Draft Recommendations

from the

Joint Outreach Team

U.S. DEPARTMENT OF ENERGY

Western AREA POWER ADMINISTRATION

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List of Acronyms

ACE	Area Control Error
ADI	ACE Diversity Interchange
ATC	Available Transfer Capability
BA	Balancing Authority
CPS	Control Performance Standards
CRSP	Colorado River Storage Project
CTS	Combined Transmission System
DOE	Department of Energy
DSS	Dynamic Scheduling System
DSW	Desert Southwest Region
EPAct of 1992	Energy Policy Act of 1992
EPAMP	Energy Planning and Management Program
EPTC	Electric Power Training Center
ESIF	Energy Systems Integration Facility
FERC	Federal Energy Regulatory Commission
IIS	Infrastructure Investment Study
IRP	Integrated Resource Planning
ITAP	Intra-hour Transaction Accelerator Platform
JOT	Joint Outreach Team
LAPT	Loveland Area Projects Transmission
LGIP	Large Generator Interconnection Procedures
MOD	Modeling, Data, and Analysis
NAESB	North American Energy Standards Board

NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
OASIS	Open Access Same-time Information System
PMA	Power Marketing Administration
RBC	Reliability Based Control
RMR	Rocky Mountain Region
RTO	Regional Transmission Organization
SNR	Sierra Nevada Region
TIP	Transmission Infrastructure Program
TSP	Transmission Service Provider
UGP	Upper Great Plains Region
VER	Variable Energy Resource
WACM	Western Area Colorado Missouri
WALC	Western Area Lower Colorado
WAPA	Western Area Power Administration
WASN	Western Area Sierra Nevada
WECC	Western Electricity Coordinating Council
Western	Western Area Power Administration

INTRODUCTION

The Department of Energy's (DOE) Power Marketing Administrations (PMAs) play a vital role in providing an electricity system that supports our Nation's economic competitiveness, security and prosperity. On March 16, 2012, DOE Secretary Chu sent a memorandum to the Administrators of the four PMAs, requesting their assistance in facilitating the transition to a more resilient and flexible grid while ensuring customers continue to receive value-added products and services at the lowest possible costs consistent with sound business principles. Embracing this challenge, staff from the Western Area Power Administration (Western) and DOE formed a Joint Outreach Team (JOT) to gather information from Western's customers, tribes, and stakeholders through a structured public outreach process. The robust interaction generated from the public process has resulted in the draft recommendations identified in this paper.

In response to input received during the stakeholder process, the JOT developed a set of principles that were used to help guide the development of the recommendations. The principles include:

- consider the unique attributes of Western's regions
- coordinate with Federal generating agencies (U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, and International Boundary and Water Commission)
- ensure that the beneficiary pays
- consider the existing efforts within Western
- ensure that Western stays within the limits of its authority

In addition to the guiding principles, the JOT recognizes that potential impacts of implementing any of the proposed recommendations, e.g. the potential for cost shifts, need to be part of the evaluation process with Western's customers, tribes, and stakeholders.

To continue meeting its statutorily defined mission, Western must also adapt and respond to additional obligations imposed by Congress, the Federal Energy Regulatory Commission (FERC), and the North American Electric Reliability Corporation (NERC) as a result of changing technologies and societal needs. For instance, Western is responsible for meeting new obligations and requirements for open access transmission service, reliable operations, and transmission development when its facilities are used to deliver the full spectrum of energy and energy-related products, including renewables, as well as transmission-related products and services to meet its customer's needs. Indeed, as our Nation's electricity system evolves, new opportunities arise for Western to continue to meet its core mission. Opportunities include a constructive role in addressing issues around cyber security, integrating and/or interconnecting new generating technologies into the Federal transmission system, and remaining fully compliant with the applicable mandatory reliability standards, among others.

Both Western and DOE recognize that resource adequacy and certainty for both funding and supporting personnel are fundamental to ensuring the successful implementation of the JOT's recommendations.

While the JOT recognizes that DOE is looking at energy solutions across multiple market sectors, e.g., wholesale and retail, based on customer, tribal, and stakeholder feedback and team expertise, as well as economies of scale, the JOT decided not to pursue any recommendations specifically targeted at energy efficiency, demand response, or electric vehicles. Further, a number of the areas addressed through the recommendations are considered on a regional basis, however, the recommendations presented below apply to all regions within Western. Some recommendations presented were developed to engage further collaboration among Western, its customers, tribes, and stakeholders along with other utilities in Western's 15-state footprint, while others focus more on harmonization internally among Western's regions and/or standardizing business practices across the organization.

