

Western Markets Exploratory Group

Consolidated Balancing Authority (CBA)

White Paper

June 2023

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1 Executive Summary

The Western Markets Exploratory Group (WMEG) is a group of utilities located in the Western Electricity Coordinating Council (WECC) who are interested in reviewing the impacts that regional organizations, organized markets, Regional Transmission Organizations (RTOs), regional planning, and regional tariff administration may have on neighboring markets and transmission systems. It appears likely that there will be several different organized markets, and market-related requirements developed in the WECC over the next several years.

The WMEG formed a Consolidated Balancing Authority (CBA) Task Force to develop an understanding of CBA issues, discuss how CBA operations may impact legacy Balancing Authority (BA) operations, and review how other regions have formed their CBA. The CBA Task Force also reviewed various operational issues and transitional steps taken by others as their markets evolved. The Task Force members evaluated approaches for how the desired CBA functions may be implemented as the WECC prepares to transition to multiple regional organizations, market operators, and potentially to an RTO.

This white paper summarizes some of the key issues regional organizations encountered when consolidating the BA functionality and how a CBA can impact the current functions for market operators, BA operators, transmission operators, and transmission providers. CBA benefits the entities joining by reducing costs through centralization of control center operations and support staff, compliance analysis and reporting for BA NERC standards, and support staff for tools, process, and applications. Additional benefits for Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) of energy and operating reserves can be realized under the different scenarios and market designs, including load diversity, resource optimization, and intermittent resource integration. The ability to effectively integrate and operate the CBA is dependent on available transmission capacity between the parties.

This white paper discusses possible approaches WMEG members may want to pursue in addition to the ongoing regional organized market development efforts. The white paper does not attempt to provide the exact approach nor create drafts of all the various documents that would be necessary to create a CBA. The White Paper does provide different potential configurations that could be initiated before or integrated with either of the two regional market development efforts underway, namely the California Independent System Operator (CAISO) managed Extended Day-Ahead Market (EDAM) and the Southwest Power Pool (SPP) managed Markets Plus (Markets+).

1.1 Current State of WECC

There are a number of utilities operating in the WECC region who manage their own balancing area. The CASIO is a CBA and operates two regional markets, manages a regional tariff, and executes the Transmission Service Provider (TSP) function. The West has four Reliability Coordinators (RCs), namely Western RC Services operated by the SPP, RC West operated by CAISO, BC Hydro RC, and Alberta Electric System Operator (AESO). There are also many BAs, Transmission Operators (TOPs), and TSPs who coordinate with their RC to maintain reliable operations of the WECC transmission system.

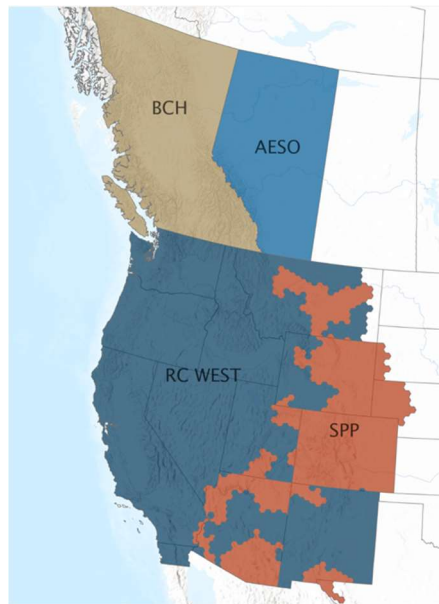


Figure 1. Reliability Coordinators Operating in WECC¹

The WECC has multiple energy markets currently in operation, including a bilateral market, the existing CAISO integrated market, the CAISO managed Western Energy Imbalance Market (WEIM), and the SPP managed Western Energy Imbalance Service (WEIS) Market. Over the last several years, many WECC entities have started the transition to organized markets with their participation in the WEIM and WEIS. The SPP has also announced the expansion of their RTO to the West, in April of 2026, with several WECC entities evaluating the benefits of joining the SPP RTO West. It is anticipated that individual organizations and regional collaborations will change the footprints of the existing RCs, BAs, and TSPs, as well as the WEIM and WEIS, as organizations transition from their current state to their desired final configuration. The CAISO integrated market does, and SPP RTO West will, use a CBA configuration, while the other developing market designs (i.e. EDAM and Markets+) contemplate the retention of the individual BA configuration.

1.2 Consolidated Balancing Authority's Operations

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 operator of a CBA needs the ability to adjust generation to account for the real-time changes in supply and demand. The exact way this is done will vary based on the tools available to the CBA. The CBA participants will need to determine who has the unit commit authority and how they will compensate each other for energy or use of capacity transferred between parties. For those CBA participants who are participating in an organized market, the CBA can coordinate with the market operator (MOP) to have the market clear the resources necessary to meet the demand for both energy and ancillary services required to respond to the instantaneous changes in supply and demand. The CBA can either coordinate directly with each TSP

¹ WECC State of Interconnection. <https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Western-Interconnection.aspx>

or MOP within their footprint to ensure the necessary ancillary services are secured through the TSP's OATT or through the MOP if they are also operating an ancillary services market (ASM). The CBA will coordinate schedules crossing the CBA boundary with the adjacent BAs and will coordinate with the RC as required in the NERC Standards to address any operational issues. The CBA maintains and manages the inadvertent energy account with other external BA operators. There may no longer be a need for each legacy BA to manage their ACE or track their inadvertent energy, for the CBA or MOP, as applicable, will settle all energy produced and consumed based on the associated governing documents.

2 Legislative and Regulatory Changes

The US Congress passed the Federal Power Act of 1992 which changed the authority of FERC. In response, FERC issued a "Mega-NOPR" on March 29, 1995, that questioned the role of transmission in reducing competition in wholesale electricity markets.

