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White Paper

WECC Efficient Dispatch Toolkit Cost-Benefit Analysis

By

WECC Staff

Western Electricity Coordinating Council
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White Paper:
WECC Efficient Dispatch Toolkit Cost-Benefit Analysis

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Executive Summary

In April 2010, WECC's Board of Directors (Board) approved a Cost-Benefit Analysis of the proposed Efficient Dispatch Toolkit, pending final approval of the 2011 Business Plan and Budget. Subsequently, two stakeholder committees were formed to provide guidance on the Cost-Benefit Analysis

The Efficient Dispatch Toolkit Steering Committee (EDTSC), which consists primarily of Board members, was developed to provide guidance on policy-level decisions regarding the Cost-Benefit Analysis. The Efficient Dispatch Toolkit Technical Review Subcommittee (EDTTRS), which reports to the EDTSC consists of technical WECC member representatives, and was established to provide guidance on technical aspects of the Cost-Benefit Analysis including assumptions and methodologies.

Working with these committees, WECC staff engaged two contractors to perform different aspects of the analysis. Energy and Environmental Economics, Inc. (E3) was selected to perform the benefits analysis and Utilicast, LLC was selected to perform the cost analysis. WECC staff worked with E3 and Utilicast to ensure consistency of key assumptions. Two separate footprints were examined, the first included all of the Western Interconnection except for the California Independent System Operator (CAISO) and the Alberta Electric System Operator (AESO), and the second further excluded Bonneville Power Administration (BPA), Western Area Power Administration, British Columbia Hydro, and all Balancing Authorities (BA) embedded within BPA. Another key assumption is that the analyses did not identify a market operator. It is important to note that although certain assumptions were made in these analyses, this does not indicate any final decision on market design or participation.

The analyses determined that the 10-year Net Present Value (NPV) of the costs was $678–$2,312 million, and the 10-year NPV of the benefits was $1,179–$1,703 million, all in 2010 dollars.

Recommendations for next steps include a BA process to determine interest in pursuing an EDT, undertaking a risk assessment, developing an organizational structure and governance analysis, and the development of a cost analysis specific to WECC as a market operator.

Background/Introduction

Issue Statement

Efficient use of transmission and generation assets in the Western Interconnection is essential to optimizing usage, and in maintaining a reliable bulk electric system. Although inefficiency exists today, several factors may exacerbate the problem in the future, including: 1) potential high levels of variable generation, 2) uncertainties in future load growth (including for example, the effect of plug-in electric vehicles), and 3) difficulty in siting new transmission and generation resources.

History of the Proposal

In order to address this issue, the Market Interface Committee, and its Seams Issues Subcommittee, developed a proposal for an EDT that would provide automation and centralization of dispatch throughout much of the Western Interconnection. In order to identify the viability and interest in this proposed project, the Market Interface Committee recommended to the Board that a Cost-Benefit Analysis was undertaken. While there are many factors that must be considered in future decisions beyond the monetary costs and benefits, this study would help provide the Board and WECC's Membership with credible data to support informed decision making.

At its April 2010 meeting, the Board approved the proposal for a Cost-Benefit Analysis of the EDT, subject to final approval of the 2011 Business Plan and Budget. In October 2010, the Federal Energy Regulatory Commission provided the final approval of the 2011 Business Plan and Budget, including the Cost-Benefit Analysis.

Proposed Solution

The Seams Issues Subcommittee has proposed to study the EDT, a system that is composed of two separate-but-related tools – an "Energy Imbalance Market" and an "Enhanced Curtailment Calculator." While the Enhanced Curtailment Calculator is a reliability tool that is proposed to be mandatory, the Energy Imbalance Market is proposed to be voluntary in certain respects.

First, a BA and/or a Transmission Service Provider (TSP) could opt out of market participation.[1] If a BA/TSP opts out, the generation and loads in that BA/TSP would not settle through the market. Bilateral arrangements would remain and imbalance would be settled through the transmission tariffs. However, it should be noted that even in nonparticipating BA/TSPs, excess capacity on transmission might still be impacted. Generators[2] and loads within the participating footprint would be required to settle in the market for any deviation from schedule. However, both could reduce exposure to the market by bilaterally scheduling. Furthermore a generator can choose whether or not to submit a supply offer. A generator that does not submit a supply offer still would see a dispatch signal, but that signal would reflect either its submitted schedule or an echo of its current output, depending on how it was identified.

<u>Energy Imbalance Market (EIM)</u>

The proposed EIM is a sub-hourly, real-time energy market providing centralized, automated, region-wide generation dispatch. The automation of the EIM is expected to allow for a more efficient usage of the system in the market footprint by providing access to balancing services from generation resources located throughout the region. It also will optimize the overall dispatch, while incorporating real-time generation capabilities, transmission constraints, and pricing. However, it would not replace the current bilateral energy market, but instead would supplement the bilateral market with real-time optimized dispatch.

The EIM is expected to allow for more efficient use of the transmission system by determining transmission availability based on actual flows in real-time, rather than based on Open Access Same-Time Information System (OASIS)-posted reserved Available Transfer Capability (ATC) on scheduled transmission paths.

While this market has many similarities to Independent System Operators (ISO) and Regional Transmission Operators (RTO) and assumes an independent market operator,

[1] Currently, it is undecided whether the option would be decided by the BA, TSP or both.

