K. R. Saline & Associates, PLC

MEMORANDUM

TO: JOT@wapa.gov

DATE: August 23, 2012

FROM: Christopher M. Fecke-Stoudt, PE[1]

RE: The Reliability of the Western Area Power Administration Desert Southwest (WAPA-DSW) Transmission System

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The goal of this comparison is to determine WAPA-DSW reliability relative to other owners' systems in Arizona. In order to perform this comparison, it is important to understand the development of the WAPA-DSW transmission system, the history of the Joint Planning Agreement (JPA) and, finally, to evaluate the publicly available transmission reliability metrics.

An Overview of the WAPA-DSW System[2]

The WAPA-DSW transmission system consists of five separate and distinct power system projects which include the Boulder Canyon Project (BC), Central Arizona Project (CAP), Colorado River Front Work and Levee System (Levee), Colorado River Storage Project (CRSP), Pacific Northwest/Southwest Intertie Project (Intertie) and the Parker-Davis Project (Parker-Davis or P-DP).

- The BC facilities were originally constructed in 1928 and include generation capacity of over 2,000 mega-watts (MW) and 230 kilovolt (kV) transmission lines from the generators primarily to Mead substation.
- CAP participated in developing the Navajo Generating Station (NGS) and transmission facilities. The NGS facilities were fully operational in 1976 and include 800 miles of 500 kV transmission lines.[3] [4] The CAP share of capacity from the NGS totals 547 MW, used primarily to power pumping facilities. Additional CAP transmission facilities include approximately 250 miles of 230 kV transmission lines

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[1] On behalf of Aguila Irrigation District, Buckeye Water Conservation & Drainage District, Electrical District No. 6 of Pinal County, Electrical District Number Seven of Maricopa County, Electrical District No. 8 of Maricopa County, Harquahala Valley Power District, Maricopa Water District, McMullen Valley Water Conservation and Drainage District, Ocotillo Water Conservation District, Roosevelt Irrigation District, Tonopah Irrigation District, and Wellton-Mohawk Irrigation & Drainage District in Arizona.

[2] All details contained within this section were obtained and paraphrased (unless otherwise footnoted) from http://www.wapa.gov/dsw/Ten_Year_Capital_Program/Final%20FY12%20Capital%20Program.pdf

[3] http://www.ngspower.com/facts.aspx

[4] http://en.wikipedia.org/wiki/Navajo_Generating_Station

from Clark County, Nevada to Parker, Arizona and approximately 51 miles of 115 kV transmission lines in La Paz and Maricopa Counties constructed during the 1980's.[5]

- The WAPA-DSW electric system facilities that are considered part of the Levee project consist primarily of 69 kV and lower voltage distribution systems connected to water wells in the Yuma area.
- The CRSP facilities were authorized in 1956 and first began operation in 1964. The CRSP project currently includes 16 generators with an operating capacity of 1,727 MW. The CRSP project includes 2,323 miles of high voltage (HV) and extra high voltage (EHV) transmission lines.[6]
- The southern Pacific Northwest/Southwest Intertie facilities were placed in-service in 1968[7] and include 420 miles of 500 kV transmission lines, 250 miles of 345 kV transmission lines and 55 miles of 230 kV transmission lines.[8]
- The Parker-Davis facilities are the most significant portion of the WAPA-DSW transmission system. The Parker-Davis facilities were constructed in 1954 with an operating capacity of 385 MW and 679 miles of 230 kV or lower voltage transmission lines.[9]

As is apparent from the information above, two large projects that are part of the WAPA-DSW transmission system were developed during the relatively short period of 1954-1965 (CRSP and Parker-Davis) and two other projects during the 1968-1976 timeframe (CAP/ Navajo and Intertie). The compressed construction windows also indicated the need for compressed major equipment replacements on each of these projects as they age unless proactive steps were taken to levelize the replacements and costs. This understanding by Western and its customers led to the development of the 10-Year Planning Process and Joint Planning Agreement ("JPA") process.

<u>The History of the 10-Year Planning Process and Joint Planning Agreement</u>

During the 1980's Western Area Power Administration (Western or WAPA) proposed a vast replacement program for its system based upon the numerical age of the facilities. The Customers[10] reacted with concerns that the equipment was well maintained and not stressed, and replacements based upon numerical ages versus condition would not be consistent with Good Utility Practices. The customers responded with proposals to peer review all of the substations and transmission lines and work with Western to prioritize and phase-in replacements based upon actual equipment condition and needs.

From that cooperative effort, Western and its customers signed several agreements related to Western's planning and Operation and Maintenance (O&M) activities on its system. The 10-Year Planning Process includes Western's obligations to deliver federal hydro power to both Project Use facilities and federal customers. During the planning processes, the customers and Western also had to address the issue that, unlike most utilities, Western does not have load growth responsibility, and load growth heavily impacts the planning and upgrading of transmission lines. Therefore, the customers and Western also implemented a Joint Planning Agreement (JPA) under which customers dependent upon Western's system could plan the

[5] http://www.usbr.gov/projects//ImageServer?imgName=Doc_1303158888395.pdf
[6] http://www.usbr.gov/projects/Powerplant.jsp?fac_Name=Glen+Canyon+Powerplant
[7] http://www.sencal.org/sencal/Timeline_files/History%20of%20California's%20%20Overhead%20Electric%20Project.pdf
[8] Transmission line mileage is estimated based upon transmission line routing as available at the time of this report.
[9] Per data request located at http://www.wapa.gov/dsw/pwrmkt/PrepaymentFunding/Main.htm
[10] The term "Customers" refers to wholesale energy customers served by WAPA-DSW

upgrade of Western's transmission lines to meet customers' load growth needs. Together these two agreements included the full range of planning demands upon Western's system: federal hydropower delivery and load growth needs.

