

QUESTIONS AND ANSWERS FROM THE EIM CROSSROADS MEETING

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GENERAL

Q: What exactly is the problem we are trying to solve? How are the Joint Initiatives projects addressing some of these problems?

A: The problem being addressed by the EIM is two-fold. First, the EIM addresses the issue of economic efficiency and use of the existing grid. Second, the EIM addresses the issue, present and future, of integrating potentially large amounts of variable generation. There are efforts underway at the Joint Initiatives to promote intra-hour scheduling, dynamic scheduling and a fast bi-lateral market for transmission and generation. No analysis has been done of the impact of the Joint Initiatives on economic efficiency, grid utilization or integration of variable generation. Although it is too early to determine the impact of an EIM versus the impact of the initiatives already underway, it is believed that current initiatives will have a lower impact than an EIM. The opportunities for widespread dynamic scheduling are limited at present, but significant work is underway to address the limitations, which may allow for great penetration of dynamic scheduling

in the future. For example, the EIM relies upon the use of dynamic schedules in order to implement the regional security-constrained economic dispatch.

Q. Is this the proverbial back door way or slippery slope into an RTO?

A. No. An EIM must be justified based on its own merits without any expectation of adding other elements typical of RTOs, such as day-ahead markets, capacity markets, transmission planning, or transmission expansion cost allocation. There is nothing in the EIM market design that forces the West to later adopt an RTO structure. In addition, the EIM should not preclude the West from taking future steps toward more efficient system operation through regional energy markets and coordinated transmission services.

Q: What other options do we have to integrate high levels of variable generation? Are we being presented a false dilemma?

A: Presently, individual BAs need to have resources to provide the integration service as a stand-alone operation. Bi-lateral arrangements can be made with parties outside the BA to help the BA balance its loads and resources. While it is always possible to change the rules under which we operate, it is a matter of getting agreement on how to do so. The EIM is one way to do that. An EIM is not the only tool available to lower the cost of integrating variable generation. Better wind and solar forecasting, intra-hour scheduling, dynamic scheduling, new storage technologies, and faster bi-lateral markets for transmission and power (e.g., I-TAP) can also lower integration costs. A fast (5 minute dispatch) market that reduces overall variability and uses the lowest cost generation to balance load and generation over a broad footprint has proven effective in lower integration costs in other regions such as MISO, SPP, and the California ISO. However, MISO and CAISO are fully implemented LMP market models that have features beyond what is contemplated with the EIM. It will be important to understand these differences when making comparisons to the EIM proposal for the Western Interconnection.

Current status of Joint Initiatives:

- Intra-hour scheduling – On track for implementing 30 minute scheduling on July, 2011 subject to the availability of automated scheduling tools.
- ITAP – In a product development phase. The product should be available later this year.
- DSS – The DSS Operating Committee has declared the DSS system as operational and established March 11th as the official “Implementation Date”.

There are presently no plans for a systematic evaluation of the benefits of the Joint Initiatives. The Joint Initiatives decision to move ahead was based on “back of the envelope” calculations that showed benefits exceeded the relatively small cost of the initiatives. There are presently no plans to track usage of the Joint Initiatives to enable an after-the-fact systemic analysis of implementation costs or benefits received.

Q: Without some kind of centralized effort like the EIM, will the West be able to integrate the large amounts of renewable anticipated under the state RPS standards?

A: Yes, the amount of renewable generation contemplated under RPS standards can be integrated without an EIM. However, it is likely that such integration will occur at higher cost than would be the case if an EIM had been in operation. Studies¹ have shown that cost of integration is higher without a mechanism to aggregate variability over a broad area and without a centrally dispatched market. It may also be that without an EIM, integration would require more downward dispatch of renewable generation, i.e. spilling wind.

Q: What is WECC’s role going forward?

A: Any WECC action related to the EIM will have to be taken by the WECC Board of Directors. At this time, WECC is committed to performing the benefit/cost analysis.