[2] For simplicity, the use of the term "generators" includes potential use of demand response.

this proposal does not intend to include implementing an ISO or RTO in the Western Interconnection. The EIM could use tools and algorithms that have been successfully implemented in other centralized markets, but it does not include a single, consolidated regional tariff. However, some tariff or contractual mechanism would be necessary to govern the market.

The EIM would depend on the Enhanced Curtailment Calculator for curtailment responsibility calculations and settlements.

Enhanced Curtailment Calculator (ECC)

The proposed ECC is a tool used for calculating curtailment responsibilities. The proposed ECC includes many enhancements over the current tool, webSAS, which is only used to calculate curtailment responsibility on the six Qualified Transfer Paths. A Qualified Transfer Path is "[a] transfer path designated by WECC's Operating Committee as being qualified for WECC unscheduled flow mitigation."[3]

The proposed ECC would calculate curtailments on many more paths; potentially all rated paths and some additional, currently unrated paths. The proposed enhancements would also allow real-time updates of transmission system data to include actual outages (currently the data is updated twice annually), and a more granular model of the physical system. The ECC can be developed and implemented independently of the EIM; however, it also provides several important building blocks necessary for the implementation of the EIM.

Stakeholder Involvement

In order to provide continuing guidance on the Cost-Benefit Analysis, the Board created an EDT Steering Committee (EDTSC), which is composed of at least one Board member from each Member Class, a representative from the Western Interstate Energy Board, and the chair of the Market Interface Committee. The EDTSC provides guidance on policy-level decisions regarding the Cost-Benefit Analysis.

The EDTSC further created the EDT Technical Review Subcommittee (EDTTRS) to provide guidance on the technical details of the Cost-Benefit Analysis. The EDTTRS included members of the Seams Issues Subcommittee, the Unscheduled Flow Administrative Subcommittee and the Variable Generation Subcommittee. All meetings were open and several additional participants also attended EDTTRS meetings regularly.

In addition to the EDTSC and EDTTRS meetings, stakeholder involvement was also sought through the provision of three stakeholder workshops, held on October 5, 2010, January 18, 2011, and April 7, 2011. These workshops provided education on how the EDT was proposed to work, and included the assumptions and methodology of the Cost-Benefit Analysis.

Approach to Analysis

The analysis was focused on the financial costs and benefits to the footprint as a whole, rather than to individual members. It is anticipated that individual members would need to consider market-sensitive information, strategic positions and risk appetite to perform

[3] Glossary of Terms used in NERC Reliability Standards, WECC Regional Definitions.

individual analyses. The WECC Cost-Benefit Analysis will provide the data and details from the broad study that can be used as inputs into the individual member's analyses. WECC will also provide a "roadmap" to assist BAs in using the results of this study to analyze the financial impact to their organization.

The analysis was divided into two separate, but coordinated efforts – one to estimate costs associated with implementation of EDT and a second to estimate the monetary benefits of EDT. This is because the analyses required different types of methodology to analyze these different data points. Finally, staff also identified and qualitatively described the benefits to reliability. All of these analyses have been brought together into this report.

Cost Analysis

Vendor Selection Process

The EDTSC determined that the most prudent approach to selecting a vendor for the cost analysis was for staff to seek proposals from two or three vendors, and select from those proposals. In order to achieve this, staff spoke to approximately eight vendors to determine whether this type of analysis was within their capability. From those discussions, staff sent a Request for Proposal to three vendors and received proposals from two. In the end, Utilicast was selected as the preferred vendor.

Approach to Analysis

The EDT Technical Review Subcommittee (EDTTRS) developed the approach for the cost analysis. This approach included two main characteristics; it is bottom-up and it includes ranges.

Using the bottom-up approach, the EDTTRS developed a list of cost categories, outlining all the areas where costs would be incurred. These categories were split between market operator costs and market participant costs. Market participant costs were defined as the costs that individual market participants would incur directly, and did not include an allocation of the market operator costs. The approach was to then develop cost estimates for each of the cost categories, and total them for an overall cost estimate. Although the approach was primarily bottom-up, the total number was also compared to total costs incurred by other organized energy markets.

The use of ranges was necessary to accommodate open design issues, as well as cost variability for considerations such as quality, vendor and complexity. For each cost category, a high estimate and a low estimate was applied and then summed for an overall high and low estimate. Individual assumptions for the high and low estimates for each cost category were provided. As a result of this approach, the overall high is likely to be artificially high and the overall low is likely to be artificially low, because it is unlikely that any design would include all of the high or all of the low assumptions.

Utilicast performed the analysis based on the approach from the EDTTRS, and through input on several items received from the EDTTRS such as:

- study assumptions,
- reasonableness of estimates, and
- approach to market participant analysis.

For market operator costs, the analysis remained neutral on which entity might undertake the role of market operator. Instead the cost ranges reflected for each cost category the highest and lowest expected costs, as reflected by the potential market operators. For example, the lowest cost Energy Management System (EMS) would be from an existing entity that already has visibility into the Western Interconnection, while the lowest Settlement System cost would be from an existing entity with existing market settlement infrastructure and similar charge types. Therefore, the low end does not represent any one specific market operator. In order to do a meaningful comparative analysis of different market operators, detailed information on each potential market operator would be necessary. This would involve in-depth interviews and knowledge of staffing, infrastructure, etc.

