Alternative Operations Study Recommendation

Western
AREA POWER
ADMINISTRATION

Upper Great Plains Region

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Executive Summary

Western Area Power Administration – Upper Great Plains Region (Western-UGP) markets Pick-Sloan Missouri Basin Program – Eastern Division (P-SMBP-ED) hydroelectric power and energy to preference entities in Montana east of the continental divide, North and South Dakota, western Minnesota and Iowa, and eastern Nebraska. The Joint Transmission System (JTS) was formed and documented in the Missouri Basin Systems Group (MBSG) Pooling Agreement dated January 31, 1963. In 1998, the Integrated Transmission System (IS), composed of Western-UGP, Basin Electric Power Cooperative (Basin), and Heartland Consumers Power District (Heartland), replaced the JTS. The IS includes approximately 9,848 miles of transmission lines owned by Basin, Heartland, and Western. Transmission service over the IS is provided under Western's Open Access Transmission Tariff (OATT), with Western-UGP serving as tariff administrator for the IS. Western-UGP also operates two balancing authority areas, WAUW and WAUE, within the IS which are separated by the Miles City DC Tie and the Fort Peck Power Plant.

Market to Non-Market Challenges

Approximately 50 percent of Western-UGP's preference load is beyond the edge of the IS and delivered across third-party transmission systems in the MISO and the SPP predominately under arrangements made by those preference customers. This separation creates market to non-market seams between Western-UGP, Midcontinent Independent System Operator (MISO), and Southwest Power Pool (SPP) and impacts both Western-UGP's and other local utilities' marketing of power across the seams. To address certain transmission congestion in the MISO and SPP footprints, the reliability coordinator cuts power schedules in and out of those RTOs under Transmission Loading Relief (TLR) protocols in addition to re-dispatching generation within its footprint. Western-UGP has experienced many TLR schedule cuts on short-term sales and purchases, as well as firm power schedules necessary to meet its obligations. Western-UGP has few options to avoid TLRs. These TLR impacts are directly related to Western-UGP and the IS owners' unique footprint in relation to energy markets. In addition to the MISO and SPP seams on the east and south, Western-UGP is constrained by limited access to the Canadian markets to the north, as well as to western markets, due to limitations of available capacity for energy transfers through the AC-DC-AC interconnection ties. Historically, Western-UGP has had opportunities to sell and purchase short-term energy from many different entities in response to hydro-generation variability. However, with entities joining MISO and its organized energy market, Western-UGP has seen those opportunities decrease significantly. With the SPP Integrated Market Place planned to become operational in 2014, Western-UGP anticipates substantial reduction in bi-lateral short-term energy trading opportunities. Western-UGP recognizes the variability of the hydro-generation and the historic need Western-UGP has had for access to energy markets to realize the lowest cost energy purchases and optimized short-term energy sales. As a result, Western-UGP has performed an assessment of the costs, benefits, and risks of alternative operating models while continuing to reliably serve our firm power commitments.

The Alternative Operations Study (AOS)

For purposes of this assessment, Western is considering placing only the portion of the IS located in the eastern electrical interconnected system within an RTO market. The options for future operating models analyzed included a Stand Alone configuration, Join MISO, and Join SPP.

The Cost/Benefit Analysis (CBA) for this study measured and compared six criteria in each of the three options.

1. RTO Trade Benefit
2. Administrative Costs
3. Transmission Expansion
4. Capacity Benefits
5. IS Transmission Revenue - Cost Shifts
6. Drive-Out Impacts

There were significant monetary separations in the CBA results. The CBA results have shown the Join SPP option provides more benefits than the other two options.

Qualitative risks were analyzed through the use of a Multi-Criteria Decision Analysis (MCDA) tool. The MCDA uses marketing plan and rate stability, and agreements as major criteria to assess the options with multiple metrics for each. Weight factors were assigned to each of the criteria and each of the metrics based on the relative importance of the criterion or metric to the overall decision. Each metric was rated according to the qualitative scale to determine the appropriate risk rating, and the risk score associated with each option was subsequently developed through application of the weighting of the risk. The risk score for the Join SPP option was the lowest and, therefore, the most favorable option from a qualitative risk standpoint.

The recommendation and supporting documents only contain information that pertains to Western-UGP. Business case studies included individual results for each IS owner and the IS operation as a whole. However, the individual non-Western IS member data is proprietary information and not revealed in this recommendation and the overall IS data is not revealed and only cited when deemed necessary for understanding Western-UGP's recommendation. **Due to Western-UGP's unique footprint in the Eastern Interconnection, the results of this study do not apply to other Western regions and their marketing and transmitting of Federal hydropower.**

Based on the analysis performed, Western-UGP concluded that the potential benefits of the Join SPP option are significant enough for Western-UGP to solicit feedback from customers and other stakeholders regarding its recommendation to pursue formal negotiations with SPP regarding membership. Timing considerations are such that these actions should proceed quickly.

The information gathered and analyzed by Western subject matter experts, combined with stakeholder comments and the expertise of industry consultants, informed the development of the recommendation that is now being published for review. The analysis recognizes the requirements of the U.S Army Corps of Engineer Missouri River Mainstem System Master Water Control Manual for the Missouri River Basin. A decision to pursue the recommendation will be informed by comments received in response to the recommendation notice. A decision by Western to move forward with formal negotiations with SPP will result in detailed membership discussions consistent with applicable statutory requirements as captured in the Alternative Operations Study's (AOS) assumptions. The mitigation of costs and risks will be a particular consideration in the negotiations regarding joining the SPP RTO with the goal to achieve rate stability and allow Western-UGP to fulfill contractual obligations to our customers.

Background

Western-UGP is an owning member and sole operator of the IS. The IS is becoming increasingly isolated, bordered on the north and the west by limited ties, on the east by MISO, and SPP. Over the last decade Reliability Coordinator (RC) initiated Transmission Loading Relief (TLR) curtailments have increased and further isolated Western-UGP by curtailing transactions between Western-UGP and its neighbors. Curtailments impact effective and efficient operation of the IS and Western-UGP through:

1. TLR curtailments of Firm Electric Service (FES) deliveries to load in MISO and SPP
2. TLR curtailments of Western-UGP energy purchases during drought periods that have impacted physical deliveries to FES customers within the WAUE Balancing Area
3. TLR curtailments of Western-UGP surplus energy sales have negatively affected revenues
4. Reduced number of bi-lateral trading partners available to Western-UGP

The TLR process is a less efficient and less controllable means of managing congestion than optimized generation dispatch within RTO markets. Typically, the TLR process results in more curtailments than would be required by economic redispatch. RTO's redispatch within their footprint based on the most economical solution for the combined system. These factors should make congestion management through RTO markets more reliable and more economical than the curtailment of scheduled transactions through the TLR process.

RTOs are not a new concept within the utility industry. The concept of joint planning, joint power supply, cost sharing and in some cases, joint transmission has occurred for decades between utilities with a common mission and goal. In Western-UGP the roots of RTO-like agreements can be traced back to the January 31, 1963, MBSG Pooling Agreement that was signed by the Assistant Secretary of the Interior and 105 utility systems across six states for participation in the Federal transmission system. This agreement established the JTS, now known as the IS, to plan, build, operate, and maintain a joint transmission system.

Subsequent to the creation of the MBSG and JTS, Western's predecessor, the Bureau of Reclamation, also became a member of the Mid-Continent Area Power Pool (MAPP). MAPP was another entity formed to promote power pooling, transmission planning, reliability, and reserve pooling. Certain MAPP members, including Western-UGP, were later involved in RTO creation efforts, including a study from 2000 through 2004 by certain MAPP members for creation of the Crescent Moon RTO. This was closely followed by another study effort from 2006 through 2008 known as the Mid-Continent Systems Group. In 2008-2009, the IS owners and MISO jointly developed a new type of tariff service (Module F) which would have allowed the IS owners to place their generation and loads into the MISO organized market but keep the IS transmission system assets out of MISO. Ultimately, the Federal Energy Regulatory Commission (FERC) rejected these tariff changes. During the 2008 to 2009 timeframe, many of the original MAPP Generation Reserve Sharing Pool members merged with MISO to share contingency reserves and formed the Midwest Reserve Sharing Group (MRSG). In 2009, the MRSG was renewing the sharing agreement and Western-UGP terminated its participation in the MRSG agreement for economic reasons. Prior to leaving MRSG, the IS owners were aware that providing contingency reserves on a stand-alone basis would have been cost prohibitive and discussions began with SPP to participate in SPP's reserve sharing group. Western-UGP then entered into a limited term agreement with the SPP reserve sharing group effective with the termination of the MRSG agreement.

With the SPP and MISO defined boundaries and market operations, Western-UGP is now being forced to either change operations to optimize a stand-alone solution or join one of the two adjacent RTOs. In other words, Western-UGP cannot remain in a status-quo condition. To-date, Western and the other IS owners have completed several analyses to better understand the costs and to determine the benefits of joining an RTO. In 2011, the IS owners engaged the Charles River Associates (CRA) to conduct a high level assessment of the costs and risks associated with the stand alone and join RTO options (CRA Study). The CRA Study also identified potential opportunities within the RTO options compared to remaining independent and recommended that further detailed analysis be conducted to better assess the associated risks. Key risk factors identified in the CRA Study included loss of Operating Reserve Agreement, lost opportunity for IS expansion cost sharing, limited access to markets, impediments to pseudo-ties, exit fees, and RTO transmission expansion sharing.

