

Western Markets Exploratory Group

Non-Production Cost Study

June 2023

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1 Executive Summary

1.1 Framework of Analysis

WMEG was formed to understand how to best work together in the face of the unprecedented changes occurring in the West. There are two day-ahead market development efforts underway, requirements for some utilities to evaluate or join a regional transmission organization (RTO), and new greenhouse gas regulations development. WMEG and Utilicast developed a list of functions that are generally part of market design efforts and requirements for an RTO (See Appendix A). WMEG and Utilicast are seeking to determine cost and benefit projections for these functions and to lay out a roadmap for WMEG members as they evaluate collaboration opportunities in the West. The intent of this Non-Production Cost Study (Study) is to help identify and quantify the cost and benefit projections that are not contemplated in the WMEG Cost-Benefit Study (CBS).

The WMEG considered several approaches for market development in the West. The California Independent System Operator (CAISO) and the Southwest Power Pool (SPP) are active in the West - both providing Reliability Coordinator (RC) services, managing energy markets, and developing day-ahead market offerings. The WMEG briefly discussed other energy market alternatives before deciding on studying the impacts for these two developing market offerings. Utilicast and WMEG developed criteria for the CBS and contracted with Energy and Environmental Economics (E3) to study the production cost impacts related to these two market offerings and the possible transitions from the current proposed day-ahead offerings up to and including a fully functioning RTO. E3 used a production cost modeling tool for projecting the production cost benefits of specified market functions.

The WMEG requested that Utilicast determine the rough cost and benefit projections for those items in Appendix A. The team started discussions regarding the effort required to create a new RTO structure but elected to pause those discussions to review how the CAISO and SPP Day-Ahead Market offerings evolve, which members participate in those markets, and whether SPP or CAISO propose a suitable RTO structure which members might choose to join.

Each of the sections below analyze and evaluate items in Appendix A independently from an RTO. However, the Study also identifies those functions that are either required to form, or are efficiently provided, by an RTO. The items in Appendix A may have production related costs, non-production related costs, quantifiable benefits, and qualitative benefits. Some of the costs and benefits provided in the various sections are derived directly from the CBS.

1.2 Functional Groups

1.2.1 Enhance Markets

WMEG members are evaluating joining either the CAISO managed Extended Day-ahead Market (EDAM) or the SPP Markets Plus (Markets+) day-ahead energy market. Several of the items in Appendix A that

are covered in this report are expected to be provided by the proposed EDAM/Markets+ market offerings. These items will be covered in Section 2.1 below. Functionality that could reasonably be considered and evaluated as potential future enhancements to the CAISO and SPP market offerings will be covered in Section 2.2 below. While the production cost implications of these proposed and potential future functions are mostly covered in the CBS, this Study will discuss the cost of setting up and administering those functions. Additionally, in this section the provision of Reliability Coordinator (RC) is covered with the expectation that this function will continue to be provided by CAISO and SPP and membership will follow their selected Market Operator (MOP).

1.2.2 *Enabling Functions*

FERC has several requirements that an organization must meet before they can be approved as an RTO. A subset of these requirements, which are independence (Section 3.1), sufficient geographic scope (Section 3.2) and a conforming regional tariff (Section 6) are enabling functions that FERC requires of any RTO. While the WMEG is not currently evaluating forming a new RTO, many of these enabling functions may be desired or required in potential future states or to provide functions on a regional basis.

1.2.3 *Transmission Planning*

The WMEG FERC jurisdictional entities and many of the non-jurisdictional entities are actively participating in regional and interregional transmission planning efforts. The planning efforts consider economics, public policy, and reliability when determining the future transmission projects for their respective regions. Section 4 below covers transmission planning that will meet both the FERC requirements of an RTO (Section 4.1.1) and enhanced regional planning efforts (Section 4.1.2). The Seams Task Force White Paper discusses a potential configuration where WMEG members could jointly evaluate transmission capacity expansion opportunities and cost allocation for the entire West footprint regardless of market affiliation. The targeted benefit for such an approach would be a more comprehensive transmission planning approach for the entire West system that can effectively manage interregional planning seams which have plagued other multiple RTO configurations.

1.2.4 *Consolidated Balancing Authority*

A Consolidated Balancing Authority (CBA) combines the Balancing Authority (BA) obligations of several legacy BAs into one organization. The CBA, based on the final configuration, could assume the NERC BA functional requirements and compliance obligations. There are several different configurations for a CBA that are discussed in the CBA Task Force White Paper with the final configuration dependent on the functionality desired by its members. A CBA can reduce the costs to serve customers through sharing of the BA responsibilities, taking advantage of load and resource diversity, and co-optimizing generation resources to provide energy and ancillary services.

1.2.5 *Transmission Tariff*

RTOs, ISOs, and other groups of transmission owners have found that collaborating on a regional tariff provides decreased compliance and regulatory costs and improved efficiencies for processing transmission service request and managing their energy markets. One of the requirements of a FERC approved RTO is to develop, provide, maintain, and administer a transmission tariff. The tariff should provide the required functions under one Open Access Transmission Tariff (OATT). There may be

potential benefits, as documented in the Transmission Rate Subgroup White Paper, associated with the consolidation of some WMEG member transmission tariffs to create a regional transmission tariff, even if not to meet the RTO requirements.

1.2.6 Resource Adequacy

The goal for Resource Adequacy (RA) programs is to ensure sufficient generating capacity is available to reliably serve the needs of customers. RA programs require companies, with load serving obligations, to construct or contract for capacity in excess of their anticipated load obligation. Most companies work with their governing bodies to balance the increase in costs for securing this additional capacity with the level of reliability desired for serving customers. Opportunities to share that responsibility with others and reduce the individual requirements are already in play in the West.

2 Market Functions

There are several functions that are or would logically be provided by the administrator of a wholesale electricity market in the scenarios considered in this report. It is worth noting that FERC only requires an RTO to provide a market for the energy imbalance ancillary service. The SPP and CAISO are currently providing Energy Imbalance Markets (EIM) (#13). The costs and benefits related to these EIMs are excluded from this Study.

Additional market functions, which are part of Appendix A, are examined as part of this Study and the CBS. Section 2.1 will cover those that are currently provided or are part of the development discussion for the CAISO EDAM and SPP Markets+ offerings that includes a Day-Ahead Market (#14) and Section 2.2 will cover those that are enhancements to what is either currently being provided or is part of the discussions for the offerings from CAISO and SPP.

2.1 Functions Expected in CAISO and SPP Market Offerings

2.1.1 Parallel Path Flow & Interregional Coordination (#7b & #12b)

Electricity flows along the path of least resistance (Kirchhoff's Laws to be specific) and does not follow a contract path from the defined point of receipt to the point of delivery. To properly model electricity flow, entities need to have a detailed, accurate, and up-to-date model of the transmission system, generation, and load; an extensive set of telemetry to get instantaneous reads on all flows and voltages in the system; as well as a State Estimator to handle the inevitable inaccuracies in some of the telemetered values.

The MOPs and RCs develop processes to observe and manage market flows over their own as well as external to their own market footprint because the markets operate over a larger footprint than a legacy BA. These are the same tools as entities in their footprint already use. Current methods can be enhanced to provide more cost-effective coordination between markets, as covered below in Section 2.2.1.