¹ See the following link for access to numerous detailed studies including comparisons of stand-alone balancing area operations with regional dispatch and the associated reduced costs of renewable integration. In particular a comparison of the two Minnesota integration studies between stand-alone and regional dispatch is instructive. The study results link is provided by the Utility Wind Integration Group at <http://www.uwig.org/opimpactsdocs.html>

WECC staff also intends to do an assessment of risks to WECC (the organization and the membership as a whole) if the EIM is implemented. Some risks will be different if WECC is the market operator than if a third party is the market operator, so these two scenarios will be examined. No decision has been made by WECC to anything beyond the study.

Q: When will stakeholders need to make a decision?

A: No firm timetable has been established. BAs will be the initial decision-makers on whether to create an EIM. Presumably, BAs will take into account the results of the WECC benefit/cost study to be completed in June and thereafter do their own internal analysis of the benefits and costs to the company. Thus, at the earliest, a decision on whether there is a critical mass of interest to form an EIM would occur in the summer/fall. At the other end of the spectrum, there is experience that decisions on whether to create a market in the West can be drawn out over years.

BENEFITS AND COSTS

WECC benefit/cost study

Q: What is the scope of the benefit/cost study of an EIM?

A: The Western Electricity Coordinating Council is conducting the benefit/cost study of a Western EIM. WECC hired Utilicast to conduct the cost study and E3 to conduct the benefits study. The cost study was completed in April. The benefits study is divided into two phases. Phase 1 was completed in March. It was intended to provide a high level estimate of benefits from BA coordination. It should be noted that Phase I included many simplifying assumptions, some conservative and some optimistic. Phase 2 has begun, and includes refinement of many of these assumptions to more accurately model both the benchmark assumptions and the market assumptions. On April 25 the approved Phase 2 study methodology was posted at http://www.wecc.biz/committees/EDT/Documents/E3_EDT_Phase2_Methodology_and_Sensitivities_2011-04-22.pdf. Phase 1 and phase 2 include broad BA participation and all else being equal decreased participation would decrease the benefit. The final combined cost and benefit studies will be presented to the WECC Board on June 22.

The cost study evaluates the overall potential range of costs for an EIM Market Operator and market participants, considering open design issues. The study will not identify the cost allocation of market operator costs to individual BAs or market participants, nor will it identify specific market participant costs, as that would require analysis on entity-specific existing infrastructure, staffing, software, and interest. The cost study will not directly compare the cost of specific design aspects, such as options for the market operator. For example, the study will not estimate the cost of having WECC, the Southwest Power Pool, the Northwest Power Pool or WestConnect as the market operator.

The benefit study will examine overall benefits to the Western Interconnection, and not identify the allocation of benefits of an EIM to specific BAs or market participants. Phase II will include development of a “roadmap” that will provide insights to enable parties to make company-specific evaluations of benefits. However it may be very difficult for companies to make an informed decision about joining the EIM until more detailed studies (beyond the Phase 2 study) can be completed to determine how BAs will benefit from an EIM. Further, based on the proposed Phase 2 methodology, the study will not evaluate the incremental benefits of an EIM above other specific reforms, such as the Joint Initiatives. The study will not evaluate within-hour benefits on an EIM. For additional information on the scope of Phase 2, please refer to the Phase 2 scope, posted on the WECC website.

Q: What process has been used to develop the benefit/cost study? (Do we believe the WECC benefit/cost study? WECC is an independent entity; are my stakeholders involved in this process? The ones in my hearing room?)

A: Thus far, WECC has held three stakeholder workshops and multiple stakeholder meetings to explain and secure input on the benefit/cost study. The meetings have included diverse participants. In addition, WECC formed a steering committee and technical review subcommittee for the study, both of which consist of members from a diverse range of entities. Meetings for both committees are open and are well-attended. Both the cost and benefit analyses are likely to present a range of outcomes. The results of the benefits study, in particular, are sensitive to assumptions that are hard to model specifically. Potential EIM participants may elect to supplement the WECC benefit/cost study at their individual BA level and by examining the experience with other markets.

Q: How will the study address the costs and benefits of different size footprints?

A: The WECC benefit/cost study will identify benefits for two different size footprints, so that the relative effect of footprint size on benefits and costs can be seen. Most of the Market Operator costs would be incurred regardless of footprint size, and would therefore

be higher (per participant or per MWh) for a smaller footprint. Market Participant costs are identified in the WECC study on a per BA basis, and would therefore scale overall with the number of BAs participating. As other markets have shown, the larger the market, the lower to market operation cost per megawatt.