A key factor in both the CRA Study and the recently completed IS Business Model analysis is the historic partnership of the IS owners in the evolution of joint marketing and transmission system development. This paper provides an analysis of the risks/benefits to Western-UGP and to a limited degree addresses these risk/benefits from an IS owner perspective.

Methodology

The high level study done by CRA indicated the need for further, more detailed analysis. After analyzing the results of the CRA Study, a Western-UGP Alternative Operations Study (AOS) Team was organized to participate in further studies with the other IS owners (AOS-IS Team). A Western-UGP Analysis Team was formed as a sub-set to the Western-UGP AOS Team. The Analysis Team was to evaluate and report on the various data collected by the AOS-IS Team, outline a business recommendation, determine risks within the recommendation, and identify opportunities that have a value to the recommendation.

The AOS-IS Team decided that the new and more detailed evaluation should keep the same strategic options used in the CRA Study. The strategic options used for this second study were possible future operating models and are: 1) Stand alone[1]; 2) Join MISO; and 3) Join SPP. Further explanations of each strategic option can be found in the Cost Benefits Analysis section of this paper.

For the business plan's recommendations to have merit there must be a basis for analysis of the strategic options chosen for evaluation. The analysis must be conducted in a rigorous, objective, and transparent manner in order to establish a level of confidence in the recommendations.

The American National Standards Institute (ANSI) International Organization for Standardization for Risk Management-Risk Assessment Techniques (ISO 31010) identifies both the CBA and MCDA as risk evaluation techniques capable of assessing the overall worthiness of multiple options and using a range of criteria both objectively and transparently. The CBA can quantitatively distinguish between various options for total expected benefits and costs and the MCDA can produce a preference of order among the available options with regard to identified risks.

A CBA can be used for risk evaluation where total expected costs are weighed against the total expected benefits in order to choose the best or most profitable option. A CBA is an implicit part of many risk evaluations. There is a major difficulty in applying CBA as the means to choose among different options that have criteria that are not associated with financial data or costs. A means of quantifying the different options to account for preference customer support, stakeholder support, marketing plans, governance variations, or other intangible criteria, in conjunction with a cost-benefit analysis would be very useful in evaluating the complexities of the given options. Therefore, since the CBA alone lacks the capability to measure the risk of the options, the team determined that a MCDA process would measure the risk of the various options in a manner to assure the objectives are met.

An MCDA utilizes a range of criteria to objectively and transparently assess the overall worthiness of various options. The overall goal is to produce a preference of order between the available options. The analysis involves the development of a matrix of options scored in a qualitative

[1] In the CRA Study the first operating model was called the "Hybrid." This term only indicated a new situation and was not descriptive of the choice between Western-UGP standing alone or joining an RTO; therefore, the name was changed to "Stand Alone."

manner against weighted criteria and weighted metrics using established measurements. The MCDA can be very useful in risk evaluations by comparing options against similar criteria that do not have a direct financial association.

The Analysis Team determined that a combination of these risk evaluation techniques could identify a recommendation that would best meet Western-UGP's objectives.

The Cost Benefit Analysis Process

Quantitative CBA aggregates the monetary value of all costs and all benefits that are included in the scope. The CBA is a good comparative analysis tool to identify separations in the results. Many simplifying assumptions are made in the system model for model performance reasons. **Therefore, the financial results should be interpreted as showing relative separation and not as actual financial outcomes.**

The AOS-IS Team patterned this study from the CRA Study done in 2011 and chose the elements based on the elements used in the CRA Study. The CBA for this study comprises six elements that were measured and compared in the scenario that each of the three strategic options depict. The six elements are:

RTO Trade Benefit

The Brattle Group was hired to analyze a comprehensive system nodal study conducted by Ventyx using the PROMOD® modeling program.

Administrative Costs

This cost indicates both MISO and SPP administrative charges that would be paid if Western – UGP would join one of the RTOs.

Transmission Expansion

Each RTO determines what future transmission expansion is needed for the RTO's reliability and economic needs. Each RTO has its own unique method of determining the purpose for the transmission expansion and how its cost will be shared within the RTO. Expansion plans of the IS were also included in the analysis.

Capacity Benefits

The analysis did not monetize any capacity benefits to Western-UGP as most benefits would be from reduced reserve requirements and from reserve sharing which Western-UGP already participates in with SPP. In addition, benefits related to capacity would be small as a result of not having additional water to create more energy under the new capacity. The other IS owners do realize capacity benefits so this element was an integral part of their CBA results.

Integrated System Transmission Revenue (Cost Shifts)

The IS recovers its annual revenue requirement utilizing a "postage stamp" pricing methodology and both of the RTOs utilize a "license plate" pricing methodology. The difference in the pricing methodologies results in changes to the load ratios for each transmission customer. This element looks at how the costs would shift between IS owners and other transmission customers.

Drive-Out Impacts

Approximately 50 percent of Western-UGP customer load is outside of Western-UGP's balancing authority areas. Joining or not joining an RTO will have a financial impact from drive-out charges on Firm Electric Energy Services contract schedules exiting each RTO.

These six elements were chosen because they are known to exist in the RTOs today, they can be both studied and measured, and they provide a reasonably complete representation of the major discriminators for each of these options. For the RTO Trade Benefits element Brattle used the PROMOD® Model to perform the nodal market simulations. Ventyx consultants conducted the model runs with guidance from the Brattle team. Western-UGP staff provided the inputs needed to calibrate the PROMOD® Model to accurately represent the transmission system and operation of generation facilities within the IS region and neighboring areas.

Brattle used Ventyx to run their PROMOD® simulations deterministically by developing a base scenario to use for comparison with runs containing different sensitivities. These differing sensitivities are entered into the PROMOD® simulation and the results are then compared to the base run to see possible affects. These differing sensitivity scenarios quantify possible risk by imputing data that is not controlled by Western-UGP such as future high gas pricing, high wind penetration, and high/low hydro generation, etc. This deterministic approach to cost benefit analysis is the industry standard.

The Multi-Criteria Decision Analysis (MCDA) Process

The purpose was to use a range of criteria to objectively and transparently assess the overall worthiness of a set of options. In general, the overall goal was to produce a preference of order between the available options. The analysis involved the development of a matrix of options and criteria that were ranked and aggregated to provide an overall score for each option.

To determine the criteria and numerical weights, the AOS Team combined factors of actual operations experience, industry trends, discussions and feedback with Western customers, the experiences of others actually in an RTO, and discussions and feedback with the RTOs themselves.

The AOS Team determined the major criteria for the MCDA and weighted them by percentage as to their relative importance to the overall recommendation. The two criteria were:

Marketing Plan/Rate Stability – 65%

Agreements – 35%

Each criterion was then evaluated to determine a subset of risk issues that pertained to each. These risk issues were called metrics. Each metric was analyzed and rated for significance of risk it posed to the criterion it fell under.

The major criteria and the metrics were captured in a matrix which assigned a numeric value to score and compared the criteria and associated metrics for each strategic option. Higher assigned values in this MCDA indicate higher risk.

The AOS Team defined the key criteria and associated weights. The Analysis Team defined specific metrics and associated metric weights within those criteria. The Analysis Team also defined the descriptions of the criteria, description of the metrics, and created a table with qualitative fields associated with metric measurement factors for consistency between options. This table is shown below:

Table 1: AOS Team Criteria

Criteria	Metric - Weight
Marketing Plan & Rate Stability Weight – 65%	Access to Bi-lateral Markets - 40%
	TLR Susceptibility – 30%
	Peaking Contracts – 10%
	Contingency Reserves – 20%
Agreements Weight – 35%	Flexibility – 40%
	Governance – 30%
	Seams – 10%
	Withdrawal – 10%
	East/West – 10%

While conducting the CBA and MCDA analyses, the Analysis Team recognized certain additional uncertainties that derive from this decision or had no treatment within the recommendation. The impact of these uncertainties cannot be qualitatively or quantitatively valued at this particular time. For example, two of the options consider RTO membership. Joining an RTO may be perceived as setting some form of precedent for Western and/or for other Federal power marketing administrations (PMA). Although the business case for an RTO option may be favorable to Western-UGP, aspects of the decision may not be perceived as favorable to some of Western's customers and stakeholders based on their particular circumstances and membership conditions. Western-UGP attempts to mitigate the potential for negative consequence by adhering to the requirements of EPAct 05 S 1232. This is partially addressed in the Agreements Criteria of the MCDA, but not necessarily given full consideration due in part to the limited PMA/customer/stakeholder input at the time of writing this paper. It is expected that Western-UGP will soon undertake a public process which will provide additional feedback on these concerns, and Western-UGP can then appropriately consider them in the MCDA when making its final decision. Similarly, other issues may arise in the public process and may cause Western to revise the MCDA.

Cost Benefit Analysis

Western-UGP along with the other IS owners have undertaken two recent quantitative studies of alternative operations. Charles River Associates (CRA) was contracted to perform a high-level analysis of three operating options for the IS owners in 2011. The Charles River study is briefly discussed below to show some of the history of the Western-UGP RTO study process. The CRA study recommendations suggested further evaluation with a full nodal study. In 2013 the IS owners completed a more in-depth study of operating options, which also included a nodal analysis of the RTO Trade Benefits that was conducted under a contract with The Brattle Group.

Charles River Associates Study

CRA performed a high-level assessment of the costs and benefits of alternative operating models for the eastern portion of the IS. The analysis looked at three options relative to the status quo at that time:

> **Hybrid** - specific amounts of IS owner generation and load currently located in the IS-WAUE region are electrically moved to the MISO or SPP systems through pseudo-ties such that IS owner generation resources and load in MISO and in SPP, including the IS owner generation and load currently in these RTOs, are in general alignment and are partially optimized within each of these RTO markets.
> **Join MISO -** simulates the market conditions assuming that the IS Owners would join MISO as new members.
> **Join SPP** - simulates the market conditions assuming that the IS Owners would join SPP as new members.