2.1 FERC Order 888

On April 24, 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888, which required public utilities to provide open access transmission service on a comparable basis to the transmission service they provide themselves. Key provisions in this Order are the following²:

1. Required that all transmission owners, subject to FERC jurisdiction, provide wholesale transmission services to all parties under the same terms and conditions that they provide service to their own generation, with the exception that utilities were able to reserve transmission for service to their own native loads (meaning end users of the utility).
2. Required utilities to functionally separate generation, transmission, power control, and distribution activities.
3. Identified six ancillary services that utilities must provide in adjunct with transmission service and allowed utilities to develop rates for these services.
4. Found that if stranded costs are caused by departing wholesale customers, the utility could recoup these costs from the departing customers so long as the utility first tried to mitigate them.
5. Encouraged, but did not require, utilities to create Independent System Operators (ISOs) and laid out criteria for FERC's approval of them.

FERC's goal in issuing the Order was to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower-cost power to the nation's electricity consumers. Order 888 put in place several key conventions that still drive the way the electricity industry operates today.

Wholesale trading expanded quickly after Order 888 was issued, growing from approximately 100 million kWh in 1996 to close to 4.5 billion kWh in 2002. However, until states began restructuring, the only buyers were still the utilities. Restructuring in some key states including California, New York, and

² Energy KnowledgeBase summary of FERC Order 888. <https://energyknowledgebase.com/topics/ferc-order-888.asp>

Pennsylvania began in the late 1990s, opening the door for marketers and generators to sell directly to end-use customers.

2.2 NERC's Response to Order 888

NERC formed several groups to debate the issues raised in the NOPR and to provide FERC comments on various proposals and their potential impact on reliability. NERC also provided recommendations on how to maintain reliability. The following are some of the areas addressed:

1. Wide Area Coordination of Reliability
2. Ancillary Services
3. Open Access Same-Time Information System (OASIS) provisions
4. Interchange Scheduling

NERC took on changes in their Standards to respond to the suggested changes and what was finally adopted in FERC Order 888. Some of these changes were:

1. Define the Functional Entities necessary to maintain reliability and establish the requirements for each function, including the new RC and TSP functions.
2. Develop a tool for those RCs to both share information and communicate with the BAs, TSPs, and transmission customers who submit their schedules in Tagging for the use of the transmission system irrespective of which TSP sold the service. This tool, known as the Interchange Distribution Calculator (IDC), would also assist in identifying the needed curtailment of flow on the transmission system based on curtailing transmission service aligned with FERC Order 888 priority of service.
3. Adjust Standards to reflect the requirements for Ancillary Services
4. Develop the function and operations of the OASIS
5. Develop and implement Tagging by fax for Interchange Scheduling

The response by the various utilities impacted by FERC's Order 888 was varied and somewhat unique. Some utilities were members of long-standing organizations that used this framework to determine their next best steps forward to meet these new regulatory challenges. Other utilities created new organizations to determine how they would meet these new regulatory challenges. Others faced additional legislative and regulatory drivers that took those entities down yet a different path.

3 Consolidated Balancing Authority (CBA)

There is no one clear best approach for forming a CBA³. Below, the Task Force briefly discusses the paths that three different entities followed to form their CBA. Each of these entities took a unique path before ultimately arriving at very similar configured CBAs, with each supported by an organized market, with sophisticated market tools and processes, that enables the CBA, working with the MOP and RC, to reliably operate the balancing area and meet the applicable NERC reliability standards. Each of these

³ U.S. Department of Energy, Analysis Methodology for Balancing Authority Cooperation in High Penetration of Variable Generation, February 2010. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19229.pdf

entities did have some authority over transmission service prior to the CBA starting operations which enabled them to effectively manage the available transmission capacity, including creating regulating reserve areas as necessary, to best serve the CBA's needs.

3.1 Evolution for CAISO

The California legislature passed AB 1890 in 1996 that placed in motion the creation of the California Independent System Operator (CAISO) and the California Power Exchange (CPX), with both organizations starting operations in 1998. AB 1890 also ushered in retail competition for the state of California, which directly impacted the three investor-owned utilities (IOU) who served roughly 70% of California's retail load.

The CAISO took over the management of the transmission services for the three IOU, with the three IOU retaining ownership of their transmission and distribution facilities. The CAISO managed services included managing the CBA for the three IOU's jurisdictional areas, operating the real-time and ancillary services markets, the TSP function, and management of transmission usage and congestion. The CPX was an independent market clearing exchange that originally cleared only day-ahead energy market submissions before adding a forward energy market in 1999 which cleared bids for up to six months out before ceasing operations in early 2001. The WECC, during this period, was the RC for the entire West.