For market participant costs, the analysis focused on aggregated asset-owning entities, namely BAs. Average high and low costs were identified for BAs, and were then multiplied by the number of BAs included in each identified footprint. It is important to note that the high and low costs themselves do not represent the absolute high and low that any BA would actually incur, but rather averages. The reason for this is that BA costs may vary significantly based on existing infrastructure, experience with organized markets, and staffing decisions. The Utilicast Report (Appendix A) lists several of the factors that a BA would need to consider in identifying specific cost estimates.

Results

For detailed results, see Appendix A - Utilicast Report. Table 1 identifies the market operator costs and indicates a startup cost of $25.6–$220.2 million and an operating cost of $33.9–$128.9 million annually.

Table 1: Market Operator Costs

Cost Category	High Costs (in millions of dollars)			Low Costs (in millions of dollars)		
	Capital	Pre-Operational	Operational	Capital	Pre-Operational	Operational
Software	**$119.6**	**$6.9**	**$26.1**	**$15.8**	**$1.5**	**$5.8**
Hardware	**$5.7**	**-**	**$3.8**	**$2.4**	**-**	**$0.9**
Infrastructure	**$37.3**	**$25.6**	**$9.5**	**$0.7**	**$2.5**	**$0.7**
Overhead	**-**	**$9.9**	**$57.2**	**-**	**$0.7**	**$13.8**
Staff	**-**	**$15.1**	**$32.3**	**-**	**$2.0**	**$12.6**
TOTAL	**$162.6**	**$57.6**	**$128.9**	**$18.9**	**$6.7**	**$33.9**

Table 2 identifies the aggregate of Market Participant costs, and indicates a startup cost of $41.31–$120.02 million and an operating cost of $46.46–$131.51 million annually. It is important to note that these values assume that all of the BAs outside of California and Alberta are participating. For details on per-BA costs that could be used to analyze a smaller footprint, see the Utilicast Report in Appendix A.

Table 2: Aggregate Market Participant Costs

Cost Category	BA High Costs (in millions of dollars)		BA Low Costs (in millions of dollars)	
	Capital Costs	Operational Costs	Capital Costs	Operational Costs
Software	$71.40	$19.72	$34.00	$6.80
Hardware	$12.92	$1.29	$5.61	$0.56
Staff	$15.30	$76.50	-	$20.40
Other	$20.40	$34.00	$1.70	$18.70
TOTAL	$120.02	$131.51	$41.31	$46.46

Overall, this means that from a societal perspective, the overall startup costs would be $66.91–$340.22 million and the operating cost would be $80.36–$260.41 million.

Benefit Analysis

Vendor Selection Process

WECC staff had a previous working relationship with Energy and Environmental Economics, Inc (E3), including work on previous market cost-benefit analyses. Based on familiarity with E3's work history, reputation, and experience, WECC contracted with E3 for the benefits analysis, in consultation with the EDTSC.

Approach to Analysis

The benefits analysis was broken down into two phases: Phase I was used to validate the model, identify areas where a further refinement of assumptions was necessary, and give a high-level look at potential benefits with the tools and models that were readily available. Phase II included the refinement of several assumptions, some sensitivity analysis, and additional detail in the models.

Both Phases used study years 2006 and 2020. The 2006 case was used primarily for benchmarking the model against historic actual flows. The 2006 case was based on actual topology and loads from 2006, and the 2020 case was based on the TEPPC 2020 base case (referred to as "PC0"). For each model year in each phase, a benchmark case was run to simulate current market operations, and an EIM case was run to simulate EIM operations. For each model year in each phase, the total benefit was calculated as the difference in production cost between the benchmark case and the EIM case.

In addition, E3 ran seven sensitivity cases: 1) Reduced BA participation; 2) Assigning a portion of Northwest flexibility reserve requirements to California; 3) CAISO Market-to-Market Coordination; 4) Low Gas Price; 5) High Gas Price; 6) CO_2 Price; and 7) Simulation of Unit Commitment Learning. For more information on the purpose and methodology for each of these sensitivities, see Appendix B – E3 Report.

Throughout the process, E3 and WECC staff worked closely with the EDTTRS to validate assumptions, methodologies and sensitivities. Each phase also included a two-week comment period on the posted methodology with a stakeholder workshop in the middle of the comment period to explain the methodology and answer questions.

Results

For detailed results, see Appendix B – E3 Report. In the primary case, E3 found a benefit of $85.3 million in 2006, and $174.5 million in 2020. Table 3 identifies the results of the sensitivity analysis. For detailed discussion of these sensitivity results and changes in dispatch, see Appendix B – E3 Report.

Table 3: Benefit Sensitivity Results

No.	Case	$MM Savings vs. Benchmark Case
0	**Phase 2 – 2020 EIM Case** (Primary EIM Case)	**$174.6**
1	**Reduced BA Participation in EIM** (exclude BPA, BPA-embedded NW BAs, WAPA)	**$62.8**
2	**Assign portion of NW flexibility reserve requirement to Calif.** (to address pseudo-tie/dynamic schedules)	**$165.8**
3	**CAISO Market-to-Market Coordination** (reduced EIM-CAISO hurdle rates)	**$216.6**
4	**Low Gas Price Cases ($4.50/MMBtu Henry Hub)**	**$243.3**
5	**High Gas Price Cases ($10/MMBtu Henry Hub)**	**$165.9**
6	**CO_2 Price Case ($36/ton CO_2)**	**$248.4**
7	**Remove hurdle rates on all gen in unit commitment cycle** (to simulate learning)	**$186.7**
	Phase 2 – 2006 EIM Case	**$85.3** **(vs. 2006 BM)**

Using the gas sensitivities as a range for potential benefits, the annual benefit would range from $165.9–$243.3 million.