CRA identified significant areas of risk with each option:

Table 2: CRA Significant Risks

	Hybrid	Join MISO	Join SPP
Operating Reserve Agreement Ending	x		
Lost Opportunity for IS Expansion Sharing	x		
Trading Access to RTO Markets	x		
Impediments to Significant Pseudo-Ties	x		
RTO Exit Fees		x	x
RTO Transmission Expansion Sharing		x	x

Five criteria were evaluated for each option:

> **Trade Benefits** - Benefits from a reduction in the cost to serve load through reduced wheeling charges and a more efficient commitment and dispatch process under an RTO.

Administrative Costs - Payment of administrative charges to the RTO and internal costs incurred to interface with the RTO as a member.

Transmission Expansion - Allocation to the new member of the RTO high-voltage transmission expansion costs.

Capacity Benefits - Increased load diversity, access to the RTO capacity market, and the ability to supply planning reserves in MISO and SPP are projected to provide significant additional capacity-related benefits to the IS Parties under the RTO models.

Transmission Revenue - Elimination of wheeling charges between the IS region and an RTO in the Join RTO options could result in lost transmission revenue for the IS, which might be offset by sharing in the through-and-out transmission revenue of the RTO at large.

Due to cost and time constraints for this high-level study, CRA did not utilize a nodal analysis to quantify Trade Benefits. Relying on previous studies, they estimated the Trade Benefits and acknowledged it as an approximation, with a recommendation for further evaluation at a later date.

The three operating alternatives reviewed by CRA appeared to have favorable outcomes relative to the Status Quo. Both of the Join RTO options showed favorable economics, but also the cost risks particularly associated with transmission expansion. The Hybrid option also had favorable economics, but the IS owners would be at risk for the potential end of contingency reserve sharing with SPP and there would be no opportunity for IS high-voltage transmission projects to be eligible for RTO cost sharing. The Hybrid option was also seen by IS owners as limiting options to economically purchase capacity and energy to meet potential load growth obligations. The CRA Study's recommendation was to conduct a more detailed analysis of the RTO and Hybrid options. In order to more accurately understand the impacts of joining an RTO, the IS owners conducted confidential discussions with both the SPP RTO and the Midcontinent ISO to determine whether these RTOs would be willing to address some of the potential risks to Western-UGP. The CRA study also identified a need to more precisely model the relative trade benefits and administrative costs of joining each particular RTO.

Integrated System Business Model

The IS Business Model was completed in 2013 as a joint effort by Western-UGP, Heartland, and Basin staff. Three operating options were modeled in the study:

Stand Alone – the current configuration of the IS as a stand-alone entity is maintained, but operations are optimized in an attempt to mitigate problems that have been experienced in the current status quo operation. The market efficiencies of the model simulation optimize Western-UGP's operation in this configuration.

Join MISO – simulates market conditions assuming the IS owners join MISO as new members.

Join SPP – simulates market conditions assuming the IS owners join SPP as new members.

Each of the options was analyzed in a "first year" and an "out year" configuration. The year 2016, which was seen as the first realistic year of membership, was studied as the first year and 2020 was studied as the "out year."

Six criteria were evaluated for each of the three options:

RTO Trade Benefits

The IS owners commissioned the Brattle Group to perform a full nodal analysis to determine the RTO Trade Benefits in each of the three options for the first year and the out year. RTO Trade Benefits were limited to related costs and revenues collectively and also individually for the IS members. The scope of the study was limited to production cost modeling of the wholesale energy markets in order to measure changes in fuel and other variable costs. In addition to a base case for each study year, several sensitivity runs were completed for key drivers such as gas prices, hurdle rates (a financial threshold that must be overcome to allow economic interchanges between markets), hydro conditions, renewable generation expansion, and estimated RTO Loss Refund percentage.

Brattle utilized an Enhanced Adjusted Production Cost (E-APC) metric to measure the net energy-related costs of serving load. In addition to the standard production costs of generators adjusted for market based purchases and revenues, the metric includes accounting of cost-based versus market-based transactions, loss refunds, and FTR revenues. Brattle also calculated marginal loss charges, loss refunds, gross and net congestion costs, FTR revenues, and off-system sales for each of the IS companies in each alternative. The annual E-APC savings for the base case in each of the options is shown below.

Table 3: Annual Western-UGP E-APC Results for Base Case

	Stand Alone ($m/yr)	Join MISO ($m/yr)	Join SPP ($m/yr)
First Year E-APC	(3.9)	(0.6)	(4.8)
Out Year E-APC	(23.6)	(13.6)	(26.9)
Note: These results include only Western-UGP market related costs			

Brattle also completed several sensitivity runs in addition to the base case. These runs varied key parameters in the study to determine the effects of the change. Definition of the parameters and the table of results are shown below in the Summary of E-APC Savings/ (Costs).

Base Case: Western-UGP Hydro generation is actual profile from 2010 data
High Hydro (First & Out): High Hydro generation is actual profile from 1997 data
Low Hydro (First & Out): Low profile generation is actual profile from 2005 data
High Gas Price (Out Year): Natural gas Henry Hub index increased from \$5/MMBtu to \$9/MMBtu
High Wind (Out Year): Wind penetration increased from present level of 838 MW to 1838 MW

Table 4: Summary of Western-UGP E-APC Results Relative to Stand Alone

	Join MISO	Join SPP
First Year	($m/yr)	($m/yr)
Base Case	(3.3)	0.9
High Hydro	9.6	15.6
Low Hydro	(5.8)	(3.8)
Out Year		
Base Case	(10.0)	3.3
High Hydro	(14.8)	7.5
Low Hydro	(2.7)	3.1
High Gas Price (from $5 to $9)	(16.9)	3.9
High Wind (additional 1000 MW)	(10.3)	2.4

The model results show more positive results for the Join SPP case regardless of the sensitivity that is analyzed.

The variability of the sensitivities relative to the Base Case is shown in the following charts.

Figure 1: First Year WAPA Trade Benefit Variability as compared to the Base Case

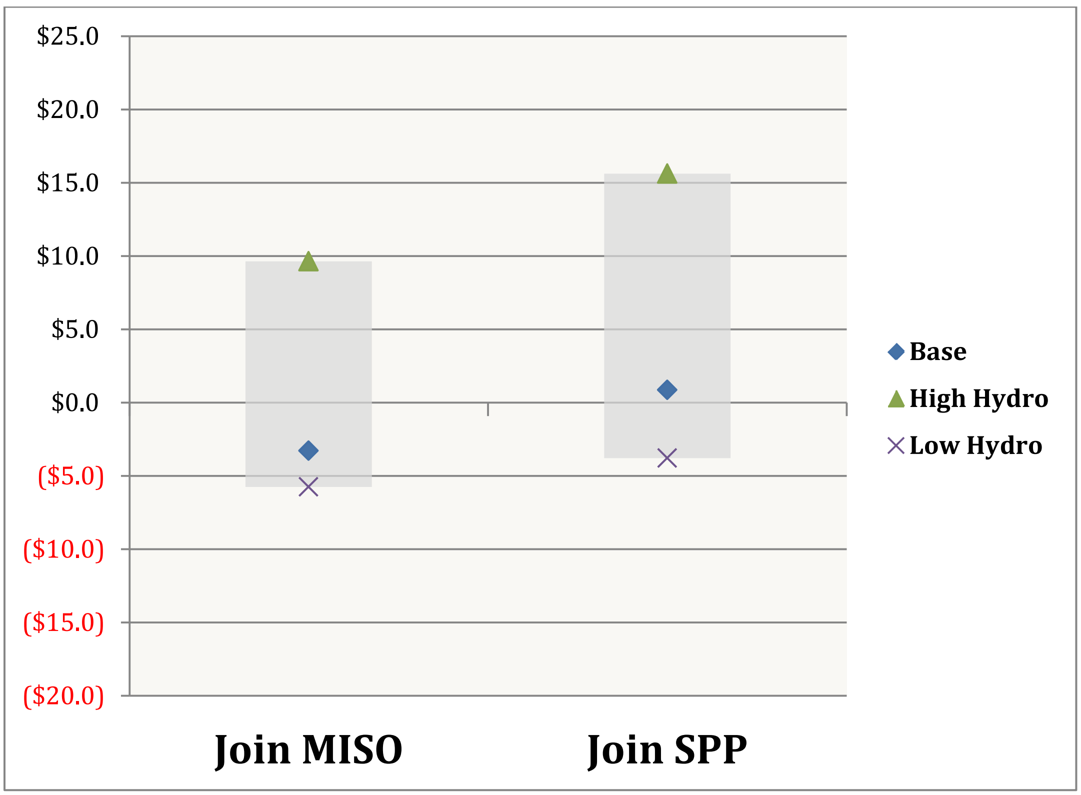
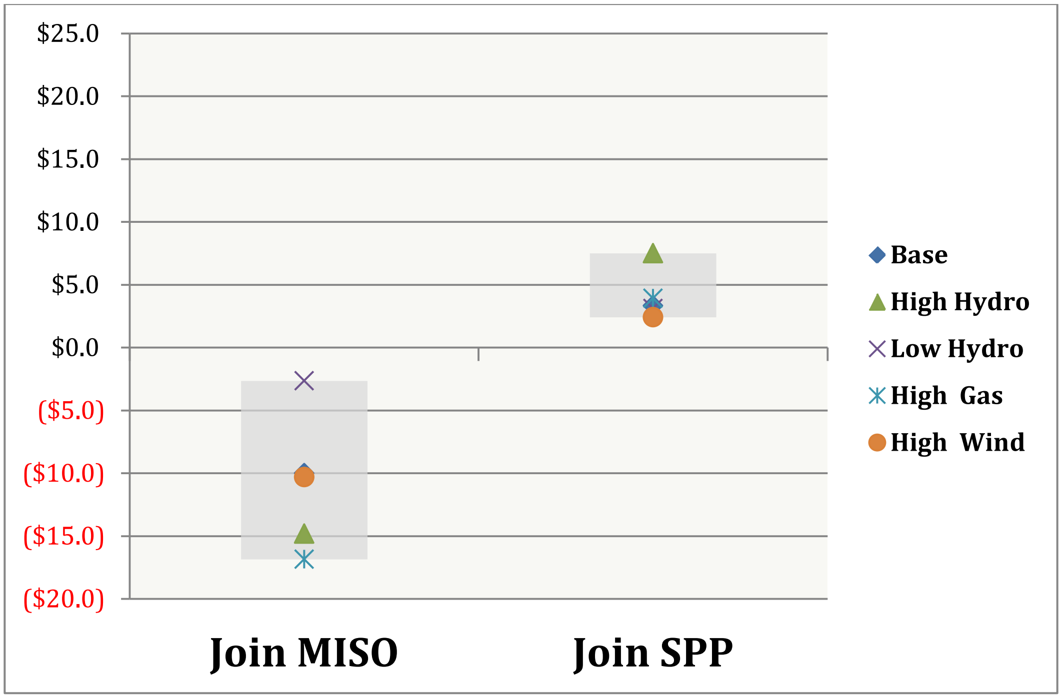