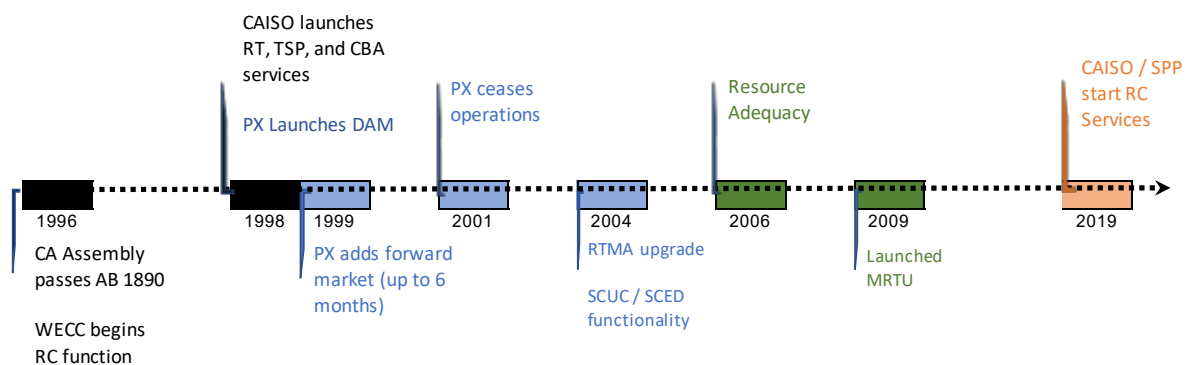


Figure 2. CAISO Development Timeline

The CAISO has continuously provided the same basic services since taking on those responsibilities in 1998. The original operational approach had the CAISO operators looking out roughly 10 minutes and then using incremental and decremental price sheets to determine the best real-time market adjustments for the participating generation units. CAISO enhanced this process in 2002 when they added the Automated Dispatch Instructions (ADI) functionality and created a must offer requirement for generation units participating in the market or connected to the CAISO managed transmission system. The next significant enhancement was the launch of the RTM Application (RTMA) in 2004. The RTMA provided the operators with the ability to look out roughly two hours ahead of the dispatch interval and gave the operator tools to determine a SCED, which helped manage the costs for managing the transmission constraints between pricing zones, and a SCUC to ensure the appropriate generation is online and ready to meet the CBA's needs. The RTMA also included an uninstructed deviation penalty (UID) for units that did not meet their dispatch instructions. The CAISO continued to make incremental improvements between 2005 and 2008 which included resource adequacy requirements for load

serving entities (LSEs) in CAISO and the identification of transmission facilities to help relieve congested zones.

The CAISO launched the Market Redesign and Technology Upgrade (MRTU) in 2009. The MRTU built on CAISO's experience and added key functionality to improve both their market tools and CBA operations. Some of the new functionality included pricing and congestion management based on a locational marginal price (LMP), the use of a full network model that identifies the physical transmission constraints to determine the SCED and SCUC, a DAM that clears both energy and ancillary services, and a real-time market that has both an hour ahead market and a real-time 5-minute dispatch market.

WECC elected to spin off the RC function and responsibility to an independent organization called Peak in 2014. Peak performed the RC functions until ceasing operations in 2019 when RC West, Western RC Services, and BC Hydro RC began fulfilling the RC functions for select entities in WECC.

3.2 Evolution for MISO

The Midcontinent Independent System Operator, Inc., formerly named Midwest Independent Transmission System Operator, Inc. (MISO) is an ISO and a RTO providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States, Manitoba, Canada, and a southern United States region. The 15 states covered in whole or in part by MISO are Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin.

MISO was established as an ISO in 1998 after voluntary discussions by several transmission owners led to its formation. One year later, the first board of directors was elected. By the end of 2000, the organization had more than 70 employees. In 2001, FERC approved MISO as the nation's first RTO.

MISO began Reliability Coordination Services for its members in December of 2001. Day-ahead reliability studies and outage coordination processes were established to provide situational awareness to the operators in real-time. Real-time monitoring of topology, power flow, reactive power, and voltages were done by the RC to ensure the reliability of the power grid. MISO built on these services in January of 2002 when they implemented real-time scheduling, tagging, and tariff administration services.

MISO launched their new Energy Markets in April 2005. These new energy markets provided a DAM and Forward Reliability Assessment and Commitments that were completed prior to the operating day. Real-time Intra-day Reliability Assessment and Commitment process committed additional resources to meet load, manage constraints, and ensure adequate operating reserves to ensure reliability. A Unit Dispatch System executed every 5 minutes, looking out ten minutes, ensured a balanced solution of generation and load while managing constraints. MISO established emergency protocols with the local BAs to manage energy shortage and surplus conditions. This newly created wholesale electricity market settled roughly \$2 billion in transactions each month. During this period, MISO grew its employee base to more than 600 staff and moved the corporate headquarters and operations center under one roof in Carmel, Indiana.

To complement their DAM and RTM, MISO added an ASM on January 6, 2009. The combined markets provide energy and operating reserves and regulation and response services supporting reliable transmission services. MISO became the BA Operator and took on the responsibility for most of the

NERC BA Standards. A few requirements remained with the local BA and were identified in a compliance matrix document. MISO was also the administrator for the reserve sharing group.

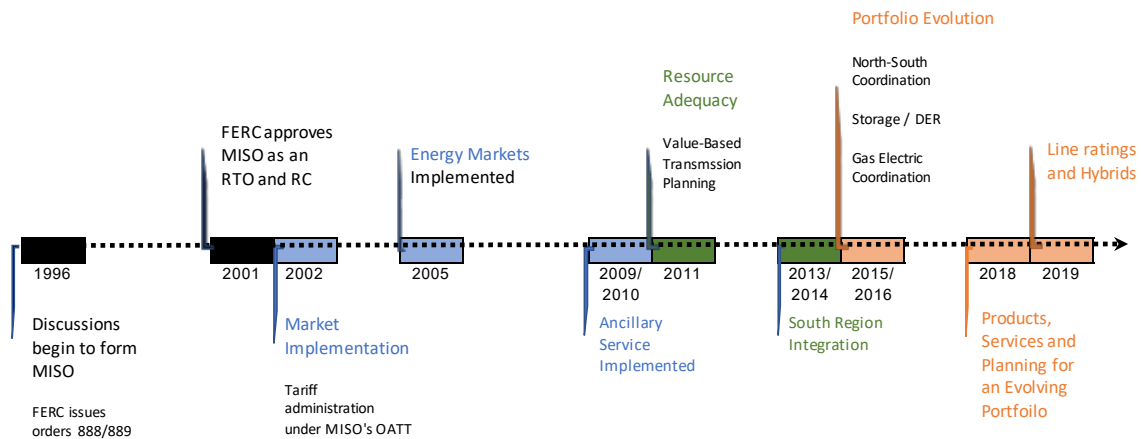


Figure 3. MISO Development Timeline

3.3 Evolution for SPP

SPP was formed in 1941 to “pool” utility resources, including transmission and generation, to meet the war time need for Aluminum. The utilities agreed to share their resources and coordinate plans to serve that war need. During and after the war, SPP continued to exist as a loose confederation of those utilities even though SPP had no staff and only a one-page paper agreement of cooperation. The next change for SPP came when they took on the role of one of the NERC Regional Councils in 1968. This new role was created when the electric industry formed national and regional organizations to document rules that would help maintain system reliability in response to the widespread blackouts in the late 1960’s and early 1970’s.