Western and its customers meet regularly to implement these programs; and Western regularly schedules field reviews of its system and equipment with customers and peer utilities to solicit best practices and share information. WAPA's planning process may be the country's most robust customer planning process, given the engagement of Western and its customers in the peer review programs and information sharing on load growth, needs, and how to fund and finance upgrades to Western's system.

The 10-Year Planning Process and JPA appear to be working, based upon transmission reliability metrics.

Evaluation of the Transmission Reliability Metrics

An evaluation of the WAPA-DSW reliability metrics indicates a well-operated and reliable transmission system. For all reported years since 2005, WAPA has met Control Performance Standards One and Two (CPS-1 and CSP-2) metrics while exceeding industry averages. The CPS-1 and CPS-2 control performance standards are designed to measure frequency error and area control error (ACE) magnitude.[11] Exceeding CPS-1 and CPS-2 indicates, "[Western's] ability to operate the power system efficiently. Western's success in exceeding industry averages with respect to these standards means fewer outages for customers and a more reliable system for the nation." [12]

The best publicly available transmission outage information for WAPA-DSW comes from 2009 data provided via prepayment funding data requests and subsequent data responses.[13] The data responses provided by WAPA-DSW on the P-DP included transmission outage rates by type.[14] The responses show that 8.2% of the outages on the P-DP system during 2009 were a result of equipment failures and none of these outages were a result of transformer failures. Further, only half of the equipment failures were transmission line, structure or tower equipment failures. Meanwhile, over 35% of the total 2009 outages were due to severe weather or weather related conditions.

When the 2009 WAPA-DSW P-DP data is compared to the most recently available APS data from 2005[15], the transmission related outage numbers are very comparable. APS had 103 reportable transmission related outages in 2005 while WAPA-DSW P-DP had 103 unplanned transmission outages in 2009.[16] [17]

Accountable outages are also an important metric to determine WAPA reliability.[18] In the reported years since 2005, WAPA has consistently set and met ambitious accountable outage goals with a single exception

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[11] http://www.wecc.biz/library/WECC%20Documents/Reliability%20Management%20System/4%20-%20Reporting%20Instructions%20and%20Compliance%20Standards/RMS%20Reporting%20Instructions%20Phase%201.pdf

[12] http://ww2.wapa.gov/sites/western/newsroom/Documents/annrep10.pdf

[13] Per data request located at http://www.wapa.gov/dsw/pwrmkt/PrepaymentFunding/Main.htm

[14] The Parker-Davis Project represents a significant portion of the WAPA-DSW High-Voltage system and is relatively sparse. Further, "Parker-Davis provides the majority of the regional power facilities." Per WAPA-DSW FY12 Ten-Year Capital Program page 2. http://www.wapa.gov/dsw/Ten_Year_Capital_Program/Final%20FY12%20Capital%20Program.pdf

[15] Per APS response to Staff Data Request JDS 2-1, ACC Docket No. E-01345A-05-0816

[16] An APS reportable transmission related outage is a transmission outage that results in 1000 or more customer hours lost.

[17] WAPA-DSW P-DP outage numbers exclude customer equipment related outages (equipment not owned by WAPA-DSW).

in 2011, where the outage metric exceeded the goal by seven accountable outages.[19] The 2011 accountable outages were described by WAPA as "most lasting less than 35 minutes".[20] Despite missing the 2011 accountable outage goal, WAPA kept an ambitious goal for 2012. When compared with the previous years' successful results, the 2012 goal seems consistent with continued high expectations for the number of accountable outages.

Conclusions

In conclusion, the WAPA-DSW transmission system was mostly developed over a relatively short period, in a bulk fashion. This bulk development means equipment useful life cycles would end in a bulk fashion resulting in bulk replacements. The 10-Year Planning Process and JPA were developed to help address the large replacements and levelize them using a measured approach so as to limit the rate impacts. The Western planning processes, by all accounts, have been successful in repairing/replacing/upgrading key portions of the system in a stepwise and cost effective manner. The 10-Year Planning Process and JPA approach appears to be working, as reflected in the transmission system reliability metrics which show that WAPA-DSW consistently operates above industry standards in CPS-1 and CPS-2 metrics, and the transmission outage rate is comparable with another major Arizona transmission system's outage rate.