Figure 2: Out Year WAPA Trade Benefit Variability as Compared to the Base Case



One of Western-UGP's requirements for RTO membership is an exemption from RTO congestion and loss charges for delivery of Western-UGP's FES obligations over the IS transmission system. SPP has indicated that they would grant Western-UGP this exemption. The Brattle study began prior to the SPP discussions, so the Brattle base case did not take this exemption into account. However, in a separate sensitivity Brattle estimated the amount of savings Western-UGP could expect with an exemption from loss and congestion charges in the IS footprint under the Join SPP option. The figure below summarizes Western-UGP's net loss and congestion charges by footprint and highlights the amount of potential savings from a congestion and loss exemption on the IS. As shown below, it is estimated that Western-UGP would save approximately $13 million from such an exemption and therefore the E-APC savings for the Join SPP option would increase by that same amount.

Table 5: UGP's Net Loss and Congestion Charges by footprint for Join SPP Case ($m/yr)

	First Year				Out Year			
	IS	MISO	SPP	Total	IS	MISO	SPP	Total
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 Losses	**13.4**	**(5.5)**	**0.0**	**7.9**	12.8	(5.0)	(1.1)	6.6
Congestion Charges	(0.9)	5.9	(1.3)	3.7	(0.6)	0.4	0.3	0.1
FTR Revenues	(0.7)	5.0	(1.1)	3.1	(0.5)	0.3	0.3	0.1
Net Congestion	**(0.2)**	**0.9**	**(0.2)**	**0.6**	(0.1)	0.1	0.0	0.0
Total	**13.2**	**(4.6)**	**(0.2)**	**8.5**	**12.7**	**(4.9)**	**(1.1)**	**6.6**

One of the key input assumptions that affect the overall E-APC savings is the amount of loss refunds that Western-UGP would receive from the RTOs. Under the base assumptions, Western-UGP receives 30 percent of the marginal losses in MISO and 50 percent in SPP. Brattle estimates Western-UGP might experience something less than 30 percent in MISO given the distance between Western-UGP generation and load. Brattle also expressed uncertainty with SPP's 50 percent rate, given FERC's questioning of SPP's proposed refund methodology. To recognize the uncertainty around these assumptions, Brattle ran a *low loss* sensitivity with loss refunds set to 20 percent of the marginal loss charges in MISO and 30 percent in SPP. In this analysis the MISO rate was reduced from 30 percent to 20 percent and the SPP rate was reduced from 50 percent to 30 percent. The potential reduction of loss refunds could have a significant monetary impact. However, SPP has indicated that Western-UGP would be exempt from congestion and losses on the IS, therefore a reduction in their rate would have little impact to Western-UGP. MISO on the other hand would not grant such an exemption. Reducing their rate from 30 percent to 20 percent correlates to an increased cost to Western-UGP of $6 million in 2013 and $13 million in 2020.

The study shows that joining SPP could provide small to moderate savings in energy-related costs for Western-UGP over the other options. Two additional factors could provide a significant positive benefit to Western-UGP in both Join options. Brattle used historical ancillary service prices to conservatively estimate that Western-UGP could anticipate net revenue of about $8 million per year by selling regulation service into the MISO or SPP markets. Also, if Western-UGP were to optimize its hourly hydro-generation pattern to maximize market revenue Brattle conservatively estimates an additional benefit of approximately $6 million per year in either of the Join RTO options.

For the IS owners as a whole, Brattle estimated that by joining SPP the IS owners could realize significant savings in both the First Year and the Out Year using the base assumptions. The amount of savings varies depending on the sensitivity considered. Joining MISO could provide a smaller savings in First Year, but could result in cost increases in Out Year using the base assumptions. The negative savings, or cost increases, under the Join-MISO case in Out Year are largely driven by the reduced prices in the IS region due to incurring marginal loss penalties, which results in lower market revenues for the generators owned or contracted by the IS owners. The results in both the Join SPP and Join MISO options are relatively sensitive to Western-UGP's hydro-generation, gas prices, and also assumed loss refunds. Reducing the assumed loss refunds from 50 percent to 30 percent in SPP and from 30 percent to 20 percent in MISO would eliminate most of the savings in the Join SPP option, and it would amplify the cost increases in the Join MISO option.

It should be noted here that Brattle indicates the following key modeling limitations tend to understate the actual savings under the Join MISO and Join SPP cases.

- Inefficiencies of TLR-based and non-market congestion management (as currently used in the IS region and applied schedules between the IS and neighboring regions) are not modeled.
- Production cost simulations are deterministic, assuming perfect foresight under normal conditions without transmission outages or challenging market conditions.
- Except as noted in the Optimized Hydro analysis, Western-UGP's hydro dispatch is assumed to be constant across all cases; hence simulations do not capture potential benefits from optimizing hydro in response to changing prices in the Join RTO cases.
- The impact of the IS owners' RTO membership on ancillary services markets in MISO or SPP is not modeled explicitly.
- The quick control response of Western-UGP's hydro generation is potentially a good match to the market's ancillary service products and provides Western-UGP an opportunity to co-optimize hydro energy and ancillary services while operating within the requirements of the U.S Army Corps of Engineer Missouri River Mainstem System Master Water Control Manual for the Missouri River Basin.

Administrative Costs

Administrative costs include payments to the RTO and internal costs incurred to interface with the RTO as a member. Three categories of administrative costs were analyzed:

RTO Day 2 Administrative Charge

The MISO administrative fees for both First Year and Out Year are based on the MISO administrative rate of $0.32 per MWh which was published in MISO's February 2012 budget release. The SPP administrative fees for both First Year and Out Year are based on the SPP administrative rate of $0.38 per MWh which was published in SPP's October 2012 budget release.

FERC Fees

Fees associated with the FERC were generically applied based on a CRA cost/benefit study that was performed for Entergy. The rate used was $0.06 per MWh.

Western-UGP Internal Costs

These costs are related to staffing and equipment costs of RTO operation. The estimated rate of $0.08 per MWh was also obtained from the CRA study for Entergy.

In the Stand Alone Option these charges are applied only to the Western-UGP load that would lie within an RTO (MISO and SPP). In both the Join MISO and Join SPP options these charges are applied to Western-UGP's entire load.

Table 6: Stand Alone Option

Western - UGP Administrative Fees	Stand Alone - $m First Year	Stand Alone - $m Out Year	Join MISO - $m First Year	Join MISO - $m Out Year	Join SPP - $m First Year	Join SPP - $m Out Year
RTO Day 2 Administrative Charge	(2.3)	(2.3)	(3.6)	(3.6)	(6.0)	(6.0)*
FERC Fees	(0.3)	(0.3)	(0.5)	(0.5)	(0.5)	(0.5)
Internal Cost - Interface w/RTO	(0.4)	(0.4)	(0.7)	(0.7)	(0.7)	(0.7)
IS Reliability Coordination	(0.2)	(0.2)				
Total Administrative Fees	**(3.2)**	**(3.2)**	**(4.8)**	**(4.8)**	**(7.2)**	**(7.2)**

*Average of the 1st year and out year administrative rate was used in both study years. To reflect potential cost overruns caused by unforeseen startup costs of the SPP Day 2 market a 25% sensitivity increase to the Admin Fee could be added. This would result in a monetary increase of approximately $1.5m. Since only 3/4 of Western-UGP total load would be subject to the increased SPP costs (MISO load pays MISO fees) the overall 2020 Join SPP savings would only be reduced by less than 5%.

Transmission Expansion

The three options addressed payments from the IS to the RTOs for their regional projects and payments from the RTOs to the IS for regionally shared projects within the IS. The cost of future transmission expansion was analyzed recognizing the different cost allocation methodologies associated with each option.

