WECC EDT
Phase 2 EIM Benefits Analysis & Results (October 2011 Revision)

Prepared for:

Western Electricity Coordinating Council

October 11, 2011

Energy+Environmental Economics

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Energy and Environmental Economics, Inc.

101 Montgomery Street, Suite 1600

San Francisco, CA 94104

www.ethree.com

Project Team:

Ren Orans

Arne Olson

Jack Moore

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Note on October 2011 Revised Report

This revised report reflects changes related to a correction in the treatment of operating reserves on hydropower units in the model runs used for the June 2011 analysis. E3's instruction to ABB for the June production simulation runs was to allow unloaded hydro capacity to count toward the zonal "committed capacity" reserve requirement. However, ABB recently discovered that only hourly hydro energy production was counted toward the committed capacity reserve requirement in the June runs.

The October model runs used to produce the values in this revised report correct this assumption by counting the full monthly maximum output of hydro units toward the reserve requirement. The revised reserve assumption allows fewer total gas units to be committed, creating a reduction in the WECC-wide production cost for both Benchmark and EIM cases, as shown in the table below.

Case Runs	Reserves met by:	WECC-wide Total Production Cost ($MM) Benchmark	EIM	Production Cost Savings ($MM) (BM - EIM)
June 2011	Committed thermal gen only	$20,949.6	$20,775.0	**$174.6**
Oct 2011	Committed thermal gen & unloaded hydro capacity	$20,876.3	$20,734.9	**$141.4**
Change: (Oct – June)		**-$73.3**	**-$40.1**	**-$33.2**

The revised assumption reduces the Benchmark Case production costs more than the EIM Case costs, resulting in a smaller EIM production cost savings. The total savings in the Primary EIM Case (vs. the Benchmark Case) are now $141 million, as compared to $175 million in the June runs. The range of savings in the EIM sensitivity cases is now $141-233 million, as compared to $165-248 million in the June runs. Two factors drive the reduction in EIM savings in the October runs:

(1) **<u>Smaller opportunity for production cost savings when the EIM reduces the quantity of flexibility reserves required</u>**. In the June 2011 Benchmark & EIM cases, all reserves had to be met by committing additional thermal generators, which incur additional costs for startup and fuel burn. By contrast, in the October 2011 Benchmark Case, unloaded hydro capacity is sufficient to satisfy reserve requirement for certain hours in hydro-rich zones. In these hours, the EIM reduces the zone's quantity of flexibility reserve required, but the simulated production cost (and fuel burn) of providing those reserves with unloaded hydro capacity is already zero, so the EIM creates no incremental production cost savings in those situations.

(2) **<u>Fewer opportunities to improve dispatch efficiency on committed thermal units when the EIM removes hurdle rates during dispatch</u>**. In the June 2011 Benchmark & EIM cases, additional thermal units were committed in many hours to provide reserves. When hurdle rates were removed in the EIM case, the additional committed units provided more opportunities to improve dispatch efficiency by increasing output on more efficient generators (with unloaded capacity) and lowering output levels of more costly units. By contrast, in the October 2011 revised runs, unloaded hydro capacity provides reserves, reducing the need to commit additional thermal units. When hurdle rates are removed in the October EIM case, fewer opportunities exist to improve the dispatch, because there is less unloaded thermal capacity available for ramping up more efficient units.

Executive Summary

Purpose and Approach

This report estimates the total societal benefits of moving to a centralized 5-minute, real-time Energy Imbalance Market (EIM) throughout the Western Interconnection, excluding the systems operated by the California Independent System Operator (CAISO) and the Alberta Electric System Operator (AESO). The analysis estimates these benefits for 2006 and 2020 by modeling parallel production simulation runs with an EIM (EIM Case) and without an EIM (Benchmark Case, reflecting system operations under the status quo). The analytical work had two distinct phases. Phase 1 served to validate the modeling approach by estimating EIM benefits with existing tools, while Phase 2 (the focus of this report), refined the geographic and operational detail used for Phase 1 and tested the EIM benefits under a range of sensitivity cases.