Comparison of Cost and Benefits

In order to compare the cost and benefit results, WECC staff calculated a 10-year Net Present Value (NPV). As an assumption, a discount rate of 3.25%[4] was used, and it

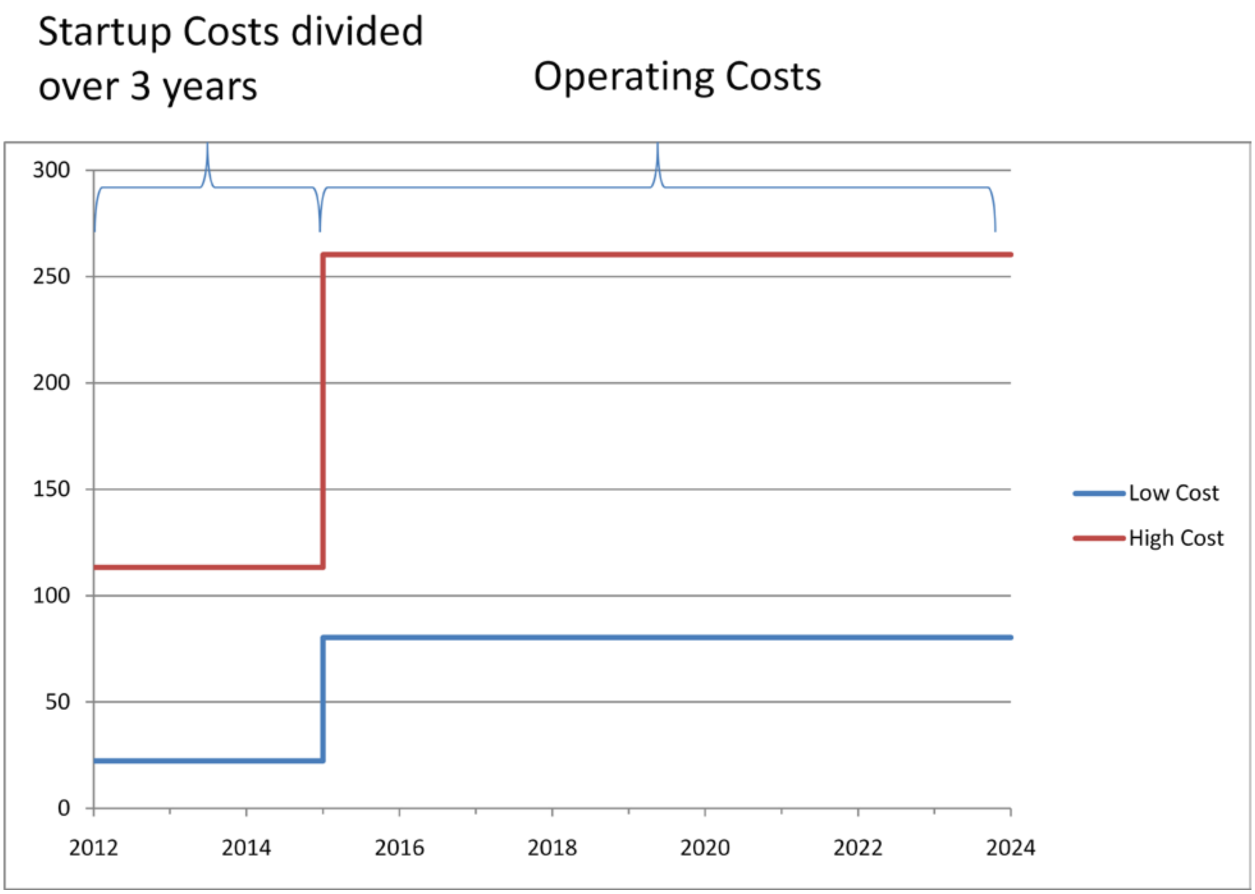
[4] Based on Wall Street Journal Prime Rate.

was assumed that market implementation would take three years (2012–2014), and the 10-year market operation period would be from 2015–2024. All results are listed in 2010 dollars.

Cost NPV

The Cost NPV is $678–$2,312 million for overall cost; assuming that the market startup costs are evenly divided over a three-year market implementation period, and that the annual operating costs stay constant over the 10-year market operation. Figure 1 depicts these assumptions.

