Comments of the American Public Power Association in Response to the Department of Energy's and the Western Area Power Administration's Joint Outreach Team (JOT) Draft Recommendations

January 22, 2013

The American Public Power Association (APPA), based in Washington, D.C., is the not-for-profit service organization for the nation's more than 2,000 community-owned electric utilities. Collectively, these utilities serve more than 46 million Americans in 49 states (all but Hawaii).

APPA was created in 1940 as a not-for-profit, non-partisan organization to advance the public policy interests of its members and their customers. Today, our members provide reliable electricity at a reasonable price consistent with the proper protection of the environment. Since two-thirds of public power utilities do not generate their own electricity and instead buy it on the wholesale market for distribution to customers, securing low-cost and reliable wholesale power is a priority for public power. Most public power utilities are owned by municipalities, with others owned by counties, public utility districts, and states. APPA members also include joint action agencies (state and regional public power entities that procure wholesale generation and transmission services for their constituent members) and state, regional, and local associations that have purposes similar to APPA.

APPA participates on behalf of its members in a wide range of legislative and regulatory forums to advocate for policies that:

- ensure reliable electricity service at reasonable costs;
- promote effective competition in the wholesale electricity marketplace;
- protect the environment and the health and safety of electricity consumers; and
- safeguard the ability of communities to provide infrastructure services that their consumers require at a cost they can afford.

Approximately 600 of APPA's members in 33 states purchase hydropower from the four federal Power Marketing Administrations (PMAs). The PMAs market the hydropower produced at large federally-owned dams operated by the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (BOR). Each of these dams is part of a multi-purpose project serving many uses. Each of these public power utilities has a unique contractual arrangement with the PMA from which it receives power. Some of these utilities get all of their wholesale power needs met through a PMA, while others only get a portion – augmenting the federal hydropower with their own generation and other resources. These include natural gas, coal, nuclear, other hydropower facilities and non-hydro renewable sources such as wind, solar, geothermal and biomass, as well as and energy efficiency and demand-side management projects. The rates that each of them pay for the PMA-marketed hydropower they obtain cover all of the costs of generating and transmitting that power, interest on the federal investment in the project, a proportionate share of the joint costs, and ongoing operation and maintenance. In some cases, the power customers also subsidize other purposes of the dams, such as irrigation and recreation.

For the public power utilities that purchase hydropower marketed by the PMAs, this system of repayment of the federal investment (through rates charged to electricity customers) has worked well for decades. As modifications and updates are made to federal dams, the power customers that receive the benefits of these upgrades repay the government for them. This principle, long-referred to as "beneficiary pays," is a core underpinning of the PMAs' operations. Another principle is that of "preference," which is essentially a "right of first refusal" to access PMA power that has been granted under federal law to not-for-profit utilities – public power and rural electric cooperatives – and a few other not-for-profit entities, such as military installations and publicly-owned universities. The preference principle is set out explicitly in the statutes that govern the PMAs' operations and marketing activities. This clear public policy principle is based on the concept that our nation's river systems, and many of the dams that have been built on them, are public goods and thus the benefits of these facilities must flow broadly to consumers on a cost-based, not-for-profit basis. This concept has had bipartisan support since the inception of federal hydropower in the early 1900s.

APPA members, as purchasers of significant quantities of wholesale power marketed by the PMAs, are directly impacted by changes to the federal power program. The PMAs' cost recovery, as described above, is based on a system of cost pass-throughs, whereby federal investment is repaid, plus interest, through electricity rates. As the costs to the federal government to provide these essential hydropower services increase, wholesale and retail electricity rates are raised correspondingly. APPA has consistently opposed proposed changes to the structure and mission of the PMAs that would have resulted in higher electricity rates for its members and their customers.

On November 20, 2012, the Department of Energy (DOE)/Western Area Power Administration (Western) Joint Outreach Team, or JOT, issued 14 draft recommendations for implementation of DOE Secretary Steven Chu's March 16, 2012 memorandum describing several changes he intends to make to the PMAs. The JOT recommendations were issued following a public meeting-and-comment period, which included discussion forums led by the JOT, about the March 16, memorandum itself.

APPA remains concerned about the process for the implementation of, and policies under consideration in, Secretary Chu's March 16 PMA memorandum. The draft JOT recommendations have omitted some of the more controversial portions of the original memorandum and do contain certain recommendations that APPA considers to be noncontroversial. However, as explained below in detail, the lack of specificity in the recommendations could allow DOE to take steps in implementation that could increase costs for the primary constituency of the PMAs: the preference customers.

APPA's comments on each specific recommendation are set out below, followed by a general conclusion. In addition, APPA is joining in separate "Limited Joint Comments" with a number of other organizations regarding legal considerations raised by the JOT draft. Finally, APPA respectfully requests that the JOT and/or DOE make public their final recommendations to the Secretary of Energy.