2.1.2 Congestion Management (#6)

Congestion in electricity markets refers to a situation where there is limited or insufficient transmission capacity to move electricity from areas with excess and more economical generation capacity to areas with high demand or higher cost generation for electricity. Congestion occurs when the most cost-effective generation to meet the demand for electricity in a specific area exceeds the available transmission capacity, leading to an increase in electricity prices in that high demand area and potentially causing reliability issues.

Congestion is handled in electricity market mainly via a Security Constrained Economic Dispatch (SCED) and Security Constrained Unit Commitment (SCUC), that is committing (SCUC) and dispatching (SCED) resources such that the load is served at the lowest production costs while also honoring transmission and stability constraints. In cases where transmission and stability limits cannot be maintained with SCED and SCUC, other actions such as transmission switching, committing units for reliability purposes, and even load shedding may need to be taken.

2.1.3 Market Monitoring (#10b)

FERC requires wholesale markets to have unbiased groups monitoring both the activity of market participants and the activity of the MOP. These market monitoring groups can either be wholly independent of the MOP (as in ERCOT or PJM) or functionally independent of the MOP (like SPP or CAISO). Market Monitoring functionality and ability will need to keep pace with developing market products and tools as each MOP considers enhancements to their market offerings. The market monitor will evaluate new product offers by the MOP and provide input on such products to help ensure they will continue to support a fair and robust market. The market monitor will continually evaluate the effectiveness of the market and suggest enhancements to the current market where they believe inefficiencies exist or where gaming by market participants may be possible. The market monitor will also evaluate market participants' behaviors and actions to ensure that such is consistent with the intent of the market offerings and FERC's rules and guidance.

2.1.4 Reliability Coordinator (#3, #4, #7c, & #12c)

Currently the MOPs in the West are the RCs for both their respective market areas and other entities who separately contract for their services. Utilicast expects that this configuration will continue, and these RCs will provide the Operational Authority, the Short-term Reliability, and the Parallel Path Flow & Interregional Coordination services for their respective day-ahead market offerings.

2.2 Possible Market Function Enhancements

2.2.1 Parallel Path Flow & Interregional Coordination (#7b & #12b)

As stated above in Section 2.1.1, parallel path flow coordination was developed to better understand the impact markets have on neighboring systems as well as to coordinate reliable operations. As evaluated in the CBS, and discussed in WMEG, there is a desire to enhance the coordination between the developing CAISO and SPP markets in the West to reduce the inter-market barriers and potentially create more efficient overall operations, as referenced in the Seams Task Force Whitepaper.

2.2.2 Ancillary Service Markets (#15)

Ancillary service markets (ASM) are wholesale electricity markets in which MOPs secure ancillary services from qualified suppliers. These services are typically procured through competitive bidding processes, with providers submitting their price to supply up to a specific quantity and type of ancillary service. Most ASM in operation co-optimize the ancillary service and energy needs to ensure suppliers are indifferent to which they provide, from a compensation standpoint. The efficiency that an ASM brings to a regional market has promoted their development. There are ways to obtain some of the benefits of sharing the provision of ancillary services without the full-blown implementation of an ASM or even as a glide path to those markets, as referenced in Section 5 below.

2.2.3 Financial Transmission Rights (#16)

A Financial Transmission Right's (FTR) market enables participants to buy and sell FTRs to financially hedge the congestion costs for energy deliveries between designated resources and their load. Most FTR markets provide the owner of the firm transmission rights for a specific physical transmission path priority for securing an FTR for or the ability to receive the auction revenues associated with that path. FTR markets provide additional benefits, for instance, identification of important congestion that could be relieved with transmission enhancements, arbitrage opportunities to provide more efficient market results, etc. FTR markets can have various process, time horizons, and auction rules.

2.3 Costs

The costs estimates provided in this Study are for the development or enhancement of the various market offerings or market enhancements to implement future functionality. These Study cost estimates do not include any costs that a WMEG member may incur to implement the necessary tools and processes within their organization to take advantage of any new market functionality. Utilicast developed their costs estimates based on publicly available information from other market development and enhancement efforts.

2.3.1 Historical Implementation Cost for Regional Markets

The market products and functionality of the current CAISO and SPP offerings are somewhat scaled back when compared to the functionality provided by other regional markets. We will examine several regional market implementations to help create a range for what the current market offerings may cost to implement. Table 1 below provides a summary of the implementation costs for various market implementation efforts. We have adjusted the actual values published at the time of implementation to reflect 2022 dollars.

A quick observation regarding these various implementation costs is the efficiencies that are possible when modifying or enhancing an existing system compared to standing up a system from scratch. For example, the SPP implemented two energy imbalance service (EIS) markets twelve years apart. SPP did not have a market software solution or the infrastructure to support a market prior to implementing their first EIM in 2007. Fast forward to 2019 when SPP was able to benefit from their existing market infrastructure to implement the second EIM (WEIS) for roughly 30% of the first EIM costs. Likewise, CAISO was able to enhance their existing infrastructure to support the WEIM for roughly half the cost of the original SPP-EIS.

Scale also has a significant impact on the final implementation costs. The MISO implementation cost was higher than the SPP Integrated Marketplace (IM) or CAISO Full Day-Ahead Market (MRTU), which could be in part due to the larger customer base and building the system from scratch. It is worth noting that the MISO cost per MW-peak is less than SPP-IM or CAISO-MRTU. The MISO implementation was also missing the ASM and CBA functionality, which was added in 2009. The costs per MW-peak for the combined MISO implementations is between the SPP and CAISO adjusted values. This helps demonstrate that there is a base cost for setting up a market or market enhancement and then some incremental costs to support functionality and scale.

Table 1. Historic Market Implementation Costs

Market	Year	Implementation Cost ¹ (\$000)	Adjusted ² Cost (\$000)	Peak (MW) ³	\$/MW-Peak ⁴
SPP – EIS	2007	\$33,000	\$48,000	43,304	\$1,115
SPP – IM	2014	\$115,000	\$147,000	45,301	\$3,253
ERCOT	2010	\$545,000	\$758,000	74,820	\$10,124
MISO	2005	\$245,000	\$381,000	116,000	\$3,281
MISO – ASM/CBA	2009	\$75,000	\$106,000	96,500	\$1,099
CAISO – MRTU	2009	\$198,000	\$280,000	46,042	\$6,080
WEIM	2014	\$18,300	\$23,000	NA	NA
WEIS	2019	\$9,500	\$11,000	NA	NA

SPP built on their EIM market solution when launching their Integrated Market (IM)⁵ in 2014. The IM added a DAM, enhanced RTM, FTRs, ASM, CBA, and various other services. SPP was the RC and TSP prior to and after the launch of each market.

The Midwest Independent System Operator (MISO) launched their energy markets in 2005 at a cost of \$245 million⁶. This initial market phase included a DAM, RTM, and FTRs.⁷ MISO was the RC and transmission service provider (TSP) prior to and after the market launch. Their members who operated

¹ Implementation costs based on published information.

² Adjusted to 2023 dollars with the Bureau of Labor Statistics CPI information encoded in <https://www.in2013dollars.com/us/inflation>

³ Peak value is based on the implementation year for that market with the exception of two EIM markets, which were not calculated because of their dynamic customer base.