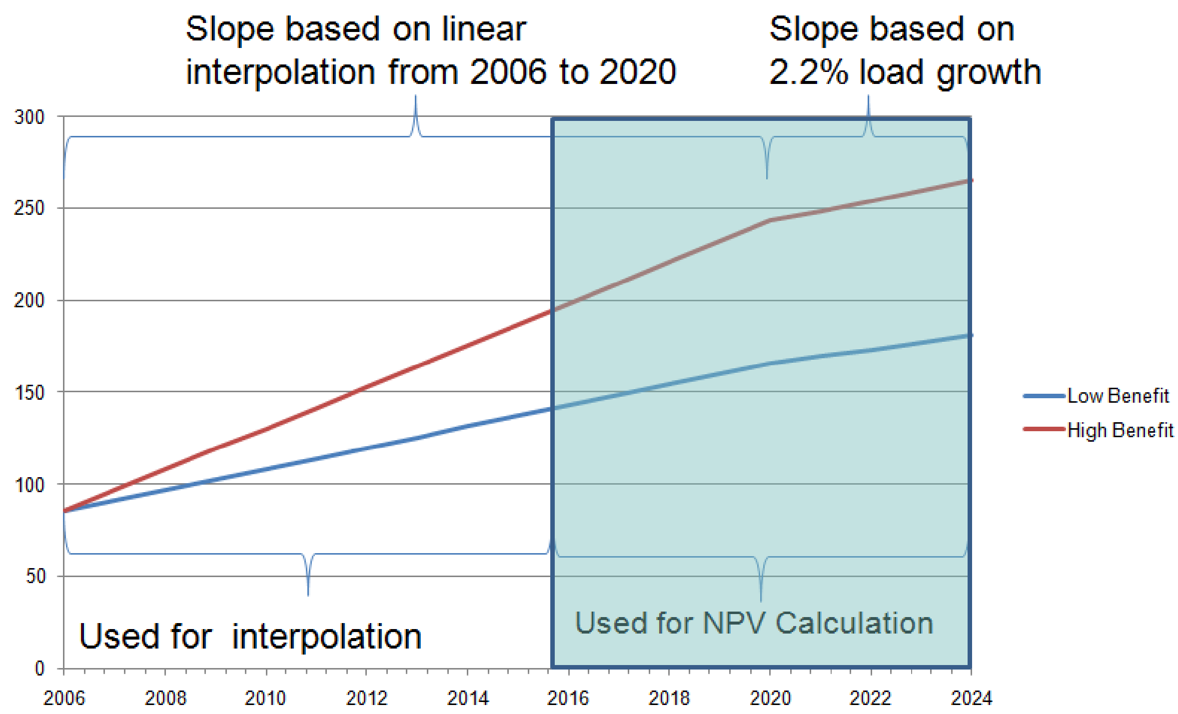
Figure 1: Cost NPV Assumptions



Benefit NPV

Using the gas sensitivities to bound benefits, the 10-year Benefits NPV is $1,179–$1,703 million. For this analysis, it was assumed that benefits would increase linearly from 2006 to 2020. For periods beyond 2020, it is assumed that there will be less change attributable to increases in variable generation, so increase in benefits are assumed to increase at a rate of 2.2 percent per year, which represents an average load growth. Only the period from 2015–2024 was used for the Benefits NPV calculation, consistent with the Cost NPV calculation. Figure 2 depicts these assumptions.

Figure 2: Benefits NPV Assumptions



Direct Comparison

Figure 3 shows a comparison of the high and low cost values on an annual basis. It is clear from this figure that if all of the high costs are incurred, costs incurred would overrun benefits. But if all low costs are incurred, costs incurred would be well below benefits. In addition, Table 4 shows a comparison of NPV between the different bookend scenarios.