<u>Recommendation No. 1</u>: 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.

Response:

JOT summarizes the purpose of this study as "identifying the amount of regulation capacity that is required to support current BA [Balancing Authority] 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." JOT Draft Recommendations at 8. On the surface, this recommendation appears to have some potential benefits, by identifying whether there are existing reserves that could be used to address variable energy resource (VER) integration. One of the flaws in the National Renewable Energy Laboratory's (NREL) analysis and estimate of the benefits of the energy imbalance market (EIM) proposed for the Western Interconnection[1] was the assumption that none of the existing contingency reserves could be used to meet the flexibility reserve requirements. To the extent there are resources available for these flexibility reserves, identification of these resources could be useful.

However, given the lack of specificity regarding the methodology to be employed and the uses of the results of the proposed regulation reserve capability analysis, APPA urges significant caution in pursuing this recommendation. Reserves which have been paid for by preference customers and that now support the delivery of their preference power cannot simply be commandeered for the integration of variable energy resources (VERs). The statutory mission of the PMAs is to provide preference customers with low-cost, reliable hydropower, and the integration of VERs must be secondary to this priority.

Furthermore, assuming that the needed flexible regulation reserves for the integration of VERs could be found within the existing pool if the current reserves were just more carefully scrutinized (like assuming that substantial cash can be found just by overturning the couch cushions) ignores the inevitable need for development of new reserves. Increasing amounts of VERs, especially wind, will necessarily entail the construction of additional natural-gas fired generation units to provide the flexible reserves needed to back up intermittent resources. Preference customers should not be saddled with the capital costs of constructing these additional reserves, which should be borne instead by the generators of VERs. The JOT seems to recognize this point: in its response to the National Rural Electric Cooperative Association's December 17, 2012 Questions (JOT Responses) at 1, the JOT states that "Western must also ensure . . . that the value of the Federal hydropower resources within the BAs are maximized for the preference customers; and, that the costs of regulation series are allocated appropriately to the parties that create the need for regulation within the BA."

<u>Recommendation No. 2</u>: Consolidate Western's four Open Access Same-time Information System (OASIS) sites within the Western Interconnection into a single OASIS site.

Response:

APPA supports the JOT's draft recommendation to consolidate Western's four OASIS sites within the Western Interconnection into a single OASIS site. APPA also agrees that Western should concentrate on the west-side regions' sites as an initial focus, given the differences between the Eastern and Western Interconnection regarding items such as calculation of Available Transfer Capability (ATC). APPA, however, supports this draft recommendation on the understanding that it is intended solely as an administrative, cost-saving recommendation and is not intended as a recommendation to direct Western to combine or otherwise homogenize or standardize the actual rates, terms and conditions of the transmission service that Western provides over its various facilities. Given that its facilities are divided into different regions, some of which are not even contiguous with the other regions (*e.g.*, the Central

[1] *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, Draft Report, November 2012, p. 8, by Michael Milligan and Kara Clark, National Renewable Energy Laboratory, Jack King and Brendan Kirby, Consultants, Tao Guo and Guangjuan Liu, Energy Exemplar, http://www.westgov.org/PUCeim/documents/drftNRELba.pdf.

Valley Project/Sierra Nevada Region facilities), that transmission service is offered and priced within each distinct project, and that different statutory frameworks govern the various projects and regions, a single Western-wide transmission rate structure would be infeasible and inappropriate. Transmission rate consolidation is also addressed in the response to Recommendation 4.

Should DOE direct Western to implement this recommendation, APPA requests that DOE and Western solicit input from preference customers throughout any such consolidation process. APPA would also encourage Western to conduct adequate advance testing of any proposed consolidated OASIS site before roll out to ensure that consolidation achieves the stated objectives to decrease Western's overhead and duplicative efforts. Western should also conduct customer training before any roll out to ensure a smooth transition and reduce customer confusion.

See also the comments under Recommendation No. 3 regarding Large Generator Interconnection Procedures (LGIP) and related revisions to Western's Open Access Transmission Tariff (OATT) provisions.

Recommendation No. 3: 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.

Response:

APPA has not reviewed in detail the LGIP changes recommended by WestConnect's LGIP Work Group. APPA has received feedback, however, from a few of its member representatives with knowledge of the WestConnect's LGIP Work Group's efforts to date. That feedback indicates that certain APPA members generally support the recommended changes to the LGIP, but other APPA members would need to review the recommendations to determine how the proposed changes would affect them.

As with any working group, certain entities and individuals are closer to the process than others. Therefore, APPA agrees that "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." JOT Draft Recommendations at 11. This formal notice and comment period will allow preference customers, and others, time to review and provide comments on the recommendations. Depending on the scope of the recommended changes, Western should consider extending the standard 30-day comment period to 60 days or longer.