Results: Phase 2 EIM Benefits

Overall, the Phase 2 analysis for 2006 identifies $50.3MM of production cost savings under the EIM compared to the Benchmark Case and $141.4MM of savings for 2020 (in 2010$). The 2020 savings has two major components. $41.8MM of the total 2020 EIM benefits are dispatch-related savings resulting from the EIM's removal of hurdle rates imposed in the Benchmark Case. These hurdle rates represent real-life impediments to trade between zones in the West, including transmission service rates, pancaked losses, and other economic and non-economic inefficiencies. The remaining $99.6MM of total 2020 EIM benefits are related to savings on "flexibility reserves." Flexibility reserves are dispatchable thermal and hydro resources that are required to ensure reliable operations under high penetration of variable generation (i.e., wind and solar). The EIM case allows for a reduction in the overall level of required flexibility reserves to reflect the diversity of wind and solar resource profiles across the EIM footprint. Additionally, the EIM case assumes that each zone could procure flexibility reserves from throughout the EIM footprint, in contrast to the Benchmark Case which strictly required flexibility reserve procurement from within the zone where the wind or solar generation is located. The simulation runs for 2006 did not include a flexibility reserve requirement due to the lower overall penetration of wind and solar, so the 2006 benefits are entirely dispatch-related.

Phase 2 Sensitivity Case Results

The Phase 2 sensitivity scenarios indicate that the EIM benefits are sensitive to assumptions about participation by BAs. Removing the Northwest, BC, and WAPA from the EIM reduces the total 2020 savings to \$54M. By contrast, the results indicate that CAISO market-to-market coordination (which could potentially removes hurdle rates between the EIM and CAISO) could raise benefits to \$182MM.

The 2020 benefits are relatively robust to changes in gas & CO2 prices. The 2020 EIM benefits range from \$157MM to \$227MM for gas prices of \$10/MMBtu and \$4.5/MMBtu, respectively (compared to \$7.23/MMBtu in the Primary Case). EIM benefits also total \$233MM in 2020 when a \$36/ton CO2 price is imposed on the EIM and Benchmark Cases.

1 Project Overview

1.1 Scope of E3 & ABB's EIM Benefits Analysis

WECC retained Energy and Environmental Economics, Inc. (E3) to estimate the total societal benefits of moving to a centralized Energy Imbalance Market (EIM) throughout the Western Interconnection, excluding the systems operated by the California Independent System Operator (CAISO) and the Alberta Electric System Operator (AESO).

The EIM assessed would be a voluntary, 5-minute market run by a central market operator that would supplement today's system of bilateral energy trading and multiple balancing authorities in the Western Interconnection. The principal benefit of such a market is reduced production costs due to more efficient dispatch of existing generating resources. E3's analysis quantifies some of these benefits at a high level using ABB's GridView production simulation model. E3's analysis estimates the *societal* benefits – defined as changes in west-wide production cost – associated with the EIM. Benefits will be shared by many entities, including IPPs, utilities, and ratepayers in each Western sub-region, and some entities may benefit more than others. Additional analysis would be required to estimate potential benefits to any particular market participant.

E3 was not asked to estimate the costs of implementing an EIM; rather, Utilicast has provided separate analysis on the potential range of costs for EIM implementation.

E3's analysis for WECC consists of two phases. Phase 1 used existing tools to quickly provide a high-level estimate of potential benefits from more centralized operations. Phase 1 was useful for validating the modeling approach for further analysis and for setting the direction for further investigation in Phase 2.

Phase 2 refines the benefit potential estimate from Phase 1 by using more granular geographic detail and improved operational characterization. Phase 2 also includes a range of sensitivity cases to test how the estimated benefits are affected by a number of factors, including gas prices, CO2 prices, and reduced BA participation in the EIM.

This report focuses on the assumptions and results from Phase 2 and references Phase 1 results only for comparison when describing the development of the Phase 2 methodology. A full description of Phase 1 results is available in a separate E3 report titled "WECC EDT Phase 1 EIM Benefits Analysis & Results," completed on April 20, 2011.[1]

1.2 Benefits from a Centralized EIM

E3's work models an EIM with the following characteristics:

[1] Available at: http://www.wecc.biz/committees/EDT/EDT%20Reswlts/E3_EDT_Phase1_Methodology_and_Results_2011-03-31[1].pdf

- Voluntary sub-hourly market across the majority of the Western Interconnection (WI) outside of CAISO and AESO.
- Includes a security-constrained, least-cost dispatch algorithm for five-minute markets.
- Day-ahead and hourly scheduling, unit commitment, and regulation (at the sub 5-minute interval level) would remain with today's Balancing Authorities.