Figure 3: Comparison of costs and benefits

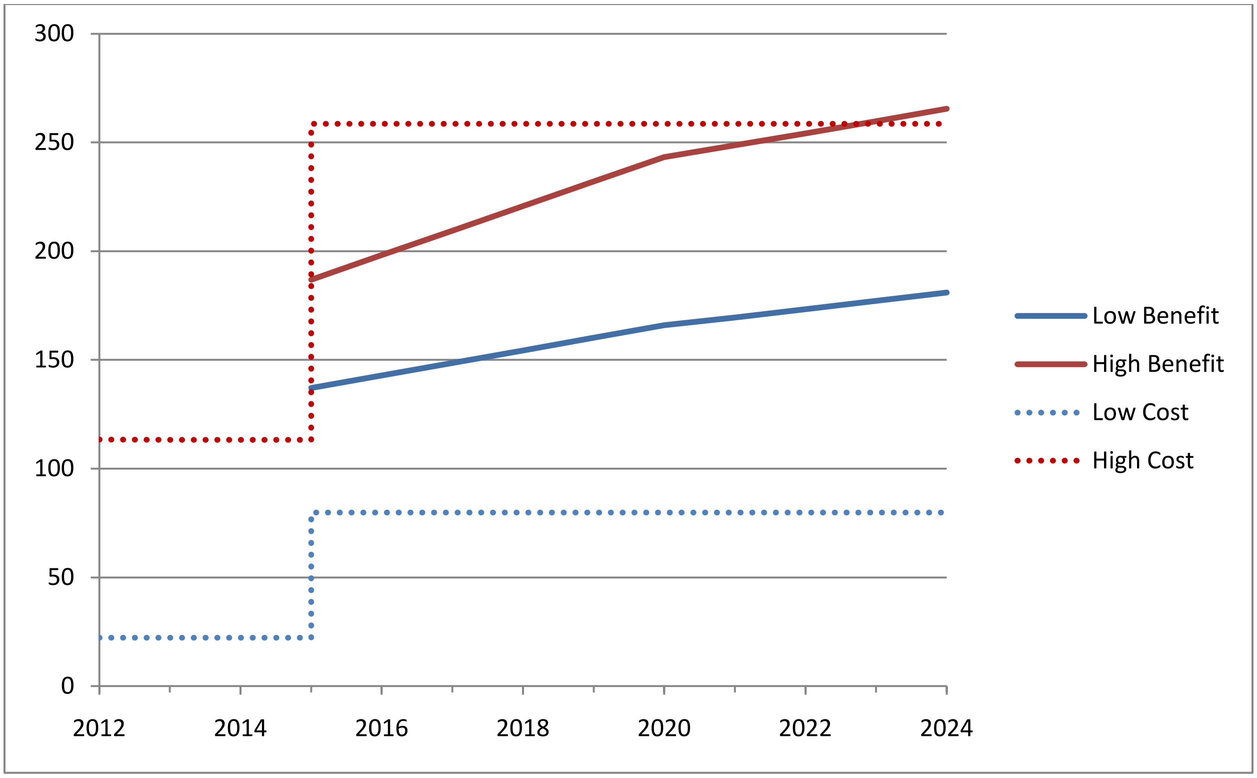


Table 4: Low and High NPV Comparison (in millions of $)

	Low Cost	High Cost
Low Benefit	$501	-$1,133
High Benefit	$1,025	-$609

Reliability Impact Analysis

Approach to Analysis

Separate from the financial analyses described above, WECC staff examined reliability impacts from existing markets to determine potential impacts within a Western Interconnection EIM. This examination included consideration of both quantitative and qualitative analyses by other markets. Because of the extensive number of variables, no appropriate quantitative measure of reliability benefit was found. Some issues that WECC identified with the approaches of other markets to quantify benefits in the West were:

- Assumptions that any difference in outage rates from market areas to nonmarket areas were due solely to the existence of markets, with no analysis on the actual cause of outages.
- Lack of differentiation between types of markets in comparison of market to nonmarket areas. Many of the current markets are more robust and have

additional features that are not part of the EIM proposal. Furthermore, one of the benefits accounted for in some of the analyses was a Reliability Coordinator for the entire region, which WECC already has in place.

- Assumptions that the average cost of an outage over the study timeframe was the appropriate cost for assessing the value of outages avoided. Of note, the 2003 Northeast blackout was included in this calculation.

The qualitative impacts seen by other markets that may be seen in the West with an EIM are listed below.

System Operating Limit Violations

A System Operating Limit (SOL) is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration, to ensure operation within acceptable reliability criteria.

The EIM automatically dispatches the system every five minutes, considering the physical constraints of generation and transmission within the EIM footprint. This means that under normal operating conditions, the market will not dispatch the system to exceed an SOL. Under unexpected conditions, such as forced outages or increased nonmarket flows, SOL violations may still occur, but the EIM will attempt to redispatch the participating generators to bring the facilities within their SOLs quickly and automatically. If other system characteristics (such as generator capacities, ramp rates, or availability to the market) prevent a full redispatch to mitigate the SOL, violations may still occur. Therefore, it is important to note that the EIM cannot eliminate all SOL violations, nor is the reduction of SOL violations the sole measure of reliability pertaining to SOLs. While dispatching participating generation for the efficient use of the transmission system has been shown to have an economic benefit, it is important to

SOL Example 1

In this example, it appears economic for Generator A to increase to meet the needs of a load. This change may interact with other schedule load/resources changes on the system in ways that cause flows to exceed system operating limits. However, in a bilateral world, with so many moving parts on the system, the interaction is not recognized immediately and the dispatch causes the SOL limit to be exceeded. With EIM, the market would automatically consider all of the dispatch signals throughout the system together and would not allow Generator A to increase in this example. Instead, it would dispatch another generator on the system to meet the load needs.

SOL Example 2

In this example, Generator X is available and is the least-cost generator to supply energy to Load Y. Transmission between X and Y is fully reserved, but not fully used from a physical standpoint. At a later point, a generator located near Load Y trips offline. In the bilateral world, this transaction could not occur because transmission is not available for reservation, so Load Y would be served by a different generator. When the generator near Load Y trips offline, the transmission between X and Y can handle the additional flow. In the EIM case, Generator X is allowed to dispatch to meet the needs of Load Y, so when the additional generator trips, flows between X and Y now exceed the SOL. The market would then need to redispatch in the next dispatch cycle to relieve the SOL.

note that operating the transmission system closer to the SOLs could have a reliability impact when system events occur, because there is less headroom available. In this case, the EIM may still be able to redispatch the system to below the SOLs. Even with a market, communication between the Reliability Coordinator function (RC), the market operator and the BA is essential.

Energy Emergency Alerts (EEA)

An EEA is declared by the RC when a load-serving entity is, or expects to be, unable to provides its customers' energy requirements and has been unsuccessful in purchasing resources from other systems; or cannot schedule the resources due to transmission constraints. The EIM can improve access to energy across the market. Today, during local area energy shortages, the entity must find and procure sufficient energy from other sources. If they cannot locate additional resources, they will request that the RC declares an EEA. In addition, the entity may be required to shed load to maintain system reliability. By providing access to, and automatically identifying and dispatching deliverable energy, in some cases the EIM can prevent the need for EEAs or potential load shedding. It is important to note that the EIM would not eliminate all EEAs. There may be other system conditions such as voltage stability limitations and transmission constraints that would prevent the EIM from dispatching sufficient energy to the deficient area. In these cases, the RC, market operator and BA must work collaboratively to mitigate the problem.