Q: Are other initiatives, e.g., Joint Initiatives, being included in the base case of the cost/benefit analysis?

A: Other initiatives are not being explicitly modeling in the benefit/cost study at this time. Intra-hour benefits (including those captured by the Joint Initiatives) are not included in the benefits analysis of the market, as the study is using hourly production cost modeling

Q: Are wind integration costs (current and future) being included in the benefits analysis? How much money could be saved by replacing integration costs with the EIM?

A: At this time, the wind integration issue is being reviewed for Phase 2. Wind integration may be considered as one of the qualitative reliability benefits.² Note that some wind integration rates are built into tariffs or business practices that WECC and the Market Operator cannot dictate, or even know.

Q: What reliability benefits will be evaluated?

A: Reliability benefits are not part of the E3 benefits study performed for WECC. However, WECC staff is planning to include in its overall benefit/cost study a qualitative assessment of reliability benefits from an EIM. For example, an EIM may reduce the risk of SOL violations by keeping the transmission system within limits and redispatching

² Please refer to the WECC Phase 2 benefits scope document posted on April 1 for any updated information on this issue. The Phase 1 results did not put any value on wind integration other than to allow for easier access to flexible generation in other zones through the removal of hurdle rates between zones.

within those limits every 5 minutes. At least one utility has found that the presence of an EIM dispatch reduces CPS compliance violations.

Q: Does the WECC EIM benefit/cost analysis assume dynamic scheduling systems (DSS) as part of the base case? If yes, doesn't EIM make DSS obsolete?

A: No explicit assumptions are made in the benefit/cost study about the contribution of DSS, which is a tool for the implementation of dynamic schedules.

Q: Will the analysis show benefits and costs to individual BAs?

A: No, the WECC benefit/cost study will not give BA-specific benefits; however, WECC will make study results available so entities can estimate their own benefits. WECC will provide a “roadmap” on how a BA can use the WECC data and study results to determine potential benefits to its BA. The WECC study will also present average, high and low-end cost estimates per BA.

Q: What additional analyses will be conducted in Phase 2?

A: As part of Phase 2 of its study of EIM benefits WECC is evaluating: greater granularity of results; distinguishing between unit commitment and unit dispatch; improved modeling of hydro; the benefits of aggregated reserves and ramp rates under an EIM; and increased granularity in the base case zones for optimization. . WECC will not evaluate the critical mass necessary to make the EIM possible, as critical mass cannot be determined as a specific number of BAs or MWs. Critical mass would vary based on topology of specific BAs as well. Furthermore, an estimation of critical mass of number of BAs or MWs would require significant iteration of the modeling runs.

Q: Please discuss the implications of using production costing for the cost-benefit analysis when the EIM is proposed to use market clearing prices for settlement? Will the actual benefits and costs change in magnitude or be allocated differently than the study predicts?

A: The dispatch order and production cost identify the societal benefits of the market, which will not change (as described below). The market settling mechanism ends up being a zero-sum equation and only changes the allocation of funds. The benefit/cost study was meant to look at the benefits from a societal perspective and does not address how allocation should be done. It may be difficult for some BAs to calculate their individual benefits even after the WECC Phase II results are available. Some BAs will need to undertake additional, more detailed studies before making decisions to join the EIM. If another market clearing mechanism is used, only the actual Market Participant knows what its bidding strategy (and therefore their settlement price) would be.

Q: Regarding how bids should be settled, isn't the WECC-sponsored cost/benefit study assuming that bids are settled at a market clearing Locational Imbalance Price? If an alternative to settle at bid price is on the table, shouldn't that be studied as part of cost-benefit study?

A: Although the WECC benefit/cost study is assuming that bids are settled at a marginal locational imbalance price, the WECC benefit/cost study is determining the benefit that could be realized based on production costs. From economic theory, using marginal pricing incents market participants to bid at actual cost. Alternative clearing mechanisms (such as pricing based on bids) incents, in many cases, market participants to bid above cost. There are then infinite possibilities of how all of the market participants would bid. However, only a subset of those possibilities (bid a flat percentage above cost, bid a flat dollar amount above cost or bid at what turns out to be marginal price) can reasonably be modeled, and they all end up with the same production cost, because the dispatch stack would be the same.