One of Western-UGP's requirements for joining an RTO is the exemption from sharing in an RTO's regional transmission costs. Both RTO options have met this requirement for Western-UGP. However, the other IS owners will share in transmission cost sharing. Western-UGP's usage share of the IS projects will likely change between the Stand Alone option and the Join RTO options and therefore Western-UGP's share of new transmission construction within the IS will change. For example, in the Join MISO option, Western-UGP's usage share increases relative to other IS customers and Western-UGP's share of the West Loop actually increases approximately $2 million.

At the time of the CBA study there were two major IS expansion projects on the planning horizon in North Dakota that have a significant impact on the results; the 345-kV West Loop and the 345-kV East Loop. The 345-kV West Loop has been approved by Basin's board and right-of-way acquisition is in progress and was therefore included in the base case of the study. The construction of the 345-kV East Loop is dependent on continued future load growth in the region and may ultimately be revised or replaced depending on how that load growth materializes. Therefore, the East Loop was included as a sensitivity in the study.

In the Stand Alone option, it was assumed there would be no cost sharing of IS projects with other RTO entities. MISO has indicated that, under the Join MISO option, the two 345-kV North Dakota IS projects would not be eligible for regional cost sharing. SPP has indicated that both North Dakota projects could be eligible for regional cost sharing provided that the IS system is deemed adequate by SPP and IS members join SPP prior to the need by date for the projects. In the CBA study, the need by date for both projects was assumed to be after the integration date and therefore the CBA study assumed SPP regional cost sharing.

SPP recently performed a system adequacy study for the IS and that study has determined that the IS transmission system currently has adequate capacity and that the need by date for the West 345-kV Loop is after the assumed integration date of October 2015. The need by date of the East 345- kV Loop is after the need by date of the West 345-kV Loop. The ultimate configuration of the East 345-kV Loop will be determined by further planning studies.

IS transmission studies have identified the need for transmission expansion in the western North Dakota region. The process for building the west 345-kV line has begun, therefore the cost of the line and the RTO cost sharing consideration have been included in the base case.

Table 7: Transmission Expansion Cost Sharing

Western – UGP Transmission Expansion Cost Sharing	Stand Alone - $m First Year	Stand Alone - $m Out Year	Join MISO - $m First Year	Join MISO - $m Out Year	Join SPP - $m First Year	Join SPP - $m Out Year
Base Case: – (Includes West 345-kV Loop)	(28.7)	(34.0)	(31.4)	(36.2)	(16.0)	(20.8)

In addition to the base case two additional sensitivities were analyzed:

- Sensitivity including both West and East 345-kV loops in cost-sharing calculation. The first year numbers in each of the options do not change since the East Loop is after 2016. The assumptions in this sensitivity are no cost sharing outside the IS in the Stand Alone, no cost sharing in the Join MISO case, and both West and East 345 kV loops are cost shared in the Join SPP case.
- Sensitivity excluding both West and East 345-kV loops in cost sharing calculation. The assumptions in this sensitivity are both loops are built but there is no RTO cost sharing for either loop.

The Transmission Expansion Cost Sharing results of the Base Case along with the two sensitivity analyses are shown below:

Table 8: Transmission Expansion Cost Sharing Results of the Base Case

Western – UGP Transmission Expansion Cost Sharing	Stand Alone - $m First Year	Stand Alone - $m Out Year	Join MISO - $m First Year	Join MISO - $m Out Year	Join SPP - $m First Year	Join SPP - $m Out Year
Base Case: – (Includes West 345-kV Loop)	(28.7)	(34.0)	(31.4)	(36.2)	(16.0)	(20.8)
Sensitivity Including Cost Sharing of West and East 345-kV Loops)	(28.7)	(44.5)	(31.4)	(47.6)	(16.0)	(21.7)
Sensitivity Excluding Cost Sharing of West and East 345-kV Loops	(28.7)	(44.5)	(31.4)	(47.6)	(28.7)	(44.5)

Capacity Benefits

Western-UGP's current Marketing Plan takes a conservative approach to marketable capacity by evaluating capacity available after a 4-year drought with declining reservoir storage (i.e. based on an adverse water year). Western-UGP does not market its capacity over the amount sold to preference customers in the Marketing Plan. In addition, the analysis did not monetize any capacity benefits to Western-UGP as most benefits would be from reduced reserve requirements and from reserve sharing in which Western-UGP already participates with SPP. In addition, benefits to capacity would be small due to not having additional water to create more energy under the new capacity, therefore the results shown here are zero. The other IS owners show positive capacity benefits from RTO membership.

IS Transmission Revenue (Costs Shifts)

This criterion reflects potential changes in the relative allocation of the current revenue for IS transmission facilities. That is, if by joining a RTO, the usage of the IS changes (due to license plate pricing, RTO drive-out rules, changed plans for resource development, etc.) this could impact Western-UGP's share of IS costs.

Table 9: IS Transmission Revenue

Western – UGP	Stand Alone - $m First Year	Stand Alone - $m Out Year	Join MISO - $m First Year	Join MISO - $m Out Year	Join SPP - $m First Year	Join SPP - $m Out Year
IS Transmission Revenue (Cost Shifts)	(55.6)	(51.6)	(61.5)	(56.0)	(53.4)	(49.5)

Drive-Out Impacts

Drive-out charges are fees associated with exporting energy from a market area.

MISO has indicated that Western-UGP would not pay the MISO drive-out charge for serving its preference customer loads outside of the MISO footprint. Western-UGP would continue to pay the IS charge.

SPP has indicated that Western-UGP would not pay the SPP drive-out charge for serving its preference customer loads outside of the SPP footprint. Western-UGP would continue to pay the IS charge.

Through recognition of grandfathered OATT transmission agreements, SPP would also exempt non-Western entities within the IS from SPP Tariff drive-out charges to serve load in MISO. They would continue to pay the IS charge. MISO however does not grant grandfather status to OATT agreements. This would require those entities to establish resources outside of MISO in order to avoid the MISO Tariff drive-out charge to serve their load outside of MISO.

Table 10: Drive-Out Impacts

Western – UGP	Stand Alone - $m		Join MISO - $m		Join SPP - $m	
	First Year	Out Year	First Year	Out Year	First Year	Out Year
Drive-Out Impacts	0.0	0.0	(0.7)	(1.2)	(0.3)	(0.4)

Cost Benefit Analysis Summary

The table below summarizes the overall CBA results for the Base case, which includes the West 345 kV Loop. The results should be interpreted as showing relative separation and not as actual financial outcomes.

Table 11: Summary of IS Business Model Overall Cost/Benefit Analysis

Western – UGP Cost Benefit Summary	Stand Alone - $m		Join MISO - $m		Join SPP - $m	
	First Year	Out Year	First Year	Out Year	First Year	Out Year
1. RTO Trade Benefits	3.9	23.6	0.6	13.6	4.8	26.9
2. Administrative Costs	(3.2)	(3.2)	(4.7)	(4.7)	(7.2)	(7.2)
3. Transmission Expansion – Base Case (Includes West 345 kV Loop)	(28.7)	(34.0)	(31.4)	(36.2)	(16.0)	(20.8)
4. Capacity Benefits	0.0	0.0	0.0	0.0	0.0	0.0
5. IS Transmission Revenue (Cost Shifts)	(55.6)	(51.6)	(61.5)	(56.0)	(53.4)	(49.5)
6. Drive-Out Impacts	0.0	0.0	(0.7)	(1.2)	(0.3)	(0.4)
Base Case Total Benefits (Costs) (Includes West 345 kV Loop)	**(83.6)**	**(65.2)**	**(97.7)**	**(84.5)**	**(72.1)**	**(51.0)**
Base Case - Join Options Relative to Stand Alone (Includes West 345 kV Loop)			**(14.1)**	**(19.3)**	**11.5**	**14.2**

Note: The above results are not indicative of Western-UGP's overall financial position.

The additional benefits for anticipated revenue from Ancillary Services, Optimized Hydro and the SPP exclusion from Congestion and Losses are shown below for each of the Join options relative to the Stand Alone option.

Table 12: Summary of Overall Cost/Benefit Analysis Relative to Stand Alone

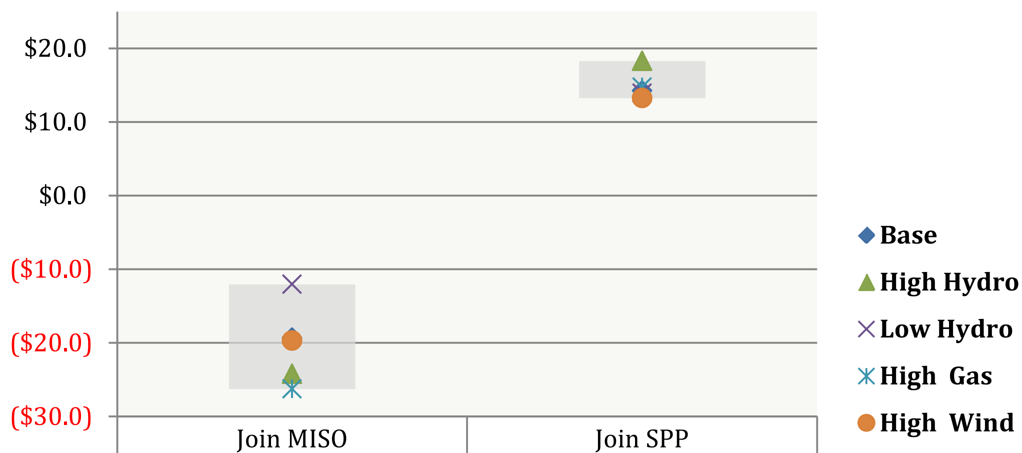
Western – UGP **Cost Benefit Summary w/Anticipated Benefits** **Join Options Relative to Stand Alone**	Join MISO - $m		Join SPP - $m	
	First Year	Out Year	First Year	Out Year
Base Case - Join Options Relative to Stand Alone (Includes West 345 kV Loop)	**(14.1)**	**(19.3)**	**11.5**	**14.2**
Anticipated Ancillary Service Benefit	8.0	8.0	8.0	8.0
Anticipated Optimized Hydro Benefit	6.0	6.0	6.0	6.0
Anticipated Benefit from Congestion and Loss Exclusion from SPP			13.2	12.7
Base Case with Anticipated Benefits **Join Options Relative to Stand Alone** **(Includes West 345 kV Loop)**	**(0.1)**	**(5.3)**	**38.7**	**40.9**

The variability in the Business Case is shown in the following charts.