SPP continued their focus on improving reliability which led to the implementation of a telecommunication network for the member utilities to share data in 1980 and an automated operating reserve sharing system in 1981. During this time, SPP staff grew from one director to about 10 employees. Because of these roles and the increased responsibilities and expected need for independence, SPP incorporated as a not-for-profit corporation in 1994.

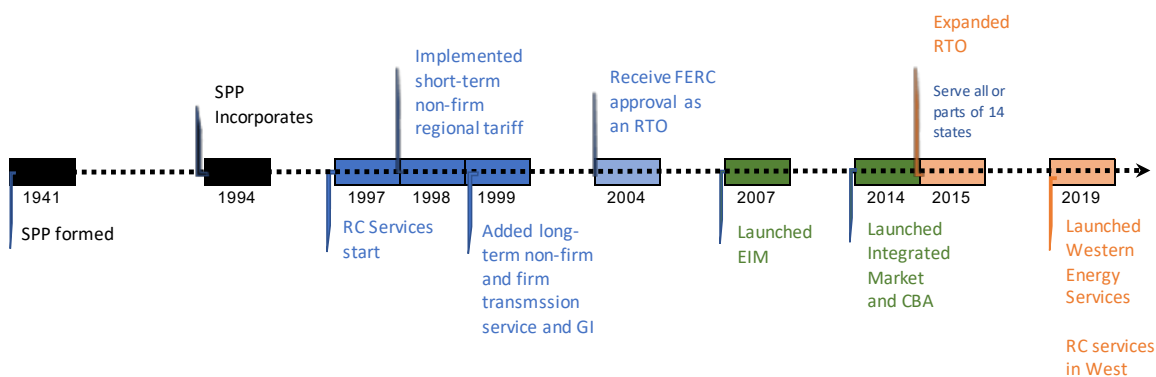


Figure 4. SPP Development Timeline

3.3.1 SPP Response to NERC and Order 888

SPP members began discussing how a regional tariff could meet the FERC NOPR expectations, provide efficiencies for managing the transmission system, and increase the efficiency of the wholesale markets by reducing the burden of “pancaked” transmission service. SPP members realized that SPP would be the best organization to take on the function of [reliability coordination](#). In order to provide the RC function, SPP invested in personnel and an EMS in order to assess the reliability of the transmission system as well as forecast any issues that would be faced in the near term. With this effort, SPP implemented the RC function in 1997 and took on those responsibilities.

SPP members also realized that if, as proposed by NERC, transmission service would be curtailed based on the flow of that service, they would push forward with a regional transmission tariff development to sell the use of the transmission service using flow-based analyses. SPP implemented the associated tariff changes in stages:

- 1998, implemented a regional tariff with Short Term, Non-Firm, Point-to-Point Transmission Service
- 1999, added Long Term, Firm and Non-Firm, Point-to-Point Transmission Service
- six months later added the remaining Order 888 Transmission Services and Generator Interconnections

3.3.2 SPP Regional Tariff Implications for BAs

FERC required that the TSP provide the defined Ancillary Services but also allow the transmission customer to self-provide those services. SPP specified in their tariff that the transmission customer could self-provide by paying the Ancillary Services rate in each of the affected BAs, and if they did not self-provide, SPP would arrange with those BAs for the Ancillary Services.

1. For regulation, operating/supplemental reserves, and imbalance, the rates would then be based on the BA’s existing published rates.
2. Physical losses for each schedule were determined by calculating the energy loss associated with moving energy from the Source to the Sink, with such losses then distributed to the impacted BA.
3. Note that the Source and Sink BAs within the SPP footprint would be the only ones approving the Tag now that a single transmission service request facilitated the desired transmission service flowing across several transmission owners’ systems.
4. Voltage control would be provided by the existing provisions of the host TOP.

3.3.3 SPP Wholesale Market Development

In 2007, SPP Implemented the Energy Imbalance Market (EIM), a 5-minute real-time market. In that market, SPP would dispatch all offered resources (generation or load control) to meet the full obligation (load – self schedule resources) of the market footprint, irrespective of the BA. The BAs were still responsible for providing the required Ancillary Services, but the market replaced the provision of energy imbalance for both load and generation.

The EIM required the BA function to include the market dispatch in their Net Scheduled Interchange (NSI). This would increase a BA’s exports if their offered resources were dispatched to meet the needs

of another BA. Conversely, the receiving BA's NSI would reflect the import of the market dispatch. This change in NSI was provided every 5 minutes by SPP based on the market dispatch and a calculation of each BA's NSI. This is very similar to the WEIM and WEIS implementations, although there are differences in how this information is provided.

Also, SPP sought and was approved for a waiver for Inadvertent Energy reporting, to report on a market footprint basis for all the BAs but to track each BA's Inadvertent for use by NERC for any need to resolve interconnection issues, as well as by SPP to assist in Inadvertent payback.

3.3.4 SPP Integrated Marketplace and CBA

In 2014, SPP implemented the Integrated Marketplace and CBA that added the DAM and ASM as well as financial Transmission Congestion Rights. The members recognized that for SPP to be a BA, it would need dispatch authority of the resources to meet the NERC BA requirements. The members also recognized that by obtaining those resources using markets, there would be savings from both the amount of ancillary services required and the cost to provide those services.

One issue that SPP faced was that the BA, under NERC Standards, is responsible to ensure that the metering for all its ties is provided and maintained. Those meters are normally installed and maintained by the transmission owner. SPP added an agreement to its tariff that requires the transmission owners to provide and maintain the metering required for the SPP CBA. There have been no significant changes in the SPP CBA functions post 2014.