A centralized EIM could have a number of potential benefits, including:

- **More efficient dispatch of generators**: Market software could call on any generator in the EIM region without considering transmission charges or pancaked losses. The security-constrained, least-cost dispatch could also result in more transmission utilization due to elimination of contract path scheduling limitations within the operating hour.
- **More efficient clearing of energy imbalances:** Within-hour deviations would be cleared optimally through the security-constrained, least-cost dispatch algorithm.
- **Reduced ramp/flexibility reserve requirements**. Under the existing operational system, the increased penetration of variable generation (such as win and solar) will raise system requirements for fast-ramping generators to follow net load. Flexibility reserves, also referred to as ramp, are a new type of reserve that a system may need to hold for

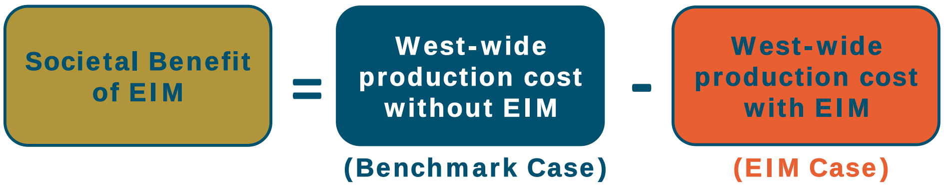
dealing with the variability and unpredictability of increasing penetrations of variable generation. Flexibility reserve requirements would be additional to requirements for traditional reserves such as contingency reserves and regulation needs related to load variability. An EIM could potential widen the area from which balancing areas could procure flexibility reserves. Also, by aggregating load and resource variability over the EIM footprint, an EIM could also potentially reduce the quantity of flexibility reserves needed.

An EIM could also produce certain other benefits, such as improved reliability and reduced curtailment that are not quantified as part of this analysis. Overall, an EIM would achieve some, but not all, of the benefits of a fully organized market in the West.

1.3 Approach

E3's approach for estimating the benefits of the EIM consists of running parallel production simulation cases with the EIM ("EIM Case") and without the EIM ("Benchmark Case") using ABB's GridView software. As shown below, E3 can then calculate the societal EIM benefits as the reduction in West-wide production costs under the EIM Case versus the Benchmark Case.

Figure 1: Approach for Calculating EIM Benefits



2 Phase 2 EIM Benefits Analysis Methodology

2.1 Overview of Methodology

E3's Phase 2 analysis estimates the production cost savings that an EIM could enable through more efficient dispatch of generating resources and through reduction in flexibility reserve requirements. The analysis quantifies these benefits for the years 2006 and 2020 by comparing the total system production cost resulting from consecutive runs of ABB's GridView production simulation model, and quantifies the benefits for sensitivity cases by making additional production simulation runs.

For each year, the Benchmark Case simulates the status quo operational arrangement, and the EIM Case simulates operations with the EIM in place. The EIM benefit estimate for each year equals the production cost under the Benchmark Case minus the production cost under EIM Case. Three key differences distinguish the EIM Case from the Benchmark Case:

1) The Benchmark Case includes **"hurdle rates"** intended to represent economic and non-economic barriers to trade across WECC interfaces; these hurdle rates are removed for EIM Case (except for the CAISO and AESO zones)

2) The Benchmark Case has higher requirements than the EIM Case for **flexibility reserves** needed to accommodate output of variable generation such as wind and solar.

3) The Benchmark Case requires that flexibility reserve requirements be met with conventional generation located in the same zone as the wind or solar resources; the EIM Case allows for **EIM-wide procurement** of flexibility reserves.

2.2 Hurdle Rate Overview

A "hurdle rate" is a $/MWh price adder intended to inhibit power flow across zonal boundaries, or "interfaces". The purpose of hurdle rates is to reflect a number of real-life impediments to trade, including:

- Point-to-point transmission rates across interfaces,
- Pancaked losses,
- Inefficiencies due to illiquid markets, and
- BAs' need to use resources to serve native load

In this analysis, hurdle are calibrated, or "benchmarked", so that hourly power flows on major WECC paths in the simulation approximate the historical flow levels on those paths.

The hurdle rates (which are in 2010$ in the model) are benchmarked for the historical year 2006 ("2006 Benchmark Case"), and then also applied to 2020, since there is no historical flow data for 2020 available for benchmarking simulated flows. The EIM Case for each study year removes these hurdle rates between zones within the EIM footprint and allows more coordinated procurement of reserve among EIM participant zones.