Q: What are the ultimate limitations of the study? (Are the right assumptions being made in the study?)

A: While there are limitations in the cost analysis, particularly a lack of actual data on market participant costs (which is confidential and market-sensitive in many cases), the larger uncertainties lie in the benefits analysis. Some of the issues being considered as part of Phase 2 of the benefits study are greater granularity to reduce grouping of BAs into zones, treatment of reserve requirements, assumptions on wind forecasting, hydro dispatch assumptions, hurdle rates and unit commitment, and treatment of embedded BAs.

Q: What is the market operator structure being looked at for the cost/benefit analysis?

A: The cost side of the benefit/cost study is developing a range of cost estimates based on factors, such as whether the market operator function leverages an existing market operator or is a greenfield operation. The cost analysis will not give cost estimates for specific market operator options, e.g., WECC, SPP or NWPP as the market operator.

Q: Could the EIM result in more coal generation? If so, will environmental costs be included in the cost/benefit analysis?

A: Yes, an EIM could result in more coal generation if such generation is the most cost-effective in the EIM market. A sensitivity analysis of carbon emissions costs is being considered in Phase 2 of the WECC benefit/cost study.

Risk Factors

Q: What are the risks and rewards to publicly-owned utilities who are not BAs? Who are BAs³?

A: Each entity needs to determine the risks and rewards based on its own position. Generally, the rewards are an opportunity to reduce balancing costs or to offer generation

³ For a list of BAs in the Western Interconnection, please go to <http://www.wecc.biz/library/WECC%20Documents/Publications/Balancing%20Authorities.pdf> .

into the market. The risks include: sharing the costs to start-up and operate an EIM; any payments required to exit the market; a failure of the market to generate sufficient bids to make it cost-effective; and market manipulation.

Q: What are the unintended consequences, including but not limited to prices in bilateral markets?

A: The range of unintended consequences is not known. An EIM could increase revenues for some generators which have the capability to increase generation at low cost. An EIM could lower revenues for generators which are no longer needed to meet imbalance requirements because of lower cost generation in the EIM footprint. How changes such as these ripple through bi-lateral markets is not known. BAs will need to carefully consider the potential for unintended consequences and develop appropriate mitigation measures as part of the EIM design.

Ratepayer Impacts

Q: What are the benefits to ratepayers?

A: The WECC benefit/cost analysis may provide an indication of the overall benefits of an EIM. Benefits might include lower cost of generation, lower cost of integrating variable generation resources and more efficient use of generation and transmission resources.

Actual flow through of benefits to ratepayers will be the responsibility of state and federal commissions and cannot be defined by the WECC cost/benefit analysis. In Arkansas, the PUC conducted a study to determine the benefit to ratepayers from the SPP EIS market. The Arkansas PUC study may provide insights into how much benefit would flow to western ratepayers from a Western EIM.

Q. What will be the allocation of costs among states?

A: Start-up costs are likely to be backstopped by existing BAs (unless a third party assumes the risk associated with start-up investments). Traditional ratemaking procedures (approvals of cost recovery by PUCs or governing boards of public power entities) will likely be employed. FERC jurisdictional entities may obtain FERC approval to add start-up costs to their OATT transmission rate. As with all utility costs, the allocation of costs among states may be an issue for BAs that span multiple states. Note, some BAs may be required by their respective regulatory commissions to demonstrate how ratepayers benefit from any additional costs. Those parties may perform additional detailed studies to estimate the benefits and costs associated with their decision on EIM participation, as well as how they would incorporate those benefits and costs in their rates.

Q. What will the rate impacts be to my customers in the near and long term and what variable will influence this?

A: At this time, it is impossible to tell what the rate impact would be to your customers. The benefit/cost study should provide insights on the potential overall benefits from an EIM but those study results will not be specific to individual companies. WECC will be providing a roadmap to allow entities to do their own individual analyses

MARKET DESIGN AND OPERATION

General

Q: Will participation in the EIM be voluntary?

A: A BA's decision on whether to join an EIM will be voluntary. Once a BA joins, generators within that BA will have the option each hour whether to offer units into the EIM. However, hourly settlements within a BA will not be voluntary. Such settlements will be determined by the EIM. It is not clear if generators outside of a participating BA or BAs which are not contiguous to participating BAs will be able to participate in the EIM.