To effectively position Western to continue meeting its core mission and the energy challenges of the twenty-first century, it must continually examine its organizational capabilities to ensure that it is properly structured with the appropriate resources to deliver its products and services as effectively as possible. Appropriate strategic planning processes must be in place for Western to make decisions within a strategic context and avoid reactive, piecemeal responses. Additionally, Western, its customers, tribes, and stakeholders must be open to innovation, change, and evolution so that the organization is suited to meet and address the future challenges of a dynamic energy industry. As an example in regulatory compliance, the areas of NERC Reliability Compliance and cyber security continue to place a heavy burden on Western's resources and merit a review to determine what potential efficiencies and/or increases in functional effectiveness could be gained through their consolidation under a single compliance organization.

To support the long-term vision outlined in Western's Strategic Plan and contemplated in the following recommendations, it is important that an enterprise planning process is in place to identify necessary future resources and prioritize long-term strategic planning activities, including:

- identifying, studying and implementing Western mission-related grid coordination, optimization, and consolidation of applications and best business practices

- supporting ongoing studies and recommendations that Western standardize its automation tools and other initiatives that incrementally and collectively contribute to grid reliability, resource optimization, cost management, potential revenue enhancement, and ways to incorporate new aspects of doing business

- incorporating policies and industry trends in long-term strategic planning contexts that ensure long-term viability and relevance and contribute to strengthening America's energy security, environmental quality and economic vitality

Collectively, these three elements provide for thoughtful, long-term strategies that account for regional differences where necessary, encourage the use and deployment of standardized tools and processes where those differences are not material, develop an organization architecture that is flexible, and allow for cost-effective oversight and management of technology tools and resources within Western to ensure a robust, mission-focused organization for the future.

RECOMMENDATIONS

Increasing Operational Efficiencies

The JOT identified several aspects of existing operations that Western may improve. Many of these recommendations build on work already being done by Western's customers and peers. Some of the recommendations within this section correspond with the recently completed Operations Study, a Western project where senior leadership retained an independent consultant in 2011 to review business practices across Western. Other recommendations in this section complement efforts underway by Western's peers, customers or that Western has previously evaluated.

Specifically, Western should determine the regulation reserve capacity required and available in each Balancing Authority (BA) or sub-BA; consolidate and administer the four Open-Access Same-time Information System (OASIS) websites under one site and one interpretation of the Tariff; and revise its Large Generator Interconnection Procedures (LGIP) to conform to changes recommended by WestConnect's LGIP Work Group. These are all efforts that could provide immediate improvements in efficiency and could relieve unnecessary redundancies and duplication.

An investigation of possibilities for consolidated rates across Western's regions may also begin promptly and could build upon previous efforts to identify such opportunities across some of Western's regions.

The recommendations within this section can be deployed quickly and concurrently depending on resource availability. More information about anticipated timeframes is included within the detail of each recommendation below.

Recommendation: Undertake an analysis to determine the regulation reserve capability that is required for each of Western's BAs or sub-BAs using a consistent methodology and criteria. Additional analysis should be conducted to determine the regulation reserve capability that is available from all dispatchable generation sources within each of Western's BAs or sub-BAs.

Why: Industry changes have occurred, prompting Western operators, under prudent utility practices, to analyze and evaluate existing regulating requirements in each of Western's BAs and determine whether the requirements may have changed. NERC has evolved away from the historic A1/A2 criteria for BA performance to the Control Performance Standards (CPS) under which BAs operate today. Additional advancements in BA performance have evolved including Reliability Based Controls (RBC) and Area Control Error (ACE) Diversity Initiative (ADI) that impact BA regulation reserve requirements. Both RBC and ADI are part of a separate recommendation.

Once this analysis has been completed, each Western BA would have to determine how much regulation capacity is required, and available, and how it may be used within the footprint of each BA/sub-BA. This can allow BA/sub-BA operators to manage existing resources more reliably and efficiently by identifying the amount of regulation capacity that is required to support current BA obligations and optimize the regulation capacity that is available to potentially support the integration of additional variable energy resources, increase reliability, reduce risk, and/or increase the flexibility of operations.

In summary, more effective utilization of regulation capacity improves the ability of Western's BA/sub-BA operators to follow their load and respond to contingencies, thus increasing the reliability of the interconnection.

Time Frame: The estimated time frame for completing this recommendation is less than one year for each Western BA and Sub-BA.

Recommendation: Consolidate Western's four OASIS sites within the Western Interconnection into a single OASIS site.

To ensure a uniform and integrated approach to posting Western's transmission information, products, and services, as well as to ensure one common interpretation and implementation of Western's Open Access Transmission Tariff, consolidate the posting and administration of Western's four separate existing OASIS sites within the Western Interconnection into one single OASIS site. Under Western's current multiple OASIS operating model, the potential for inconsistent interpretation and implementation of Western's OATT exists.