EEA Example 1

In this example, a BA realizes that it is short on local energy supply, and energy is physically available and deliverable from a remote BA. In the bilateral world, the BA would attempt, through multiple bilateral calls, to locate energy to import. Since this is a manual process, it is possible that the BA would not be able to locate energy and transmission, even though it is physically available, and would instead have to resort to requesting an EEA. With the EIM, if the energy is physically available and deliverable in the market, the EIM would automatically dispatch the energy to meet this need.

EEA Example 2

In this example, the BA realizes that it is short on local energy supply and transmission, or that voltage constraints keep it from importing energy. In this case, the BA would have to request an EEA in both the bilateral and EIM worlds, as the EIM would not be able to alleviate those types of problems.

System Balance and Variable Generation

When unexpected events or changes in the system occur, currently BA operators must dispatch energy from their own available resources, or manually procure energy from other BAs, in order to regain or maintain system balance. Similarly, variable generation (such as wind and solar) can vary output significantly and unexpectedly in short periods of time. These variations cause system imbalance that may require manual adjustment. Similar to when forced outages occur, resources must be procured or energy must be dispatched from other available resources in order to regain system balance. The EIM would automatically identify and dispatch available resources from a wider resource portfolio to more quickly regain system balance. This automatic dispatch may be able to prevent some curtailment of variable generation that happens under the bilateral scheduling paradigm. However, just as in manual dispatch, the ability of the EIM to regain this system balance is contingent on the availability of balancing resources and the transmission availability. Furthermore, other system characteristics, such as voltage and reactive support, also affect system stability and reliability, and will not be addressed by EIM. However, just as today, these reliability concerns will require communication and coordination. With the market, the RC, market operator and BAs must work together to maintain communication.

System Visibility

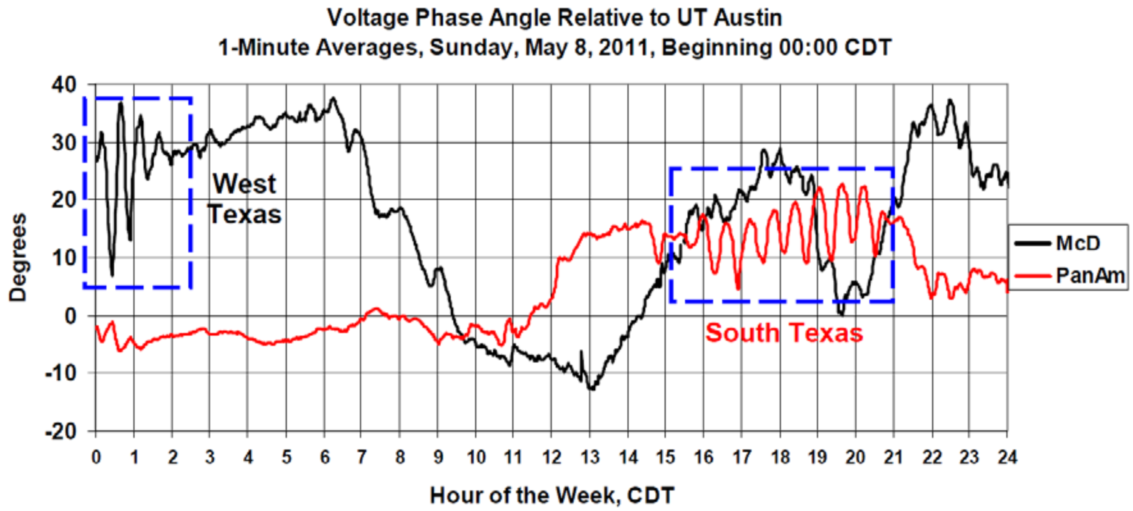
System visibility could be enhanced through improved processes and tools brought on by the EDT. Communication and visualization by the EDT of transmission constraints would give reliability entities, such as RCs, BAs and transmission operators, improved awareness of system conditions and details regarding the automated redispatch taking place. Models and network application solutions used for EIM inputs also are used in reliability coordination, and would likely see improved quality and transparency of system conditions. Some entities may implement more revenue quality metering, which would also give both the entity and the RC better quality data and visibility. Due to the importance of data and reliance on this system visibility, it is critical that the data is accurate. Close coordination and communication between the market operator and reliability entities is required to ensure correct inputs and to recognize false signals that may be caused by, for example, failed remote terminal units.

Dynamic Transfer Effects

It is unclear what effects the increase in dynamic transfers may have on the Western Interconnection system. Northern Tier Transmission Group has been leading a task force to examine Dynamic Transfer Capabilities and the potential need for dynamic limits. The results of this work must be considered in market design.

Some new low frequency oscillations (peak to peak time elapsed roughly 30-60 minutes) have been seen in the Electric Reliability Council of Texas (ERCOT) that are being attributed to the nodal market (see Figure 4). However, it does not appear that these oscillations have caused any significant issues on the system. It is unclear whether any other existing market have caused oscillations, but preliminary research suggests that certain business practices, including the approach to curtailing nondispatchable units, such as variable generation, may impact whether these oscillations occur. Small, incremental curtailments or other business practices may reduce or avoid the occurrence of these oscillations. In addition, a larger system, such as the Western Interconnection, may not see the impact experienced by a smaller system, such as ERCOT.