Q: If a BA joins, what is the obligation of loads and generation to participate in EIM?

A: If a BA decided to participate in the EIM, all loads and generation in that BA must participate in settlements for deviation from scheduled operation. That said, the decision to offer in the market (or self-schedule) is made hourly by the market participant on a unit-by-unit basis. This means that if a generator in a participating BA does not wish to offer into the market, it may choose not to do so and self-schedule instead. Loads within a participating BA are settled through the EIM.

Q: What changes in role, responsibilities and business practices of companies and BAs will be necessary under an EIM?

A: This will be determined on a BA by BA basis. Generally, participating BAs will need to make changes or upgrades to software in order to accommodate the market offer process and the 5-minute dispatch of the EIM. In addition, additional staff and training may need to be considered by each BA. Other changes and costs associated with participation in the EIM are addressed in the WECC cost analysis. The final cost analysis is available at:

<http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Analysis%20-%20FINAL%20v3%201.pdf>.

Q: What happens to non-jurisdictional entities in terms of FERC regulation under an EIM?

A: According to FERC staff opinion, these entities would not become jurisdictional based on their participation in an EIM. Just as in the WestConnect pricing experiment, methods of constructing the EIM tariff and structure could allow non-jurisdictional entities to participate without becoming jurisdictional.

Q: How would a load-serving entity (LSE) that is not a BA, but has its own resources, participate in this market?

A: If the LSE's host BA is part of the market, the LSE would have the opportunity to offer its resources into the EIM market. If the LSE's host BA is not in the market, it might still be possible for the resources to be offered into the market. This would be decided through the market design. Loads inside participating BAs would, by definition, participate in the market settlement process for any imbalance between scheduled and actual energy flows.

Q: What will be the exiting rights/fees, etc. of an EIM?

A: Exiting rights/fees should be set forth in the governing documents. At this time, we can only speculate that the Market Operator will want some assurances that its start-up investments would be paid back. This would require some type of exit fee.

Structure and Operation

Q: Have the EIM structure options discussed at the Crossroads meeting been deployed in any other region and is there an opportunity to leverage off what others have done?

A: This exact market structure has not been implemented elsewhere. The Southwest Power Pool Energy Imbalance Service market is similar to the concept being considered in the West, however the Western Interconnection represents a far more diverse region with respect to generation and transmission topology and balancing authority footprints. It is possible that the EIM could leverage what others have done, particularly the areas of market rules and procedures and software development, but the degree to which leverage could occur it is uncertain at this stage.

Q. Given the challenges of operating a market in non-contiguous geographic areas, should a requirement to join the EIM be that the BA has to be physically connected to other BAs already in the EIM?

A: No, but to have material benefits there must be a way to allow for dispatch of generation between non-contiguous areas. There may be a need to address the issue of compensation for use of transmission. However, this issue may need to be addressed regardless of whether markets are contiguous or not.

Q: Given that apparently “bigger is better” for EIM and that the current EIM proposal allows individual BAs to opt in or out of an EIM, it seems important that any EIM model in the West allow for non-contiguous BA participation in an EIM. Are the costs and difficulty associated with developing non-contiguous BA arrangements, such as the ComEd-PJM integration, significantly different than arrangements for contiguous BAs?

A: The costs incurred to incorporate non-contiguous BAs would be more in time and effort to get the appropriate operating agreements in place. It is not expected that the cost of tools for this type of operation would be significantly different, though the transmission costs for integration of non-contiguous BAs could be higher.

Q: How might those non-contiguous transfer limits affect the efficacy of markets like EIM?

A: Any limitation on the ability to move generation to serve loads will restrict the amount of benefits that might be realized. The level of this impact would depend on what the restrictions are and how the restrictions impact the optimal generation dispatch compared to the actual allowed.

Q: How should bids in the market settled?

A: All operating markets presently settle on the market clearing price.

Q: Can an EIM exist without having the functional control of the grid?

A: Yes.

Q: We don't want participants to lean on the system and should not incentivize such activity.