[18] Accountable outages are described as,"...accountable outages, which could have been avoided if different actions were taken. Potential causes are failure to install new equipment or maintain equipment as necessary or incorrect operation of equipment. Western works diligently to limit our number of accountable outages." http://ww2.wapa.gov/sites/western/newsroom/Documents/pdf/annrep11.pdf

[19] http://www.cfo.doe.gov/budget/10budget/Content/Volumes/Volume6.pdf

[20] http://ww2.wapa.gov/sites/western/newsroom/Documents/pdf/annrep11.pdf

K. R. Saline & Associates, PLC

MEMORANDUM

TO: JOT@wapa.gov

DATE: August 23, 2012

FROM: Kenneth R. Saline, PE[1]
Christopher M. Fecke-Stoudt, PE

RE: EIM Markets and Western's Consolidation Efforts

Department of Energy (DOE) Pre-Read Background: Centralizing Dispatch

Western Area Power Administration (WAPA or Western) operates four Balancing Authority Areas (BAA), three in the Western Interconnection and one in the Eastern Interconnection. Western also operates a sub-BAA or metered subsystem within the California Independent System Operator (CAISO) footprint.

Western is also evaluating the potential for participating in an Energy Imbalance Market (EIM) within the Western Interconnection, which would centralize the dispatch of the generators participating in the market. Western is working with Western Electric Coordinating Council (WECC), the Public Utility Commission Energy Imbalance Market Committee (PUCeim), National Renewable Energy Laboratory (NREL), other utilities, customers and stakeholders on this proposal.[2]

General Response:

Western needs to proceed cautiously with any operational integration of its operating centers and ensure compliance with Federal Laws originally establishing the Federal Projects and defining their purposes, including:

- Federal Obligations to the States and Native Americans;
- Priority Use loads;
- Obligations for Delivery of Federal Preference Power;
- Contractual obligations for sharing of information and customer funding;
- Participating Agency obligations in environmental litigation and power plant operations;
- Obligations under regulations of the Federal Energy Regulatory Commission (FERC) on transmission system operations and wholesale markets.

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[2] Adapted from DOE/Western Joint Outreach Team: Defining the Future Workshop Pre-Read Materials, page 7
http://ww2.wapa.gov/sites/western/about/Documents/Defining%20the%20future/Public%20Meeting%20PreRead.pdf

<u>Responses to Energy Imbalance Market Proposals</u>
The goal of this memorandum is to respond to documentation and discussions regarding three different initiatives within the generic topic of "centralizing dispatch": (i) formation of an Energy Imbalance Market; (ii) Western's currently ongoing efforts to consolidate its operating functions (staffing, equipment, and operators); and (iii) consolidation of Western's BAAs. Each of these initiatives would impact the operations of the Federal Projects and their fulfillment of Congressionally mandated purposes. FERC Order 764 and the EIM proposal raise key issues and have significant implications for Western's goals for its operations and for any BAA consolidation efforts; therefore, centralized dispatch and EIM require closer examination.

Electric utility restructuring has been underway across the country as a result of the 1992 Energy Policy Act requiring FERC to restructure the wholesale electricity markets and provide open access transmission service. FERC has issued numerous orders; and there are numerous legal cases interpreting the requirements governing pricing, terms and conditions of wholesale power, transmission services and ancillary services in the US markets. There is a similar library of laws and cases governing the Federal Power Projects.

Currently, the majority of ancillary services in the WECC are cost-based services regulated by FERC, and are mostly supplied by generators that also serve large urban areas and retail customers. All retail customers pay comparable rates for ancillary services and transmission services under the FERC rules. Many of Western's generation and transmission customers have loads outside of Western's BAA's, and they purchase supplemental power supplies and reserves for their electrical loads from those non-Western Native Load BAA's through the Open Access Transmission Tariff's (OATT) provisions.

Some areas of the nation that had long-standing power pools, such as PJM, found centralized markets to be more efficient with the introduction of merchant generators because of the number of transactions that could occur and the large populations served by their transmission network managed by their power pools.

However, in contrast, areas like the WECC do not have a single market. Instead, they have distinct regional markets, including Palo Verde, NP15, SP15, COB, Mead, etc., which already reflect the locational costs of power from energy resources physically available to supply those regional areas. There are some regional power pools; and, most regions have urban load pockets with import limits and local generation fleets needed to maintain reliability.

These regional markets have numerous physical and financial participants, ensuring the robustness of the regional markets that already exist. Reserve sharing and many other programs to strengthen and derive efficiency from pooling the electrical resources are underway in subregional areas, where adequate transmission networks exist. These programs are happening because they make good business sense; and the existing regional markets enable these improvements to continue. Furthermore, the FERC Order 764 requirement to offer 15-minute scheduling clearly will progress into 15 minute commercial practices, out of necessity. This current development, alone, will capture the majority of the benefits identified in the EIM studies without moving to a bid-based centralized market.

In summary, in an extensive and wide-spread geographic arena, i.e. west-wide, centralization such as an EIM has not proven to be politically or electrically possible because of the potential for economic dislocation and distortion of what are currently good, physically and financially functional regional markets. The reality of the geographic distances and diversities, coupled with the lack of direct transmission lines connecting the vastly separated markets, will prevent any centralized market from achieving economic savings anywhere close to those projected by the various studies being touted. Any different outcome would require tremendous politically unacceptable socialization of power costs and rates between the high cost regions and low cost regions in the west, and the expenditure of billions of dollars for transmission upgrades costing consumers several cents/kWh in retail rate increases.