4 CBA Potential Configurations

In considering the various ways to look for benefits in consolidation of BA functions in the West, the other functions that have been discussed by the Task Force (see Appendix A) are currently performed by the same entities as those performing the current BA functions. To consider options, it is important to understand how the BA function is related, especially to the TSP and RC functions. Current ISO/RTO, for the most part, started as a TSP and/or RC (but both before), and then added the CBA functions later as markets matured or were implemented, with few taking on a limited TOP role. The availability and management of the transmission system is a key for effectively managing the CBA. This could require regulating reserve area limitations to respect transmission capacity availability.

In the WMEG, there is discussion about consolidation of the tariffs, which would imply the TSP function. The NERC standards and functional model does have some interactions between the TSP and the BA, but those interactions are mostly either by data exchanges, as in the interchange schedules, or by telephone. This is how an RTO/ISO can perform as the TSP before taking on any part of the BA functions. This implies that two or more BAs could consolidate balancing areas while their TSP functions could remain with each of the legacy BA. However, the consolidated balancing areas would need to be managed by one BA.

The RC function in the West is currently provided by RC West, Alberta, British Columbia, and Western RC Services. This is somewhat of an efficient arrangement as they are also market operators which rely on an extensive oversight of the grid in their market as well as methods to forecast and anticipate future states of the grid. Also, with the discussion of DAMs and unit commitment in EDAM and Markets+,

these markets could then consider not just generation capacity to produce energy but also for the ancillary services that are used to meet the requirements of the BA. This would be a natural evolution of market products to support those who take on the BA functions. As such, since the WMEG is assessing the future that looks to contain these DAMs, the WMEG can consider just allowing those markets to evolve with the BA function. Absent that evolution, the following options can be considered by the WMEG as either interim steps to meet the requirements or obtain the benefits of consolidating the BA function:

The Task Force discussed multiple paths that could be used or evolved to obtain the benefits of a CBA. These benefits include:

1. Reduction in Regulation Reserve requirements (Contingency Reserves requirements are already reduced by Reserve Sharing Groups)
2. Reduction in the cost of the needed resources to meet the Regulation or Contingency Reserve requirements
3. Relief from the NERC compliance requirements of a BA

Below are a few of these optional paths with each addressing the above benefits as well as the impact on resources, BA functions, NERC compliance, and costs.

4.1 Netting ACE – CBA Net

The general premise of this option is to net the ACE values of two or more BAs. The net would then be allocated to those BAs to control to, rather than using their own ACE. Normally this is to provide the proportion of the net to only those BAs with an ACE in the same direction as the net ACE. Each BA would still need to hold their existing Regulation Reserve requirement. The benefit is only in reducing the movement of resources and any maintenance or operating expenses; it does not have any impact on how those BAs would report inadvertent energy. There is minimal expense as this can be done by one entity and with minimal system impact.

In this option there would be no change in any RC, BA, TSP, or TOP responsibilities to NERC Standards.

4.2 Regulation Reserve Sharing – CBA Reg

In this option, the premise is an additional step to combine 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. As this is reflecting additional impact on the operation of the Bulk Electric System, it might require a waiver from NERC/FERC (including any impact of inadvertent reporting) from some of the changes in the expectation of the BA NERC standards. Benefits that would be expected are reducing both the amount of regulation reserve requirements as well as the movement of resources. Compensation may be appropriate based on the allocation of the regional ACE and allocation in the reduction of regulation reserve requirement. Again, the cost to implement should be minimal, especially if based on an existing member performing the function but could be more if a new entity were set up.

In this option there would be some NERC Standards that would be shared with the legacy BA. No changes to any of the RC, TSP, or TOP responsibilities.

4.3 Transfer Regulation and Operating Reserve responsibilities to a CBA – CBA Lite

For this option, 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). This option would require the CBA to register as a BA with NERC/FERC with shared responsibilities with the legacy BAs (including any impact of inadvertent reporting).

The benefits expected would be reducing both the amount of regulation reserve requirements, and possibly the cost of regulation or contingency response, as well as the movement of resources. Compensation would be appropriate based on the method of use of the resources provided. Resources could be submitted with costs that could be used to deploy the resources and then for determining compensation. Cost would be based on whether an existing member performs the function or if a new entity is set up.

In this option some of the NERC Standards would be on the new entity with the rest retained by the legacy BAs. No changes would be needed to any RC, TSP, or TOP responsibilities, although they would interact with the CBA as required instead of the legacy BA (will show this in the NERC BA standards chart). As stated above, the MOP would be the most obvious entity to take on the CBA operations but could also be the RC or an independent organization.

4.4 Transfer BA responsibilities to a CBA (limited ones retained in BAs) - CBA Full

In this option all 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. This would require the CBA to plan and arrange with each legacy BA for deployment of resources. The CBA would deploy the provided resources to meet the regional requirements for regulations as well as respond to a contingency.

The benefits would be based on reducing both the amount of regulation reserve requirements, the cost of regulation or contingency response, as well as the movement of resources.

This implementation would require registration fully as a BA with NERC/FERC or with shared responsibilities with legacy BAs, which could include those BAs retaining the metering requirements of the BA function.

There would probably be appropriate compensation based on the method of use of the resources provided. In this option all the NERC Standards would be on the new entity with some portion as stated

above retained by the legacy BAs. No changes would be needed to any RC, TSP, or TOP responsibilities but they would interact with the CBA instead of the legacy BAs (will show this in the NERC BA standards chart). As stated above, the MOP would be the most obvious entity to take on the CBA but could also be the RC or an independent organization. This would be the highest cost if it involves the setup of an independent entity, but less if it is the MOP or RC.

5 Infrastructure Requirements

The actual infrastructure required for a CBA will depend on the desired configuration. As discussed above, there are some CBA configurations where the functionality will require very limited infrastructure to support their operation. Other configurations will require extensive communication networks, various software solutions, redundant control centers, and a considerable number of displays to provide the needed situational awareness.