As noted in the Limited Joint Comments submitted concurrently in response to the JOT Draft Recommendations, "to the extent any actions in pursuit of the JOT's Draft Recommendations stray from the preference principle by providing benefits to other customers or customer classes, at the expense of preference customers, such actions would violate the Congressional directives governing Western's operations and activities." In light of the *Iberdrola Renewables, Inc., et al. v. Bonneville Power Administration* proceeding before the Federal Energy Regulatory Commission (FERC) in FERC Docket

No. EL11-44, including the December 20, 2012, order denying rehearing in that case,[2] APPA believes that Western must include provisions in its LGIP/Large Generator Interconnection Agreement (LGIA) and its OATT making clear that the granting of transmission service to non-preference customers, be it interruptible, conditional firm or firm, is subject to curtailment or any other actions necessary for Western to meet its statutory obligations to its preference customers. Such action is necessary to preserve the statutory preference principle under which Western operates, for the reasons set out below.

In this FERC docket, Iberdrola and a number of other wind generators filed a complaint against BPA in June 2011, under Section 211A of the Federal Power Act (FPA). They alleged BPA was providing them "non-comparable" and discriminatory firm transmission service because BPA (due to high water conditions and environmental obligations) was substituting federal hydropower for their own wind generation for delivery to their customers, under BPA's "Environmental Redispatch Policy." They alleged, among other things, that BPA should pay them to <u>not</u> produce power ("negative pricing"), as this way they would be kept whole for the loss of the production tax credit (PTC) they suffered when their power production was curtailed.

BPA stated that it had implemented its Environmental Redispatch Policy to balance the statutory obligations under which it must operate, including its obligations to market federal hydropower to its preference customers, with its OATT obligations to the wind generators, which had firm transmission agreements. BPA explained that the payment of negative prices to wind generators would be inconsistent with BPA's obligations to its preference customers under the Northwest Power Act. That statute requires BPA to establish "the lowest possible rates to consumers consistent with sound business practices."[3] BPA stated that requiring its preference customers to foot the bill for payments of negative prices to wind generators was inconsistent with this statutory obligation.

In *Iberdrola*, FERC ruled that BPA's statutory obligations did not justify what it saw as discrimination in providing firm transmission service. At P 47, it said "[w]e disagree with parties arguing that the federal hydroelectric facilities and non-federal resources are not similarly situated for purposes of transmission curtailments at issue in this proceeding." It reasoned that since both BPA's hydropower and the third-party wind power are transmitted under firm transmission agreements, they are indeed similarly situated as a matter of fact, putting an end to any further discrimination analysis. These rulings evince a clear decision on FERC's part to elevate the voluntarily assumed obligation to provide firm transmission service over all other prior existing statutory obligations of BPA (and by extension, other PMAs), including environmental and federal preference obligations. APPA believes that FERC's rulings in the *Iberdrola* matter are not properly made under FPA Section 211A in the first instance, and that even if they were, FERC's rulings are wrong on the merits because FERC has given insufficient deference to the preference principle and other statutory obligations under which BPA must operate.

[2] *Iberdrola Renewables, Inc. v. Bonneville Power Administration*, 141 FERC ¶ 61,233 (2012) (denying requests for rehearing of an order issued on December 7, 2011, which granted a petition against Bonneville Power Administration (BPA) by a group of wind generators alleging that BPA's Environmental Redispatch Policy resulted in non-comparable transmission service for certain resources, including wind generation, connected to BPA's transmission system) (*Iberdrola*).

[3] 16 U.S.C. § 838g.

Nonetheless, given the result in *Iberdrola*, APPA believes that Western must revise both its OATT and its LGIP/LGIA to make clear that its statutory obligations to its preference customers do indeed constitute binding prior legal obligations that justify curtailments of third-party firm transmission customers. Such actions (or other actions) are necessary to ensure continued service to the preference customers who have paid for the federal transmission system and associated hydropower facilities through their long-term agreements to pay the costs necessary to defray service to them. In the absence of such provisions, APPA would oppose Western entering into any future firm transmission agreements with third-party transmission customers or LGIAs with third-party generators. The lesson of *Iberdrola* for preference customers is that FERC will not honor PMA statutory obligations once firm transmission service is granted unless forced to do so by the courts; hence, the provision of generator interconnection and transmission service must be conditioned as an initial matter to ensure that Western continues to meet its preference obligations.

<u>Recommendation No. 4</u>**: 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.