FERC Order 764 and EIM

15-minute scheduling, promulgated by FERC Order 764, will rapidly progress and modify the utilities' current scheduling, billing, and accounting procedures. This will enable multiple commercial clearing intervals within the hour, thus substantially capturing the benefits identified in all the studies on such matters.[3] K. R. Saline & Assoc. currently manages scheduling with Western for many of Western's customers. When the regional utilities start providing 15-minute schedules, all the billing, scheduling and accounting procedures will soon be modified to standardize scheduling systems and practices. Very quickly all wholesale participants in the WECC markets will be able to settle transactions in 15 minute intervals. The BAA's will necessarily have to provide the 15-minute services and modify their billing programs to accommodate such services in order to comply with FERC's Order 764. A centralized billing system for 15-minute settlements is not necessary and would be duplicative of functions that the BAA's will already have to perform.

15-minute scheduling will also be reflected in the various existing tools such as the Open Access Same-Time Information System (OASIS). In the OASIS, fields can be modified and upgraded at reasonable OASIS costs in order to provide 15-minute available transmission capacity (ATC) calculations and reservations, substantially expanding the processes to accommodate Variable Energy Resources (VERs). The OASIS can also be modified to provide situational awareness sharing and VERs forecasting between BAA's. In a few years, most wholesale entities will be capable of supporting 15-minute intervals, at about the same time that thousands of megawatts (MW) of VERs will begin producing power. Over time, as contracts expire, new contracts will be signed or rolled over, and the procedures will be fully implemented as a practical matter. We fully expect the FERC 764 Order in the WECC to evolve quickly into 15 minute settlements and markets as more and more VERs request the shorter scheduling periods. With Dynamic Scheduling Systems and 15-minute scheduling, we believe the current initiatives are more than adequate to support the VERs planned in the region.

In contrast, the proposed EIM will require new, undeveloped tools, a centralized dispatch center, and the imposition of significantly greater costs across the entire WECC, with unclear potential benefits. It is also unclear from the DOE materials if EIM is meant to be a "Flexible Reserve Market" or a centralized standardized energy market which supplants the current bilateral markets. The EIM studies clearly capture redispatch savings on the assumption that the EIM will dispatch all of the generators. The studies also ignore the "market issues" caused when an EIM moves from cost based pricing to bid based pricing for the

[3] Docket No. RM10-11-000; Order No. 764, Integration of Variable Energy Resources, Issued June 22, 2012, http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf

same service for many retail customers. We have not seen any new market which has lowered the rates in a region.

We do not see *merchant* VER projects occurring or being financed. Therefore, the VERs will not be purchasing flexible reserves, so we see no reason to create an EIM for the VERs. For the foreseeable time being, the VERs that are constructed will be purchased from utilities, who already operate their own fleets of resources, participate in the regional markets and reserve sharing groups, and will operate and dispatch the VER plants in accordance with FERC regulations. The utilities in their procurements clearly are monitoring resources which fit within the utilities' ability to operate such resources in accordance with WECC and NERC requirements. Therefore, we do not foresee a runaway situation where an EIM is needed to force reserve sharing; and we do not see any energy crisis. We believe the assumptions of magnitude and location of resources made in the NREL and other studies are highly speculative. If the current locally sourced pattern continues for VER projects being procured, then the large interstate VER generation assumptions and transfers reflected in the EIM justification studies are seriously overstated.

When the benefits of 15-minute scheduling are removed from all the EIM projected benefits studies, and the parties focus on flexible reserves versus a unified economic dispatch across the WECC, we believe there will not be sufficient justification for EIM to proceed. The studies clearly are not focused on flexible reserves, which are highlighted as the problem for VER resources that the EIM is intended to resolve. This underlying assumption in the studies insinuates that the utilities that purchase the VERS's will select generation sources they cannot regulate nor have dispatching control over. The requirement for utilities to operate within NERC reliability requirements will prevent the grid from getting into unreliable operating situations on a large scale and instead it will occur sequentially as the systems are developed and implemented to expand VER transfers safely and reliably. Clearly the recent situation in the Northwest is being handled using the FERC approach, where the issues are being addressed when they occur, in working groups and with studies to determine how the region implements new procedures for the resources in its area. For areas which do not encounter the same situation, it hardly makes sense to implement procedures and install equipment to remedy resource situations which may never occur in their area. A regional-specific approach is the only way to prevent untimely or stranded costs for generation, transmission lines, or markets which are not needed.

In addition, recent studies assume all generators participate in the dispatch based upon their heat rates and efficiency. Yet that is not how any market works. The markets are not dispatched based upon heat rates but are, instead, dispatched based upon bids. Similarly, a large component of generators in some centralized markets are still self scheduled and do not participate in the markets for economic dispatch. Any centralized market analysis which assumes 100% participation of generators based upon each plant's efficiency is not a true model of a market and such an analysis will overstate the benefits.

The existing bilateral markets easily include generation from third parties used to provide reserves and regulation services to support any BAA. Therefore, a bid-based, centralized energy market is unnecessary for further reserve sharing or wholesale transactions between the 37 BAA's and the other much smaller transmission-dependent wholesale utilities in the WECC who purchase reserves from the BAAs at cost based rates.