A: Preventing participants from leaning on the system will be an important consideration in the market design and an important function of the market monitor. It is critical that the market monitor should be able to prevent the gaming of an imbalance market, as it could result in serious capacity short-falls in real-time, jeopardizing reliability.

Q: Can an EIM work in the West if un-consolidated balancing authorities do not all convert to flow-based transmission?

A: Yes. The concept of converting to flow-based transmission is associated with Open Access Transmission Tariff calculations of available transmission capability (ATC). The EIM does not use ATC calculations to provide service. Hence decisions regarding ATC calculation methodology are independent and moot from the point of view of the EIM.

Q: How will hydro bid into the EIM?

A: Hydro will be allowed to bid into an EIM in the same way as other generation, including the option to self-schedule without response to market signals. How hydro system operators choose to participate is not known. In Phase I, the WECC benefit/cost study assumes hydro is dispatched as it has been traditionally. In Phase 2 of the benefit/cost study, WECC is planning on modeling more price-responsive hydro dispatch, which has also been incorporated into TEPPC modeling for transmission expansion.

Q: To what degree will transmission constraints on the existing grid hamper an EIM?

A: The EIM would take physical transmission constraints into account when determining the Locational Imbalance Price for each node. Increased constraints on the existing system could result in higher LIPs at certain nodes. The Security Constrained Economic Dispatch (SCED) algorithm would select the most economic resources, given the transmission constraints. To estimate the impact of transmission constraints, one would need to remove transmission constraints in the production cost model and run cases with and without an EIM. This is not part of the WECC benefit/cost study. The presence of transmission congestion in the EIM dispatch is an indication that grid capability is being utilized efficiently. Existing contractual transmission constraints that restrict long term firm transmission access would not restrict EIM transactions.

Q: What are the ACE implications of an EIM?

A: During the operating hour, the BA will receive a Net Scheduled Interchange signal to include in its Area Control Error (ACE) that ramps based on the five-minute dispatch. Within the five-minute intervals, the BA is responsible for maintaining generation/load balance and deploying reserves for contingency events.

Q: Will an EIM replace schedules 4 & 9 of the OATT?

A: Yes.

Q: Will the tariff agreements, bylaws, etc. be structured to accommodate diverse membership?

A: Such agreements will need to accommodate diverse organizations, particularly any unique needs of public power entities. FERC has indicated that parties joining an EIM will not become FERC jurisdictional; only the EIM itself will be FERC jurisdictional. Public power entities have become members of other markets (e.g., SPP, MISO, California ISO).

Seams

Q: If only some of the BAs participate in the EIM, what are the coordination and reliability concerns?

A: These would be addressed through a Seams Agreement between the Market Operator and the non-market areas (as well as with the California ISO and Alberta Electric System Operator markets). This agreement would be similar to any agreement between to market areas within the interconnection. All reliability standards would have to be complied with on both sides of a seam.

Q: How do we address seams issues with other markets, non-participating BAs and non-contiguous participants?

A: Operating or seams agreements will be needed for each of these.

Market Power

Q: How can we be sure to check the exercise of market power?

A: The most important deterrent to the exercise of market power or gaming of the market is to develop sound market rules that remove the incentives for such behavior. Lessons from the design of other markets need to be considered. The second line of defense is a market monitor. It is likely that FERC will require a market monitor. The EIM market monitor is primarily responsible for monitoring and policing the market pursuant to rules approved by FERC.

Cost-Allocation and Revenues

Q: How are ongoing costs of EIM going to be paid?

A: The answer depends upon how the market is structured. One means currently being discussed would be to have a per unit charge on energy cleared through the market. Other options, such as an allocation to BA participants have also been discussed.

Q: How do we allocate the costs of an EIM? Across participants? Across states (ratepayers)?

A: The allocation of costs would be determined based upon the market structure. At this time, it is expected that the cost of the market would be paid through a usage fee paid by market participants. Whether that cost would be passed on to the ratepayers served by those entities would depend upon the pricing process for any individual market participant.

Q: Who gets the market revenues?

A: Market revenues will be used to pay back start-up costs and ongoing market operation costs. An undecided issue is whether market revenues need to be generated to provide compensation for transmission use. Such compensation could be to transmission owners for lost revenues due to any reduction in non-firm transmission revenues from the

operation of an EIM, or to transmission rights holders for use of transmission held under firm transmission contracts. These details remain to be negotiated among stakeholders and filed with FERC as part of future detailed EIM design and tariff specifications.