Figure 3: First Year WAPA Overall Business Case Variability as compared to the Base Case ($M)

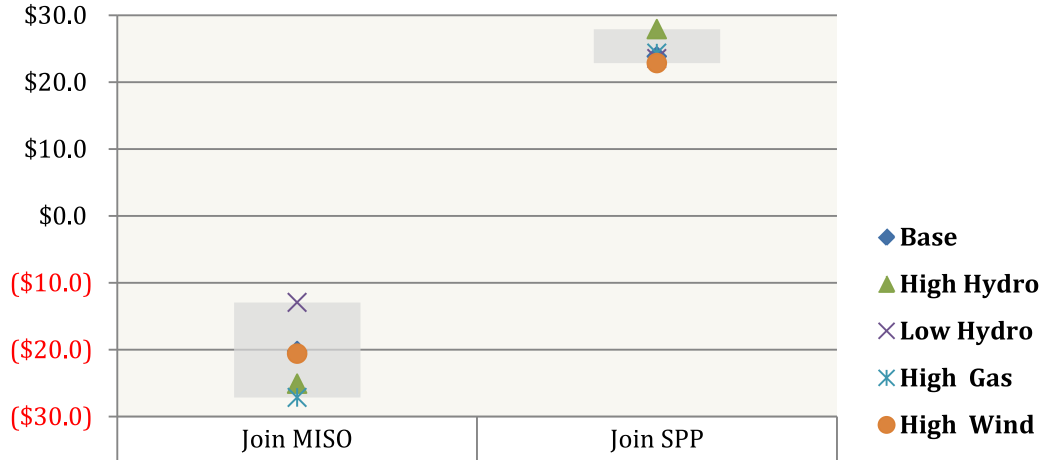
	Join MISO	Join SPP
Base	(14.1)	$11.5
High Hydro	(1.3)	$26.2
Low Hydro	(16.7)	$6.8

Figure 4: Out Year WAPA Overall Business Case Variability as compared to the Base Case ($M) (West 345 kV line only)



	Join MISO	Join SPP
Base	(19.3)	$14.2
High Hydro	(24.2)	$18.3
Low Hydro	(12.1)	$13.9
High Gas	(26.3)	$14.7
High Wind	(19.7)	$13.2

Figure 5: Out Year WAPA Overall Business Case Variability as compared to the Base Case ($M) (Both 345 kV lines)



	Join MISO	Join SPP
Base	(20.2)	$23.8
High Hydro	(25.1)	$27.9
Low Hydro	(13.0)	$23.5
High Gas	(27.2)	$24.3
High Wind	(20.6)	$22.8

Multi Criteria Decision Analysis

The objective was to use a range of criteria to objectively and transparently assess the overall worthiness of the options. In general, the overall goal was to produce a preference of order between the options. The analysis involved the development of a matrix of criteria that were ranked and aggregated to provide an overall score for each option.

To determine the criteria and numerical weights, the AOS Team combined factors of actual operations experience, industry trends, discussions and feedback with Western customers, the experiences of others actually in an RTO, and discussions and feedback with the RTOs themselves.

The MCDA used two major criteria to assess the options. The AOS Team determined the major criteria and weighted them by percentage as to their relative importance to the overall recommendation.

The degrees of risk, insignificant through extreme, were established based on combined factors of actual experiences, trends as related to that particular topic and/or discussions and feedback from Western customers, industry partners, and the experiences of others actually in an RTO. While these assignments (risk ratings) are somewhat subjective, we believe them to be supportable by pertinent and relevant information as discussed in each criteria or metric. Western-UGP utilized the following evaluation criteria/metrics, weighting and ranking questions to select among the three options under consideration:

<u>Marketing Plan & Rate Stability</u>

(Weighting = 65 percent)

Western-UGP's ability to fulfill its marketing plan has been adversely impacted during the last drought and over the past few years on the occasions when it has been unable to provide contracted FES to its customers from its own resources. Availability of resources for purchase is particularly important during periods of low reservoir levels which result in reduced hydropower generation. In cases where outside resources are required and available, the ability to deliver the purchased resources can be adversely impacted by constrained transmission paths which cause the RC to call for TLR to curtail schedules impacting the congested path. Similarly, on those occasions when Western-UGP has surplus energy to sell, lack of available purchasers and constrained transmission can hinder Western-UGP's sales efforts. In both cases, these events can and have placed upward pressure on firm power rates.

One of the principles under which Western operates is that its cost-based rates should be maintained at the lowest possible rates to customers consistent with sound business principles. Several factors can impact costs (and subsequently rates). These include: the cost of purchases in the event that Federal resources are insufficient to meet commitments; the inability to make sales of surplus energy due to the non-availability of purchasers or transmission congestion; costs associated with RTO membership; and, transmission system expansion costs assigned to or incurred by Western-UGP. Maintaining rates at as low a level as possible is one concern, and the ability to project future rates and rate volatility are others. Frequent rate changes that require public processes would create significant additional effort for Western-UGP. Customers and other stakeholders demonstrate significant interest in rate stability. Several metrics were considered while evaluating Marketing Plan and Rate Stability risk. The metrics and their risk ratings are:

Access to Bi-lateral Markets

(Weighting = 40%)

The loss of bilateral trading partners impacts Western-UGP's potential to purchase and sell energy on favorable terms. The assignment of risk was directly correlated to Western-UGP's access to bilateral trading partners or a market. The degree of risk is solely based on Western-UGP's ability to continue to trade into the future.

What is the impact to the number of bilateral trading partners?

Stand Alone Option

The risk for the Stand Alone Option is rated as "Extreme" as the access to trading partners is nearly eliminated. Since 2002, the number of potential bilateral trading partners has dwindled from 55 to an estimated 11 in 2014. All indications point to this number continuing to decline as more and more potential trading partners join organized markets.

MISO Option

The risk for the MISO Option is rated as "Insignificant" as MISO operates an organized trading market and the need for bilateral trading partners is nearly eliminated by the market.

SPP Option

The risk for the SPP Option is rated as "Insignificant" as SPP currently operates an Energy Imbalance market, but is transitioning to an organized trading market similar to MISO. In either case the need for bilateral trading partners is nearly eliminated by the market.

TLR Susceptibility

(Weighting = 30%)

Being outside an RTO market exposes energy purchases and sales to the possibility of being curtailed due to Transmission Loading Relief calls instead of market re-dispatch. The degree of risk is based on actual TLR's, the path or seam over which these TLR's occurred, and the likelihood of recurrence.

What is the Transmission Loading Relief (TLR) potential?

Stand Alone Option

In order to effectively reduce the potential for TLR, Western-UGP would have to pseudo-tie hydro power generation into one or both of the RTOs to take advantage of market re-dispatch protocols used by the RTOs. However, pseudo-tying hydro-generation into the RTOs reduces the flexibility of the hydro-generation fleet to respond to Western-UGP's load in all market and non-market areas resulting in a "Major" risk rating for this option.

MISO Option

Joining MISO would eliminate the east-west seam, but while elimination of this seam would reduce the frequency of TLR calls compared to the Stand Alone Option, it would reduce them to a lesser extent than elimination of the north-south seam. Therefore, the risk for this option is rated as "Moderate."

SPP Option

Elimination of the north-south seam by joining SPP would provide the greatest reduction of TLR calls short of eliminating all seams. It is, therefore, rated as a "Minor" risk.

Peaking Contracts

(Weighting = 10%)

Generation in the same market area as the peaking contract customers eases the delivery and return of peaking energy. Western-UGP has three Peaking contract customers, one in WAUE and two in Nebraska (SPP). The degree of risk is assessed based on some or the entire load being in the same market as generation.

What is the impact to peaking contracts?

Stand Alone Option

Remaining in the Stand Alone Option keeps less than 50 percent of peaking customers in the same market area as the generation that provides this service. Consequently, this risk is rated as "Extreme" for this option.

MISO Option

Adoption of the MISO Option would result in less than 50 percent of the peaking customers in the MISO market area in which generation would be located. This results in an "Extreme" risk rating for this option.

SPP Option

Risk is rated as "Insignificant" in the SPP Option as all peaking customers would be in the same market as generation.

Contingency Reserves

(Weighting = 20%)

Contingency reserves are required to enable the system to carry the load in the case of a failure of any one generating unit. By sharing the reserve requirement among several entities, the requirement (and therefore costs or lost sales opportunities) can be lessened for all entities sharing the reserve requirement. Western-UGP (and the other IS owners) is vulnerable to the potential end of its current reserve sharing agreement. The degree of risk associated with this metric was established based on the ability to enter into a reserve sharing agreement as well as the longevity of such an agreement.

What is the Contingency Reserve Requirement?