Why: Western currently has separate OASIS sites and NERC-registered Transmission Service Providers (TSP) for each region, and multiple TSPs posted on OASIS in some regions: SNR (TSP = WASN), DSW (TSP = WALC), RMR (TSP = LAPT and WACM), UGP (TSP = WAPA). Western currently administers multiple projects under a single TSP registration in DSW, and multiple Transmission Owners' facilities under a single TSP registration in UGP (i.e. the Integrated System).

The west-side regions utilize OATI WebOASIS and WebTrans software that is more consistent, and has similar Available Transfer Capability (ATC) methodologies required by the NERC Modeling, Data and Analysis (MOD) Standards. The UGP WebTrans software platform is significantly different, based upon Flowgate and Allocation requirements under Seams Agreements with Regional Transmission Organization (RTO) markets, and primarily utilizes Flow-based ATC Standards instead of the Contract-Path ATC approach commonly utilized in the west-side. These fundamental differences cannot be eliminated in the near future and therefore, consolidation of the west-side regions' OASIS sites is the initial focus.

Western has TSP compliance requirements for each OASIS site under FERC Orders, NERC Reliability Standards, and North American Energy Standards Board (NAESB) Standards and OASIS Posting Requirements. There are currently duplicative compliance postings on the multiple OASIS sites.

Potential outcomes include:

- Reduce confusion and difficulty experienced by transmission customers seeking transmission service across multiple regions. Reduce registration requirements for transmission customers.

- Reduce technical barriers to other Western-wide transmission products and services, such as inter-regional Non-Firm redirects.

- Reduce Western's overheads (e.g. maintenance/tracking, OASIS annual fees, NERC registries, etc), NERC reliability compliance exposure, and risks. Simplify ATC postings with posted paths located in common location(s). Simplify and consolidate business practices.

Time Frame: The estimated time frame for consolidating Western's four existing OASIS sites within the Western Interconnection into a single OASIS site is one to two years from initiation to completion.

Recommendation: Revise Western's Large Generator Interconnection Procedures (LGIP) to conform to changes recommended by WestConnect's LGIP Work Group and successfully implemented by several WestConnect participants.

Western should solicit feedback from customers, tribes, and stakeholders regarding proposed revisions to its LGIP through a separate *Federal Register* Notice and public comment period. The proposed LGIP revisions, based on the recommendations of the WestConnect LGIP Work Group, would:

- eliminate the feasibility study from the interconnection study process
- establish a six-month study cluster standard for all interconnection system impact studies
- allow only for good-faith facilities study cost estimates to be provided within 90 days
- replace the initial deposit and study deposit requirements with a single, two-level initial deposit requirement, and increase the deposit applicable to optional interconnection studies
- make the revised initial deposit amount increasingly non-refundable as the interconnection process advances
- increase the deposit required in lieu of demonstrating site control

Why: There are ongoing stakeholder concerns regarding the length and complexity of Western's interconnection queue process. Revising the LGIP follows the primary focus of the WestConnect queue reform effort that was previously vetted by a wide variety of stakeholders.

From a Western perspective, LGIP reform is anticipated to reduce the time required to process large generation interconnection requests and discourage speculative requests, thereby conserving Western's resources. From a customer perspective, LGIP reform is expected to provide increased certainty for applicants, faster timelines, reduced duplication of studies, and subsequent restudies.

Time Frame: Western should put its proposed LGIP reforms out for the standard 30-day public comment period. If Western elects to pursue the reforms and should FERC accept them, after one year, Western should evaluate the new procedures with customers, tribes, and stakeholders to determine progress has been made and whether additional reforms are necessary.

Recommendation: Conduct a study of the transmission and ancillary services rates charged by each Western-owned transmission project. Determine the feasibility and the appropriate level of potential consolidation of transmission rates from the bottom up, i.e., intra-regionally, inter-regionally, or Western-wide.

Western would engage in a robust, collaborative process with customers, tribes, and stakeholders to determine whether a business case exists to consolidate transmission rates intra-regionally, inter-regionally, or Western-wide.

Why**:** Transmission customers conducting business across Western's multiple transmission systems incur pancaked transmission charges. These customers are concerned that pancaked transmission charges result in inefficient use of transmission resources and impact their ability to seek new business opportunities and markets for their products. Western offers multiple transmission and ancillary service rates across its footprint due to varied authorizing legislation for multiple systems and requirements to ensure repayment consistent with project authorizations.

Consolidating rates, where appropriate and legally possible, may facilitate more efficient use of available transmission capacity and more appropriate path construction and replacements throughout Western's systems. Additionally, it may also facilitate the use of secondary redirection of transmission rights across separate transmission systems, which is not currently allowed.

Further opportunities that may be realized through the elimination of rate pancaking include encouraging the optimization of existing transmission systems, providing cost effective opportunities for movement of energy throughout Western's transmission systems, and potentially increasing the viability of Conditional Firm Transmission Service.

Time Frame: The estimated time frame for completing this recommendation to study and develop a business case to implement transmission rate consolidation is one to two years from initiation to completion.

TRANSMISSION PRODUCTS AND SERVICES OPPORTUNITIES

Numerous areas for improvement to Western's existing transmission products, processes and/or services were reviewed. There are various opportunities to move the organization toward a standard approach when serving customers on the Western transmission system. Through comments received and a review of internal processes that Western is currently exploring or has previously explored, areas that could be investigated or further developed include:

- investigating consistent transmission and ancillary services rates and methodologies across the 13 projects within Western
- improving administration of its customer Integrated Resource Planning (IRP) program
- identifying opportunities where Western can partner with customers, stakeholders and others to develop a stronger and more flexible transmission grid
- initiating a Western-wide Infrastructure Investment Study to prioritize investments in the transmission system

A related recommendation is to study movement to a flow-based environment in the Western Interconnection. These initiatives may allow for more efficient and widespread use of Western's transmission system, leading to additional operational flexibility and lower overall costs to all users.

Recommendation: Initiate a collaborative process with Western regional offices, customers, tribes, and stakeholders to identify the best rate-setting methodologies currently in use by one or more of Western's regions. To the extent possible, explore the potential to harmonize transmission and ancillary service rate setting methodologies across Western.

Additional services, such as load-following service and generation-based ancillary services should be investigated through this process for possible addition to Western's portfolio of products.

Why: This effort would seek to ensure that the most effective transmission and ancillary service rate methodologies are used consistently across Western. By standardizing methodologies across Western, where allowed under law, efficiencies in process and cost recovery might be realized.

Customers, tribes, and stakeholders may benefit from the use of a more uniform and consistent approach to transmission and ancillary service rate setting across regions to the extent practicable, while ensuring that the costs of providing the service go to the customers actually using the service.

Time Frame: Studying Western's transmission and ancillary services rates and identifying opportunities for creating consistency would likely take between 6 and 12 months.

Recommendation: Western should evaluate its customer Energy Planning and Management Program (EPAMP) IRP guidelines and processes to ensure Western-wide uniformity of administration and to conduct customer outreach to identify opportunities for training on the planning process. Western should immediately implement a quality control program to ensure that customer plans are complete, conform to existing guidelines and procedures, and accurately reflect the activities that have been accomplished using the planning process. Evaluation of an IRP program's effectiveness should include evaluation and mitigation of drivers that may inhibit customer efficiency efforts, such as concerns that future allocations could be reduced by previous years' load reductions, as well as understanding what percentage of an individual customer's load requirements is met through an allocation of Western power.

Western should conduct periodic and regular customer outreach and evaluate the customer IRP process to keep pace with industry changes and to ensure that Western is continuing to meet its obligations under Section 114 of EPAct of 1992 and EPAMP. These periodic examinations should include an evaluation of potential alignment between Western and DOE strategic and policy goals and identification of synergies that may be available within Western's implementation of Section 114 requirements.

Why: Western's EPAMP was implemented to comply with the requirements of Section 114 of EPAct of 1992.[1] Western's current IRP and alternative plan process administration is not consistent across Western's regions, which is inefficient and potentially confusing for customers, while also making it more difficult for Western to fulfill its obligation under Section 114 to report aggregate data to Congress. Improving the administration of the program across the regions could also yield customer IRP data that might be more useful to Western. While Western's requirements in administering an IRP program are specifically to fulfill requirements of EPAct of 1992, Western could consider providing training on the planning process, rather than just providing compliance training on reporting. Training on the planning process would provide a benefit to Western's customers of increased understanding of the benefits and opportunities associated with conducting the planning process and could reduce the perceived and actual burden of the IRP and alternative plan process. Customers conducting a robust resource planning process have the ability to understand and quantify externalities, which, among other benefits, helps identify programs that may or may not be successful in practice. This additional training could also increase awareness of Western's Energy Services program, which offers tools and training to assist customers in meeting their own energy efficiency, demand-side management, and renewable energy goals. Customers have raised concerns that efficiency efforts resulting in decreased load might reduce their power allocations in future years, so it is important to evaluate and mitigate drivers that cause these concerns.

Time Frame: Western should immediately implement a quality control program; evaluate and mitigate concerns regarding how existing allocation methodologies may disincentive efficiency and conservation programs; and conduct customer outreach to evaluate whether to offer training on integrated resource planning. Five years after refining its administration of the IRP program, Western should conduct customer outreach and internal evaluation to consider industry changes and whether updates to EPAMP are needed.

[1] 65 FR 16795, Mar. 30, 2000, as amended at 73 FR 35062, June 20, 2008.

Recommendation: Perform a Western-wide infrastructure investment study (IIS). The IIS would determine the state of Western’s infrastructure and the commercial value of transmission paths over which Western transacts business to ensure continued reliability on the system and to maximize return on investment, prioritize grid capital investment projects identified and proposed in Western's 10-year transmission plan as well as interconnection-wide, interregional, regional and sub-regional expansion planning processes.

Western should broaden its current transmission planning process to include important data and information on the value of Western’s transmission assets and existing transmission paths. Doing so would improve Western-wide planning decisions; reduce inconsistencies within Western through the development of a consistent IIS model and decision making protocol; allow Western staff to be better informed about system conditions with regard to capacity and adequacy; and complement on-going WestConnect and Western Electricity Coordinating Council (WECC) transmission planning efforts.

The IIS would provide the most value as an annual process. Further, the data collection and model development should be done in collaboration with other related industry efforts to enable the broadest benefits.

Why: With over 17,000 miles of Federally owned transmission lines and a limited annual capital investment budget, Western needs to optimize its process for evaluating and prioritizing transmission upgrades and new transmission projects. Competing regional interests and capital funding mechanisms result in base infrastructure investment decisions not being uniform across Western. The IIS would supply Western and its customers, tribes, and stakeholders with improved information based on a more granular review of future scenarios that consider proposed regional transmission projects, investments and demand for renewable energy, environmental and policy impacts on transmission paths and non-wires solutions, among other relevant issues. This information would allow Western to avoid unnecessary upgrades on some projects, while focusing its attention and resources on needed projects. This information has the added benefit of allowing Western to gain the knowledge it needs to identify corridors for uprating and to rightsize projects or replace aging assets in key rights of way.

Western has numerous statutory and regulatory obligations that need to be met. This study would ensure best use of Western's limited grid capital investments by optimizing its process for evaluating and prioritizing transmission upgrades and new transmission projects and identify key locations needed for upgrades. This IIS would also ensure transmission upgrades provide the best value and enable Western to make sound, data-driven judgments about the effect overbuild and greenfield projects would have on the transmission system’s paths.

Without a firm understanding of the relative commercial values of Western’s existing transmission paths, informed business decisions and choices related to the allocation and prioritization of resources to the most effective and cost efficient maintenance and upgrades cannot be realized. This study would ensure that Western has the relevant information when planning, resulting in a robust decision making process.

Time Frame: The length of the initial IIS would depend on the resources devoted to the project and the scope of the assignment; the tool would provide the most value as an annual process.

This work in data collection and model development needs to be done in collaboration with other related industry efforts to enable broader efforts and initiatives across WECC, WestConnect, etc. that support FERC Order 1000.

The estimated time frame for completing this recommendation is one to three years from initiation to completion.

Recommendation: Conduct a study across Western's DSW, CRSP, and RMR service areas to identify combined transmission system (CTS) opportunities; while encouraging continued CTS efforts in Western's SNR and UGP service areas.

In collaboration with customers and stakeholders, Western should study where opportunities exist for increased integration of transmission systems in its regions; support efforts already underway; and implement cost-effective solutions where benefits are clearly identifiable and assignable, and cost-shifting is minimal.

Western would begin scoping out two individual CTS studies: 1) an integrated study looking at CTS opportunities across the RMR, DSW, and CRSP Management Center service areas, and 2) a study conducted across each region to determine opportunities for greater integration within that region, taking into account the unique aspects of each region's service area. Western would determine the merits of moving a CTS study(s) forward with one or more regions. Should the study(s) move forward, Western would competitively seek a qualified contractor to provide technical support in conducting the CTS study(s). Additionally, Western would identify and request customer, tribal, and stakeholder participation.

Why: While all Western regions are different, in general, the creation of a CTS allows Western to capture efficiencies; cut costs for itself and its energy and transmission customers; enable greater flexibility for itself and its preference customers to deliver energy to native loads; increase system reliability; enhance new revenue opportunities; and support more efficient transmission planning, posting, construction, and operations.

The CTS model fosters joint system planning and operations. Stakeholders point to the CTS as a successful example of coordination. In multiple areas, entities have shown interest in more integrated systems and approaches as evidenced in stakeholder workshops and written comments.

Additionally, a CTS should improve grid operations and planning and allow Western to consolidate and standardize interconnection agreements and reduce interconnection costs, supporting BA consolidation, reducing Western's exposure in NERC Reliability Compliance audits, and assisting in reserve margin requirements.

Time Frame: The estimated time frame for completing this recommendation is one to three years from initiation to completion.

Recommendation: Conduct a study to explore potential options for moving to a flow-based environment in Western's footprint in the Western Interconnection and away from a contract-path environment.

Western should engage customers and stakeholders to evaluate efforts within the WECC footprint to move from a contract-path to a flow-based approach. As part of Western's analysis, it should ensure that outcomes are cost effective and that benefits are clearly identifiable and assignable, and costs are neutral or that any cost-shift is minimized.

Why: In the Western Interconnection, transmission is currently operated in a contract-path environment (the California Independent System Operator and Bonneville Power Administration's eleven network flowgates notwithstanding), allowing entities to buy capacity/contract rates. A single entity such as Western or a single Balancing Authority may not itself represent a large enough footprint to justify the transition costs and seams issues created in moving to a flow-based environment. Rather, it is desirable for all or most members in a regional footprint to implement a flow-based environment together. In addition, if such a change is desired, moving forward within close time proximity and providing a transition period may help minimize the impacts and encourage a more orderly transition.

Transitioning to a flow-based environment is likely to yield an increase in ATC, which would allow efficiencies to be captured and would support more reliable and efficient transmission planning, construction and operations. A flow-based environment would also continue to provide low-cost, reliable power to customers, align with best practices, help identify opportunities customers can undertake that have low financial impact on themselves and Western, enhance security, offer more options to address contingencies, establish a broad consensus for making investment decisions, expand and uniformly price transmission service products, deliver price transparency, eliminate pancaking, result in greater consistency in operations and transmission planning, expedite queue requests, and enhance renewables integration and common billing.

Emerging market mechanisms and the implementation of intra-hour scheduling requirements in the Western Interconnection would drive the use of locational marginal pricing algorithms. These in turn would drive the need for flow-based, as opposed to contract-based scheduling systems.

As part of long-range planning efforts to prepare for this possible future, conversations should take place with affected customers and stakeholders to ensure that investments in legacy infrastructure and scheduling systems are appropriately considered should a change in scheduling methodologies occur.

Time Frame: The estimated time frame for completing this recommendation is two to four years from initiation to completion.

Recommendation: Study the feasibility of transitioning the Electric Power Training Center (EPTC) to the National Renewable Energy Laboratory's (NREL) Energy Systems Integration Facility (ESIF) in Golden, Colorado.

Why: Since its inception, the EPTC has provided hands-on power operations training to Western, Federal agencies, and other utilities. In 1998, a decision was made that the EPTC should recover all of its costs through tuition. The goal of the EPTC recovering its costs has not been met since 1998, and the resulting shortfall is shouldered by Western and recovered via power rates. Although the costs of operating the EPTC may ultimately be recovered via tuition, the ability to provide a quality, state-of-the-art training facility is increasingly difficult to sustain without a significant investment of more capital. As a result, Western is proposing to transfer the EPTC into the DOE's state-of-the-art ESIF to enable the ESIF to host power operations training for the electric power industry with an emphasis on renewable and variable generation technologies, demand-side technologies, and energy storage technologies. The mission of NREL's ESIF is to research, develop, and transition new energy systems technology to help in the quest for America's energy independence. Transferring EPTC to ESIF would advance a clearer understanding of grid integration technologies, tools, and best practices with the nation's power system operators, utility executives, non-utility professionals, and tribes.

Time Frame: The EPTC lease expires in June 2015 with the move out date of December 2014. Western will open dialogue with NREL and all EPTC stakeholders, including the Federal agencies, to ensure the continuity of EPTC's mission.

VARIABLE ENERGY INTEGRATION

To respond to an evolving environment, numerous operational and business practices were examined, as well as comments from customers, tribes, and stakeholders, to fully understand how existing and new initiatives such as RBC, ADI, Dynamic Scheduling System (DSS), Intra-hour Transaction Accelerator Platform (ITAP)[2], and intra-hour scheduling and markets, could be used by Western to efficiently and effectively operate and optimize transmission services. These initiatives may provide BAs additional flexibility by allowing them to fully meet load demands, generation changes, and disturbances and enable integration and aggregation of variable energy products that could provide cost effective alternatives to customers, tribes, and stakeholders. Based on feedback and additional discussions, it has become apparent that many of the industry initiatives can provide benefits on their own or build upon one another in a systematic manner minimizing the impacts on reliability.

Western currently is participating in the WECC RBC field trials and will evaluate ADI and will implement FERC Order 764 intra-hour scheduling. A natural next step is to study DSS to determine its impact on RBC and ADI and benefits to the BA and marketing. Lastly, Western should continue to analyze various energy imbalance market initiatives to fully understand impacts and benefits associated with the different alternatives. Implementation and evaluation of RBC, ADI, DSS and intra-hour scheduling could accomplish some of the benefits of the energy imbalance markets initiatives. Therefore, energy imbalance market initiatives would continue to be studied, but their potential implementation would not be undertaken before the benefits of the other initiatives, such as ADI, RBC, DSS and intra-hour scheduling have been fully evaluated.

[2] ITAP allows merchants to advertise resources for sale and others to purchase resources. Western has been participating in ITAP. It is complementary to DSS.

Recommendation: Pursuant to FERC Order No. 764 (Integration of Variable Energy Resources (VER)), Western BAs/sub-BAs should work with regional reliability organizations, Western regional offices, customers, tribes, and stakeholders to coordinate the implementation of intra-hour scheduling consistent with neighboring utilities, including the implementation of 15-minute scheduling.

Why: Western should work with neighboring utilities toward the consistent implementation of intra-hour scheduling, including 15-minute scheduling to improve the reliability of the bulk electric system associated with increasing VER integration. In June 2012, FERC issued Order No. 764, which required amendments to the pro forma Open Access Transmission Tariff to better facilitate the integration of VERs. Specifically, FERC required each public utility transmission provided to offer intra-hourly transmission scheduling. The Order is intended to remove unduly discriminatory practices and to ensure just and reasonable rates for VER related services.

Intra-hour scheduling would enable transmission customers to align transmission schedules with actual generation output more effectively, reduce the need for expensive operating reserves, and provide for greater system flexibility by utilizing available resources in a more efficient manner.

Time Frames: Order No. 764 gives transmission providers 12 months from the effective date of the rule (60 days after publication in the *Federal Register* on June 22, 2012) to make compliance filings that would modify their transmission tariffs to offer 15-minute scheduling intervals.

Recommendation: Western BAs and sub-BAs in WECC's footprint should evaluate the benefits and costs of ADI, RBC, and DSS, and if appropriate, proceed with implementation. The control systems may be modified to accept the programming requirements needed to implement any of the initiatives.

Why: WECC is currently evaluating the feasibility of implementing all three initiatives on a WECC-wide basis. Within Western, various regions have implemented a number of these initiatives already. There is an opportunity to examine the potential for Western-wide use of these techniques to improve business efficiency. DSS is a technology-based tool to reduce the time required to establish dynamic schedules from weeks and months to minutes through standardized business practices and automated scheduling infrastructure around a centralized node. ADI seeks to take advantage of control error diversity among participating BAs in the West by allowing for inadvertent interchange (positive and negative deviations) to be netted out among the participants. The RBC standard would provide a more flexible control performance regime tied to system conditions than CPS1 and CPS2. RBC could help BAs better manage interchange at lower cost.

Time Frame:

- RBC – currently participating in field trials. Full implementation is contingent on WECC and NERC approval.
- ADI – start analysis within 12 months.
- DSS – start analysis after the conclusion of both RBC and ADI – 18 months.

Recommendation: Undertake a study to evaluate the benefits and costs to Western and its customers, tribes, and stakeholders in participating in either regional or sub-regional initiatives investigating energy imbalance markets. The study should identify methods that enable Western's impacted parties to maximize the physical benefits of sub-hourly generation scheduling and inter-BA coordination.

Why: Current hourly generation scheduling practices do not provide access to the full flexibility of all generators. Similarly, current hourly inter-BA scheduling practices limit aggregation benefits that could otherwise reduce the net variability of system load and variable generation. Methods that permit the sharing of sub-hourly generator resources over a broad, multiple-BA footprint have been found to reduce required regulation and load-following margins while increasing access to available responsive resources, simultaneously increasing reliability and reducing costs. An energy imbalance market is one possible way to achieve some of the benefits of sub-hourly scheduling and improved inter-BA coordination. The details of how an energy imbalance market would function are critical to ensure that the benefits are allocated fairly, cost shifts are accounted for properly, and that unintended consequences are avoided. A full evaluation is required to determine if the specific proposal is in the best interest of Western customers, tribes, and stakeholders and to identify alternatives that can improve an energy imbalance market.