Chapter 3 of this report describes the hurdle rate benchmarking process in more detail.

2.3 Flexibility Reserve Overview

Flexibility Reserves are dispatchable thermal or hydro resources that are required to ensure reliable operations under a high penetration of variable generation. NREL has developed a methodology[2] to estimate expected flexibility reserve requirements in three categories ("Flex", "Spin", and "Supplemental"), based on characteristics of the expected variability of wind, solar and load within a particular zone. NREL has generously provided estimates of zone-by-zone hourly flexibility reserve requirements for the Phase 2 2020 Benchmark Case, EIM Case, and Reduced BA Participation Sensitivity Case.[3]

The flexibility reserve requirement quantities (in MW) provided by NREL are lower under the EIM Case than the Benchmark Case, as the EIM Case enables aggregation of variability across the EIM footprint. The diversity of resource

[2] This methodology is described in NREL's 2010 Eastern Wind Integration and Transmission Study, EWITS (available at **http://www.nrel.gov/wind/systemsintegration/ewits.html**)

[3] The hourly reserve requirements provided by NREL were based on zone geography and other assumptions specified for this study and reported to NREL for producing the calculations. While based on a similar methodology, some assumptions used for this analysis differ from those in NREL's EWITS study or from any other existing NREL study.

profiles lowers the aggregated variability, and the reduced reserve requirement results in production cost under the EIM compared to the Benchmark Case.

Additionally, the EIM Case allows for greater efficiency and production cost savings by allowing zones that participate in the EIM to meet the flexibility reserve requirement by procuring it from dispatchable thermal or hydro generation units anywhere in the EIM footprint, as opposed to procurement solely within a zone. This change allows for a more optimized selection of the lowest-cost flexibility reserves compared to the Benchmark Case, which requires that flexibility reserve needs must met with generation in the same zone in which the wind or solar resources are located.

2.4 Key Changes for Phase 2 Methodology versus Phase 1

For Phase 2, E3 made six major changes to the Methodology used for Phase 1, The first three of these changes have the most significant influence on resulting EIM benefits for Phase 2. These changes are shown in the table below, and are each described in more detail in this section.

Table 1: Major Changes to Methodology between Phase 1 and Phase 2

Assumption Change	Impact on EIM Savings	Intended to reflect
Increased from 12 to 24 Zones with hurdle rates	↑	Greater base case friction to transactions in absence of EIM
Improved representation of current contingency reserve practices for Benchmark Case	↓	Need to procure regulation from local sources
Added "Flexibility reserve" requirement to support variability of renewable generation	↑	Need for reserves to address load and resource variability & uncertainty
Incorporated price responsive hydro dispatch using Hydro Thermal Coordination (HTC)	↑	Partial price responsiveness of some hydro resources
Maintained hurdle rates for unit commitment in EIM case (except for Gas CTs)	↓	Potential that 5-min real-time market would have limited influence on day-ahead commitment decisions
Used day ahead forecast of wind generation in unit commitment cycle	↑	Day-ahead uncertainty of certain resource output

2.4.1 INCREASED FROM 12 TO 24 ZONES WITH HURDLE RATES

Within each zone created for the Phase 2 Benchmark Cases, power transactions are assumed to flow according to generation patterns and physical transmission constraints, but unimpeded by any economic constraints. For zonal interfaces (i.e., all lines interconnecting two different zones), the physical transmission constraints and any nomogram constraints characterized by TEPPC still apply, but E3 also applies hurdle rates to economically constrain powerflows on these interfaces.

It is important to note that the GridView database simulates operations within each of the 39 TEPPC Load Areas, which in the TEPPC database corresponds to the approximate geography of most Western BAAs. The aggregation of these Load Areas into 24 Zones for Phase 2 is used to determine where hurdle rates should be applied to interfaces between particular BAAs.

E3 increased the number of zones to 24 for Phase 2 to improve the geographic granularity of the hurdle rate and dispatch savings analysis. The additional zones for Phase 2 result primarily from breaking out and imposing hurdle rates between BAs in the Northwest, California, and Arizona, each of which had been aggregated for Phase 1. It is important to note, however, that additional historical power flow data was typically not available for internal interfaces between zones that had been aggregated in Phase 1, so the tariff rate plus losses was used for these interfaces unless clear flow results on the interfaces with historical data indicated otherwise.