Stand Alone Option

Western-UGP currently participates in a limited term agreement with a contingency reserve sharing group. It is anticipated that when the term expires for the current agreement, Western-UGP may still be able to enter into another limited term agreement for contingency reserve sharing. However, the terms and conditions of such an agreement are unknown and the risk associated with the uncertainty has been determined as "Major."

MISO Option

The MISO membership participates in the sharing of contingency reserves. The terms of the sharing arrangement are well known and not time limited. Consequently, the risk for this option is rated "Insignificant."

SPP Option

Like the MISO Option, the SPP membership participates in the sharing of contingency reserves. The terms of the sharing arrangement are well known and not time limited. Consequently, the risk for this option is rated "Insignificant."

Agreements

(Weighting = 35 %)

The terms and provisions of various agreements can impact the viability of Western-UGP membership in an RTO. In fact, without certain terms and provisions in some of the agreements, Western-UGP would, by statute, be prohibited from joining an RTO. An example is the capability to withdraw from membership as required by EPAct05, Section 1232. The terms and provisions of agreements can directly impact the ease and expense involved with Western-UGP's ability to perform its statutory obligations and to provide its services through the lowest possible rates consistent with sound business principles. The assignment of risk was predominantly based on the following; actual agreements, whether expired or existing; the willingness of each entity to negotiate and reach acceptable terms; and the likelihood that each entity will support Western-UGP in reaching desired terms. Western-UGP staff has met with representatives from both MISO and SPP numerous times over the preceding year discussing the various aspects of the metrics being assessed under the Agreement Criteria. The assignment of risk categories for each metric below is based on feedback received from the RTO representatives. The following metrics were considered in evaluating agreement risk and are presented with their risk ratings:

Flexibility

(Weighting = 40%)

Alternative operations options will need to have the flexibility to adapt to Federal requirements. An RTO participation or membership agreement will require specific provisions before Western-UGP will be able to commit to joining/participating in an RTO. Regardless of RTO Board/Management support for the required provisions, individual members of the RTO may protest their inclusion. Changes to RTO tariffs (with subsequent FERC approval) are required to include provisions necessary for Western-UGP's participation in an RTO. Regardless of RTO Board/Management support for the tariff changes, individual members of the RTO may protest the requested tariff changes when submitted to FERC. Future RTO tariff changes pose some risk in that adoption of these changes may erode Western-UGP's position. What may be best for the majority of the RTO membership may not be in Western-UGP's best interests.

What is the flexibility to adapt to Federal requirements?

Stand Alone Option

In an independent, stand-alone operation, Western-UGP has control of how it adapts to Federal requirements and there would be no RTO or RTO member opposition to Western-UGP's adaptations. Therefore, risk for this metric is rated "Insignificant."

MISO Option

It is anticipated that there would be major RTO and RTO member opposition to supporting Western-UGP's membership in MISO with the adaptations necessary to meet Federal requirements. Risk for this metric is rated "Major."

SPP Option

With the membership of SPP consisting of organizations that more closely resemble Western-UGP and having previously had a PMA as a member (and currently with a participation agreement), RTO and RTO member opposition to supporting Western-UGP's membership in SPP with the adaptations necessary to meet Federal requirements is anticipated to be very low. Therefore, the risk rating for this metric is "Minor."

Governance

(Weighting = 30%)

Western-UGP's capability to influence and/or control decisions affecting its interests is important to maintaining cost levels as low as possible and to have rate stability.

Does the organizational structure give Western-UGP influence in policy?

Stand Alone Option

Operating independently, Western-UGP has total control of policy. Therefore, the risk for this metric is rated "Insignificant."

MISO Option

The membership of MISO is made up of a diverse group of organizations. The interests of these organizations do not necessarily coincide with Western-UGP's interests and consequently Western-UGP's influence as a member of MISO would be lessened. MISO's greater number of members also dilutes Western-UGP's influence. Western-UGP is a non-jurisdictional entity, while the majority of MISO's transmission-owning members are jurisdictional entities. MISO's transmission system also has a greater concentration of load to transmission circuit mile than the IS, creating philosophical differences in policy development. While Western-UGP would have some influence in MISO's governance, it would not be significant and the risk is rated "Moderate" accordingly.

SPP Option

The organizations that make up SPP have more similarities to Western-UGP, with the majority of transmission owning members being non-jurisdictional entities similar to Western-UGP. Also, SPP has past experience with PMAs as they currently have a participation agreement with Southwestern Power Administration. SPP's slightly smaller size when compared to MISO will allow Western-UGP to make up a larger portion of the membership with corresponding representation. SPP's transmission system has nearly as many miles of transmission lines as MISO despite having only half of the generation. Western-UGP (and the IS) having considerable transmission facilities will fit better with an organization that relates more toward transmission organizations. For these reasons, which should provide significant influence, the Governance metric is rated "Minor" risk.

Seams Agreement(s)

(Weighting = 10%)

Seams agreements with and between RTOs can impact Western-UGP's ability to retain revenue at the current level. The current Seams Operating Agreement with SPP provides that Western-UGP will be compensated for the use of its transmission system. Should Western-UGP join SPP, it could be subject to SPPs Joint Operating Agreement with MISO which allows contract path capacity sharing arrangements. However, the joint operating seams agreement between MISO and SPP is in dispute and currently in litigation.

What is the risk of revenue loss due to seams agreements?

Stand Alone Option

Under the Stand Alone Option, Western-UGP would retain all its transmission revenue generated in concert with the currently existing seams agreements. As Western-UGP has no revenue impact, the risk is rated as "Insignificant."

MISO Option

Western-UGP would lose some transmission revenue by joining MISO. Consequently, the risk for this metric is rated “Moderate.”

SPP Option

Western-UGP would lose some transmission revenue by joining SPP. Consequently, the risk for this metric is rated “Moderate.”

Withdrawal

(Weighting = 10%)

RTO membership agreements and tariff terms specify that members can withdraw from the RTO. However, the required notice period and the costs associated with the withdrawal differ and can result in significant cost to Western-UGP.

What are the limitations and terms of withdrawal?

Stand Alone Option

No withdrawal provisions are required if Western-UGP remains in a stand-alone status, therefore, the risk for this metric is rated “Insignificant”.

MISO Option

The withdrawal provisions available with MISO membership require a 5-year membership period followed by a one calendar year notice period, along with significant charges estimated to be $5 million in addition to any transmission allocation cost obligations. Therefore, the risk for this metric is rated “Major”.

SPP Option

SPP’s current withdrawal provisions require twelve month notice period* plus a negotiated exit fee including the member’s share of SPP’s long-term obligations and any obligation relating to the construction of new facilities. Therefore, the risk for this metric is rated “Moderate.”

*The Market Operations Policy Committee has recommended a 24 month notice period. As of this writing, it is awaiting action by the SPP Board of Directors.

East-West

(Weighting = 10%)

Maintaining a single rate for transmission service in both of Western-UGP’s transmission systems in the East and West balancing areas is essential regardless of Alternate Operations option pursued.

Can Western-UGP maintain a single rate between WAUE and WAUW?

Stand Alone Option

There are no changes to current east-west rates (between WAUE and WAUW) in the Stand Alone Option which results in a risk rating of "Insignificant."

MISO Option

Discussions with MISO have indicated that MISO would accommodate maintaining a single rate between WAUE and WAUW. However, with some uncertainty concerning how this would happen, the risk has been rated "Minor."

SPP Option

Discussions with SPP have indicated that SPP would accommodate maintaining a single rate between WAUE and WAUW. However, with some uncertainty concerning how this would happen, the risk has been rated "Minor."

The summary results of the MCDA are shown in the following chart.

Table 13: Multi-Criteria Decision Analysis Summary

Criteria	Weight	Metric	Weight	Optimized Stand Alone	MISO	SPP
Marketing Plan & Rate Stability	65%	Access to Bilateral Markets	40%	Extreme	Insignificant	Insignificant
		TLR Susceptibility	30%	Major	Moderate	Minor
		Peaking Contracts	10%	Extreme	Extreme	Insignificant
		Contingency Reserves	20%	Major	Insignificant	Insignificant
Agreements	35%	Flexibility	40%	Insignificant	Major	Minor
		Governance	30%	Insignificant	Moderate	Minor
		Seams Agreement(s)	10%	Insignificant	Moderate	Moderate
		Withdrawal	10%	Insignificant	Major	Moderate
		East - West	10%	Insignificant	Minor	Minor
RISK SCORE (Lower score is less risk)				**62**	**42.2**	**22.3**

Opportunity

EPAct 05

Western-UGP has both the challenge and the opportunity to define how the first PMA addresses the requirements of Section 1232 of the Energy Policy Act of 2005 (EPAct 05) in joining an RTO. Western has been explicitly authorized to participate in a transmission organization pursuant to EPAct 05. This statute gives Western explicit authority to transfer control and use of all or a portion of its transmission system to a transmission organization. It states that none of the existing statutory provisions that require or authorize Western to transmit power or to construct, operate or maintain a transmission system prohibit Western from transferring control and use of its transmission system to a transmission organization. The section does not give FERC any jurisdiction over the electric generation assets, electric capacity or energy marketed by Western nor does it give FERC jurisdiction over the power sales activities Western engages in.

Congress has stated that the " . . . appropriate Federal regulatory authority may enter into a contract, agreement, or other arrangement transferring control and use of all or part of the transmission system of a Federal utility to a Transmission Organization."[2] The statute goes on to state that " . . . the Secretary may designate the Administrator of a Federal power marketing agency to act as the appropriate Federal regulatory authority with respect to the transmission system of the Federal power marketing agency."[3] Western's Administrator has been designated as the appropriate Federal regulatory authority with respect to transmission facilities within the PSMBP-ED in accordance with Section 1232(a) (1) (A) of the Energy Policy Act of 2005. A copy of Section 1232 of EPAct 05 is included as an attachment to this paper.