⁴ Using the values in the Adjusted Cost column

⁵ SPP BOD Minutes for April 2014, p. 26. Value excludes \$38.5 MM for deferred/carry over/future projects and \$23.5 MM for technology updates. <https://www.spp.org/documents/22363/bodmc%20minutes%204.29.14.pdf>

⁶ MISO Market System Evaluation, September 11, 2017, Section 1.3 https://cdn.misoenergy.org/MSE_Final%20Report_Public140327.pdf

⁷ 2005 State of the Market Report Midwest ISO. <https://www.potomaceconomics.com/wp-content/uploads/2017/02/2005-State-of-the-Market-Presentation.pdf>

a legacy BA continued to operate balancing zones within the MISO region after this initial market launch. MISO launched their ASM and completed the consolidation of the legacy BAs in 2009.⁸

CAISO implemented their Market Redesign and Technology Upgrade (MRTU) in 2009 that included multiple enhancements to the DAM, RTM, a co-optimized ASM, congestion revenue rights (CRRs), and other significant enhancements.⁹ CAISO was the BA and TSP prior to and after the MRTU launch. CAISO took on the RC role in 2019. CAISO developed their WEIM product¹⁰ and started offering their WEIM services in 2014 to a single customer. In the FERC filing for WEIM, CASIO stated they would charge their original customer \$2.1 million with the expectation that others would join later and pay a similar charge when they joined.

ERCOT changed their zonal market out to a Nodal Market and included enhancements to the Real-Time Market, development of a Co-optimized Day-Ahead Market for energy and ancillary services, and added a Congestion Revenue Rights Market.¹¹ ERCOT was the BA, RC, and TSP prior to and after the change in market structure. This market implementation cost appears to be an outlier when compared to other implementation efforts and for that reason will not be used for cost estimation purposes.

2.3.2 Ongoing Cost for Select Markets and Market Functions

Table 2 below provides a summary of the 2023 budgets and an average charge per MWh based on the most recent published actual load values. These budgets are a mix of operating and debt service costs. Part of the debt service cost is for the amortization of the debt issued to fund the implementation cost shown in Table 1. Most of the Markets have separate charges for various activities, such as FTR, virtual trading, system operations, and market operations. Where possible, the ongoing charges for these various activities are itemized in Table 3.

CAISO and SPP are providing market and RC services to various West entities. The CAISO 2023 budget estimates revenues of \$19.7 million for providing RC services and \$15.3 million for managing the WEIM¹². SPP does not break out their RC service cost or revenues and combines the projected revenues for the West RC and WEIS in the SPP budget with other contract services. SPP stated in their FERC Filing to implement the WEIS tariff that they forecast the annual operating cost for WEIS to be \$5 million, which includes incremental costs to operate the market plus an annualized payment to cover the original implementation costs of \$9.5 million amortized over 8 years, which produced an ongoing cost of

⁸ MISO Energy and Ancillary Services Co-optimization

https://www.ercot.com/files/docs/2019/09/18/4_MISO_Energy_and_Ancillary_Service_Co-optimization_091819.pdf

⁹ MRTU FERC Update, October 6, 2008.

http://www.caiso.com/Documents/October6_2008MRTUMonthlyStatusReportinDocketNo_ER06-615-000_MRTUTariff.pdf

¹⁰CAISO Filing of ISO Rate Schedule No. 73, April 2013.

http://www.caiso.com/Documents/Apr30_2013EnergyImbalanceMarketImplementationAgreement-PacifiCorpER13-1372-000.pdf

¹¹ ERCOT Accounting of Costs and Revenues of Implementing the Nodal Market page 6.

https://www.ercot.com/files/docs/2012/07/02/ercot_accounting_of_costs_and_revenues_nodal_market.pdf

¹² CAISO 2023 Budget and Grid Management Charge Rates at p. 37. <http://www.caiso.com/Documents/2023-Budget-and-Grid-Management-Charge-Rates-Book-Final.pdf>

\$0.22/MWh.¹³ RC services will continue to be a requirement for participants in both EDAM and Markets+, so no adjustment for this service will be factored in our cost estimates.

Table 2. Budget Values for Various Markets

Market	2023 Budget (\$000)	\$/MWh
SPP ¹⁴	\$184,500	\$0.683
MISO ¹⁵	\$339,000	\$0.505
CAISO ¹⁶	\$199,600	\$0.946
ERCOT ¹⁷	\$287,000	\$0.668

Table 3 provides a summary of the MWh charge for each Market’s itemized activities. The sum of the charges for a specific Market operator below do not equal the values listed in Table 2 above, which are based on the annual load. The values listed in Table 3 are the billing rates furnished by the RTO.

The Sys Ops column below is generally for the RTO to provide transmission related services and will be assessed to users of the transmission system. The Sys Ops values include transmission planning, BA functions, NERC compliance responsibilities, Regional Tariff administration, and some also include other non-RTO functions, which partially explains the differential between the CAISO and WEIM rates. The Market Ops is generally for market operations and will be assessed for MWhs related to market operations. Again, the difference in rates between CAISO and WEIM for Market Ops may represent the additional costs for facilitating the DAM. The FTR column is a little more diverse than the other columns. The SPP assesses this charge for each FTR MWh submitted to the FTR auction. CAISO assess this charge for each CRR that clears the market plus a \$1.00 fee for each CRR nomination made. MISO assesses this charge based on the FTRs that clear the FTR auction. The charge in the Misc column for CAISO and WEIM is for RC services. The charge in the Misc column for SPP is assessed to each MWh settled in the market. The WEIS value is from the SPP FERC filing as noted earlier.

¹³ FERC Docket Nos ER21-3-000 and ER21-4-000, Paragraph 32.

https://spp.org/documents/63679/20201223_order%20-%20western%20energy%20imbalance%20service%20tariff_er21-3-000.pdf

¹⁴ SPP 2023 Budget-Draft, pgs 4-5. <https://www.spp.org/documents/67873/2023%20budget%20document%20-%20draft-stakeholder%20feedback.pdf>

¹⁵ MISO Annual Revenue Requirement 2023 – 2027 Budget. https://cdn.misoenergy.org/2023-27_Budget_Table628480.pdf

¹⁶ 2023 Budget and Grid Management Charge Rates, \$/MWh calculated using the Budget amount divided by the System Operations MWhs from p. 42. <http://www.caiso.com/Documents/2023-Budget-and-Grid-Management-Charge-Rates-Book-Final.pdf>

¹⁷ ERCOT’s 2022/2023 Biennial Budget and System Administration Fee Submission. https://www.ercot.com/files/docs/2021/09/21/ERCOT_2022-2023_Biennial_Budget.pdf

**Table 3. Break Down of Ongoing Market Costs by Activity
(\$/MWh)**

Market	Sys Ops	Market Ops	FTRs	Misc
CAISO ¹⁸	0.2070	0.1320	0.0071	0.0305
MISO ¹⁹	0.2400	0.1800	0.0200	
SPP ²⁰	0.2080	0.1290	0.0060	0.0300
WEIM ²¹	0.1035	0.0832	NA	0.0305
WEIS		0.2200		

The cost for market monitoring is embedded in the Market's budget for ongoing costs. The SPP and CAISO have market monitoring activities occurring in the WEIM and WEIS. The market monitoring effort and costs are expected to increase some to support the added complexity of the EDAM and Markets+ offerings. Table 4 below provides a summary of the cost that other regional markets pay for external market monitoring services. These values represent a small percentage of the overall budget for each of the regional markets listed and as such, any change in cost related to the increased functionality for EDAM or Markets+ will be negligible for cost estimation purposes.