A limited number of BAs are still aggregated within a larger zone for Phase 2, either due to the small size of the BAs' load, or because EIM benefits were expected to be less significant (e.g., for the Mid-Columbia PUDs in the Northwest, where internal generation is almost exclusively hydro).

The table below identifies the TEPPC Load Areas that are included within each of the 24 zones for Phase 2.

Table 2: Phase 2 Zones for Benchmark Case

Phase 2 Zone	TEPPC Load Areas Included
1. British Columbia	British Columbia Transmission Corp (BCTC)
2. Alberta	Alberta Electric System Operator (AESO)
3. BPA	BPA, Chelan Co PUD (CHPD), Douglas Co PUD(DCPD), Grant Co PUD (GCPD), Seattle City Light (SCL), Tacoma Power (TPWR)
4. NWE	Northwestern Energy Montana (NWMT), WAPA Upper Missouri (WAUM)
5. Northern Nevada (NNV)	Sierra Pacific Power
6. PACE	PacifiCorp East
7. WACM	WAPA Colorado/Missouri (WACM)
8. PSCO	Public Service Colorado (Xcel)
9. California	PG&E Bay, PG&E Vly, SCE, SDGE, CFE
10. Nevada Power (NVP)	Nevada Power (NV Energy)
11. AZPS	APS
12. New Mexico	PNM
13. PSE	Puget Sound Energy
14. AVA	Avista Corp.
15. PGN	Portland General Electric
16. PACW	PacifiCorp West
17. IPC (Idaho Power)	Idaho Power (Far East, Magic Vly, TreasVly)
18. WALC	WAPA Lower Colorado
19. SRP	Salt River Project
20. TEP	Tucson Electric Power
21. BANC	BA of Northern California, Turlock ID
22. EPE	El Paso Electric
23. LADWP	LA Dept. of Water & Power

24. IID	Imperial Irrigation District

Under the EIM Case, hurdle rates are maintained between CAISO and AESO (which are assumed not to participate in the EIM), and adjacent zones that are EIM participants. The Phase 2 analysis, however, also includes three zones as EIM participants that are geographically embedded in CAISO (BANC, LADWP, and IID). To properly model benefits under the EIM Case for these zones, it is necessary to remove the hurdle rates on transmission interfaces linking these zones to the rest of the EIM footprint. However, since the zones are embedded inside CAISO in the model, exports to or imports from the rest of the EIM must pass through CAISO territory, incurring the CAISO hurdle rate costs in both the Benchmark and EIM cases.

In actual practice, each of these zones (BANC, LADWP and IID) has certain contract rights or shared ownership of transmission lines that link these embedded BAs to the rest of the EIM footprint outsize of CAISO. Zonal production simulation models such as GridView, however, characterize each transmission facility (or each substation) as located in a single zone, limiting the ability to simulate share rights on a particular transmission facility. For Phase 2, therefore, E3 made a number of limited adjustments to the transmission topology in the model to break out specific lines linking these embedded zones the rest of the EIM based on approximate ownership shares. The major modifications are:

- **BANC**: Modeled partial contract rights on the California Oregon Intertie (COI) via Transmission Agency of Northern California (TANC)

- **LADWP**: Modeled ownership rights on Pacific Direct Current Intertie (PDCI) & Intermountain Power Project (IPP) DC lines (which are also used by utilities embedded that are actually part of the CAISO BAA)

- **IID**: Modeled ownership rights on Southwest Powerlink (SWPL) shared with SDG&E and Arizona utilities.

2.4.2 IMPROVED REPRESENTATION OF CURRENT CONTINGENCY RESERVE PRACTICES FOR BENCHMARK CASE

A significant share of the Phase 1 EIM savings was related to the cost of procuring conventional reserves – i.e., regulation and contingency-related spinning reserves. The Phase 1 Benchmark Case required each of the 12 Phase 1 zones to meeting its conventional reserve requirement (equal to 4% of the zone's load in each hour) using only resources that were located within the zone. This assumption was overly restrictive to the model, as it did not accurately capture the current reserve sharing and regional procurement practices in the West. For example, in the Northwest Power Pool certain BAs carry reserves on hydro resources that are located in a different zone. Additionally, the Phase 1 EIM Case assumed all conventional reserves needs for zones within the EIM could be met by generators from anywhere within the EIM footprint, which is overly optimistic, as the EIM is not proposed to include a market for conventional reserves.

For Phase 2, E3 put significant focus into creating a more accurate representation of current conventional reserve sharing practices in the West, working with EDTTRS members and others familiar with reserve requirement details to gather information and incorporate it into the modeling framework.