5.1 Communication and Metering Infrastructure

The CBA will require a sufficiently robust communication system that allows the CBA to electronically interface with all members who operate generation and transmission assets. This communication system should have redundant paths to ensure uninterrupted communication between the CBA and each party. Inter-control Center Communications Protocol (ICCP) is standard data exchange over Wide Area Networks between utility control centers, ISOs, and RTOs. The metering infrastructure is usually handled by the transmission owner. The transmission owner enters an agreement with the CBA to install and maintain the appropriate metering infrastructure required on their transmission infrastructure to enable the CBA to effectively perform the BA functions. The transmission owner generally installs meters on their tie lines with adjacent transmission owners, at each generator station, at key load locations, and at other locations on their transmission infrastructure as required by the CBA. The values from these meters will be electronically transferred to the CBA operation center on a nearly real-time basis.

5.2 Energy Management System (EMS)

The CBA will need to install an EMS with an AGC package to manage the meter data that is coming into their system. The EMS system will enable the CBA to monitor their interties with adjacent systems and the overall performance of the balancing area. The CBA will also use this system to help manage the real-time balance of supply and demand. Depending on the CBA functionality, the BA may also use this information to commit and deploy generation to ensure sufficient operating reserves and ancillary services are available to effectively manage the CBA's ACE obligation.

5.3 Facility and Personnel

A significant investment for standing up a CBA is the need for two larger control centers residing in independent hardened structures that are located sufficient distance apart to minimize the risk of both centers being impacted by a notable event. These control centers will also need duplicative operating infrastructure with emergency backup energy supply and a considerable number of displays to provide the needed situational awareness. The facilities will need to meet all the NERC criteria for primary and backup control centers.

The number of personnel to operate and manage a CBA will be somewhat proportional to the desired functionality. There will be a number of operational personnel who will be directly monitoring the system and actively managing changes required to perform the BA functions. There will also be a significant number of technical support staff who will address computer and communication system issues on a real-time basis to ensure the operators maintain full visibility of the CBA.

The typical configuration of a fully functioning CBA, MOP, and RC control center will have 8-10 desks in operation around the clock. The number of desks will depend on the physical size of the CBA footprint. Functions included in this type of configuration include RC, BA, Scheduling, Tariff Administration, market operator positions for unit commitment, unit dispatch, generation dispatcher, and shift management. These desks will typically have six operators for each desk to provide coverage for all hours. Six operators on a six-week schedule allows for training and coverage for absences, such as for vacation or illness. There will also need to be management and support staff for the rotating shifts functions.

In addition to real-time staff and support, there will be DAM operators, forward reliability assessment and commitment support, reliability engineers, and outage coordination support.

5.4 Market Products

There are various market products that will help support the operations of a CBA. Energy markets help meet the energy demands of the CBA. Unit commit authority helps ensure sufficient generation is on-line and ready to serve load. Ancillary service markets help with committing generation units to respond to load uncertainty and unexpected changes in unit operations. With the higher saturation levels of variable energy resources, the ability to commit additional generation units based on this variability is proving to be necessary.

The DAM will clear the bid in load and reserve requirements while managing the constraints on the grid. Ramp may be part of the process that can be cleared in the DAM. DAM should be followed by a reliability assessment and commitment process using forecasted load and additional security constrained commitment process to manage congestion. DAM and SCUC processes should align with the gas operating day to ensure resources can procure fuel.

Current day processes should include SCUC and SCED processes and applications. Additional ramp capability products and/or look ahead dispatch and look ahead commitment processes can enhance reliability with near term changes to system conditions. The look ahead dispatch can ensure adequate ramp for system changes and can also be used as a resiliency tool for reliability when system failures occur to Unit Dispatch System (UDS) or Communications.

Adding a short-term reserve product for replenishing operating reserves to an ancillary service market will help with reliability and reflect the commitment process by operators that are ensuring adequate resources for near term changes to load, scheduled interchange, congestion management that is trapping generation behind the constraint, and forced outages.

6 Benefits of a CBA

Centralized security constrained unit commitment and dispatch will optimize the resources to meet load and operating reserve requirements. Operating reserves requirements will be less for a larger footprint with an Energy and Ancillary Service Market. Reduces operations and support staff for entities that perform this function as a BA.

6.1 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.

6.2 Ancillary Services Impacts

Energy and Ancillary Service Markets 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.

6.3 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 variable energy 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 variable energy resources 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.

7 Recommendation

The development of the new DAM, namely EDAM and Markets+, is in full swing. These development efforts have not contemplated sharing of the BA responsibilities. The WMEG should explore the sharing of the BA functions all the way to the consolidation of BAs during this interim period. As the market development efforts proceed, the WMEG members may also want to conduct a more complete cost and benefit(s) analysis for some of the options listed above in Section 4 or even an evolution of one or more of those options.

8 Abbreviations

ACE	Area Control Error
AGC	Automated Generation Control
ASM	Ancillary Service Market
BA	Balancing Authority
CAISO	California Independent System Operator
CBA	Consolidated Balancing Authority
CPX	California Power Exchange
DAM	Day-Ahead Market
EDAM	CAISO Extended Day-Ahead Market
EIM	Energy Imbalance Market for SPP East entities
EMS	Energy Management System(s)
E-Tag	NERC Electronic Tag
FERC	Federal Energy Regulatory Commission
GOP	Generator Operator(s)
IOU	Investor-Owned Utilities
LMP	Locational Marginal Price
LSE	Load Serving Entity
Markets+	SPP Markets Plus
MISO	Midwest Independent System Operator
MOP	Market Operator(s)
MP	Market Participant(s)
MW	Megawatt
NERC	North American Electric Reliability Cooperation
NSI	Net Schedule Interchange
OATT	Open Access Transmission Tariff
OASIS	Open Access Same-time Information System
RC	Reliability Coordinator(s)
RTM	Real-Time Market
RTMA	Real-Time Market Application
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SPP	Southwest Power Pool
TOP	Transmission Operator(s)
TSP	Transmission Service Provider(s)
WECC	Western Electricity Coordinating Council
WEIM	CAISO Western Energy Imbalance Market
WEIS	SPP Western Energy Imbalance Service
WMEG	Western Markets Exploratory Group