Table 4 – Annual Market Monitoring Costs

Market	Cost (\$000)	\$/MWh	% of Budget
SPP	\$3,200	0.0118	1.7%
MISO	\$6,700	0.0100	2.0%
PJM	\$12,300	0.0158	3.0%
ERCOT	\$4,300	0.0100	1.5%

2.3.3 Cost Estimates for EDAM and Markets+ Market Offerings

One of the factors for the implementation costs is scale. The values in Table 5 provide a quick comparison between CAISO and SPP. The SPP and CAISO appear to be similar in size based on system peak and annual energy values, and both have significant variable energy resource in their market footprint. The WMEG group as one entity is nearly the same size as CAISO and SPP combined. E3 provided a quick summary of the total energy cleared in the CBS for the 2026 Split Market footprint case, which are shown in the table as EDAM (CBS) and Markets+ (CBS).²²

¹⁸ CAISO Finance Division GMC and Other Rates for 2004-2023 Effective 5/1/2023, p. 2.

<http://www.caiso.com/Documents/Grid-Management-Charge-Rates-for-2004-2023-Effective-May-01-2023.pdf>

¹⁹ *Supra* note 15

²⁰ *Supra* note 14 at p 59

²¹ *Supra* note 18 at p. 44

²² These values do not include pumping or charging loads. There is an additional 21,690 GWH of load in WECC that is part of the CBS but not included in either market.

Table 5. General Statistics for RTOs and Market Offerings

Market	Peak (MW)	Load (GWh)
CAISO	43,982	211,020
MISO	122,000	671,688
SPP	52,870	270,182
ERCOT	80,038	429,885
WMEG		464,254
EDAM (CBS)		194,072
Markets+ (CBS)		219,371

The range of the projected implementation costs for EDAM and Markets+ are shown in Table 6 below. These implementation values exclude the costs for defining their market offerings before getting approval from their respective Boards to proceed with the market development. We anticipate each operator will have a base cost for standing up their market system plus incremental costs based on their anticipated number of market participants. Our projected implementation costs are towards the lower end of other implementation efforts listed in Table 1. We anticipate that both MOPs will enhance their existing infrastructures to support their respective market offering.

To develop our estimates, we used the SPP IM Implementation cost. This value is more representative of what it costs to enhance an existing market into a regional market that includes the functionality discussed in this Section 2. As noted in footnote 5, the SPP IM implementation cost excludes \$60 million in various technology upgrades to support the market and various market functions identified during the implementation phase that were delayed until after the market was placed in service. When this \$60 million is added to the SPP IM costs, the resulting implementation cost is just slightly favorable to the CAISO-MRTU costs. We are not anticipating that either market implementation cost will be burden with such costs, making the SPP-IM implementation costs the more appropriate value to consider for estimation purposes.

The next factor to determine is the discount the MOP may be able to realize when enhancing an existing system that has most of the functionality already in service. Both MOPs will need to stand up a new market software solution and hardware. The amount of hardware required will be impacted by the scale of the new membership base. The EDAM and Markets+ footprints in Table 5 are similar in size to both the CAISO and SPP legacy market footprints, resulting in no discount or premium adjustment to our cost estimates related to scale. Both MOPs are using their existing market protocols to help define these new market offerings. We anticipate they will be able to reuse their core logic but will need to determine how best to modify this logic to accommodate the desired changes sought by potential market participants. The savings related to the decrease in some functionality like no ASM, CBA, and FTRs, may be replaced with costs to implement other new designs, such as the greenhouse gas solutions, individual BAs requirements, market charge for transmission usage, and others. The SPP was able to implement the WEIS for roughly 25% of the cost to implement their original EIM market. This was a more like-for-like implementation regarding market features and functionality and the WEIS was a smaller scale. Based on the changes currently under consideration in the market offerings, we are

projecting the implementation cost for EDAM and CAISO may fall between 40% and 50% of the SPP IM Adjusted Implementation cost.

The ongoing cost in Table 5 are expected to cover the amortization of the implementation costs, some contribution for the use of existing infrastructure, and operational costs. These projections are based on the Sys Ops and Market Ops costs from Table 3 and excludes RC related costs and any possible amortization costs that would be related to unrecovered WEIM or WEIS implementation costs. The ongoing costs are an estimated averages that would be split between the market and system operations buckets noted above in Table 3 above and applied to generation and load within the market footprint.

Table 6. Projected Range of Costs for Market Offerings

Market	Implementation Cost (\$000)		Ongoing Cost (\$/MWh)	
	High	Low	High	Low
EDAM	\$75,000	\$55,000	\$0.30	\$0.25
Markets+	\$75,000	\$55,000	\$0.30	\$0.25

2.3.4 Costs Estimates for Market Function Enhancements

The potential market enhancements listed above in Section 2.2, are anticipated to be implemented in the various market offerings at different times with the exception for those enhancements that target improved coordination between the markets. The improved market coordination will require a coordinated effort between adjacent MOPs and should be implemented at nearly the same time.

Financial transmission / congestion market implementation costs were included in the original MISO and SPP day-ahead market offerings and the CAISO MRTU, making it difficult to impossible to determine the FTR market setup cost, based on public information. However, ERCOT did split out the costs of the individual components of its Nodal Program and found that its Congestion Revenue Rights program cost \$18.9 million²³. In addition to the cost of setting up a market, there are ongoing cost to operate the market. Recently SPP unbundled their charges for its scheduling and operational services. One of these components is for the administration of the FTR market. The projected rate for 2023 is \$0.006 per FTR MWh which is based on a Net Revenue Requirement for 2023 of \$4.52 million. The CAISO charges a fee for each CRR submitted and a charge of \$0.0071 per CRR MWh, based on an FTR Net Revenue Requirement of \$4.2 million²⁴.

SPP's Market Monitoring Unit recently estimated that implementation of a Coordinated Transaction Scheduling process would cost \$6 million to \$10 million dollars²⁵.

²³ ERCOT Accounting of Costs and Revenues of Implementing the Nodal Market page 19.

https://www.ercot.com/files/docs/2012/07/02/ercot_accounting_of_costs_and_revenues_nodal_market.pdf

²⁴ 2023 Budget and Grid Management Charge Rates, P. 43. <http://www.caiso.com/Documents/2023-Budget-and-Grid-Management-Charge-Rates-Book-Final.pdf>

²⁵ Coordinated Transaction Scheduling (CTS) Study p.28

<https://www.spp.org/documents/62154/coordinated%20transaction%20scheduling%20study%2020200508.pdf>

2.4 Benefits

The quantifiable benefits for these Market Functions are included in the benefits calculated by E3 in the CBS. The E3 report states that the impact for individual entities varies widely for each case, with the regionwide Adjusted Production Cost being \$60 million lower in the EDAM Bookend Case, \$221 million higher in the Main Split Case, and \$218 million higher in the Markets+ Bookend. The sum of the Total Net Cost declined for the WEMG members was \$26 million. The size of this cost decline reflects the net impact of reduced wheeling revenues modeled for WMEG entities compared to the BAU case. If the impact on the model of reduced wheeling revenue were omitted from Net Variable Costs, WMEG members would together have a \$266 million Net Variable Cost reduction in the Main Split case compared to the BAU. Individual WMEG entities that experience lower net Variable Net Costs in the EDAM Bookend do not all experience lower Total Net Variable Costs in the Main Split Case. The Main Split case also showed a \$247 million Total Net Cost increase for the non-WMEG entities. The driver of this cost increase for non-WMEG members is that the Main Split Case introduces a larger cost of wheeling over the market seams.