Response:

The language of this recommendation and the corresponding JOT Response implies that the consolidation of transmission rates is not a foregone conclusion. For example, the recommendation refers to the *potential* consolidation of transmission rates, and states that the recommendation is to "determine whether a business case exists to consolidate transmission rates…" JOT Draft Recommendations at 12. Such an approach is more reasonable as it leaves open the possibility that the collaborative process may result in a decision that consolidation is not the best option. As described below and stated in the prior response to Recommendation 2, a single Western-wide transmission rate structure would be infeasible and inappropriate. APPA therefore urges that the study process not assume that the end point will be a decision to consolidate; in fact, that end point should be taken off the table.

It is also not clear how this recommendation would interact with the Recommendation 5 to "explore the potential to harmonize transmission and ancillary service rate setting methodologies across Western." JOT Draft Recommendations at 14. As discussed in the comments on Recommendation 5, APPA recommends that Western not be required to duplicate efforts under these two recommendations.

JOT conditions its recommendation on rate consolidation with the caveat "where appropriate and legally possible." JOT Draft Recommendations at 12. APPA emphasizes that the legality of such consolidation should be assessed prior to any study, and that the study should not proceed if it is found that the consolidation is not legally permissible under the statutes applicable to Western.

Any assessment of the consolidation of rates needs to take into account the diversity of the regions in terms of differences in costs, resources, and transmission access. Were the focus solely on eliminating pancaking of rates, it might be possible to accomplish this within some sub-regions where legally permissible and in a manner that would not compromise the priority access to hydropower for preference customers. But, regional and project differences in costs, resource types, and transmission systems would likely produce inefficiencies in rate consolidation and cost-shifting that could benefit one customer or customer class at the expense of another or reduce costs to a third-party generation provider by increasing preference customers' costs. APPA recommends against such consolidation given the diversity among the regions and likelihood of cost shifting, which would be inconsistent with the cost-causation principle.

A longer run central concern regarding a Western-wide consolidation of transmission rates is the potential for this to be a step towards implementation of a Regional Transmission Organization (RTO). An RTO would be costly to implement and operate, would likely raise energy prices, and would inevitably involve increased FERC jurisdiction. Given the FERC's decision in *Iberdrola* discussed above, any such step would face strong opposition from preference customers in the region.

Recommendation No. 5: 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.

Response:

As noted in the Limited Joint Comments being submitted concurrently in response to the JOT Draft Recommendations, any activities Western undertakes to further Recommendation No. 5 must comport with Western's statutory obligations to its customers in the area of rates and rate design.

The JOT Draft Recommendation states that "[t]his effort would seek to ensure that the most effective transmission and ancillary service rate methodologies are used consistently across Western." JOT Recommendations at 14. APPA believes that this effort, if undertaken, should be intended to determine the best rate setting "methodologies" for a region, as opposed to implementing single system rates or rate methodologies across regions. Hence, the term "best rate-setting methodologies" in this context means:

- ensuring that costs are borne by those customers or customer classes that cause Western to incur the costs;
- ensuring that Western is able to deliver federal hydropower to preference customers at the lowest cost consistent with good business practices, as the relevant statutes require;
- recognizing the unique attributes of Western's various regions and projects; and
- recognizing the statutory and operational requirements of the Federal Generating Agencies, the Corps and the BOR.

Western should not adopt a common rate-setting methodology or new services if such changes would: (i) result in cost-shifting inconsistent with the cost-causation principle, (ii) benefit third-party generators at the expense of preference customers, or (iii) benefit one group of preference customers at the expense of other preference customers.

Additionally, the study proposed on page 12 of the JOT Draft Recommendations (Draft Recommendation 4) appears to be closely related to the study proposed on page 14 of the JOT Draft Recommendation (Draft Recommendation 5). Any studies undertaken pursuant to the Recommendations should themselves be consolidated to eliminate potential duplication, and should be streamlined to take advantage of existing data bases and prior studies on the same subject, to ensure that dollars are not needlessly expended.

<u>Recommendation No. 6</u>: 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.

Response:

There are two prongs to this Draft Recommendation. The first is to improve customer reporting under Western's integrated resource planning (IRP) process. The second appears to be a recommendation to enhance or revise the planning process itself, which could interfere with state requirements and impede local control of the planning process.

If this recommendation were concerned solely with ensuring that the customer plans are "complete, conform to existing guidelines and procedures, and accurately reflect the activities that have been accomplished using the planning process" (JOT Draft Recommendations at 15), APPA could possibly support such a recommendation, as it could improve the data gathered as part of the IRP. The reporting process, however, should not itself become overly burdensome, especially to smaller preference customers with limited staffs and resources.