Furthermore, and perhaps the most important consideration when looking at Western's BAAs, Western doesn't have the power plants or the customer base to support an EIM. All of the federal power projects are allocated to customers in accordance with the projects' governing laws. There is very limited flexibility within Western's binding generation commitments to also supply any EIM market. Most of Western's customers serve loads not in Western's BAA, and purchase reserves and supplemental power in their Native Load control areas. Currently the power generated by the Federal Projects is contracted to Western's customers who use the resources in accounting for their required supplies and reserves in their Native Load BAA in accordance with FERC regulations. Any changes by Western will affect its commitments and its customers. Western may very well need its contractors' consent as well as Congressional authorization to participate in an EIM.

Responses to Western's Initiatives on internal consolidation and BAA consolidation.
Industry reviews of an organization's internal functions, whether electric or otherwise, are nothing new. Industry business practices, computer systems and restructuring to improve services and lower costs occurs primarily to reduce costs by means of removing duplicate efforts, eliminating overhead or optimizing existing resources. However, a major trigger is typically required. For the U.S. electric system, such a trigger occurred in the form of the 1992 Energy Policy Act. All major U.S. utilities separated their transmission and generation functions in accordance with the 1992 Energy Policy Act and subsequent acts enabling FERC to promulgate regulations on wholesale restructuring and markets.

As Western separated its transmission functions, it also recognized its Statutory Services obligations. Western implemented programs to consolidate its systems and staffing into the wholesale model and the operating centers functioning today. In this sense, WAPA is the same as other electric utilities -- i.e., it evaluates internal functions and equipment to improve efficiency, reliability and response, and security to reduce costs while implementing existing and forthcoming FERC requirements. We will see Western continue to upgrade its systems and operations toward a 15-minute market for scheduling and settlements as initiated by FERC in Order 764.

Western's consolidation efforts will have impacts in three key respects: (i) operating center consolidation, (ii) BAA consolidation and (iii) reliability issues with consolidation of Western BAAs. In the following sections, we will examine each in more detail. The first section addresses Western operating center consolidation.

WAPA Operating Center Consolidation Efforts
In general, WAPA *operating center* consolidation efforts have been supported by Western's customers, with a single caveat: customers have urged Western to move forward very cautiously, in a measured, methodological, stakeholder involved approach so as to not negatively impact the Federal Projects' statutory obligations or customer information processes. The issue of combining dispatch centers is currently under careful examination within each of the Project contractor groups because, historically, as

local input and communication decreases, the ability of the Projects to meet and comply with their statutory obligations and requirements becomes much more difficult.[4]

Western *BAA* consolidation, however, is a much more complex proposal. The following section discusses some of these complexities.

Consolidation of Western BAAs

Proposed consolidation of Western's BAAs raises the potential for creating both electrical and contractual issues for the Federal Power Projects and contractors. Western's system currently serves a vast area of the West with multiple Federal Power Projects, each with specific Congressionally mandated obligations and responsibilities. Any changes which affect operating priorities, water deliveries, environmental restrictions, or contractor obligations are a concern and require additional consideration and vigilance. The DOE examination will need to get granular to the levels of those communities impacted. Otherwise DOE will neglect the existing, wide-spread benefits developed over decades from the regional dependence on the federal water and power projects in the Southwest and the West. In many of these regions, there is an economic dependence on Western, and significant price sensitivity to any cost/rate increases from Western.

For example, Hoover power is already dynamically scheduled by Western's Contractors in the three states of California, Nevada and Arizona. Hoover is not Congressionally committed or obligated to support Western's BAA. Too many studies fail to understand that, while Hoover is in the Western system model, Hoover is already fully committed by Congress to economic dispatch by regional utilities which serve over 20 million water and electric customers across Arizona, Nevada, and Southern California. Hoover already has wide-spread use and has significantly driven the development of the Southwest through expanded electricity access and affordability.

Any combination of BAAs or any concepts which affect the dynamic scheduling of Hoover inherently must take away generation already committed and dynamically dispatched in the Southwest for super-peaking operation, regulation and reserves pursuant to law and various contracts and arrangements. Hoover only has enough water and energy for its current operations and contractual obligations; therefore, any displacement of this energy would necessarily increase the use of gas turbines in the urban population centers of Los Angeles, Phoenix, and Las Vegas. Hoover is a major example of the fulfillment of public purposes within the three states that must be maintained by these Projects. By law, Western is obligated to honor the obligations of the Federal Projects.

Another example is the Glen Canyon dam. It is important to note that environmental restrictions at Glen Canyon have already resulted in the reduction of 300 MW of peaking capacity. It is unclear how Western could participate in an EIM without using these already fully committed Federal Projects that are unable to change flow rates to respond to an EIM. It is also unclear how the Western BAAs , one of which serves the Southwest and others which serve California, Utah, Colorado, and the upper Midwest, can consolidate

[4] "Project" or "Projects" refers to one or all of the five separate and distinct power system projects located in WAPA which include the Boulder Canyon Project (BC), Central Arizona Project (CAP), Colorado River Front Work and Levee System (Levee), Colorado River Storage Project (CRSP), Pacific Northwest/Southwest Intertie Project (Intertie) and the Parker-Davis Project (Parker-Davis or P-DP).