Parallel path flow management and FTRs are part of the overall CBS results. The 2030 and 2035 cases did have decreasing friction between markets to help quantify the benefits of improved coordination between the MOPs, resulting in production costs savings of up to \$200 million. These benefits can be achieved through both the improved parallel flow coordination and improved trading tools to support intermarket trading activity. Examples of efforts that can improve parallel flow management and interregional coordination are Coordinated Transaction Scheduling as mentioned above in Section 2.3.4 and Market to Market relief request systems.²⁶

The CBS did specify the addition of an ASM and a CBA for each respective market footprint in the 2030 case. The 2030 case had a production costs savings of \$10 million related to the addition of the ASM and CBA. The model represented a CBA by aggregating the Spinning Reserve, Non-Spinning Reserve, and Regulating Reserve requirements for each BAA to a level of a sub-region of each market footprint allowing zones to purchase reserves from their neighboring zones in the same market. The CBA case does not reduce the total quantity of reserve requirements needed within each sub-region. It is possible that the quantity of Regulating Reserves could be reduced through BA consolidation but calculating potential changes in these needs would require intensive sub-hourly data analysis. Potential Regulating Reserve quantity reductions represent an additional potential opportunity for savings not examined here. For comparison, the MISO ASM and CBA implementation had a projected annual savings of \$60 million, with expected savings coming from more efficient commitment and dispatch of energy and operating reserves and reduced regulation and spinning reserve requirements.²⁷

FTR markets primarily enable market participants to hedge their forward congestion risk, but also provide additional benefits such as identifying heavily congested paths that could be relieved with transmission enhancements, arbitrage opportunities to provide more efficient market results, etc.

²⁶ OMS-RSC SEAMS STUDY: MARKET-TO-MARKET COORDINATION p26 [Microsoft Word - Seams Study_MISO IMM M2M Evaluation_Final \(spp.org\)](#)

²⁷ *Supra* note 8 at slide 11

2.5 Summary

Table 7 below provides a summary of costs and benefits for the various market functions expected in the EDAM and Markets+ offerings and the possible enhanced functionality described in Section 2.2. The Benefits listed below are from the CBS; the DAM Offering benefits are based on the production costs savings for just the WMEG members in the Main Split case. The Implementation Cost is the projected cost for CAISO and SPP to each implement the stated function in their respective markets. The implementation costs shown assume that the markets implemented closely resemble markets already implemented by CAISO and SPP. Deviations from the existing designs would likely cause costs to go higher.

Table 7. Summary of Benefits from CBS

Function	Implementation Cost ²⁸ (\$000)	Benefits (\$000)		
		2026	2030	2035
DAM Offering	130,000	26,000 ²⁹		
Parallel Path Flow & Interregional Coordination	8,000		162,000 ³⁰	206,000 ³¹
Added Transmission Infrastructure				387,000 ³²
Co-optimized ASM and CBA-Full	26,000 ³³		10,000 ³⁴	10,000 ³⁵
Financial Transmission Rights	13,000 ³⁶	The ability to hedge congestion costs and a more targeted congestion rent distribution method.		

3 Enabling Functions

3.1 Independence (#1)

FERC requires an RTO that can affect the cost or terms and conditions of wholesale energy or capacity to be independent from either one or any group of like-minded entities. As WMEG or other groups of entities form organizations to provide region functions or obtain services from a MOP or other regional organizations, they will need to consider Independence. The independence of RTOs is critical to ensure

²⁸ In cases where there is a range of estimates, costs in this column represent the midpoint. A two-market implementation is assumed, and these costs also reflect the sum of costs to implement in each market.

²⁹ E3 WMEG CBS Report p15

³⁰ Ibid. p20

³¹ Ibid. p21

³² Ibid. p22

³³ 20% of DAM Offering based on MISO CBA/ASM implementation cost of 30% of their DAM implementation and reduced to reflect SPP and CAISO's experience in implementing CBA and A/S markets.

³⁴ *Supra* 29, p 22.

³⁵ Ibid.

³⁶ 10% of DAM Offering based on ERCOT's cost of 15% of their DAM implementation and reduced to reflect SPP and CAISO's experience in implementing FTR markets.

fair and efficient operation of the power system. Whether or not WMEG considers a full RTO or some other entity performing some subset of RTO or regional responsibilities, there are reasons why these regional organizations must be independent:

- Independence avoids conflicts of interest: entities performing functions described later must be independent to avoid conflicts of interest between the different parties involved in the electricity transmission operations and markets. RTOs are responsible for ensuring fair access to the transmission grid for all market participants, regardless of their ownership or affiliation.
- Independence promotes competition: An independent entity can help promote competition in the electricity market by ensuring that all market participants have equal access to the transmission grid. This allows for a more competitive market, which can lead to lower prices for consumers.
- Independence ensures reliability: the entity that is responsible for maintaining the reliability of the transmission system, if independent, can make objective decisions based on engineering and operational criteria, without being influenced by commercial interests.

Independence provides transparency: An independent entity can provide transparency in the operation of the transmission grid, which can help build trust among market participants. Transparency can also help regulators and policymakers understand the operation of the grid, which can lead to more informed decision-making. Overall, the independence of entities performing the functions addressed in this document is critical to ensure fair and efficient operation of the transmission grid and promote competition in the electricity market.

3.2 Sufficient Scope and Configuration (#2) to support a Regional Tariff (#18)

FERC requires that any organization who is seeking to manage a regional operations have a sufficient scope and configuration of operations. This is true of an RTO, a regional tariff, a CBA, or other functions that are performed on a regional basis.

A group of like-minded entities could create a regional tariff for some things but not others. It is at least conceivable that you could create a regional tariff or common tariff for elements that could span market footprints and MOPs. At this time, one can reasonably assume that EDAM and Markets+ will each have sufficient scope and configuration of operations to support having a regional tariff. The consolidation of BAs could also grow to be of sufficient scope and configuration to support the creation of a regional tariff or for possible efficiency reasons be included in the MOP's regional tariff.

The expansion of the SPP RTO to the West may not warrant a separate regional tariff. Instead, the parties may elect to formalize any special considerations necessary for entities in the West through changes to the existing SPP Regional Tariff. Adding the necessary changes to an existing tariff is assumed to be more cost effective than creating an entirely new tariff.

3.3 Costs

The costs to ensure independence typically involve setting up an independent board and employing staff to manage the day-to-day activity. The overall size and scope of this independent organization will be

somewhat commensurate with the scope of the organization for which it is providing governance. Table 8 below provides cost information on salaries for various independent boards of directors.

Table 8. Independent Board Cost

Market	Annual Board Comp (\$000)	Board Members	Estimated Misc. Costs (\$000)	Annual Cost (\$000)
SPP	\$1,500	9	\$200	\$1,700
CAISO Board of Governors	\$470 ³⁷	5	\$200	\$670
MISO	\$175/member	9	\$200	\$1,775
ERCOT	\$87 - \$100	8	\$200	\$1,000
WPP (WRAP portion) ³⁸				\$327

3.4 Benefits

The independence does provide a different perspective for issues brought forth by the parties and can help determine or negotiate an agreeable solution without the need to involve FERC in the decision making. Independence also provides confidence in the decisions of the regional organization so that members or market participants can rely on both the operations of the organization as well as the changes that are approved. FERC provides some deference to those organizations it deems are independent.