But, as with several of the Draft Recommendations, the intent of the second prong is not clear. A number of statements made in the Draft Recommendation appear to indicate that JOT may be considering proposing a revamp of the planning process itself, although the extent of this revision or the process for obtaining customer input on it is not explained. For example, JOT proposes that Western conduct periodic examinations of the IRP process and that those 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." JOT Draft Recommendations at 15 (Emphasis added.) While vague, this appears to be encouraging Western to rethink its policy goals to conform with broader DOE goals. Such an approach ignores the unique characteristics of Western's various regions and the importance of state policies and local control. Further, the recommendation asserts at 15 that customers "conducting a robust resource planning process have the ability to *understand and quantify externalities*…" (Emphasis added.) The inclusion of externalities in the planning process could substantially change the fundamental criteria used to evaluate a project, and could override local customer decision-making. Such a change would be highly controversial, and APPA urges the JOT not to proceed with this recommendation.

Statements concerning improvements in consistency also raise some concerns, such as: "Western's current IRP and alternative plan process administration is not consistent across Western's regions…" JOT Draft Recommendations at 15. Such a lack of consistency is not necessarily a bad thing given the regional diversity and the variations in state requirements and local preferences. Standards for renewable energy and energy efficiency are established by the states or the governing bodies of public power utilities, and not by Western or DOE, resulting in differences among states and communities that reflect more localized policy choices. As a recognition of the importance of the range of applicable policies, Western states that "[c]ustomers who are required by state, Federal or tribal law to invest a portion of their resources in demand-side management (DSM) initiatives, including energy efficiency and load management, and/or renewable energy activities may provide a copy of that report in lieu of an IRP."[4] Implementation of the Draft Recommendation should not override such alternative options, which would increase the reporting burden on preference customers solely for the sake of "consistency."

For some preference customers, there are cross-cutting resource policies that must all be incorporated into the development of overall good utility practices and IRP plans. For example, groundwater use may be reduced by drip irrigation practices, although the associated energy use is greater. Good utility practices form the core of an evaluation of preference customer planning and performance, taking into account the unique characteristics of each region and variations in state requirements.

APPA therefore recommends that, if there is an interest in improving the reporting and planning processes, Western could support forums where different utilities in the region exchange ideas about their best practices in IRP implementation and use this opportunity to learn ways to improve their operations, achieve cost savings and meet the goals of the IRP.

<u>Recommendation No. 7</u>: 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, inter-regional, regional and sub-regional expansion planning processes.

[4] Energy Efficiency/Renewable Energy report review and evaluation checklist, http://ww2.wapa.gov/sites/western/es/irp/Pages/eerereviewlist.aspx

Response:

APPA understands that in this Draft Recommendation, Western is essentially seeking to improve both the information and the processes used in making decisions regarding capital expenditures for both new transmission facilities and upgrades to existing facilities. APPA also understands that currently there is not a consistent approach in all of Western's regions for evaluating and prioritizing such potential projects. And as the JOT notes, funds for capital additions and upgrades are limited.

Thus, it would be appropriate for Western to conduct infrastructure investment studies (IIS) periodically to gather pertinent data in a consistent manner. The use of an IIS would allow Western to establish a more comprehensive and valuable tool for evaluating projects across its service territory, maintain a sound business model, and more prudently allocate limited budget resources. Such a tool could be conceptually consistent with the statutory obligation to conduct Western's operations using sound business principles. It would be important, however, to ensure that the decisions resulting from the evaluations are tied back to the project in a manner that is consistent carrying out the project's original statutory intent and obligations, maintaining reliability, and ensuring the lowest costs to the customers, as required by law.

However, there is also language in this recommendation that creates great concern about how the results of an IIS might be used. The phrase "commercial value of transmission paths" is of particular concern. Electric transmission is often a scarce resource desired by numerous and varied wholesale market participants. Some state and federal policymakers have proposed directly and indirectly greater use of PMA transmission facilities to advance certain policy goals that may be politically in vogue at a point in time, but not necessarily consistent with Western's statutory obligations.

For example, various interest groups continue to advocate for the establishment of a west-wide regional transmission organization (RTO) like those in eastern wholesale electricity markets. An RTO would necessarily include new transmission pricing methodologies as well as elements with new transmission-related costs and revenues such as congestion pricing, as discussed elsewhere in these comments. Such an RTO would also be a FERC-jurisdictional entity. None of those developments would be positive for Western's preference customers. A determination by Western of the "commercial value" of its transmission thus could become an additional financial incentive, and/or an opportunity by profit-making entities seeking those types of policy changes to shift costs to existing preference customers.

Western's transmission assets and all associated values, however, are required to be used in the first instance for the benefit of the preference customers. Thus it would be imperative that this aspect of the IIS be handled in a manner that ensures it is used only to support the internal analysis, prioritization and decision-making process discussed above.