K. R. Saline & Associates, PLC
160 N. Pasadena, Suite 101 • Mesa, AZ 85201-6764 • Phone 480.610.8741 • Fax 480.610.8796

without impacting the generation dispatch and reserve obligations of Western to its customers in those control areas. Additionally, there are specific control area obligations on Glen Canyon and the lower Colorado River Projects related to their contracts, water releases and other statutory purposes. How resources which are 100% committed by Congressional Act to specific contractors for specific purposes could now serve other purposes outside their restricted marketing areas without contracts and without violating the federal preference laws is a compelling question for any EIM initiative.

In addition to contractual and statutory concerns, the following section describes regional reliability concerns with Western BAA consolidation.

Reliability Concerns with BAA Consolidation

Technical issues related to the Western BAA Consolidation require close scrutiny due to the complex islanding schemes and generation commitments to sub-areas. These islanding schemes result in the separation of one or more BAAs when the overall electric system is disrupted, such as during the September 8, 2011 outage. BAA separation results primarily from transmission line limitations between areas in the bulk electric system. It involves stability limits and voltage support from remote generation that must remain online even during significant electric system outage events. Western's system includes the control of many phase shifters, management of several Transmission Operation Transfer (TOT) paths, and many reliability obligations of reserve and balancing support for Western's contractors in their sub-regions. These sub-regional separation schemes are the mechanisms which allowed a majority of the WECC electric systems to stay online during the September 8th outage when some other portions of the system failed to maintain balance and blacked out. Any consolidated Western BAA, with its resulting vast geographic area and electrically interconnected characteristics, would still need to ensure adequate ability to separate and balance sub-regionally without losing the entire system or potentially suffering an outage event significantly more disastrous than September 8th. Technical studies to evaluate separation schemes are still pending in the WECC Variable Generation Subcommittee (VGS) study forum for the integration of renewable resources. It is unclear if these studies would examine a consolidation of the Western BAAs; however, this would seem to be an appropriate forum for these technical analyses which are fundamental and should be mandatory.

Conclusions

In conclusion, the Federal Projects have specific obligations that require careful consideration. Consolidation of electrical operation center functions is normal in the current electric industry environment. Consolidation efforts that reduce costs and improve efficiency are generally supported when implemented in a cautious, measured and methodological approach without sacrificing customer services.

However, with the lack of clear, logical and methodological information and reports, it is difficult to conclude that the consolidation of Western's BAAs should or can be effectuated, given the vast geography of Western's transmission system and the fully committed statutory status of the Federal hydropower projects. Consolidation of Western's BAAs may present significant challenges and issues within the sub-regional areas which have relied on Western's resources in that subregion to provide reserves and support regional reliability.

Until FERC Order 764 is fully implemented, any EIM is premature at best and wrong at worst.

K. R. Saline & Associates, PLC

MEMORANDUM

TO: JOT@wapa.gov

DATE: August 23, 2012

FROM: Christopher M. Fecke-Stoudt, PE[1]

RE: Transmission Planning Processes in the Southwest United States

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The goal of this paper is provide an overview of the coordinated transmission planning processes in the Southwest United States. Specifically this report will describe the transmission planning processes that Western Area Power Administration – Desert Southwest (WAPA-DSW) participates in by first providing a description of transmission planning in general, then describing WAPA-DSW role in transmission planning and finally providing an overview of the transmission planning activities in the Southwest including WAPA-DSW's involvement.

Description of Transmission Planning

Transmission planning is the engineering of the electrical system using the least-cost approach to system additions that enable the transmission network capable of adequate supply to loads and the facilitation of power marketing. Transmission planners must factor in a significant number of issues and factors when making development decisions. These issues and factors include:

- Load Forecasts;
- Resource Location;
- Environmental and Right of Way (ROW) Constraints;
- System Coordination with Neighboring Utilities;
- Stakeholder Concerns

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K. R. Saline & Associates, PLC
160 N. Pasadena, Suite 101 • Mesa, AZ 85201-6764 • Phone 480.610.8741 • Fax 480.610.8796

Electric system coordination and stakeholder involvement are two of the integral factors in successful transmission planning. Both historically and present-day WAPA transmission planning have significant involvement these two important factors.

WAPA's Role in Transmission Planning

WAPA-DSW has an extensive customer review program and contractual agreement with customers through the DSW 10 Year Plan and Joint Planning Agreement (JPA) Principles to manage system improvement and ensure WAPA-DSW meets all Western Electric Coordinating Council (WECC)/ North American Electric Reliability Corporation (NERC) reliability regulations and standards. The 10-Year Planning Process includes Western's obligations to deliver federal hydropower to both Project Use facilities and federal customers. During the planning processes, the customers and Western also had to address the issue that, unlike most utilities, Western does not have load growth responsibility, and load growth heavily affects the planning and upgrading of transmission lines. Therefore, the customers and Western also implemented a JPA under which customers dependent upon Western's system could plan the upgrade of Western's transmission lines to meet customers' load growth needs. Together these two agreements included the full range of planning demands upon Western's system: federal hydropower delivery and load growth needs.

Transmission Planning in the Southwest

Transmission planning is the Southwest is best described by relative geographic planning area size: local, subregional and regional.