4 Planning

Transmission planning identifies enhancements for the transmission system to ensure reliable and resilient service for customers. Transmission planners study the impacts that their solution may have on adjacent transmission systems and transmission regions to ensure there are no unintended negative impacts.

4.1 Planning Functions

The Seams Task Force White Paper details the various planning regions and the regional and interregional planning activities. The planning activities have various FERC requirements that must be factored into the various related processes. The West currently has three different regional planning entities who are fulfilling these FERC requirements. Based on the current state of the West, two functions were considered for this Study; meet an RTO requirement and enhance the current state.

4.1.1 Planning and Expansion (#11)

FERC requires an RTO to have responsibilities related to planning and expansion of the transmission grid, namely system planning, maintaining current transmission service, and interconnection studies. The

³⁷ CAISO 990 Form 2021

<https://projects.propublica.org/nonprofits/organizations/943274043/202233199349309433/full>

³⁸ Western Power Pool 2023-2024 Budget Resolution p2 https://www.westernpowerpool.org/private-media/documents/2023.05.30_2023-2024_Budget_Resolution.pdf

entity performing these functions develops long-term plans for the transmission system that ensures the reliability and security of the grid. These plans typically involve assessing future demand for electricity, identifying areas where new transmission infrastructure may be needed, and evaluating potential solutions. The RTO also evaluates and approves new transmission infrastructure projects and conducts interconnection studies for new generation facilities.

4.1.2 Regional Transmission Planning (#20)

Most regional planning entities in the East are aligned along their regional market and RTO footprints and have their planning process as part of their regional tariff. The alignment of markets and transmission planning regions aids with setting up the economic dispatch models to determine which new transmission facilities are needed to support both the reliable and economic needs of the region.

As discussed in the Seams Task Force White Paper, the West entities may want to evaluate developing a single planning region for planning, evaluating, and funding transmission solutions for the entire West system. The development of a single planning region would require significant effort and extensive negotiations to get all stakeholders to agree on the key principles. To simplify this concept some, this single planning region could reduce its scope and focus on larger, higher voltage solutions, such as 300kV and above, and then have other groups focus on lower voltage projects that are driven by more localized needs. Cost allocation would need to be resolved to ensure that those facilities that are approved will be built and funded.

4.2 Costs

The costs for the regional planning activity will vary based on scope and the geographic region. Regional Planning entities who are aligned with a regional market footprint or RTO generally have larger planning staffs to develop future states of the markets, forecast public policy impacts, and independently evaluate the needs for the facilities that are part of their planning area. These staff members will also need to evaluate stakeholder projects to determine the desired final portfolio of projects, the benefits associated with the final portfolio, and potential cost allocations.

4.2.1 Ongoing Costs

After discussions with a former RTO planning executive an estimate of the size and composition of the planning group was made. The anticipated group would be staffed with eight engineers focused on stability, eight engineers focused on economic modeling, four regulatory staff, six information technology staff, four admin staff, four managers, and one executive. This estimate represented a good place to start to support the activities related to the single west planning entity. Also, a regional planning group would need to be independent with an independent board of directors. Using assumed rates of \$125,000/FTE for staff level (like that used in the SPP Member Value Statement), \$175,00/FTE for manager and above, and an assumption board of director costs of \$327,000 that is similar to the costs for the WRAP shown in Table 8 above, results in an estimated annual cost of approximately \$5 million.

4.2.2 Implementation Costs

The effort to develop a single planning region will need to define the market dispatch approach, how to handle individual state mandates, determination of benefits, cost allocation, various other rules, draft a regional tariff, etc. and to stand up such an organization is projected to be somewhat comparable to that of standing up Markets+, yet slightly less complicated. Using SPP's cost estimate of \$9.7 million for developing the Markets+ market protocols and the associated FERC tariff, the projected implementation cost for a single planning region to work with stakeholders and develop a regional tariff is estimated between \$2 million and \$5 million.

4.3 Benefits

There are significant benefits that can be realized through an effective regional planning effort. The table below details the benefits published by several RTOs who have a regional planning effort and a FERC approved process for costs allocation. The CBS produced a value of \$387 million³⁹ in the 2035 Main Split RTO case made possible by increased transfer capabilities between various members. This is a gross benefit number and does not include the offset that would be required to fund the annual transmission revenue requirement to support the transmission infrastructure buildout. The improved transfer capability was determined on a wholistic basis for the West and not what was best for a specific market footprint. An effective comprehensive transmission planning approach for the entire West system may be able to effectively manage interregional planning seams that have plagued other multiple RTO configurations to develop a cost-effective, robust West wide transmission portfolio.

Table 9. Transmission Portfolio Benefits

Region	Annual Net Benefit (\$000)	Annual Net Benefit (\$ per MWh)
SPP ⁴⁰	528,000	1.83
MISO ⁴¹	1,900,000	2.83
PJM ⁴²	300,000	0.39

³⁹ WMEG Western Day Ahead Market Production Cost Impact Study, Section 5.1.6, p. 51

⁴⁰ The Value of Transmission: A Report by the Southwest Power Pool 2021 Edition 2022 benefits and costs netted p19 [2021 value of transmission report.pdf \(spp.org\)](https://www.spp.org/2021-value-of-transmission-report.pdf)

⁴¹ LRTP Tranche 1 Portfolio Detailed Business Case slide 16, midpoint estimate of 20-year present value divided by 20 for an annual number.
<https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf>

⁴² PJM Value Proposition slide 2. <https://www.pjm.com/about-pjm/~media/about-pjm/pjm-value-proposition.ashx>

5 Consolidated Balancing Authority (#17)

5.1 Description of the CBA Functions

The basic operational goal of a CBA is the same as any other BA; ensure supply and demand are equal within the metered boundary and meet the NERC Standards required of a BA. The CBA Task Force White Paper discussed four different configurations with increasing sophistication and costs.

5.1.1 *Netting ACE*

This is the simplest configuration included in the White Paper. It can accommodate two or more entities who elect to net their Area Control Error (ACE). It does not include the sharing of ancillary services.

5.1.2 *Regulation Reserve Sharing*

This combines each individual BA's ACE value to develop a regional ACE. The regional ACE would be allocated to every BA involved for their operation instead of their own ACE. Based on this method there could be a reduction in the regulation requirement for the regional ACE to meet the NERC Standards and thus for the BAs involved.

5.1.3 *CBA Lite*

The ACE calculation, and the deployment of resources with regulation and contingency reserves, would be transferred to a CBA. The CBA would gather the data needed from the ties to external entities, as well as the schedules across that boundary, and then calculate the regional ACE. Each legacy BA would supply to the CBA the resources needed to meet their portion of the reserve requirements, regulation, and contingency. The CBA operator would deploy the provided resources to meet the regional ACE requirement for regulations as well as respond to a contingency (either to the resource or through the existing BAs).