MARKET OPERATOR

Q: Who will be the market operator?

A: At this time it is not known who will be the market operator. The WECC benefit/cost analysis may provide insights into what characteristics make for a more costly and less costly market operator option.

Q: What are the options for the market operator?

A. Four groups of market operator options have been identified: 1) a new division within WECC; 2) a reconstituted form of one or more of the existing Subregional Entities (e.g., WestConnect, NTTG, ColumbiaGrid, Northwest Power Pool); 3) an existing third-party which operates a market; or 4) a new third-party market operator. The advantages and disadvantages of the options were discussed in a draft paper at <http://www.westgov.org/EIMcr/documents/eim-options.pdf>.

Q: What principles should be used in developing the EIM market operator?

A: Several principles have been suggested in a [draft options paper](#), including:

- Previous experience operating a market;
- Knowledge and existing visibility of the Western Interconnection;
- Linkage to data flows from WECC Reliability Centers;
- Ability to leverage existing EMS, control centers, and support staff; and
- Cost

There has not been a systematic comparison of the principles for selecting a market operator and the currently identified market operator options.

Q: What kind of entity should the market operator be?

A: This question will have to be answered by stakeholders in the design process, or by the EIM governing entity if it is given the responsibility of selecting the market operator.

Options suggested thus far include: an existing subregional entity such as the Northwest Power Pool or WestConnect, WECC, the operator of an existing market (e.g. Southwest Power Pool, California ISO), and a new third-party.

Q: What are the possibilities for the start-up of the market in an incremental fashion? Could the market be tried for small sub-regions?

A: An EIM could be created that covers only a portion of the Western Interconnection (outside of the California ISO and Alberta Electric System Operator). Such subregional implementation may ease the difficulties of reaching agreement across a broad geographic area. The major challenge for subregional implementation of an EIM will be cost. It is expected that the WECC cost analysis will show that much of the cost of an EIM does not change with the size of the EIM. There may be ways of mitigating the cost penalty inherent in creating a subregional EIM, such as creating sub regional EIMs with identical market structures, software, etc. which would later be merged. Another challenge to subregional implementation of an EIM would be the reduced benefit because a smaller pool of market participants would not reduce overall load and generation variability as much. Nor would it provide as large a pool of balancing resources as a bigger EIM. Seams issues would also need to be addressed.

Q: What will prompt action on whether or not to create and EIM?

A: Individual BAs will need to decide whether to establish an EIM. The general drivers for a BA decision are likely to be the costs and benefits of an EIM to the BA. A complicating factor is that individual BA calculations of costs and benefits will be affected by the decisions of which other BAs decide to participate. There is no regulatory requirement that a BA decide to join an EIM or not.

Q: What are the obligations of the Market Operator related to compliance with NERC standards?

A: This would depend on the ultimate structure of the Market Operator and the participating entities. It is possible that the Market Operator could be responsible for compliance with some reliability standards.

START-UP AND STAGING

Q: What is the critical mass required to make this work? How will it show up? When does it have to show up?

A: We don't know what will be a critical mass to warrant creation of an EIM. The WECC benefit/cost study may provide insights on what constitutes a critical mass, but will not directly address this question. An initial indicator of whether a critical mass can be reached will likely be when discussions among BAs result in the commitment of parties to invest in efforts to define a market design and identify a market operator. A critical mass must show up before making major investments in market implementation.

Q: Why are BAs the primary decision makers? What voice should BPA's 135 wholesale customers have, given that they will be paying the bill?

A: The BA has the primary determination since they will have to provide significant resources to interact with the Market Operator's systems and have primary responsibility for ensuring balance between loads and resources. The customers within any BA should review the expected impacts of an EIM, determine their position and let that position be known to the pertinent entities.

Q: How will utilities address regulatory risk of the decision to participate in an EIM?

A: Utilities, particularly those that operate BAs, will need to consult with their regulators on participation in an EIM. The results of such consultations will figure into each company's internal evaluation of the costs and benefits of participating in an EIM.

Q: How do we control runaway start-up costs?

A: A robust market design is perhaps the best way to control start-up costs. The more design decisions that can be made up front and not changed throughout the development

process, the lower the potential for runaway costs in the implementation process. Putting together a project management plan will help reduce the risk of runaway costs.

Additionally, a test period where the EIM is operated in parallel with traditional balancing procedures has been shown to be important in the successful implementation of new market systems. The cost analysis of the WECC benefit/cost analysis is expected to show lower implementation costs when building on existing operations compared to a greenfield start-up. The WECC cost analysis will also identify some of the risk factors for runaway costs and some suggestions for mitigation efforts.

Q: How can the risk of duplicate costs be checked? How can costs be contained and cost certainty be provided?

A: Cost control will be important in implementing an EIM. To control start-up costs it will be critical to have a well-developing market design that is not subject to change through the development process. Other ways of providing incentives to a market operator to control start-up and operational costs need to be explored. Spreading costs over a larger footprint will minimize costs for participating parties.

Q: How do and to what extent can we leverage existing systems?

A: This depends a lot on the type of market operator chosen. If an existing entity is chosen, the ability to leverage existing systems is greatly increased. This would lower start-up costs.

SPP AND MISO EXPERIENCE

Q: What are the annual benefits of the EIM market in SPP area? Annual costs? What were the costs of starting up the EIM in the SPP area?

A: Prior to proceeding, the SPP Regional-State Committee conducted a study of implementing an Energy Imbalance. The study estimated benefits of \$86 million. After implementation, SPP calculated the 2007 benefits of an EIM to be \$107 million. At the Crossroads meeting, SPP presented information showing initial capital investment over six years of \$40 million and continued capital investment of \$7-8 million and annual ongoing operating and maintenance costs of \$5.1 million. However, these costs do not reflect services the EIM shares with other SPP functions and thus are not analogous to costs of a Western EIM. The WECC benefit/cost study cannot obtain sufficient detailed data to compare SPP implementation and operation costs with options for a Western EIM.

Q: Was there opposition to SPP creating an EIM, what those issues were and how they were resolved?

A: Yes, there were concerns expressed by various stakeholders which included state-level concerns about FERC pre-emption of regulatory jurisdiction, and utility-level concerns that such a simple design compared to full LMP-style markets would not yield sufficient benefits. In actual practice these concerns appear to have been unwarranted.

Q: Has anyone departed SPP or MISO and for what reasons?

A: SPP has not had a member depart the market. MISO has had parties depart. E.ON (Kentucky) withdrew in 2009, and First Energy and Duke Ohio are in the process of withdrawal to more closely align all of their obligations under the PJM market (presently split between MISO and PJM). Also the MISO has added Dairyland Power Cooperative

and Mid-American Energy as new members since their formation. Entergy has announced their intention to join MISO on 1/1/2014.

Q: Do SPP and MISO believe that their regions would have been able to integrate the current level of renewable generation without their organizations, would it have simply been more costly?

A: Integrating the amount of wind being developed in SPP and MISO would have been more difficult and expensive without a market.

Q: How do MISO and SPP go about quantifying the benefit of increased reliability?

A: MISO regularly calculates the benefits of its operations, which include reliability benefits. The MISO methodology for calculating reliability benefits can be found on its web site.

Q: In the SPP market, can participants indicate that they do not want to trade with particular plants, e.g., coal plants? [In the Northwest our policymakers have directed us not to trade with coal plants if possible.]

A: The SPP market does not limit the resources offered into the market or selected by the EIM for dispatch within the hour. It seems feasible that an EIM could generate information on emissions from generation selected for dispatch within each hour.

MISCELLANEOUS

Q: BPA has proposed a "Dynamic Transfer Limit" which limits the amount of in-hour variability of power flows at seams and across the transmission system. Do the California ISO or PJM power systems have similar limits?

A: To our knowledge, neither the California ISO nor PJM currently have dynamic transfer limits, however, the CAISO is working on dynamic transfers.

Q: For Steve Beuning: does the 39% of wind generation you mentioned include only energy that Xcel is purchasing or is that simply the wind energy on the system and purchased by others than Xcel?

A: This percentage of supply was from company-owned and contracted wind resources serving our own requirements within the PSCO balancing area.