With respect to interconnection-wide, regional, inter-regional, and sub-regional transmission planning, we understand and support the need for Western to participate in those efforts as part of its mission and its obligations as a provider of wholesale transmission service. Such participation is encouraged for non-jurisdictional utilities by FERC under Order No. 1000. APPA further understands how an appropriately conducted IIS and the improved business model that results could benefit both Western's customers and its participation in such planning processes. At the same time, APPA urges Western to be diligent in representing its preference customers' interests and not allowing other entities involved in the planning process to shift costs onto Western's preference customers in pursuit of other policy or financial goals.

<u>Recommendation No. 8</u>**: 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.**

Response:

APPA agrees that DOE should encourage the increased use of joint transmission ownership and operation, where practicable and beneficial to Western's preference customers, and continued use of the CTS model in Western's regions. APPA believes that increased use of the CTS model could improve grid operations and planning, and assist in financing needed new transmission facilities. APPA views the jointly owned Integrated System of Western, Basin Electric Power Cooperative, and Heartland Consumers Power District as a successful example of the CTS model. Any efforts to develop further CTSs, however, should comport with all applicable statutory requirements, and recognize the significant dollars that preference customers have paid over many years to finance the construction and maintenance of the current Western transmission system.

<u>Recommendation No. 9</u>**: 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.

Response:

Because the term "flow-based environment" is not defined by JOT, APPA is basing these comments on its interpretation of what this recommendation entails. It is APPA's understanding that the primary difference between a contract-path and flow-based approach is that the former entails an arrangement to sell power from a specific source to a sink on an identified transmission path, although power will not necessarily flow according to that contract path. A flow-based approach recognizes that the actual paths of power flows are determined by the laws of physics rather than any identified contract transmission path. Therefore, a flow-based approach entails selling and buying power into and out of a regional transmission grid, rather than across a specific transmission path. APPA agrees that there are certain benefits to a flow-based system in terms of better identification of congestion and increases in ATC.

APPA believes exploration of a flow-based approach can provide valuable information to Western and its preference customers, but only if the approach is considered on an interconnection-wide basis and not solely for the Western transmission system. Implementation of a flow-based system cannot be accomplished by one transmission owner alone; any study work must be a coordinated effort with broad participation by Western Interconnection utilities.

Additionally, while the recommendation initially proposes a study of potential options, language that appears later in the recommendation lists a number of assumed positive outcomes from a flow based environment, in addition to increasing ATC:

> 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. JOT Draft Recommendations at 19.

APPA urges JOT to refrain from making such broad statements about the benefits of its proposals prior to any careful study of them.

Additionally, the impetus and rationale for making this recommendation is not clearly spelled out. JOT states that: "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." JOT Draft Recommendations at 19.

This appears to be circular reasoning. As clarified by JOT, "emerging market mechanisms" refer to the PUC EIM-led discussions of an energy imbalance market (EIM). JOT Responses at 6. The implementation of an EIM is not a foregone conclusion, however, and numerous concerns have been raised by a number of Western's customers within the PUC EIM forum. Moreover, JOT later recommends that the EIM itself be subject to further study. Were there no EIM or other centralized dispatch, locational pricing algorithms would not necessarily be imposed on Western, and are not inherent in intra-hourly scheduling. (JOT also stated that the potential link between intra-hour scheduling and locational marginal pricing is being reviewed and "will be clarified or removed as appropriate." JOT Responses at 6. APPA commends JOT for reconsidering this assumption.) It appears that JOT is assuming that centralized dispatch will be implemented first, and is then using this assumption as the basis for justifying the move to a flow-based environment.

JOT states that it "does not believe that a flow based system necessarily needs to lead to locational marginal pricing system." JOT Responses at 6. While APPA understands that there may not be an inevitable path from flow-based scheduling to LMPs or other features of regional transmission organization (RTO) markets, we urge that caution be exercised in this process to ensure that such an outcome is avoided. A move toward an RTO or RTO-like market would create additional complications and costs that would detract from the benefits of flow-based scheduling.

In sum, APPA recommends that a priority should be placed on a review of the outcome of implementation of intra-hourly scheduling and the initiatives discussed in recommendation 12 prior to moving forward with a flow-based study.

<u>Recommendation No. 10</u>: 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.

Response:

APPA has been an active participant in the process of reviewing and providing input into the NREL evaluation of the benefits of an EIM conducted under the auspices of the PUC EIM. APPA found the work conducted by NREL on this issue to be highly problematic. The study was revised several times, errors were found and had to be corrected, and some faulty assumptions were corrected, but others remained. As a result, the benefits estimates fluctuated by hundreds of millions of dollars. Many observers of this process have criticized the study as well as the inability to obtain the data used by NREL in its modeling. Against this backdrop, APPA has concerns with the allocation of any additional responsibility to NREL.