5.1.4 *CBA Full*

The BA responsibilities would transfer to a new CBA who would perform all the functions of a BA under NERC (except as noted below). The resources needed to meet the reserve requirements would be provided by the legacy BAs or the entities within them (for instance, the LSE). These could be used based on rotated deployment, or if cost is submitted, based on deploying the least expensive needed resources (or through an ASM). The CBA would deploy the provided resources to meet the regional requirements for regulations as well as respond to a contingency.

5.2 Costs

The costs of implementing a CBA will vary based on the desired configuration of its members. As discussed above, there are some CBA configurations where the functionality will require very limited infrastructure to support their operation and other configurations that will require extensive communication networks, various software solutions, and redundant control centers to provide the necessary functionality.

5.2.1 Communication and Metering Infrastructure

The CBA will require a sufficiently robust communication system to electronically interface members. This communication system should have redundant paths to ensure uninterrupted communication between the CBA operator and each party.

The transmission owner for each participant typically enters an agreement with the CBA operator to install and maintain the appropriate metering infrastructure to enable the CBA to effectively perform the BA functions. The values from these meters will be electronically transferred to the CBA operation center on a nearly real-time basis.

5.2.2 Energy Management System (EMS)

The CBA may need to install an EMS to manage the meter data that is coming into its system. The EMS will monitor their interties with adjacent systems and the overall performance of the balancing area.

5.2.3 Facility and Personnel

The required functionality will drive the type of facility and the number of personnel required to operate the CBA. This could be as simple as using the existing personnel and facilities of the members entirely new facilities and larger staffs for a CBA Full functionality. The new facilities would need to meet all the NERC criteria for primary and backup control centers.

The typical configuration of a CBA Full (See Section 5.1.4) is to have a primary and fully functional backup control center to support operating roughly eight to ten desks around the clock. The number of personnel will depend on the physical size of the CBA footprint and the operational requirements. Functions included in this type of configuration are the RC, BA, Scheduling, Tariff Administration, market operator positions for unit commitment, unit dispatch, generation dispatcher, and shift management.

5.3 Benefits

Centralized security constrained unit commitment and economic dispatch through the energy imbalance and day ahead markets will optimize the resources to meet BA's load requirement. The total operating reserve requirements, though not selected in the markets being developed, will be less in an Energy and ASM that is serving a CBA footprint than it would be for the sum of each individual BA meeting their own requirements. The CBS projected a combined annual savings for a CBA and ASM of \$10 million for the West, though this was only a function of reduced Flex requirements and the co-optimized procurement or Energy, Reserves and Flex.

Another benefit of the CBA is the ability to reduce the responsibilities for staff and compliance efforts at each individual BA and shift those responsibilities to the CBA. This shift may result in savings for personnel and for NERC compliance activity. The SPP and MISO have released value statements that estimate these savings to be roughly \$61 million and \$164 million respectively. Table 10 below provides some of the SPP and MISO member value that each RTO is providing their members.

**Table 10. Values for a CBA-Full in RTOs
(\$/MWH)**

Market	Compliance	Wind Integration
MISO	0.24	0.60
SPP	0.23	0.90

5.3.1 Compliance Impacts

Centralized compliance for CBA will reduce the support staff for entities in the CBA footprint. This also reduces the amount of data being submitted to NERC for compliance with BA standards and the amount of effort for entities to participate in NERC audits.

5.3.2 Ancillary Service Impacts

Energy and ASM allow for the efficient and effective use of resources to meet load and Operating Reserve requirements, contingency reserves, and regulation reserves. A market Unit Dispatch System sends out a balanced dispatch plan every five minutes looking out for 10 minutes to meet forecasted load, scheduled interchange, and managing transmission constraints. A five-minute dispatch process allows the CBA to carry less regulation to balance load and generation and meet the BA NERC standards.

5.3.3 Integration of Resources and Load Diversity

The integration of resources and load across a wider area enables the BA to take advantage of the natural diversity associated with the various resources and loads. For example, as load increases in one area, there may be a decrease in loads in a different area offsetting the overall need to change the output of the resources. This same dynamic can impact intermittent resources as weather patterns move across the area increasing generation in one location, while other areas may experience offsetting impacts. The diversity of load and its intermittency reduces the overall required regulation reserve required for the CBA and is less than what would be required for the sum of the individual BAs. This diversity combined with the diversity of output from resources, including those that are intermittent such as wind or solar, also reduces the required regulation reserve. The availability of more resources for this reduced regulation provides for more efficient use of the resources that once were reserved for regulation, as well as can foster a market-based selection of resources and greater reduction in the cost of regulation.

6 Regional Transmission Tariff

6.1 Description of the Functions

6.1.1 Transmission Tariff Administration and Design, OASIS with TTC and ATC Postings, Energy Imbalance, and Market Monitoring – Transmission Service (#5, #9, & 10a)

As discussed in the Transmission Rate Subgroup (TRSG) Whitepaper, there are benefits and costs to consolidating the administration under a group of individual transmission tariffs into one regional tariff.

FERC Order 2000 requires an RTO to have a transmission tariff to cover all the facilities under its control to provide transmission service. FERC Order 2003 added the Generation Interconnection (GI) service requirement for the RTO. This includes the OASIS requirements and postings. Note the TRSG Whitepaper covers how to discuss and look at a regional tariff, even if not a consideration of an RTO.

6.1.2 Parallel Path Flow and Interregional Coordination (Transmission Service aspect) (#7a & #12a)

Regional tariffs must consider these aspects as they are required by FERC to coordinate with affected system as any other Order 888 tariff. FERC also requires the RTO to provide these functions within its transmission tariff.

6.1.3 Ancillary Services (RTO Backstop) (#8)

A regional tariff that meets FERC Order 888 requirements is required to include the provision of the required ancillary services. Section 2 above covers the requirement of some of these provisions. For RTOs, FERC has not required markets to be used and some RTOs have used backstop methods to provide those services.

6.1.4 Market Monitoring (#10b)

FERC does monitor the provision of the transmission service and GI “markets” and could require market monitoring for that function, even if provided by a regional organization. Table 4 above summarizes the annual costs that various RTOs pay for market monitoring services, which would include these services.

6.2 Costs

Cost to implement a regional tariff will be based on the performance of the functions that are required within the tariff. An example, excluding RTOs, was the Integrated System that integrated into the SPP Tariff.⁴³ The costs for this effort is not publicly available.

6.2.1 Ongoing Costs

The ongoing cost to support the operations of a Regional Tariff for transmission service activity were estimated based on six staff handling real-time transmission service requests, five handling long term transmission service request, five handling generation interconnection requests, five performing stability studies related to long term transmission service and interconnection requests, eight information technology staff, six tracking tariff and filing issues, six administrative staff, four managers, one executive, and an independent board. Actual requirements will depend on the scope of the Tariff and the relevant footprint. Using assumed rates of \$125,000/FTE for staff level (like that used in the SPP Member Value Statement), \$175,00/FTE for manager and above, and an assumption of board of director costs of \$327,000 that is similar to the costs for WRAP from Table 8 above, results in an estimated annual cost of approximately \$6.3 million.

with WAPA Upper Great Plains, Basin Electric Power Cooperative and Hartland Consumers Power District comprised the Integrated System.

6.2.2 Implementation Cost

The development of a regional tariff to handle transmission service is projected to be somewhat comparable to possibly a little more complicated than developing a single planning region tariff and less complicated than developing market protocols and an associated tariff. Using SPP's cost estimate of \$9.7 million for developing the Markets+ market protocols and the associated FERC tariff, the projected implementation cost for a regional tariff is estimated between \$2 million and \$6 million. For clarity, the estimated total cost to create a single regional tariff that handles both transmission service and transmission planning would be slightly less than the sum of this estimated implementation cost and the estimated implementation costs for the planning activity in Section 4.2.2 above.