Appendix A – NERC Functional Model

The NERC Functional Model was created to help guide the development of reliability standards and how to measure compliance of those standards. As the functions for maintaining reliability of the Bulk Electric System was already shared among different entities with similar if not the same functions, NERC issued and revised the NERC Functional Model to name those entities and their functions. As the reliability standards became more settled, NERC has not continued to update the NERC Functional Model, the last revisions were in 2018. It does, however, provide a good list of functions to maintain reliability and groups them in entities that can be used to understand those functions and:

1. Discuss what functions would be considered for consolidation,
2. Compliance responsibility that would be transferred in consolidation,
3. Shared responsibilities
4. And required agreements between entities

Review of Entities

The NERC Functional Model covers the following entities:

1. Balancing Authority (BA)
2. Transmission Service Provider (TSP)
3. Transmission Operator (TOP)
4. Reliability Coordinator (RC)

In the following sections, each of these will be introduced along with the functions in the NERC Functional Model. This is to provide the framework for further discussions about West BA consolidation and which functions should be considered.

Balancing Authority

The responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.

Ahead of Time

1. Receives operating and availability status of generating units and operational plans and commitments from Generator Operators (including annual maintenance plans) within the Balancing Authority Area.
2. Receives annual maintenance plans from Generator Owners within the Balancing Authority Area.
3. Receives reliability evaluations from the Reliability Coordinator.
4. Receives final approval or denial of a request for an Arranged Interchange from the Interchange Authority(ies).
5. Compiles load forecasts from Load-Serving Entities.

6. Develops agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submits integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
8. Confirms Arranged Interchange with Interchange Authority(ies).
9. Confirms Ramping capability with Interchange Authority(ies).
10. Implements generator commitment and dispatch schedules from the Load-Serving Entities and Generator Operators who have arranged for generation within the Balancing Authority Area.
11. Acquires reliability-related services from Generator Operator.
12. Receives dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
13. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
14. Receives information from Load Serving Entities on self-provided reliability-related services.
15. Coordinates system restoration plans with Transmission Operator.
16. Provides generation dispatch to Reliability Coordinators.

Real-Time

17. Coordinates use of controllable loads with Load-Serving Entities (i.e., interruptible load that has been bid in as a reliability-related service or has agreed to participate in voluntary load shedding program under resource/reserve deficiency situations).
18. Receives loss allocation from Transmission Service Providers (for repayment with in-kind losses).
19. Receives Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.
20. Receives operating information from Generator Operators.
21. Provides Real-time operational information for Reliability Coordinator monitoring.
22. Receives reliability alerts from Reliability Coordinator.
23. Complies with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
24. Verifies implementation of emergency procedures to Reliability Coordinator.
25. Informs Reliability Coordinator and Interchange Authority(ies) of Confirmed Interchange changes (e.g., due to generation or load interruptions) involving its Balancing Authority Area.
26. Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in Real-time.

27. Directs Transmission Operator (or Distribution Provider) to reduce voltage or shed load if needed to ensure balance within its Balancing Authority Area.
28. Directs Generator Operators to implement redispatch for congestion management as directed by the Reliability Coordinator.
29. Implements corrective actions and emergency procedures as directed by the Reliability Coordinator.
30. Implements system restoration plans as directed by the Transmission Operator.
31. Directs Transmission Operator to implement flow control devices.
32. Receives information of Implemented Interchange and Confirmed Interchange Curtailments from Interchange Authority(ies).

After the hour

33. Confirms Implemented Interchange with Confirmed Interchange provided by the Interchange Authority(ies) after the hour for “checkout.”
34. Confirms Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities after the hour for “checkout”.

Transmission Service Provider

The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.

Ahead of Time

1. Receives Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from Planning Coordinator, Transmission Planner, Transmission Operator and Reliability Coordinator, and coordinates Available Transfer Capability with these entities and other Transmission Service Providers.
2. Receives transmission Facility Ratings from Transmission Owners.
3. Receives transmission expansion plans identified by the Planning Coordinator to help determine ability to accommodate long-term Transmission Service requests.
4. Approves or denies Transmission Service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.
5. Confirms validity of Transmission Service requests indicated in the Arranged Interchange with Interchange Authority(ies).
6. Develops agreements or procedures with Transmission Owners.
7. Receives final approval or denial of Arranged Interchange from Interchange Authority(ies).

Real-Time

8. Receives Confirmed Interchange implementation (including curtailments) from the Interchange Authority(ies).
9. Receives reliability alerts from Reliability Coordinator.
10. Provides loss allocation to Balancing Authority(ies).

Transmission Operator – TOP

The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission Facilities.

Ahead of Time

1. Coordinates restoration plans with Reliability Coordinator, Transmission Operators, Balancing Authorities, and Distribution Providers.
2. Receives maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receives Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receives reliability evaluations from the Reliability Coordinator.
5. Develops agreements with adjacent Transmission Operators for joint transmission facilities.
6. Defines Total Transfer Capabilities and System Operating Limits based on facility information provided by the Transmission Owners and Generator Owners and assistance from Reliability Coordinator.
7. Arranges for reliability-related services from Generator Operators.
8. Develops contingency plans, and monitors operations of the transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provides facility and operating information to the Reliability Coordinator.
10. Provides to the Transmission Planner information on the capability to curtail (reduce) and shed load during emergencies.
11. Provides Total Transfer Capabilities and System Operating Limits to, and coordinates Available Transfer Capability with, Transmission Service Provider.
12. Receives operating and availability status of generating units from Generation Operators including status of automatic voltage regulators.
13. Develops operating agreements or procedures with Transmission Owners.