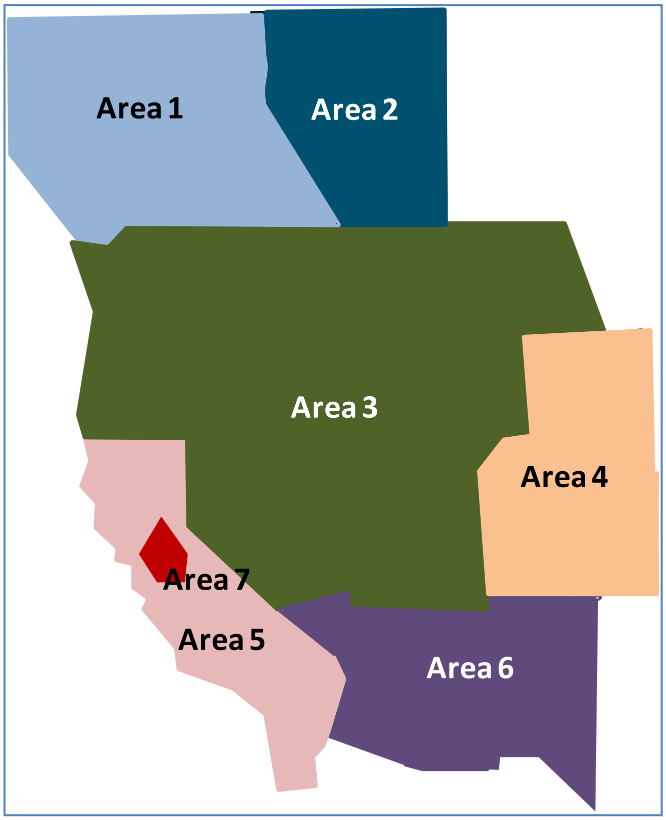
In Phase 2, conventional reserves are treated the same in the Benchmark and EIM Case. This change helps to avoid attributing benefits from operational changes that would not necessarily occur under the EIM. All Phase 2 Cases still require that the total conventional reserves equal to 4% of hourly load. Phase 2, however, splits these reserve requirements – requiring only a portion to be procured locally within one of 24 zones, while allowing the remaining requirement to be met with generation located within one of 7 Reserve Procurement Areas. Imposing a reserve requirement at both the zonal and procurement area levels required customization of the GridView software by ABB engineers.

The 7 Reserve Procurement Areas are listed in the table below, and shown in the following map.

Table 3: Phase 2 Reserve Procurement Areas

Reserve Procurement Area	Zones Included
1. British Columbia	British Columbia Transmission Corp (BCTC)
2. Alberta	Alberta Electric System Operator (AESO)
3. Northwest	BPA, PGN, PSE, PACW, AVA, NWE, IPC, PACE
4. Rockies	WACM + PSCO
5. California	CAISO + CFE
6. Southwest	PNM, APS, TEP, SRP, WALC, NVP, IID, LADWP
7. BANC	BANC

Figure 2. Phase 2 Reserve Procurement Area Map



The BC, Alberta, California, and BANC reserve procurement areas consist of only a single zone, so all conventional reserve requirements must be carried on generation within that zone. Stakeholder feedback indicated that, on average, approximately 25% of reserve requirements for zones in the Northwest Reserve Procurement Area are typically met with resources inside of the BA, and the remaining 75% (largely contingency reserves) can often be carried on resources located elsewhere in the Reserve Procurement area, so a 25%/75% split was applied to conventional reserves within the Northwest (Area 3). For example, a sizeable portion of PSE's reserve requirement is carried on hydro units located on the Mid Columbia (Mid-C), which are outside of the PSE BAA and are part of the BPA zone in the Phase 2 analysis.

Similarly, zones in the Rockies and Southwest region indicated that 90% of reserves are typically carried on resources in the local zone while 10% can be met with resources in the wider procurement area, so a 90%/10% spilt was applied to zones in these areas.

The one exception made to this characterization is Hoover Dam, which is a highly important resource for meeting reserve needs in both the Southwest and California area. To more accurately represent reserves carried on Hoover, E3 allocated Hoover reserve flexibility between zones (CAISO, LADWP, NEVP, SRP, APS, WALC) based on available information on reserve procurement rights & ownership shares. Each zone's allocated share of Hoover is counted as "within zone" generation for reserve fulfillment. The 90%/10% split for the Southwest Procurement Area is applied after allocating Hoover resources to the local zones.