Figure 4: Texas Oscillations



Partial Participation Impacts

Due to the voluntary nature of this proposed market, it is important to note that the impacts described above will primarily impact the market footprint. In addition, there may be reliability seams issues due to different transmission availability calculation methodologies, and due to system visibility in the market versus outside of the market. Some data may only be available to market participants, or only available through the WECC Data Sharing Policy process. This may be especially problematic if there are holes in the market footprint or noncontiguous areas of the market footprint. These issues have been addressed in the Midwest Independent Transmission System Operator (Midwest ISO) and PJM,[5] but must be considered carefully in any future market design.

Conclusions and Recommendations

Conclusions

It is clear that if the market is designed well, and there is strong participation from the market members, significant financial and reliability benefits could be achieved by the implementation of the EDT. Depending on gas prices, these net benefits could be more than $1 billion over the first 10 years of operation.

It is also clear that costs are highly variable, and if market design is not carefully considered, the net benefits could be seriously degraded and costs could potentially overrun benefits. If the EDT moves forward, each design question must be examined closely in order to mitigate cost overruns. Design concerns such as customization, poor design and poor scope governance must be closely monitored during the design process.

[5] Commonwealth Edison was a part of PJM that was wholly surrounded by the Midwest ISO (and was therefore a hole in the Midwest ISO system and a noncontiguous part of PJM).

Overall, the wide range of costs and benefits indicate how robust the design process must be.

In addition to the financial issues, reliability impacts must also be considered. Several reliability benefits could be achieved, but roles, responsibilities, coordination, and business practices must be carefully considered in order to achieve benefits and mitigate risks.

Recommendations

In order for stakeholders to decide whether to move forward with design and implementation of the EDT, it is recommended that BAs make several key decisions, as discussed below. In addition, in the event that the membership asks WECC to consider operating the EDT, WECC staff recommends performing several additional analyses to inform the Board of Directors' potential decision about whether WECC would be interested in being the market operator. Those additional analyses include: 1) Risk Assessment; 2) Organizational Structure and Governance Analysis; and 3) WECC-Specific Cost Analysis.

<u>BA Decision Process</u>

The first step in the process is for BAs to take a close look at this analysis and determine what it means for them individually. This analysis would include both an individual financial analysis and an individual risk assessment. WECC and E3 will be providing a roadmap for BAs to be able to determine individual benefits based on the results of the overall benefit analysis. The Utilicast Report (Appendix A) also includes considerations for BAs to perform individual cost analyses. From these individual analyses, BAs can determine whether they support moving forward with an EDT.

The next step would be for BAs to collaborate and decide whether they collectively support moving forward with design and implementation of the EDT. As BAs individually determine whether they support an EDT, they can begin to have collective discussions and determine how much support there is in the Western Interconnection.

If a group of BAs decides to move forward with EDT, that group would then need to identify the mechanism for designing the market, selecting the market operator and decide upon the next steps moving forward. It is recommended that any market design carefully consider the assumptions used in the cost analysis, and how the different options may affect overall cost.

<u>Risk Assessment</u>

Risks are future issues that can be avoided or mitigated, rather than present problems that must be immediately addressed. Risk exposure can further be defined as the impact, the magnitude of the effect if the future event occurs, multiplied by the likelihood of occurrence. The **impact** is assessed without any consideration of controls that may be in place. The **likelihood** takes into account the controls in place to mitigate or avoid the risk.

A thorough risk assessment identifies an organization's vulnerabilities and the estimated cost of recovery in the event of damage. It also summarizes defensive measures and associated costs based on the amount of risk the organization is willing to accept.

The risk assessment would focus on the vulnerabilities associated with the implementation and operations phase of the EDT. The assessment will look at two potential futures: WECC as the market operator, and a third party as the market operator. The major categories of risk assessed will be: 1) operations, 2) regulatory, 3) compliance, and 4) financial. The assessment will focus on the risk exposure to WECC as an entity and its membership as a whole, but not the individual members. It is recommended that WECC staff perform this analysis prior to the September Board meeting.

Organizational Structure and Governance Analysis

If WECC assumes a market operator role, changes may be necessary to the organizational structure and governance in order to maintain separation between its role as the Regional Entity and its role as market operator. WECC staff has had preliminary discussions with the Southwest Power Pool (currently a Regional Entity and market operator) to understand the governance and operational separation they have made, the discussions they had with FERC on separation issues, and considerations they used in developing their ultimate structure and governance.

The Organizational Structure and Governance Analysis would identify several potential structure and governance options, along with the pros and cons of each option. As a result of these pros and cons, the analysis will also include a recommendation for a specific structure, and the rationale behind that recommendation. It is recommended that WECC staff perform this analysis prior to the September Board meeting.

WECC-Specific Cost Analysis

Although many open design issues contribute to the large ranges in the Cost Analysis, one of the major open issues is the identification of the market operator. An analysis of WECC as the market operator would allow for a reduction in the ranges (though ranges would still exist), and could help inform the Board in more detail what the cost exposure to WECC would be if it were to become the market operator. It is recommended that WECC staff perform or contract for this analysis prior to the September Board meeting.

References

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Appendix A –
Utilicast Report

Appendix B –
E3 Report