It is not clear whether NREL possesses qualifications to provide hands-on training for utility operators that would justify this transfer. APPA therefore recommends that JOT provide further support for the selection of NREL as the home for the EPTC, prior to moving forward with this recommendation.

This recommendation also does not address the need for EPTC to be self-funding. APPA's understanding is that EPTC currently does not recover its expenses, and therefore is partially funded by Western's preference and transmission customers through Western's rates. JOT notes that it believes that Western had decided to close the EPTC, which APPA interprets to mean that this transfer will not maintain the EPTC under Western's budget. JOT Responses at 7. Were EPTC to be transferred to NREL, costs to run the EPTC should be removed from Western's budget and be charged directly to parties taking EPTC training services.

<u>Recommendation No. 11</u>: 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.

<u>Recommendation No. 12</u>: 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.

Response: APPA supports these recommendations and includes a discussion of these recommendations in its comments on Recommendation No. 13.

<u>Recommendation No. 13:</u> 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.

Response (to Recommendations 11-13):

The language of Recommendation 13 is for a study that will "evaluate the benefits and costs to Western and its customers, tribes, and stakeholders of participating in either regional or sub-regional initiatives investigating energy imbalance markets." JOT Draft Recommendations at 24. It is therefore unclear from a literal reading of the wording whether the recommendation is for a study of the benefits and costs of a regional or sub-regional EIM, or an assessment of the value of Western's potential participation in an EIM. APPA urges the latter approach – given the amount of uncertainty about the benefits of an EIM, it may not be worthwhile to engage in further analysis of an EIM, and participation in further efforts to investigate this option should be carefully evaluated.

The potential incremental value of an EIM appears to be small, and is likely to be exceeded by the costs associated with such an EIM. As noted by JOT in Recommendations 11 and 12, there are a number of planned or ongoing initiatives in Western that will promote the integration of VERs and create efficiencies in the procurement of reserves. These efforts include Western's initial implementation of half-hour scheduling in 2011 and the likely transition to 15-minute scheduling in accordance with FERC Order No. 764. The significant benefits of the shorter scheduling interval were explored in the NREL assessment of the benefits of an EIM. When the two categories of benefits were isolated from each other, even NREL concluded that "most of the savings are realized when going from hourly to 10-minute dispatch."[5]

Additional initiatives being implemented, planned, or field tested include ACE Diversity Interchange (ADI), Reliability Based Controls (RBC) and the Dynamic System Scheduling (DSS). As acknowledged by JOT, these initiatives, along with intra-hour scheduling, "could accomplish some of the benefits of the energy imbalance markets initiatives." NREL also confirmed this finding in its EIM benefits study, stating that:

> In that sense, movement to the 10-minute BAU represents efficiency improvements, similar to the existing and emerging practices of intra-hour transaction accelerator platform (ITAP), the dynamic scheduling system (DSS), and ACE diversity interchange (ADI). Although these methods are different than a 10-minute dispatch, they all qualitatively represent efficient improvements which would lessen the benefit of the EIM.[6]

[5] *NREL et al.*, November 2012, p. 66.
[6] Ibid., p. 65

Given the indirect correlation between the success of these initiatives and the benefits of an EIM, along with the lower risk and costs of these alternatives to an EIM, APPA supports the JOT recommendation to evaluate the benefits and costs of ADI, RBC, and DSS. APPA suggests that JOT acknowledge that several Western BAs have already participated in the development of these tools and, along with several of their neighboring preference customers, are currently utilizing them in BA operations or offering them to transmission customers. APPA does recommend, however, that adoption of these initiatives by those Western BAs not currently participating only be done following a determination that the benefits do exceed the costs and taking into account the implementation of 15-minute scheduling.

Regarding the recommendation to undertake a study of an EIM, two detailed studies of the benefits of an EIM in the Western Interconnection have been undertaken to date; one by Energy and Environmental Economics, Inc. (E3), commissioned by the WECC, and the other by NREL, commissioned by the PUC EIM working group. WECC also commissioned a cost estimate by Utilicast and compared the costs to the benefits, resulting in a present value of net benefits over a 10-year period that ranged from a high of $941 million and a low of a *net cost* of $1.25 billion.[7] These costs did not include the additional costs that would accrue under the likely scenario that the EIM would eventually to evolve into a full RTO.

NREL's analysis did not include an assessment of the costs, but after multiple revisions, NREL arrived at an annual benefit of $146 million for a 10-minute dispatch EIM, very close to the $141 million estimated by E3. (As noted earlier, NREL assumed a 10-minute dispatch in both the baseline and EIM cases to remove the benefits of the move from hourly to 10-minute dispatch and isolate the benefits of just the EIM.)