6.3 Benefits

The benefits of a regional tariff are first based on the reduced administrative cost for each of the entities now performing the transmission tariff administration vs the cost of the regional tariff administration. Second, the facilitation of more use of the transmission system has created more opportunities to exchange energy between the parties as well as longer term use of generation resources through bi-lateral contracts. Third, regional tariffs have facilitated more robust planning of transmission and the sharing of cost of those based on the shared use of those facilities. Fourth, market implementation is simplified to recognize the change in use of the system from the current markets to a wider wholesale market. The 2021 SPP Member Value Statement estimated an annual benefit due to reduced administration cost and elimination of individual OASIS sites of \$24.2 million.

7 Resource Adequacy (#19)

Resource adequacy (RA) is the function of ensuring that there are or are planned, sufficient generation to meet the expected load demand requirements in the future and including a margin to account for the risks of those generation resources not being available. In WMEG considering a resource adequacy program or requirement, the present implementation of the WRAP as well as the requirements of CAISO in their market development are being considered and below are those costs and benefits. If WMEG considers a different RA provision, then these benefits and costs would change.

8 Conclusion

As part of the overall efforts of the WMEG, this analysis provides significant information about considering the various ways that the West and specifically WMEG could continue to extend their original intents to work together on regional collaboration for benefits across the whole West. The use of this and further work would see benefits from the functions that are pursued but also builds an organization that allows the utilities of the West to seek other opportunities to enhance the West operations and planning for additional benefits.

9 Abbreviations

ASM	Ancillary Service Market
BA	Balancing Authority
BAU	Business as usual
CAISO	California Independent System Operator
CBA	Consolidated Balancing Authority
CBS	Cost Benefit Study
CRR	Congestion Revenue Rights
DAM	Day-Ahead Market
E3	Energy and Environmental Economics
EDAM	CAISO Extended Day-Ahead Market
EIM	Energy Imbalance Market
EIS	Energy Imbalance Service
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
GHG	Green House Gas
IM	Integrated Market
ISO	Independent System Operator
LMP	Locational Marginal Price
Markets+	SPP Markets Plus
MISO	Midwest Independent System Operator
MOP	Market Operator
MRTU	Market Redesign and Technology Upgrade / CAISO Full Day-Ahead Market
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Cooperation
NPC	Non-Production Costs
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
PJM	PJM Interconnection, LLC
RA	Resource Adequacy
RC	Reliability Coordinator
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SPP	Southwest Power Pool
TOP	Transmission Operator
TRSG	Transmission Rate Sub-Group
TSP	Transmission Service Provider
WECC	Western Electricity Coordinating Council
WEIM	CAISO Western Energy Imbalance Market
WEIS	SPP Western Energy Imbalance Service
WMEG	Western Markets Exploratory Group
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program

Appendix A

List of Functions

Documentation of Functional Groups and Cost/Benefit Sources
Based for WMEG Roadmap Discussion

Function Group – Enabling Functions

Description	WMEG Group	Category
#1 – Independence <ul style="list-style-type: none"> An Independent Governance, a vibrant Stakeholder Process with State Regulators and other NGO input 		Min RTO Characteristic
#2 - Scope and regional configuration <ul style="list-style-type: none"> FERC will judge this based on the footprint and the functions. 	Market Footprint Task Force	Min RTO Characteristic
#18 - Regional Tariff <ul style="list-style-type: none"> Method to include FERC jurisdictional regional functions but governed outside the members as in #1 above As noted before this is not the RTO requirements, see #5 & #9 - Transmission Tariff Administration and Design & OASIS with TTC and ATC Postings 	Transmission Rates Subgroup	WMEG Principle

Function Group – Resource Adequacy

Description	WMEG Group	Category
#19 - Resource Adequacy / Capacity Market <ul style="list-style-type: none"> NOT an RTO function Pursued as RTOs realize the coordination of transmission planning, operations, BA operations, and wholesale market responsibilities. Acknowledge ongoing efforts by WRAP CAISO / Markets+ approaches continue to evolve 	Seams Task Force (WRAP) RA Task Force Market Design Task Force	WMEG Principle

Function Group – Planning

Description	WMEG Group	Category
#11 - Planning and Expansion (+ Order 1000) <ul style="list-style-type: none"> RTOs are required to perform Transmission Planning as in Order 888 and meet the requirements of Order 2000 & 1000 for their region. Current regional planning groups could probably meet this requirement: <ol style="list-style-type: none"> Would have to be aligned with the RTO “region” vs the interregional requirements of Order 1000. Need to review the Order 1000 regional requirements also in light of the expectation of cost allocation, etc. within the RTO “region” 	Seams Task Force	Min RTO Function
#20 - Regional Transmission Planning <ul style="list-style-type: none"> Some RTOs have gone beyond the requirements of Order 888 & 2000 and have met the Order 1000 requirements with both: <ol style="list-style-type: none"> More transmission planning responsibilities being performed by the RTO Cost Allocation of RTO approved projects, sharing of cost for projects that have been approved through the RTO planning processes 	Seams Task Force	WMEG Principle

Function Group – Transmission Tariff

Description	WMEG Group	Category
#5 & #9 - Transmission Tariff Administration and Design & OASIS with TTC and ATC Postings #7a & #12a - Parallel Path Flow & Interregional Coordination – Transmission Service #8 - Ancillary Services (RTO Backstop) [Except EI from #13 Energy Imbalance Market (EIM)] #10b - Market Monitoring – Transmission Service <ul style="list-style-type: none"> Each of these functions is an RTO requirement 	Transmission Rate Subgroup Seams Task Force	Min RTO Functions

Function Group – Reliability Coordinator

Description	WMEG Group	Category
#3 - Operational Authority #4 - Short-term reliability (Reliability Coordination)	Seams Task Force	Min RTO Characteristics
<p>#7c & #12c - Parallel Path Flow & Interregional Coordination – Operations</p> <ul style="list-style-type: none"> Each of these functions is an RTO requirement <ol style="list-style-type: none"> RTO requirements were before FERC empowered NERC as the mandatory reliability entity and their push to have the RC have required control on the facilities in their footprint. <p>As such, for RTO they are usually the RC within their footprint.</p>	Seams Task Force	Min RTO Functions

Function Group – Enhance Markets

Description	WMEG Group	Category
#15 & #17 - Ancillary Service Markets & Consolidated Balancing Authority (CBA) <ul style="list-style-type: none">Enhancement to RTO requirement to be the provider of the Ancillary Services	CBA Task Force	Utilicast – Estimate the increase in Market fees
#16 - Financial Transmission Rights <ul style="list-style-type: none">The purpose of this function is under discussion with EDAM and Markets+	Market Design Task Force	WMEG Principle
#7b & #12b - Parallel Path Flow & Interregional Coordination – Market Service <ul style="list-style-type: none">Expect that when the seam between any of the market (WEIM, WEIS, EDAM, Markets+, CAISO, SPP RTO) are present then there will be pushes to remove the barriers across the seam.Examples are both implemented and under development in the Eastern Interconnection.	Seams Task Force	Min RTO Functions