Real-Time

14. Coordinates load shedding with, or as directed by, the Reliability Coordinator.

15. Provides Real-time operations information to the Reliability Coordinator and Balancing Authority.
16. Notifies Generator Operators of transmission system problems (e.g., voltage limitations or equipment overloads that may affect generator operations).
17. Requests Reliability Coordinator to assist in mitigating equipment overloads. (e.g., redispatch, transmission loading relief).
18. Deploys reactive resources from Transmission Owners and Generator Owners to maintain acceptable voltage profiles.
19. Directs Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.
20. Implements flow control device operations for those ties under the Transmission Operator's purview as directed by the Balancing Authorities or Reliability Coordinator.
21. Receives reliability alerts from Reliability Coordinator.
22. Directs Balancing Authorities and Distribution Providers to implement system restoration plans.

Reliability Coordinator – RC

The entity that is the highest level of authority who is responsible for the Reliable Operation of the BES, has the Wide Area view of the BES, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

Ahead of Time

1. Coordinates with other Reliability Coordinators, Transmission Planners, and Transmission Service Providers on Transmission limitations.
2. Receives Facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.
3. Receives generation dispatch from Balancing Authorities and issues dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).
4. Receives integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.
5. Receives Transmission and generation maintenance plans from Transmission Owners and Generator Owners, respectively, for reliability analysis.

6. Develops Interconnection Reliability Operating Limits, based on Transmission Owners' and Generator Owners' specified equipment ratings, and provides them to Transmission Operators.
7. Assists Transmission Operators in calculating and coordinating System Operating Limits.
8. Provides reliability analyses to Transmission Operators, Generator Operators and Balancing Authorities in its area as well as other Reliability Coordinators.
9. Directs Generator Owners and Transmission Owners to revise generation and transmission maintenance plans that are adverse to reliability.
10. Receives balancing information from Balancing Authorities for monitoring.
11. Receives final approval or denial of Arranged Interchange from Interchange Authority.
12. Provide IROLs and TTC to the Transmission Service Provider for ATC calculation.
13. Develops operating agreements or procedures with Transmission Owners.
14. Coordinates with Transmission Operators on system restoration plans, contingency plans, and reliability-related services.

Real-Time

15. Coordinates reliability processes and actions with and among other Reliability Coordinators.
16. Receives Real-time operational information from Balancing Authorities, Interchange Authority(ies) and Transmission Operators for monitoring.
17. Issues reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Authority(ies), Regional Entities and NERC.
18. Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to Transmission Operators, Balancing Authorities, Generator Operators, Distribution Providers, and Interchange Authority(ies).
19. Specifies reliability-related requirements (e.g., reactive requirements, location of operating reserves) to Balancing Authorities.
20. Receives verification of emergency procedures from Balancing Authorities.
21. Receives notification of Confirmed Interchange changes from Balancing Authorities.
22. Orders redispatch of generation by Balancing Authorities.
23. Directs use of flow control devices by Transmission Operators.
24. Responds to requests from Transmission Operators to assist in mitigating equipment overloads.

Appendix B – BA NERC Standards

Standard	Description	"Blank" Means - Legacy BA has Compliance performs the Function			
		"CBA Shared" Means - Legacy and CBA share Compliance			
		CBA Net	CBA Reg	CBA Lite	CBA Full
BAL-001-2	Real Power Balancing Control Performance		CBA	CBA	CBA
BAL-002-3	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event			CBA	CBA
BAL-002-WECC-2a	Contingency Reserve			CBA	CBA
BAL-002-WECC-3	Contingency Reserve			CBA	CBA
BAL-003-2	Frequency Response and Frequency Bias Setting		CBA	CBA	CBA
BAL-004-WECC-3	Automatic Time Error Correction		CBA	CBA	CBA
BAL-005-1	Balancing Authority Control		CBA	CBA	CBA
CIP	Critical Infrastructure Protection		CBA Shared	CBA Shared	CBA
COM-001-3	Communications			CBA Shared	CBA
COM-002-4	Operating Personnel Communications Protocols			CBA Shared	CBA
EOP-004-4	Event Reporting			CBA Shared	CBA
EOP-008-2	Loss of Control Center Functionality		CBA Shared	CBA Shared	CBA
EOP-011-1	Emergency Operations		CBA Shared	CBA Shared	CBA
EOP-011-2	Emergency Preparedness and Operations		CBA Shared	CBA Shared	CBA
EOP-011-3	Emergency Operations		CBA Shared	CBA Shared	CBA
INT-006-5	Evaluation of Interchange Transactions			CBA Shared	CBA
INT-009-3	Implementation of Interchange		CBA Shared	CBA Shared	CBA
IRO-001-4	Reliability Coordination - Responsibilities and Authorities		CBA Shared	CBA Shared	CBA
IRO-006-5	Reliability Coordination - Transmission Loading Relief (TLR)			CBA Shared	CBA
IRO-006-WECC-3	Qualified Path Unscheduled Flow (USF) Relief		CBA Shared	CBA Shared	CBA
IRO-010-4	Reliability coordinator Data Specification and Collection			CBA Shared	CBA
IRO-017-1	Outage Coordination			CBA Shared	CBA
MOD-004-1	Capacity Benefit Margin			CBA Shared	CBA
MOD-031-3	Demand and Energy Data			CBA Shared	CBA
MOD-032-1	Data for Power System Modeling and Analysis			CBA Shared	CBA
NUC-001-4	Nuclear Plant Interface Coordination			CBA Shared	CBA
PER-003-2	Operating Personnel Credentials			CBA Shared	CBA
PER-005-2	Operations Personnel Training			CBA Shared	CBA
TOP-001-5	Transmission Operations			CBA Shared	CBA
TOP-001-6	Transmission Operations (Future)			CBA Shared	CBA
TOP-002-4	Operations Planning			CBA Shared	CBA
TOP-003-4	Operational Reliability Data			CBA Shared	CBA
TOP-003-5	Operational Reliability Data (Future)			CBA Shared	CBA
TOP-010-1(i)	Real-time Reliability Monitoring and Analysis Capabilities			CBA Shared	CBA