In Phase 2, as in the Phase 1 and in TEPPC PC0, the analysis assumes that sufficient capacity is available from hydro and CTs (not requiring day-ahead commitment) to cover the 2-3% non-spin reserve needs, so the simulation does not commit additional resources for meeting non-spin requirements.

2.4.3 ADDED "FLEXIBILITY RESERVE" REQUIREMENT TO SUPPORT VARIABILITY OF RENEWABLE GENERATION

In addition to these conventional reserve needs, the Phase 2 Analysis imposed a flexibility reserve requirement. The Phase 1 analysis did not impose any additional requirements for flexibility reserves, but rather used only the conventional reserve requirements from TEPPC 2020 PC0 Case.

For Phase 2, NREL generously provided estimates of flexibility reserve requirements for the 2020 Benchmark Case, EIM Case, and Reduced Participation Sensitivity Case. NREL has developed a methodology to estimate expected flexibility reserve requirements in three categories:

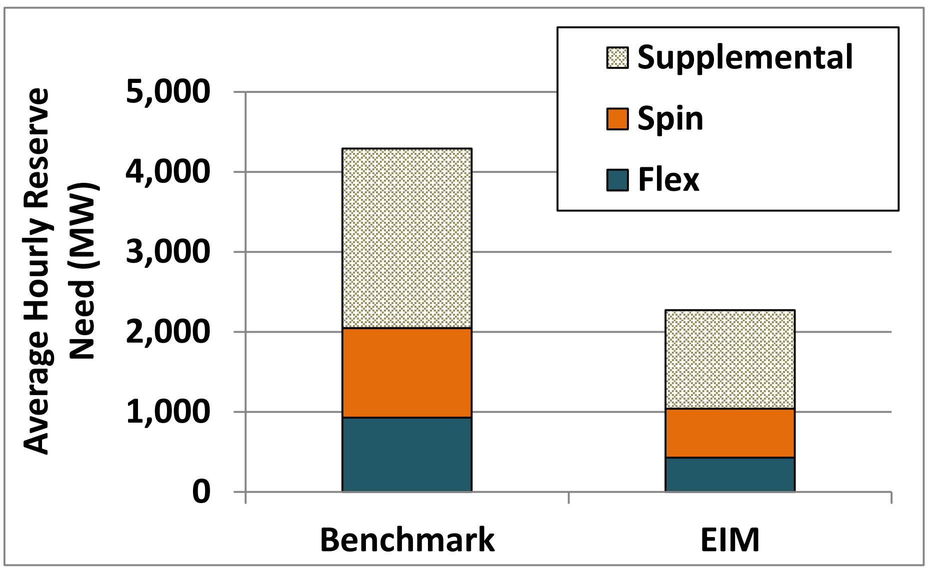
+ "Flex": Based on intra-hour wind & solar variations that would require regulation-like resources
+ "Spin": Calculated based on the 1st standard deviation of the hour-ahead forecast error for wind and solar resources
+ "Supplemental": Calculated based on the 2nd and 3rd standard deviation of the hour-ahead forecast error for wind and solar resources.

Per discussions with NREL, the supplemental category of reserve needs was assumed to function similar to non-spin conventional reserve requirements, so no additional units were committed in the production simulation runs to meet the supplemental reserve needs.

The MW levels required for flexibility reserves depend on the geographic footprint of the area that must support the variable generation. Aggregation of individual zones into the EIM footprint in the EIM Case results in a 45% reduction in average flexibility reserve needs relative to the Benchmark Case, as a reflection of the diversity in wind & solar hourly profiles across the EIM footprint.

The figure below shows the change in average hourly flexibility reserve needs by type under the 2020 Benchmark and EIM Cases. Overall, the EIM shows a 1,000 MW reduction in average "Flex" + "Spin" flexibility reserve needs compared to the Benchmark Case.

Figure 3. Average Hourly Reserve needs for Zones in EIM Footprint - 2020



(Note: Excludes CAISO and AESO.)

Additionally, the EIM Case allows for greater efficiency and production cost savings by allowing zones that participate in the EIM to meet the flexibility reserve requirement by procuring it on dispatchable thermal or hydro generation units anywhere in the EIM footprint. This change allows for a more optimized selection of the lowest-cost flexibility reserves compared to the Benchmark Case, which requires that flexibility reserve needs must be met with generation from the same zone in which the wind or solar resources are located.