Business objectives for participation in an energy imbalance market would address a number of customer, tribe, and stakeholder concerns, including:

- Benefits must exceed costs.
- Investments in existing legacy infrastructure must be recovered.
- Provide increased capability to integrate variable resources into the Western BAs
- Provide quantifiable operational efficiencies
- No adverse affects on system reliability or Western's ability to comply with NERC and WECC reliability standards
- Participation costs must be allocated to the market beneficiaries on a fair and equitable basis.
- Will not increase congestion on the already constrained paths in the region
- Must provide stability and predictability - energy imbalance market operator must provide business stability and predictability
- Minimize/mitigate seams issues
- Preserve option to withdraw.
- Equitable compensation for use of transmission
- Recognize that economic redispatch opportunities for Federal hydropower facilities are limited

- Viewed as a voluntary endeavor and not a first step towards formation of a RTO

Time Frame**:** Complete precursor Western analyses such as identifying imputed transmission rates, identifying regulation and load-following capacity, and estimating each BA's level of energy imbalance requirement within 3-6 months and continue to participate in on-going regional/sub-regional market design activities. The ultimate decision to study the feasibility of joining an energy imbalance market is contingent on the state of market design and governance activities occurring in each region/sub-region. Western recognizes that it may not be practical to implement an energy imbalance initiative prior to a detailed evaluation of RBC, ADI, DSS and implementation of intra-hour scheduling initiatives.

Recommendation**:** Establish a position within Western's Renewable Resource Program office to be a Renewable Energy Liaison for facilitating renewable energy interconnection to Western's transmission system for Native American tribes and other customers and stakeholders. Undertake proactive measures to facilitate and encourage the interconnection and integration of renewable energy projects into the Federal transmission system. A number of customers are unfamiliar with the opportunities and the processes to interconnect renewable projects to the Federal transmission system. Assisting in the identification of feasible, cost-effective renewable energy projects as well as assisting stakeholders and customers better understand and navigate Western's processes could assist customers, tribes, and stakeholders, e.g., renewable generation developers and Federal generation agencies, interested in interconnecting to the Federal transmission system by:

- Conducting focus group meetings and facilitating customer, tribal, and stakeholder collaboration to identify renewable initiatives/renewable integration opportunities
- Facilitating the evaluation of the benefits of thermal integration with Federal hydropower that could provide Western with a more diverse portfolio for operations and support greater amounts of variable resources
- Western, working through the PMMC, could identify supplemental power needs, price points, delivery specifics, etc. and collaboratively work with preference power customers to identify opportunities that could include renewable integration/purchases when economically feasible
- Forming a Western-wide Variable Energy Resource Assessment Team consisting of staff from all functional areas that works collaboratively with Western's Renewable Resource Program to identify Western's constraints, design mitigation strategies, and provide customer support

With this information, create and maintain a database of possible project proposals and renewable generation requirements. Development of the database includes the following next steps:

- Analysis/inventory of all current or emerging state and Federal Renewable Portfolio Standard/Renewable requirements
- Market assessment to identify potential off-takers or exchange partners of renewable energy
- Consolidate all applicable data from renewable energy zone studies that have been completed into a Western database.
- Develop a matrix of all potential opportunities for renewable development and potential off-takers across Western's system
- Evaluate potential exchange opportunities

Why**:** This effort would further partnership and cooperation potential with Native American communities looking to invest in renewable generation projects. It would also compliment efforts to address current demands for renewables within Western's service area and further Western’s support for the DOE’s efforts to diversify America’s energy supply, protect the environment, strengthen the economy, and modernize our energy infrastructure. Identifying potential renewable energy projects and exploring integration/ aggregation opportunities ensures that customers, tribes, and stakeholders have value-added information readily available to help make more informed decisions about immediate and future renewable resource procurements. Through a tribal-, customer-, and stakeholder-driven process, Western could facilitate partnership arrangements that could lead to larger aggregated renewable energy development opportunities, new transmission capacity, and more economic development within Western's 15-state service area.

Additionally, this effort would streamline value-added information sharing between Western, its regions, and its customers, tribes, and stakeholders, ultimately eliminating duplication of effort within individual regions and providing greater efficiency in identifying and evaluating renewable development opportunities. Western, tribes, and customers would benefit by having a larger pool of data and resources available to them in one centralized location.

Establishing a Renewable Energy Liaison would provide continuity and succession planning within the Renewable Resource Program office. Throughout the customer stakeholder meetings, listening sessions, and other venues, Western received comments from Native American customers that Western should provide more support with facilitating renewable energy development. Furthermore, Western heard from stakeholders that Western could be doing more to support integration and delivery of variable energy resources, and a large percentage of Western’s preference power customers support renewable integration as long as they are not negatively impacted. By conducting customer outreach and exploring integration/aggregation of renewable energy projects, there may be opportunities for all (customers, tribes, and stakeholders) to benefit.

Time Frame**:**

- Conduct outreach to explore integration and aggregation of renewable energy projects within 24 months
- Establish Renewable Energy Liaison within 12 months