Local transmission planning typically focuses on smaller, load-serving area with specific growth needs. The following groups address these local transmission planning needs in the Southwest:

- Central Arizona Transmission System High-Voltage (CATS-HV) Study Group – The CATS-HV study group focus on the growth requirements in the general Pinal County area. WAPA-DSW participated in this group. Other participants included WAPA customers, other Arizona utilities, government officials and various other stakeholder groups.
- Central Arizona Transmission System Extra High-Voltage (CATS-EHV) Study Group – The CATS-EHV study group focused on the bulk electric system in Arizona, looking primarily at long-term bulk power transfers. WAPA-DSW participated in this group with other Arizona utilities.
- Colorado River Transmission (CRT) Study Group – The CRT study group was formed to study the geographic region along the Colorado River from Mexico up to and including Nevada. The CRT study group works on seams issues between Arizona and California and focuses on the portions of the WAPA-DSW system between them. The CRT study group included WAPA-DSW and other California and Arizona utility.
- El Dorado Valley Study Group (EVSG) – The EVSG is a study group that focuses on the electric system development in the El Dorado Valley located in southern Nevada, a key import point for California and specifically for out of state renewable. The EVSG was formed to address multiple merchant transmission developers with projects in the area. WAPA participates in this study group along with California and Arizona utilities and the merchant developers.
- Short Circuit Working Group (SCWG) – The SCWG was developed to provide a coordinated effort toward short circuit analyses in the Southwest. WAPA-DSW, California and Arizona entities have developed, and continue to maintain, a short circuit model.

- Arizona Biennial Transmission Assessment (BTA) – The Arizona BTA is a biennial assessment of the adequacy of the Arizona transmission system. The BTA process includes coordinated transmission system evaluations including: WECC/NERC reliability, reliability must run (RMR) assessments for load pockets, system import limitations for load pockets, extreme contingency analysis and project sensitivity analyses. WAPA is not required by statue to participate, but does with varying levels of involvement in each analysis.

Subregional transmission planning typically focuses broader transmission and coordination issues. The following groups address these subregional transmission planning needs in the Southwest:

- Southwest Area Transmission (SWAT) Group – SWAT is a subregional planning group comprised of electric utilities in California, Arizona, Nevada and New Mexico including WAPA-DSW. As a subregional planning group, the utilities meet in an open and transparent forum to discuss planed transmission projects, industry topics and provide a group to interface at the regional level. SWAT also has a joint meeting with adjacent subregional planning groups on an annual basis including the following two subregional groups.
- Colorado Coordinated Planning Group (CCPG) – CCPG is a subregional planning group comprised of electric utilities in Colorado, Wyoming and Nebraska including Western Area Power Administration Rocky Mountain Region (WAPA-RMR). CCPG's responsibilities are very similar to SWAT's responsibilities and functions.
- Sierra Subregional Planning Group (SSPG) – SSPG is a subregional planning group comprised of electric utilities in California and Nevada including Western Area Power Administration Sierra Nevada Region (WAPA-SNR). SSPG's responsibilities are also very similar to SWAT's responsibilities and functions.

Together SWAT, CCPG and SSPG make up the regional transmission planning group each are associated with, WestConnect.

Regional transmission planning typically focuses on 20-year transmission planning, seams planning coordination and market issues. The following groups address these regional transmission planning needs in the Southwest:

- WestConnect – "WestConnect is composed of utility companies providing transmission of electricity in the United States. The members work collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the Western Interconnection."[2] WestConnect also coordinated with other regional transmission planning groups including Northern Tier and Colombia Grid. WAPA participates in the WestConnect market enhancements and planning activities.
- WECC – "WECC is the Regional Entity responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. In addition, WECC provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws."[3] WECC membership includes electric utilities and stakeholder throughout the entire Western Interconnection WECC transmission planning activities include: coordinated power flow case

[2] http://www.westconnect.com/aboutwc.php
[3] http://www.wecc.biz/About/Pages/default.aspx

development, 20-year congestion analysis/transmission development and reliability planning. WAPA participates in regional transmission planning activities.

WAPA must also meet various reliability mandates and standards related to the transmission planning function:

- Federal Electric Reliability Organization (FERC) Orders 888 and 889 – Orders 888 and 889 mandated the unbundling of electric system services, the development of tariffs, required transmission capacity be made available on real-time open access information systems and prohibits sharing of market information. WAPA was required to comply with Orders 888 and 889.
- FERC Order 1000 – Order 1000 requires additional intra and inter regional coordination and cost allocation for regional transmission projects. WAPA actively participates in the Order 1000 process and compliance development.
- NERC MOD-029 Standard – The MOD-029 standard was developed to ensure that rated paths values were evaluated and transmission capacity adjustments reflected in open access information system. WAPA was required to comply with MOD-029 standards.

Conclusions

In conclusion, WAPA's involvement in transmission planning is both comprehensive and expansive. WAPA's transmission planning process is working well offers many opportunities to stakeholder involvement and electric utility coordination. In fact, WAPA coordinates and cooperates at every level. From joint planning with their customer, to joint transmission studies with adjacent utilities to subregional and regional coordinated stakeholders at all levels have the opportunity to provide input and coordinate system planning and enhance electric markets . WAPA continue to lead transmission planning coordination efforts and is involved in 10 and 20-year transmission planning processes that plan well beyond the boundaries of WAPA's existing transmission system.