Even this relatively low benefit was likely overstated as a result of a number of flaws in NREL's analysis,[8] including: a projection of a significant decrease in natural gas generation and an increase in the production of electricity from coal, without a consideration of the impact of pending coal plant retirements; an absence of accounting for existing bilateral contracts in the baseline; and an assumption that prices would not exceed costs.

APPA urges against any further study of an EIM at this time, or at least until 15-minute scheduling has been implemented in Western and a full assessment has been completed of the other initiatives listed above. To the extent that Western determines, with the input from customers, that a study of an EIM is warranted in the future, such a study should not repeat the flaws of the methodology used by NREL.

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[7] *White Paper, WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)*, WECC Staff, October 2011, Table 4, http://www.wecc.biz/committees/EDT/Documents/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf

[8] For a full critique of NREL's methodology see *Critique of the NREL/Plexos Analysis of the Proposed Energy Imbalance Market (EIM) in the Western Interconnection,* by Kenneth Rose, Ph.D., Independent Consultant, Prepared for the American Public Power Association and National Rural Electric Cooperative Association (Revised), November 20, 2012, https://www.publicpower.org/files/PDFs/NREL_EIM_model_critique_K_Rose_11-20-12.pdf

<u>Recommendation No. 14</u>

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

Response:

There are three policies being proposed within this recommendation: 1) creation within Western of a new position to provide technical assistance on VER integration to Native American tribes and others; 2) for Western to conduct outreach and a study to determine the breadth of non-hydropower renewable projects with the potential to connect to Western's system – not limited to those being undertaken by Native American tribes; and, 3) for Western to determine the markets/customers of such renewable energy projects.

At first glance, this proposal may seem appropriate, but there is much more to it than is apparent on first review. Regarding the first part of the recommendation – to create a new position -- APPA does not take issue with the need for enhanced outreach and technical assistance to Native American tribes, and perhaps others, with regard to transmission interconnection of all types of renewable energy projects, including wind, solar, geothermal, biomass, and new, small hydropower. Western's expertise on transmission-related issues could be valuable in enhancing development of these projects on or near tribal lands. In terms of funding, however, there are at least two questions that should be answered related to a proposal to create an additional position within Western. The first is: will this position be paid for by the existing power customers? If not, where will the funding for such a position derive? Secondly: if funding is a concern, then will this new position replace an existing FTE, given the efficiencies being proposed elsewhere in the JOT recommendations? Or will the position require a new FTE?

On the second policy being proposed – to study the breadth of existing or potential non-hydropower renewable energy projects – we have greater concern. This project has a number of action items as part of the recommendation, many of which appear to be well beyond the mission of Western. Western was established to market and transmit federal hydropower, not to promote and inventory new or proposed non-hydropower renewable projects. While many APPA members have developed or purchase non-hydropower renewables and will continue to do so for various reasons, it is not Western's job to oversee, promote or investigate such projects, their viability or availability. It is one thing for Western to consider providing additional technical assistance to interested parties, including Native American tribes, on VER integration, but it is quite another for Western to identify "potential renewable energy projects…" and, "…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."

It is also likely that, should Western undertake such actions, they would be duplicative of existing efforts within states and regions, as well as within the federal government. For example, NREL has a state and local policy team that "examines the effects of policy on renewable energy development and deployment at the local, state, and regional levels." This ongoing activity at NREL would appear to obviate the need for Western to undertake many of the action items suggested in the recommendation, including the analysis/inventory of renewable portfolio standard requirements.

Even if APPA agreed with this shift in focus away from Western's core mission, which it does not, there are similar questions about how this type of effort would be paid for and who would conduct the investigation and ongoing partnership-development envisioned in the proposal. It is difficult to envision that the new position being proposed to help provide technical assistance to Native American tribes and others would also be able to undertake this level of analysis and outreach without significant help.

Finally, the proposal would have Western undertake a market analysis as to who might be the "off-takers" for these hypothetical or actual non-hydropower renewable energy projects. Again, we do not believe it is Western's role to undertake such market analyses outside of its core mission of marketing and transmitting federal hydropower.

Conclusion

APPA appreciates the opportunity to provide these comments on the JOT draft recommendations. Furthermore, APPA appreciates the apparent shift in tone and, to some extent, policy characterized by the JOT draft. In addition, APPA remains concerned that DOE (under this or future Presidents) could use these recommendations to overhaul the PMAs for the benefit of new "stakeholders" and at the cost of PMA customers. While many of the goals outlined by Secretary Chu in the March 16, PMA memorandum are important, the federal hydropower system was built in partnership, with and paid for by, the PMA preference customers. When considering these, and other, changes to this vibrant system, APPA urges DOE to continue supporting this collaborative, historical partnership. Finally, APPA respectfully requests that the JOT and/or DOE make public their final recommendations to the Secretary of Energy.