Transmission Project Timing and Cost Sharing

SPP has stated that transmission expansion cost sharing starts on Western-UGP's join date. IS facilities with "need by" dates which are after the join date would be eligible for cost sharing with SPP. Implementation into a Market can take up to two years, making the fall of 2015 the earliest expected date for joining.

SPP recently performed a system adequacy study for the IS and that study has determined that the IS transmission system currently has adequate capacity and that the need by date for the West 345-kV Loop, with an estimated cost of 300 million dollars, is after the assumed integration date of October 2015. The need by date of the 250 million dollar East 345 kV Loop is after the need by date of the West 345-kV Loop. This results in the potential of 550 million dollars being eligible for cost sharing.

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[2] Energy Policy Act of 2005 § 1232, 42 U.S.C. § 16431 (2012).

[3] Energy Policy Act of 2005 § 1232, 42 U.S.C. § 16431 (2012).

Recommendation

Western-UGP and the IS owners have experienced operational issues related to their unique footprint that have impacted access to energy markets and ability to deliver its contractual obligation to FES customers. Western-UGP faces ongoing issues with TLR curtailments across non-market to market seams along with the loss of bilateral trading partners as a result of the development of integrated markets within MISO and SPP. Western-UGP recognizes the variability of the hydro-generation and the historic need Western-UGP has had for access to energy markets to realize the lowest cost energy purchases and optimized short-term energy sales. As a result, Western-UGP has performed an assessment of the costs, benefits, and risks of alternative operating models while continuing to reliably serve our firm power commitments.

The most recent study, the IS Business Model, shows that the most favorable cost-benefit is with the Join SPP option, regardless of the sensitivity applied. Much of this benefit to SPP is derived from the ability to cost share upcoming IS transmission expansion projects if the Join SPP option is realized by the fall of 2015, which is prior to those projects "need by" date. In the MISO and Stand Alone options there is no opportunity for cost sharing on these projects.

The MCDA risk analysis shows the least risk with the Join SPP option. Western-UGP's criteria and weighting and subsequent ranking resulted in a significant risk separation between each of the three options. The Join MISO option has a risk score of nearly double the Join SPP option, and the Optimized Stand Alone option risk score is nearly three times the Join SPP option.

Based on the analysis, Western-UGP concludes that the potential benefits of the Join SPP option are significant enough for Western-UGP to solicit feedback from customers and other stakeholders regarding its recommendation to pursue formal negotiations with SPP regarding membership. Timing considerations are such that these actions should proceed quickly. A decision to pursue the recommendation will be made after the public process is completed and Western-UGP can assess the feedback gained from that process. A decision by Western to move forward with formal negotiations with SPP will result in detailed membership discussions consistent with Western-UGP statutory requirements. A negotiated membership agreement would be structured to ensure that the risks, benefits, and costs addressed in the evaluation are realized and that Western-UGP's statutory requirements as a power marketing administration of the Department of Energy are met.

Glossary

ANSI	American National Standards Institute
AOS	Alternate Operations Study
Basin	Basin Electric Power Cooperative (BEPC)
Balancing Authority Area	The functional entity that integrates resource plans ahead of time, maintains balance (generation balancing load and interchange) within a Balancing Authority Area, and contributes to Interconnection frequency in real time
Brattle Group	Consultant that provided the RTO Cost/Benefit nodal analysis for the IS Business Model
CBA	Cost Benefit Analysis
Charles River Associates	Provided a High-Level Assessment of Alternative Operating Models for Western-UGP, Basin Electric Power Cooperative, and Heartland Consumers Power District - 2011
CRA	Charles River Associates
Drive-Out	Fees associated with exporting energy from a market area
DOE	Department of Energy
E-APC	Enhanced Adjusted Production Cost
EPAct05	Energy Policy Act of 2005
FERC	Federal Energy Regulatory Commission
FES	Firm Electric Service
FTR	Financial Transmission Rights
Heartland	Heartland Consumers Power District (HCPD)
Integrated System	Western-UGP, Basin Electric Power Cooperative, and Heartland Consumers Power District's jointly owned and operated high voltage transmission system
ISO	Independent System Operator
IS	Integrated System – Transmission system co-owned by Western Area Power Administration, Basin Electric Power Cooperative (BEPC), and Heartland Consumers Power District (HCPD). Western-UGP operates the IS under its tariff.
IS Companies	Western Area Power Administration, Basin Electric Power Cooperative (Basin), and Heartland Consumers Power District (HCPD)

IS Owners	Western Area Power Administration, Basin Electric Power Cooperative (BEPC), and Heartland Consumers Power District (HCPD) as co-owners of the IS
JTS	Joint Transmission System (now known as IS)
MAPP	Mid-Continent Area Power Pool
MBSG	Missouri Basin Systems Group
MCDA	Multi-Criteria Decision Analysis
MCSG	Mid-Continent Systems Group
Midcontinent ISO	Midcontinent Independent System Operator (MISO)
MISO	Midcontinent Independent System Operator
MRO	Mid-West Reliability Organization
MRSG	Midwest Reserve Sharing Group
PMA	Power Marketing Administration
PROMOD®	A Fundamental Electric Market Simulation solution which incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, and market system operations to support economic transmission planning.
RC	Reliability Coordinator
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
TLR	Transmission Loading Relief
UGP	Upper Great Plains
UGPR	Upper Great Plains Region of the Western Area Power Administration
Ventyx	Consultant that provided the ProMod functionality to Brattle
WAUE	Western Area Power Administration Upper Great Plains Area East balancing authority area
WAUW	Western Area Power Administration Upper Great Plains Area West balancing authority area
Western	Western Area Power Administration
Western-UGP	Western Area Power Administration - Upper Great Plains

Attachments

Energy Policy Act 2005

SEC. 1232. Federal Utility Participation In Transmission Organizations.

(a) DEFINITIONS.—In this section:

(1) APPROPRIATE FEDERAL REGULATORY AUTHORITY.—The term ‘‘appropriate Federal regulatory authority’’ means—

(A) in the case of a Federal power marketing agency, the Secretary, except that the Secretary may designate the Administrator of a Federal power marketing agency to act as the appropriate Federal regulatory authority with respect to the transmission system of the Federal power marketing agency; and

(B) in the case of the Tennessee Valley Authority, the Board of Directors of the Tennessee Valley Authority.

(2) FEDERAL POWER MARKETING AGENCY.—The term ‘‘Federal power marketing agency’’ has the meaning given the term in section 3 of the Federal Power Act (16 U.S.C. 796).

(3) FEDERAL UTILITY.—The term ‘‘Federal utility’’ means—

(A) a Federal power marketing agency; or

(B) the Tennessee Valley Authority.

(4) TRANSMISSION ORGANIZATION.—The term ‘‘Transmission Organization’’ has the meaning given the term in section 3of the Federal Power Act (16 U.S.C. 796).

(5) TRANSMISSION SYSTEM.—The term ‘‘transmission system’’ means an electric transmission facility owned, leased, or contracted for by the United States and operated by a Federal utility.

(b) TRANSFER.—The appropriate Federal regulatory authority may enter into a contract, agreement, or other arrangement transferring control and use of all or part of the transmission system of a Federal utility to a Transmission Organization.

(c) CONTENTS.—The contract, agreement, or arrangement shall include—

(1) performance standards for operation and use of the transmission system that the head of the Federal utility determines are necessary or appropriate, including standards that ensure—

(A) recovery of all of the costs and expenses of the Federal utility related to the transmission facilities that are the subject of the contract, agreement, or other arrangement;

(B) consistency with existing contracts and third-party financing arrangements; and

(C) consistency with the statutory authorities, obligations, and limitations of the Federal utility;

(2) provisions for monitoring and oversight by the Federal utility of the Transmission Organization's terms and conditions of the contract, agreement, or other arrangement, including a provision for the resolution of disputes through arbitration or other means with the Transmission Organization or with other participants, notwithstanding the obligations and limitations of any other law regarding arbitration; and

(3) a provision that allows the Federal utility to withdraw from the Transmission Organization and terminate the contract, agreement, or other arrangement in accordance with its terms.

(d) COMMISSION.—Neither this section, actions taken pursuant to this section, nor any other transaction of a Federal utility participating in a Transmission Organization shall confer on the Commission jurisdiction or authority over—

(1) the electric generation assets, electric capacity, or energy of the Federal utility that the Federal utility is authorized by law to market; or

(2) the power sales activities of the Federal utility.

(e) EXISTING STATUTORY AND OTHER OBLIGATIONS.—

(1) SYSTEM OPERATION REQUIREMENTS.—No statutory provision requiring or authorizing a Federal utility to transmit electric power or to construct, operate, or maintain the transmission system of the Federal utility prohibits a transfer of control and use of the transmission system pursuant to, and subject to, the requirements of this section.

(2) OTHER OBLIGATIONS.—This subsection does not—

(A) suspend, or exempt any Federal utility from, any provision of Federal law in effect on the date of enactment of this Act, including any requirement or direction relating to the use of the transmission system of the Federal utility, environmental protection, fish and wildlife protection, flood control, navigation, water delivery, or recreation; or

(B) authorize abrogation of any contract or treaty obligation.

(3) CONFORMING AMENDMENT.—Section 311 of the Energy and Water development Appropriations Act, 2001 (16 U.S.C. 824n) is repealed.