K. R. Saline & Associates, PLC

MEMORANDUM

TO: JOT@wapa.gov

DATE: August 23, 2012

FROM: Kenneth R. Saline, PE[1]

RE: Improved Utility Situational Awareness Proposal

September 8, 2011 System Disturbance Issues from Department of Energy ("DOE") Materials:

Background from DOE: *On September 8, 2011, the Western Interconnection sustained a major outage resulting in cascading failures of the bulk electric system transmission facilities. As a result, nearly 2.7 million customers in Arizona, Southern California, and Baja California, Mexico were left without electric power for up to 12 hours. In their April 2012 Report entitled Arizona-Southern California Outages on September 8, 2011 ("September 8, 2012, Report"), the Federal Energy Regulatory Commission ("FERC") and North American Electric Reliability Corporation ("NERC") identified key findings, causes and recommendations. Western Area Power Administration ("Western" or "WAPA") is participating in efforts with reliability organizations, its neighboring utilities and regional transmission planning and operations forums to respond to these recommendations.*

Response: In accordance with existing FERC and NERC policies, the affected utilities are working with the appropriate agencies to review the event and identify actions to improve the reliability of the grid. As noted in the September 8, 2012, Report, the outage of the 500kV Southwest Power Link ("SWPL") was one of the major events leading to the September 8, 2012, system disturbance. The Western Electric Coordinating Council ("WECC") has identified a SWPL "N-1" outage as a significant outage that is evaluated in all southwest extra-high voltage ("EHV") power flow studies.[2] While the recently energized 500kV Sunrise Project will improve

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[1] On behalf of Aguila Irrigation District, Buckeye Water Conservation & Drainage District, Electrical District No. 6 of Pinal County, Electrical District Number Seven of Maricopa County, Electrical District No. 8 of Maricopa County, Harquahala Valley Power District, Maricopa Water District, McMullen Valley Water Conservation and Drainage District, Ocotillo Water Conservation District, Roosevelt Irrigation District, Tonopah Irrigation District, and Wellton-Mohawk Irrigation & Drainage District in Arizona.

[2] "N-1" refers to an outage of a single element of the electric power system such as a transmission line segment or transformer. Reliability criteria require that the bulk electric system be designed and operated to absorb "N-1" outages without cascading failure of additional bulk electric system facilities.

the reliability from Imperial Valley into San Diego, the outage of the remainder of SWPL will remain a critical contingency.

In California, the California Independent System Operator ("CAISO") Transmission Planning studies have repeatedly indicated the proposals for fixing the SWPL "N-1" outage are not economic. Instead the CAISO 10 Year plan continues to rely upon abundant supply of renewable projects locally located within California and does not plan for additional interstate EVH facilities to reduce the risks of a SWPL outage.

The September 8th outage reinforces the need to have engineering studies performed on the system operations and planned generation fleet, versus theoretical generation energy zones. The majority of renewable projects coming on-line by 2016, when the American Recovery and Reinvestment Act of 2009 ("ARRA") expires, should be under contract and going through final development stages. The planning studies need to make sure the system is reliable with those Variable Energy Resources ("VERs") anticipated to be operating in 20 years, versus theoretical, speculative generators, which do not have contracts and are far in excess of the market needs or commercial viability given the high generation reserves currently projected in the WECC footprint.

Additional Coordination Suggestion: The September 8, 2012, Report highlighted the need for better coordination and improvements in day-ahead and real-time operations. The affected utilities and WECC are following the FERC and NERC recommendations. We suggest that a cost effective and prudent approach would be to utilize the existing Open Access Same-Time Information System ("OASIS") for all WECC Balancing Area Authorities ("BAAs") to maintain a real time transmission line status file and a generator status and availability schedule for units in their BAA.

Such data from each control area could be shared through the OASIS with all BAAs to enable all control areas to run their operational sensitivities and emergency preparedness planning as events occur. Today, this information is not shared between utilities on a real time basis; and many utilities are already developing internal software to provide the data to WECC Reliability Coordinators. All participating BAA's already have secure communications with the real time OASIS. The OASIS can fill the role of maintaining a "Line Status" database and "Generator Status" database to enable real time situational sharing between all WECC utilities, with minimal incremental costs.

From the OASIS, each control area can import the Line Status and Generator Status information into their operational power flows and state estimators to examine contingences and make necessary adjustments. It is up to each BAA to convert that data from the OASIS into their software and keep their operating EHV models updated. Over time, this simple step will create the needed data bases and exchange processes to enable the coordination expected and required to provide the Security Coordinators with needed information and to operate the system better.

With these OASIS regional upgrades and full participation by all WECC BAAs in status reporting, the improvements sought in regional reliability could be implemented with minimal costs or changes. As renewable forecasting develops, the forecast production curves could be updated for regional VERs and also shared with all BAAs to examine and anticipate stresses on the interconnected grid. As the VER projects operate under various weather conditions, improved forecasting will develop over time with the OASIS being the central data base for sharing WECC-wide VER forecasts and outage schedules.

We believe the upgrade of the OASIS could be completed in one year. It would also avoid WECC, as a reliability organization, having to add staff or equipment when the OASIS is already secure, developed and operating. The following diagram depicts the OASIS and suggested modifications: