other pools	$8.0	$8.0	$8.0

We use the same hurdle rates for unit commitment and dispatch. We use a zero hurdle rate (in all three cases) among the companies within the IS region, assuming that there will be enough coordination to commit and dispatch resources effectively.

In the Stand-Alone case, we set the hurdle rates among IS, MISO, and SPP pools to $8.0/MWh, except for the companies' remote load areas. We use $2.0/MWh as the hurdle rates from the IS region to the Companies' remote load areas, which is lower than the $8.0/MWh to reflect coordinated dispatch of resources.

We eliminate the hurdle rate between IS and MISO under the Join MISO case, since IS will be a part of the MISO pool. Also, we increase the hurdle rate between the IS region and remote load in SPP to $8.0/MWh. The $8.0/MWh hurdle rate reflects a wheeling out charge of $5.6/MWh plus an assumed transaction cost of $2.4/MWh. The wheeling out charge is calculated based on the hourly rates in MISO's Schedule 1 and 8 for scheduling, system control, dispatch services, and non-firm point to point transmission service.

Under the Join SPP case, we remove the hurdle rate between the IS and SPP regions, and set the hurdle rate between IS and the Companies' remote load in MISO to $6.7/MWh. The $6.7/MWh hurdle rate reflects a wheeling out charge of $4.3/MWh plus an assumed transaction cost of $2.4/MWh. The wheeling out charge is estimated based on the hourly rates for Schedule 1 and 8 in SPP's Open Access Transmission Tariff document.

Our hurdle rate assumptions are generally consistent with those used by others, although the exact levels vary depending on the study performed and the pools considered. For example, MISO has used a hurdle rate of $10/MWh between the IS and MISO pools for commitment, and $4–7/MWh for dispatch in its recent "value proposition" analysis and MTEP studies. Similarly, SPP has been using a $10/MWh hurdle for commitment and a $5/MWh for dispatch.

B. Other PROMOD Inputs

This section describes our key PROMOD input data for the load, generation, cost-based contracts, fuel prices, and emission allowance prices. Additional details on the modeling of the IS Companies' remote load and generation in MISO and SPP are provided in Attachment A.

1. Load Forecast

We relied on the data provided by Basin, Heartland, and WAPA for peak demand and energy projections in the IS region and remote areas in MISO and SPP. Heartland's forecasts were available only through 2017; therefore, we escalated based on the growth rate in Basin IS load (about 3% per year) to get 2020 load estimates. For WAPA, we used 2010 historical load data, and assumed no load growth through 2020. We used the Nebraska Public Power District and Otter Tail Power load shapes to generate hourly forecasts for the remote loads in MISO and SPP, respectively.

Figure 7 below summarizes the annual peak demand and energy assumptions for Basin, Heartland, and WAPA.

Figure 7
Peak Demand and Energy in Basin, Heartland, and WAPA
(Eastern Interconnection Only)

	Peak Demand			Annual Energy		
	2013 *(MW)*	2020 *(MW)*	Growth *(%/yr)*	2013 *(GWh)*	2020 *(GWh)*	Growth *(%/yr)*
Basin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]						
Heartland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]						
WAPA	**1,602**	**1,602**	**0.0%**	**8,826**	**8,826**	**0.0%**
IS	722	722	0.0%	4,472	4,472	0.0%
MISO	355	355	0.0%	2,436	2,436	0.0%
SPP	525	525	0.0%	1,917	1,917	0.0%
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]						

Notes:

[1] Load numbers are grossed up for transmission losses.

[2] Total peak demand calculated as the sum of the non-coincident peak demand for each area and/or company.

[3] WAPA is assumed to have no load growth, therefore the same 2010 actual load data was used for both 2013 and 2020. PROMOD adjusts the hourly shape to align weekend and weekday definitions while meeting monthly energy inputs.

[4] WAPA's westside is not included (westside load and generation are netted and modeled as a cost based transaction for Miles City DC Tie in Fig 12) and WAPA's peaking obligation to Basin is not included (also modeled as a cost based transaction in Fig 12).

Figure 8 shows the load assumptions in other regions modeled in PROMOD. We used data compiled by Ventyx for peak demand, annual energy, and hourly load shapes of these regions.

Figure 8
Peak Demand and Energy in Neighboring Regions

Region	Peak Demand			Annual Energy		
	2013	2020	Growth	2013	2020	Growth
	(MW)	*(MW)*	*(%/yr)*	*(GWh)*	*(GWh)*	*(%/yr)*
MISO	119,311	128,454	1.1%	655,349	694,379	0.8%
SPP	46,556	49,343	0.8%	232,328	245,652	0.8%
SERC	94,656	104,171	1.4%	476,529	526,623	1.4%
PJM	160,026	178,154	1.5%	831,898	928,298	1.6%
TVA	46,668	51,493	1.4%	240,930	263,317	1.3%
MHEB	4,646	5,140	1.5%	24,981	27,856	1.6%
Saskatchewan	3,306	3,669	1.5%	20,935	25,747	3.0%

Notes:
[1] Load numbers are grossed up for transmission losses.
[2] Entergy is assumed to be a part of MISO region.

2. Generation Capacity

The generation data used in the PROMOD runs are based on Ventyx's database released in July 2012. We made further adjustments to reflect information provided by the IS Companies.[18] Figure 9 shows the amount of generation capacity owned or contracted by Basin, Heartland, and WAPA for the study years 2013 and 2020. The major changes in 2020 include [redacted]

[18] Adjustments included updates to unit capacities and characteristics, changes to ownership and entitlements shares, as well as generation additions to the IS Companies' operating fleets.

Figure 9
Generation Capacity Owned by Basin, Heartland, and WAPA

(a) Study Year = 2013

Region	Coal (MW)	CC Gas (MW)	CT Gas (MW)	CT Other (MW)	Oil (MW)	Nuclear (MW)	Wind (MW)	Hydro (MW)	TOTAL (MW)
Basin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]									
Heartland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]									
WAPA	0	0	0	0	0	0	0	**2,554**	**2,554**
IS	0	0	0	0	0	0	0	2,554	**2,554**
MISO	0	0	0	0	0	0	0	0	**0**
SPP	0	0	0	0	0	0	0	0	**0**
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(b) Study Year = 2020

Region	Coal (MW)	CC Gas (MW)	CT Gas (MW)	CT Other (MW)	Oil (MW)	Nuclear (MW)	Wind (MW)	Hydro (MW)	TOTAL (MW)
Basin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]									
Heartland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]									
WAPA	0	0	0	0	0	0	0	**2,554**	**2,554**
IS	0	0	0	0	0	0	0	2,554	**2,554**
MISO	0	0	0	0	0	0	0	0	**0**
SPP	0	0	0	0	0	0	0	0	**0**
TOTAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Figure 10 summarizes the amount of generation capacity assumed in other regions modeled in PROMOD, including MISO and SPP, among others in Eastern Interconnect.

Figure 10
Generation Capacity in Other Regions Modeled in PROMOD

(a) Study Year = 2013

Region	Coal (MW)	Gas (MW)	Oil (MW)	Nuclear (MW)	Solar (MW)	Wind (MW)	Hydro/PS (MW)	Other (MW)	TOTAL (MW)
	Technology								
MISO	80,082	72,198	3,081	13,466	1	13,909	4,717	1,140	**188,594**
SPP	24,103	28,612	1,209	2,455	51	7,355	2,853	100	**66,737**
SERC	43,859	44,592	3,560	17,615	78	0	11,170	473	**121,347**
PJM	77,006	57,650	12,563	34,068	444	8,322	8,216	2,573	**200,842**
TVA	19,347	18,330	59	6,913	19	286	7,220	29	**52,203**
Manitoba	97	400	0	0	0	357	4,947	0	**5,801**
Saskatchewan	1,651	1,247	0	0	0	197	855	20	**3,970**
TOTAL	**246,144**	**223,029**	**20,472**	**74,517**	**594**	**30,427**	**39,977**	**4,335**	**639,495**

(b) Study Year = 2020

Region	Coal (MW)	Gas (MW)	Oil (MW)	Nuclear (MW)	Solar (MW)	Wind (MW)	Hydro/PS (MW)	Other (MW)	TOTAL (MW)
	Technology								
MISO	69,275	76,600	2,707	13,466	1	17,261	4,727	1,504	**185,541**
SPP	20,844	30,428	1,158	2,455	65	8,192	2,853	215	**66,211**
SERC	28,105	58,448	3,172	22,083	83	82	11,170	775	**123,919**
PJM	67,000	73,681	10,865	34,068	758	10,794	8,335	2,952	**208,454**
TVA	15,510	19,378	59	8,077	19	313	7,397	46	**50,799**
MHEB	97	337	0	0	0	357	4,947	0	**5,738**
Saskatchewan	1,651	1,586	0	0	0	197	855	20	**4,309**
TOTAL	**202,481**	**260,459**	**17,961**	**80,149**	**927**	**37,197**	**40,283**	**5,514**	**644,971**

3. Coal Plant Retirements

There is a fair amount of coal capacity that is at risk of retirement due to the EPA's emerging environmental regulations and future market conditions. This will likely have a significant impact in energy markets in the regions we model in PROMOD.

For study year 2020, we started with Ventyx's generation database (released in July 2012) which has unit-specific retirement projections based on public announcements. Relying on the findings of our recent study on coal plant retirements, we made further adjustments to capture that additional amount of coal capacity that could retire in various regions.[19] Figure 11 summarizes the coal plant retirement assumptions made in our PROMOD simulations.

[19] Potential Coal Plant Retirements: 2012 Update," by Metin Celebi, Frank C. Graves, and Charles Russell, *The Brattle Group, Inc.*, October 2012.

Figure 11
Summary of Coal Plant Retirements

Region	Existing Coal Capacity by 2013 (MW)	Projected Retirements in the Ventyx Database (MW)	Incremental Retirements based on Brattle Analysis (MW)	Total Coal Capacity Retired by 2020 (MW)	Total Coal Capacity In-Service by 2020 (MW)
MISO	80,082	6,086	4,721	10,807	**69,275**
SPP	24,103	838	2,421	3,258	**20,844**
PJM	77,006	10,006	0	10,006	**67,000**
SERC	43,859	5,397	10,357	15,754	**28,105**
TOTAL	**225,050**	**22,327**	**17,500**	**39,826**	**185,224**

4. Cost-Based Transactions Modeled

Figure 12 shows the cost-based energy purchases and sales modeled in PROMOD. The underlying data is provided by the IS Companies' staff. The transaction quantities and related costs or revenues are assumed to be constant across all three cases simulated, except for the Rapid City and Stegall DC-ties. The transaction quantities for the Rapid City and Stegall DC-ties are assumed to vary based on market conditions and prices. To capture this, they are modeled as dispatchable coal plants in the Join-MISO and Join-SPP cases, and the costs are calculated based on heat rate and other unit characteristics provided by Basin, and using the Laramie River coal price.

Figure 12
Cost-Based Transactions Modeled in PROMOD

Unit/DC-Tie	Purchaser Company	Seller Company	Capacity 2013 (MW)	Capacity 2020 (MW)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]
Miles City DC Tie	WAPA-IS	WAPA-WAUW	144	144
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
WAPA-Basin Fleet	WAPA-IS	Basin-IS	268	268
WAPA-Basin Fleet	Basin-IS	WAPA-IS	268	268
WAPA-NPPD Fleet	NPPD-SPP	WAPA-IS	46 GWh	46 GWh

[redacted]

5. Fuel and Emission Prices

Figure 13 below summarizes the fuel and emission allowance prices assumed in the PROMOD simulations. The natural gas price projections are based on the July 2012 IHS CERA forecasts. As shown in

Figure 13, we assumed an average Henry Hub price of $3.83/MMBtu in 2013 and $5.04/MMBtu in 2020. Coal prices reflect the range of delivered prices across all plants. Prices vary for each plant depending on the transportation cost adder. NO_x and SO_2 prices are assumed to be $40/ton. In addition, for the purposes of this study, we assumed zero CO_2 prices in 2013 and 2020, except for a RGGI CO_2 cost at $1.91/ton.

Figure 13
Fuel and Emissions Allowance Prices

Gas Price ($/MMBtu)	
Henry Hub	$3.8 in 2013 → $5.0 in 2020
Coal Price ($/MMBtu)	
IS	$0.9-1.4 in 2013, grows at inflation
MISO	$0.9-3.5 in 2013, grows at inflation
SPP	$0.9-2.2 in 2013, grows at inflation
Emissions Price ($/ton)	
SO_2	$40 constant
NO_X	$40 constant
CO_2	$0 except for RGGI

6. WAPA's Hydro Generation

Figure 14 summarizes the nameplate capacity, the assumed annual generation and capacity factors for WAPA's hydro plants modeled in PROMOD. The study footprint includes only the Eastern Interconnection. Therefore, WAPA's generation facilities located in the Western Interconnection are not included. However, the surplus energy provided by these facilities is modeled as a part of the Miles City DC-Tie west to east transfers.

WAPA provided the actual hourly generation schedules from 2010, a normal hydro year. The data is used for both the 2013 and 2020 simulations.

Figure 14
WAPA's Hydro Generation Modeled in Eastern Interconnection
(Normal Weather Conditions)

Unit	**Nameplate Capacity** *(MW)*	**Generation Output** *(GWh)*	**Capacity Factor** *(%)*
Big Bend	527	919	19.9%
Fort Peck (MAPP)	137	631	52.6%
Fort Randall	360	1,779	56.4%
Garrison	614	2,016	37.5%
Gavins Point	132	752	64.9%
Oahe	784	2,479	36.1%
Total	**2,554**	**8,576**	**38.3%**

C. SENSITIVITY ANALYSIS ASSUMPTIONS

In addition to comparing the results among the Stand-Alone, Join-MISO, and Join-SPP cases under base projections of normalized market conditions, we also performed sensitivity analyses to capture the effects of key uncertainties. Specifically, we simulated *high hydro* and *low hydro* conditions to test the impact of the generation output from WAPA's hydro plants; a *high gas price* future that would affect energy prices and price differentials among the IS, MISO, and SPP regions, and a *high wind generation* future in which significantly more new wind resources owned by entities other than IS Companies are added within the IS region. Figure 15 summarizes the core sensitivity runs we performed.

Figure 15
Core Sensitivities Analyzed in PROMOD

	Key Driver & Input Assumption		
	Gas Price	Hydro Generation	New Wind
Base	$3.83 in 2013 → $5.04 in 2020 (Henry Hub in nominal dollars)	8,500 GWh/yr	0 MW in IS
High Hydro	same as Base	14,600 GWh/yr	same as Base
Low Hydro	same as Base	5,300 GWh/yr	same as Base
High Gas	$9.00 in 2020	same as Base	same as Base
High Wind	same as Base	same as Base	~1,000 MW in IS (only in Join-MISO and Join-SPP)

We also analyzed three additional types of sensitivities: optimized hydro, low/high hurdle rate, and low loss refunds.

In the *optimized hydro* sensitivity, we used revised hydro schedules for the Join-MISO and Join-SPP cases to capture the WAPA hydro plants' ability to respond to price signals. The schedules are developed by the WAPA staff, based on the hourly LMPs observed under the base assumptions.

The hurdle rate sensitivities are performed to capture the impact of our hurdle rate assumptions, reflecting financial thresholds that must be overcome to allow economic interchanges between the IS region and its neighboring regions. In the *low hurdle rate* sensitivity, we used a hurdle rate of $6/MWh instead of the $8/MWh assumed under the base assumptions. In the *high hurdle rate* sensitivity*,* we raised the hurdle rates to $10/MWh. In addition, we also ran a sensitivity for reducing the hurdle rates to serve remote load in the MISO and SPP regions from $8/MWh in the Join-MISO case, $6.7/MWh in the Join-SPP case, to the $2/MWh hurdle rate assumed in the Stand-Alone case.

Under the base assumptions, the IS Companies are assumed to receive loss refunds equal to 30% of the marginal loss charges in MISO and 50% in SPP. In the *low loss refund* sensitivities, we analyzed the impact of reduced loss refunds (20% in MISO and 30% in SPP) on the IS Companies' net costs.

IV. SUMMARY OF RESULTS

A. BASE ASSUMPTIONS

1. E-APC Metrics

The following figures summarize the estimated energy-related E-APC estimates for 2013 and 2020 under the base assumptions.

We find that, the total E-APC to serve the combined load of the Basin, Heartland, and WAPA companies, does not change substantially among the three cases for the 2013 study year. [redacted].

In 2020, we estimate the overall production costs and the E-APC metric to be higher than in 2013 due to substantial load growth in the IS region and an increase in gas prices. However, as in 2013, we found very little difference among the three cases analyzed. The total E-APC is [redacted] in the Stand-Alone case, [redacted] in the Join-MISO case, and [redacted] in the Join-SPP case. This corresponds to an annual [redacted] in the Join-MISO case, compared to the Stand-Alone case. On the other hand, the results for the Join-SPP case translate to an annual [redacted]

Overall, the changes in the E-APC across the 3 cases analyzed reflect a relatively small share of the total costs in both 2013 and 2020 study years.

More detailed results on the E-APC metric are provided in Attachment B.

[redacted] The slightly higher savings in the Join-SPP case is mostly related to higher loss refund assumptions in the SPP footprint, relative to MISO. [redacted] On the other hand, WAPA has slightly higher costs under the Join-MISO case. This is mostly related to the price reduction in its generation nodes in the IS region, resulting in lower revenues for its excess generation. WAPA's increased loss refunds play an offsetting role, but fall short under the Join-MISO case as only 30% of the loss charges are refunded.

In 2020, we find an [redacted] in the total E-APC of IS Companies under the Join-MISO case, relative to the Stand-Alone case. [redacted] WAPA's costs increase by $10 million. The [redacted] in total E-APC is mainly related to price reductions at the WAPA generation buses due to marginal loss penalties, resulting in lower market revenues collected by the WAPA's generators under the Join-MISO case. We observe smaller price reduction effects under the Join-SPP case (due to the smaller penalties for marginal losses on IS generation units), and these effects are offset by the higher loss refunds assumed in the SPP region. This results in an E-APC savings of [redacted] $3.3 million in WAPA under the Join-SPP case. [redacted]

Figure 16
Annual E-APC Results under the Base Assumptions
Study Year = 2013

	Company	Stand-Alone	Join-MISO	Join-SPP	Join-MISO minus Stand-Alone	Join-SPP minus Stand-Alone
		($m/yr)	*($m/yr)*	*($m/yr)*	*($m/yr)*	*($m/yr)*
	Basin					
(+)	Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	Cost-Based Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Cost-Based Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	LMP-Based Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	LMP-Based Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	FTR Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Adjustments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	E-APC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Heartland					
(+)	Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	Cost-Based Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Cost-Based Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	LMP-Based Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	LMP-Based Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	FTR Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Adjustments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	E-APC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	WAPA					
(+)	Production	$0.0	$0.0	$0.0	$0.0	$0.0
(+)	Cost-Based Purchases	$0.0	$0.0	$0.0	$0.0	$0.0
(-)	Cost-Based Sales	$0.0	$0.0	$0.0	$0.0	$0.0
(+)	LMP-Based Charges	$101.4	$203.4	$199.5	$101.9	$98.1
(-)	LMP-Based Revenues	$94.1	$181.5	$179.0	$87.4	$84.8
(-)	FTR Revenues	$6.1	$5.5	$3.1	-$0.6	-$3.0
(-)	Loss Refunds	$1.4	$10.0	$15.2	$8.6	$13.7
(-)	Loss Adjustments	$3.7	$7.0	$7.0	$3.3	$3.4
	E-APC	**-$3.9**	**-$0.6**	**-$4.8**	**$3.3**	**-$0.9**
	Grand Total					
(+)	Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	Cost-Based Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Cost-Based Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	LMP-Based Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	LMP-Based Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	FTR Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Adjustments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	E-APC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
					(-0.5%)	**(-3.0%)**

Figure 17
Annual E-APC Results under the Base Assumptions

Study Year = 2020

	Company	Stand-Alone	Join-MISO	Join-SPP	Join-MISO minus Stand-Alone	Join-SPP minus Stand-Alone
		($m/yr)	*($m/yr)*	*($m/yr)*	*($m/yr)*	*($m/yr)*
	Basin					
(+)	Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	Cost-Based Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Cost-Based Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	LMP-Based Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	LMP-Based Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	FTR Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Adjustments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	E-APC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Heartland					
(+)	Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	Cost-Based Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Cost-Based Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	LMP-Based Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	LMP-Based Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	FTR Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Adjustments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	E-APC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	WAPA					
(+)	Production	$0.0	$0.0	$0.0	$0.0	$0.0
(+)	Cost-Based Purchases	$0.0	$0.0	$0.0	$0.0	$0.0
(-)	Cost-Based Sales	$0.0	$0.0	$0.0	$0.0	$0.0
(+)	LMP-Based Charges	$153.8	$324.6	$332.2	$170.9	$178.4
(-)	LMP-Based Revenues	$169.8	$316.3	$331.8	$146.5	$162.0
(-)	FTR Revenues	$0.4	-$0.8	$0.1	-$1.1	-$0.3
(-)	Loss Refunds	$1.5	$11.3	$15.5	$9.8	$14.1
(-)	Loss Adjustments	$5.7	$11.4	$11.7	$5.7	$5.9
	E-APC	**-$23.6**	**-$13.6**	**-$26.9**	**$10.0**	**-$3.3**
	Grand Total					
(+)	Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	Cost-Based Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Cost-Based Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(+)	LMP-Based Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	LMP-Based Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	FTR Revenues	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(-)	Loss Adjustments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	E-APC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
					(0.7%)	**(-4.1%)**

2. Load and Generation LMPs

In 2013, we estimate the average load LMPs to be around \$18/MWh in the IS region and remote load areas in SPP, and \$22/MWh in remote load areas in MISO. The difference between load and generation LMPs in the IS region is very small in the Stand-Alone case as a result of the limited internal congestion observed. However, the generation LMPs decrease by about \$1/MWh in the Join-MISO and Join-SPP cases due to marginal loss penalties for the IS generators. This widens the LMP differential between load and generation in the IS area and affects the LMP-based charges and revenues calculated under the E-APC metric.

The LMPs increase in 2020 across all three cases as a result of the expected increase in the IS Companies' load and higher gas prices. The LMP difference between the IS region and remote load areas in MISO drops from \$4/MWh in 2013 to almost zero in 2020. This is mainly driven by the higher load growth in the Basin area (relative to other regions), requiring more expensive generators to set the LMPs in the IS region. As in 2013, we estimate the difference between generation and load LMPs for the IS region to be very small in the Stand-Alone case, but to widen by \$2-3/MWh in the Join-MISO and Join-SPP cases.

Figure 18 summarizes the annual average load and generation LMPs under the base assumptions. More detailed results are provided in Attachment B.

Figure 18
Annual Average LMPs under the Base Assumptions

Study Year = 2013

	Stand-Alone		**Join-MISO**		**Join-SPP**	
	Load LMP ($/MWh)	Gen LMP ($/MWh)	Load LMP ($/MWh)	Gen LMP ($/MWh)	Load LMP ($/MWh)	Gen LMP ($/MWh)
Basin						
IS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MISO						
SPP						
Heartland						
IS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MISO						
SPP						
WAPA						
IS	$17.6	$17.4	$18.0	$16.3	$18.3	$16.4
MISO	$21.9	n/a	$21.8	n/a	$22.0	n/a
SPP	$17.6	n/a	$17.9	n/a	$17.3	n/a

Study Year = 2020

	Stand-Alone		**Join-MISO**		**Join-SPP**	
	Load LMP ($/MWh)	Gen LMP ($/MWh)	Load LMP ($/MWh)	Gen LMP ($/MWh)	Load LMP ($/MWh)	Gen LMP ($/MWh)
Basin						
IS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MISO						
SPP						
Heartland						
IS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MISO						
SPP						
WAPA						
IS	$32.1	$32.2	$30.3	$28.5	$32.0	$30.1
MISO	$31.2	n/a	$31.3	n/a	$31.4	n/a
SPP	$31.2	n/a	$31.7	n/a	$31.1	n/a

* LMPs reflect simple averages across 8,760 hours.

3. Marginal Loss and Congestion Charges

In the Stand-Alone case, the load and generation in the IS region are not subject to LMPs except for the off-system purchases and sales. Therefore, the IS Companies' exposure to marginal congestion charges is limited to their remote load areas in MISO and SPP and off-system purchases and sales. The marginal losses in the IS region are not simulated in the Stand-Alone case, so the IS Companies are responsible for only the marginal loss charges to be paid in their remote load areas. As a result, the IS Companies' total marginal loss and congestion charges much smaller in the Stand-Alone case, compared to the Join-MISO and Join-SPP cases.

We estimate the total marginal loss charges (before loss refunds) in 2013 [redacted]

Figure 19 below summarizes the marginal loss charges and refunds under the base assumptions. More detailed results are provided in Attachment B.

Figure 19
Marginal Loss Charges and Refunds under the Base Assumptions

	2013			2020		
	Stand-Alone ($m/yr)	Join-MISO ($m/yr)	Join-SPP ($m/yr)	Stand-Alone ($m/yr)	Join-MISO ($m/yr)	Join-SPP ($m/yr)
Basin						
Gross Loss Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Loss Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heartland						
Gross Loss Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Loss Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
WAPA						
Gross Loss Charges	$0.1	$25.1	$23.1	-$1.8	$27.9	$22.2
Loss Refunds	$1.4	$10.0	$15.2	$1.5	$11.3	$15.5
Net Loss Charges	**-$1.4**	**$15.1**	**$7.9**	**-$3.3**	**$16.6**	**$6.6**
Grand Total						
Gross Loss Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Loss Refunds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Loss Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

We estimate the total gross congestion charges (before FTR revenues) in 2013 [redacted] in the Stand-Alone case to [redacted] in the Join-MISO case and [redacted] in the Join-SPP case. [redacted]

[redacted], and a similar reduction between the MCC for WAPA's remote load in MISO and cost-based purchases from IS. We estimate the gross congestion charges to be [redacted] Note that we assume that 85% of these congestion costs are hedged through allocated ARRs in both the MISO and SPP regions; therefore, the IS Companies are exposed to only 15% of these congestion charges on a net basis, after they get the FTR revenues.

Figure 20 below summarizes the marginal congestion charges and FTR revenues under the base assumptions. More detailed results are provided in Attachment B.

Figure 20
Marginal Congestion Charges and FTR Revenues under the Base Assumptions

	2013			2020		
	Stand-Alone ($m/yr)	Join-MISO ($m/yr)	Join-SPP ($m/yr)	Stand-Alone ($m/yr)	Join-MISO ($m/yr)	Join-SPP ($m/yr)
Basin						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heartland						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
WAPA						
Gross Congestion Charges	$7.2	$6.5	$3.7	$0.4	-$0.9	$0.1
Hedged FTR Revenues	$6.1	$5.5	$3.1	$0.4	-$0.8	$0.1
Net Congestion Charges	**$1.1**	**$1.0**	**$0.6**	**$0.1**	**-$0.1**	**$0.0**
Grand Total						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

WAPA staff asked us to estimate the amount of savings if WAPA could get an exemption from loss and congestion charges in the IS region, under the Join-SPP case. Figure 21 below summarizes WAPA's net loss and congestion charges by region, and highlights the amount of potential savings from such an exemption. We estimate WAPA to pay about $13 million for the net loss and congestion charges in both 2013 and 2020 study years (in the IS region only). If avoided, this could increase WAPA's E-APC savings in the Join-SPP case by the same amount.

Figure 21
WAPA's Net Loss and Congestion Charges by Region
(Join-SPP Case)

	2013				2020			
	IS ($m/yr)	MISO ($m/yr)	SPP ($m/yr)	Total ($m/yr)	IS ($m/yr)	MISO ($m/yr)	SPP ($m/yr)	Total ($m/yr)
Gross Loss Charges	$27.1	-$5.5	$1.5	$23.1	$26.8	-$4.7	$0.1	$22.2
Loss Refunds	$13.7	$0.0	$1.5	$15.2	$14.0	$0.3	$1.2	$15.5
Net Loss Charges	**$13.4**	**-$5.5**	**$0.0**	**$7.9**	**$12.8**	**-$5.0**	**-$1.1**	**$6.6**
Gross Congestion Charges	-$0.9	$5.9	-$1.3	$3.7	-$0.6	$0.4	$0.3	$0.1
Hedged FTR Revenues	-$0.7	$5.0	-$1.1	$3.1	-$0.5	$0.3	$0.3	$0.1
Net Congestion Charges	**-$0.1**	**$0.9**	**-$0.2**	**$0.6**	**-$0.1**	**$0.1**	**$0.0**	**$0.0**
TOTAL	**$13.3**	**-$4.7**	**-$0.2**	**$8.5**	**$12.7**	**-$5.0**	**-$1.1**	**$6.6**

4. Net Off-System Sales

We find that the IS Companies import energy on a net basis under the normal hydro conditions. In 2013, we estimate the net cost of off-system purchases (net of revenues from off-system sales) to be [redacted] The IS Companies purchase significantly more energy in the Join-MISO case as their internal generation decreases in response to reduced LMPs.

Figure 22 below summarizes the off-system sales under the base assumptions. More detailed results are provided in Attachment B.

Figure 22
Net Off-System Sales under the Base Assumptions

	2013						2020					
	$m/yr			GWh/yr			$m/yr			GWh/yr		
	Stand-Alone	Join-MISO	Join-SPP	Stand-Alone	Join-MISO	Join-SPP	Stand-Alone	Join-MISO	Join-SPP	Stand-Alone	Join-MISO	Join-SPP
Basin	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]			[redacted]		
IS	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]		
MISO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
SPP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Heartland	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MISO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SPP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
WAPA	**$1**	**-$5**	**-$10**	**232**	**231**	**231**	**$19**	**$4**	**$11**	**241**	**240**	**240**
IS	$31	$48	$54	1,743	2,893	3,223	$93	$103	$112	2,657	3,339	3,431
MISO	-$20	-$20	-$53	-864	-864	-2,344	-$50	-$50	-$76	-1,569	-1,569	-2,344
SPP	-$11	-$33	-$11	-647	-1,798	-647	-$25	-$49	-$25	-847	-1,530	-847
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]		[redacted]	[redacted]		
IS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]		
MISO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]			[redacted]		
SPP	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]		

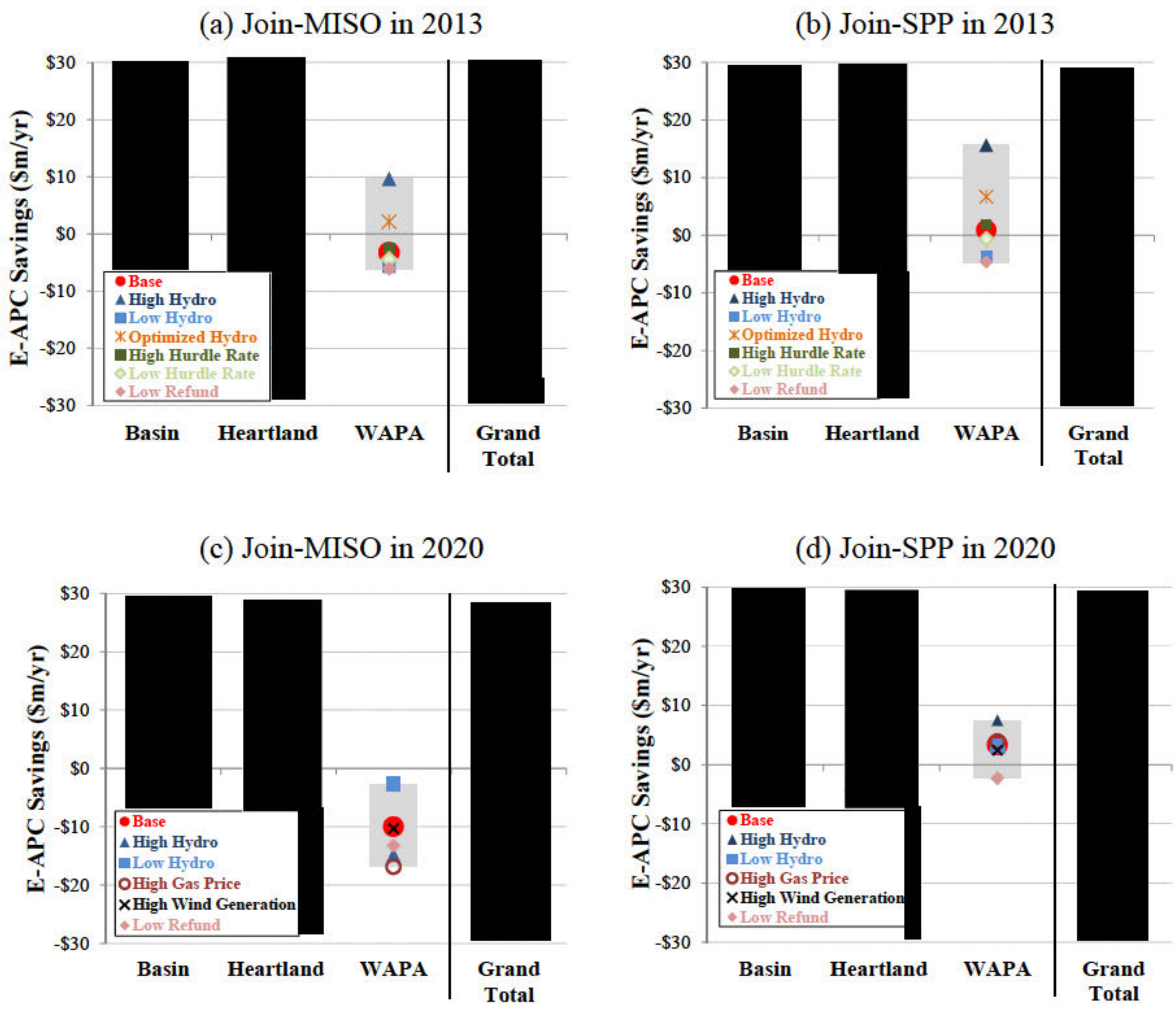
* Negative reflects net purchases.

B. Sensitivity Analysis

Figure 23 below summarizes the annual E-APC savings under the Join-MISO and Join-SPP cases relative to the Stand-Alone case, in the various sensitivities analyzed.

Figure 23

Summary of Annual E-APC Savings relative to the Stand-Alone Case



1. Hydro Conditions

WAPA's generation output is assumed to increase by about 70% (or 6 TWh) in the *High Hydro* sensitivity, compared to normal hydro conditions. This results in WAPA having higher market-based sales. It also reduces the LMPs, especially in the IS region. The relative cost savings or cost increases across the three cases for ISO membership largely depend on the magnitude of changes in LMPs across generation and load buses. In 2013, the overall E-APC [redacted] in both

Join-MISO and Join-SPP cases are about [redacted] under the *High Hydro* sensitivity compared to the E-APC [redacted] estimated under the base assumptions. Most of the [redacted] in E-APC [redacted] occurs in WAPA, as a result of smaller LMP reductions across its generation locations. In 2020, the total E-APC [redacted] in the Join-MISO case [redacted] under the *High Hydro* sensitivity, whereas the E-APC [redacted] in the Join-SPP case [redacted] by [redacted]. These results are also primarily affected by the relative LMP changes across IS Companies' generation locations. The LMP reductions in Join-MISO and Join-SPP cases are lower compared to those under the base assumptions, but they are still fairly significant, and WAPA's exposure to LMP changes are higher in proportion to its generation level.

The IS Companies' E-APC [redacted] move generally in the [redacted] under the *Low Hydro* sensitivity, where we assume WAPA's generation output to be 40% (or 3.2 TWh) lower compared to normal hydro conditions. We find that the magnitude of the changes is smaller relative to the results under the *High Hydro* sensitivity. This is because the reduction in WAPA's hydro generation is not as large, limiting the price effects in the IS region. In 2020, WAPA's E-APC increase in the Join-MISO case is mostly eliminated under *Low Hydro* sensitivity. This is because WAPA is not affected by the reduction in generation LMPs as much, as it generates significantly less (and becomes a net purchaser of energy).

In addition, we ran the Optimized *Hydro* sensitivity for the 2013 study year, where we used revised hydro schedules for the Join-MISO and Join-SPP cases to capture the WAPA hydro plants' ability to respond to price signals. The E-APC savings increase by about $6 million in both cases, most of which occurs in WAPA as a result of higher market revenues.

2. Gas Prices

The average LMPs increase across all the regions by almost 50% under the *High Gas Price* sensitivity (which assumes Henry Hub gas prices to reach $9/MMBtu instead of the base assumption of $5/MMBtu) that we ran for the 2020 study year. However, the price difference between the IS region and remote load areas in MISO and SPP remains relatively small. This limits the potential E-APC savings that could be achieved. We estimate the total [redacted] in E-APC in the Join-MISO case (relative to the Stand-Alone case) to be [redacted] in 2020. The results are similar to those under the base gas price assumptions, except that WAPA's net costs increase from $10 million to $17 million. This is primarily because the reduction of WAPA's generation LMPs in the Join-MISO case (relative to the Stand-Alone case) is higher under the increased gas prices. This reduces the LMP-based revenues that WAPA collects.

We find that the total 2020 E-APC savings in the Join-SPP case (relative to the Stand-Alone case) is about [redacted] under the *High Gas Price* sensitivity run for 2020 This is slightly [redacted] than the [redacted] estimated under base gas prices. [redacted]

3. Wind Generation

We ran the *High Wind Generation* sensitivity for the Join-MISO and Join-SPP cases in 2020, which resulted in lower prices in the IS region. The average LMPs decrease by \$0.2/MWh in the Join-MISO case, relative to those under base assumptions. The price decrease is \$0.7/MWh in the Join-SPP case.

Lower prices reduce the LMP-based charges paid by the load in the IS region. However, they also reduce the LMP-based revenues that the generation gets in the IS region. Overall, we estimate the reduction in LMP-based charges and revenues to be similar; therefore, the E-APCs do not change significantly (compared to the estimates under the base assumptions).

The total E-APC of the IS Companies [redacted] by about [redacted] in the Join-MISO case relative to the Stand-Alone case. This is approximately the same as the cost increase estimated under the base assumptions. In the Join-SPP case, we estimate the total E-APC [redacted] to be [redacted]. This is approximately [redacted] than the [redacted] calculated under the base assumptions.

4. Hurdle Rates

Using different hurdle rate assumptions had a very small impact on the E-APC savings. Changing the assumed hurdle rates by \$2/MWh moved the total E-APC savings for the IS Companies by less than \$1 million in 2013.

The *Low Hurdle Rate* sensitivity results in average LMPs to increase by about \$0.6/MWh in the IS region in the Stand-Alone case while the prices in Join-MISO and Join-SPP cases remain relatively unchanged. [redacted]

[redacted] On the other hand, higher LMPs add to WAPA's revenue for net market-based sales under the Stand-Alone case, so WAPA's E-APC savings marginally decrease.

We see opposite effects under the *High Hurdle Rate* sensitivity. The average LMPs decrease by \$0.4/MWh in the Stand-Alone case. [redacted] On the other hand, lower LMPs result in less revenue for WAPA's net market-based sales under the Stand-Alone case, and translate into higher E-APC savings in Join-MISO and Join-SPP cases.

SPP has stated that, if the IS Companies join SPP, all existing transmission arrangements would be grandfathered and exempt from drive-out fees. To capture that, we performed an additional sensitivity run for the Join-SPP case were we reduced the hurdle rate between the IS region and the remote load areas in MISO from \$6.7/MWh to the hurdle rate assumed in the Stand-Alone case (\$2/MWh) while keeping all the other hurdle rates the same. This did not have any material effect on the LMPs and the E-APC results since the IS Companies' remote load in MISO accounts for a relatively small share of their total load.

5. Lower Loss Refunds

One of the key input assumptions that affect the overall E-APC savings is the amount of loss refunds that the IS Companies would receive. Under the base assumptions, the IS Companies collect 30% of the marginal loss charges in MISO and 50% in SPP. To recognize the uncertainty around these assumptions, we ran the *low loss refund* sensitivity with loss refunds set to 20% of the marginal loss charges in MISO, and 30% in SPP.

Under this sensitivity, we estimate the IS Companies to receive [redacted] in loss refunds in 2013 under the Join-MISO case, and [redacted] in 2020. This translates into a net E-APC [redacted] in 2013 and [redacted] in 2020, both relative to the Stand-Alone case.

In the Join-SPP case, the total loss refunds received [redacted] in 2013 and [redacted] in 2020. [redacted] It translates into a net E-APC [redacted] in 2013, and a net decrease of [redacted] in 2020, relative to the Stand-Alone case.

V. LIST OF ATTACHMENTS

Attachments include the following:

- **Attachment A:** Promod assumptions and methodology
- **Attachment B:** Detailed results (in spreadsheet format)