2.4.4 INCORPORATED PRICE RESPONSIVE HYDRO DISPATCH USING HYDRO THERMAL COORDINATION (HTC)

For the Phase 1 analysis, GridView modeled hydro using only Proportional Load Following (PLF) logic (which shapes hydro output based on the zonal load shape) and fixed hourly output profiles. By contrast, the TEPPC 2020 PC0 case, as modeled in PROMOD, partially simulates price responsive hydro generation for approximately 40 hydro plants (located primarily in California, British Columbia, and the Northwest) using Hydro-Thermal Coordination (HTC) logic. HTC is a process that iteratively adjusts the hourly hydro output shape for each month (subject to energy, capacity and operational ramping constraints) to minimize the resulting locational marginal prices (LMPs) in the model. At the time of the Phase 1 analysis, GridView's hydro model for the Western Interconnection did not yet have the validated functionality to model price responsive hydro.

For Phase 2, the ABB team customized the GridView software (without charging software development costs to the EIM Benefits analysis project) to develop a Hydro-Thermal Coordination module for GridView that replicates the functionality and price-responsiveness of hydro in PROMOD. The HTC module in GridView generally results in a similar dispatch pattern as PROMOD, and results were shared with TEPPC staff and members of the Modeling Working Group.

The net effect of this hydro modeling change on the EIM benefits analysis is that in Phase 2, HTC-dispatched hydro units are now able to respond to the price effect of hurdle rate removal in the EIM while still respecting the hydro's own operational constraints. While this piece likely has a small effect on the overall benefit level, HTC-dispatched hydro generation can at times dispatch more optimally to displace more costly gas resources in hours of high system need, lowering total system production costs.

Total hydroelectric availability for most zones in the Phase 2 analysis (as for Phase 1) is based on data from the TEPPC 2020 PC0 Case, which is typically based on 2006 actual conditions. The year 2006 was considered an average hydro year for the Northwest, but was an abnormally high hydro year for California, so the TEPPC 2020 PC0 Case models California hydro based on its availability during the year 2002 rather than 2006. TEPPC data for BC Hydro is also based on a "typical year," rather than a specific historical year.

When calibrating hurdle rates for Phase 1 and Phase 2, E3 discovered indications that certain differences between simulated and historical 2006 path flows were resulting from differences between 2006 historical and simulated hydro output for California. Thus, for the 2006 cases, E3 adjusted the California hydro plant output to match historic hydro availability data specific for 2006, as provided by WECC staff.

For British Columbia, path flow data also implied that the hydro patterns in TEPPC differed from the 2006 historical hydro levels, so for Phase 1 and Phase 2 E3 calculated an estimate of total hourly hydro output in BC as the sum of hourly 2006 BC load (from TEPPC data) plus 2006 BC net exports over interties to Alberta and BPA (as reported on the BC Hydro website), less any relatively small non-hydro generation in BC (which was estimated from simulation run data). Aggregate hydro for BC was then allocated proportionally to plant groupings in the TEPPC database based on the relative monthly energy amounts originally provided by BC for the 2020 PC0 case.

2.4.5 MAINTAINED HURDLE RATES FOR UNIT COMMITMENT IN EIM CASE

In the Phase 1 EIM Cases, the analysis removed hurdle rates between zones within the EIM for all generation during both unit commitment and dispatch. Comments from stakeholders from the Phase 1 results indicate that a 5-min real-time EIM may not permit fully-optimized day ahead unit commitment decisions. For Phase 2, the EIM case was modified so that hurdle rates are maintained during unit commitment for all thermal units other than gas-fired combustion turbines (CTs). This means that combined cycle gas turbines (CCGT) and steam units must make day-ahead commitment decisions with the hurdle rates in place, but then the hurdle rates are removed for all generation during the dispatch. CTs were assumed not to require day-ahead commitment, so uncommitted CT units are allowed to still run during dispatch regardless of their commitment status.

2.4.6 USED DAY AHEAD FORECAST OF WIND GENERATION IN UNIT COMMITMENT CYCLE

In addition to reflecting hour-ahead wind and solar variability through imposition of flexibility reserve requirements, Phase 2 also attempted to evaluate the potential effects of day-ahead uncertainty of wind. The hourly wind resource profiles in TEPPC, which are based on NREL data for actual 2006 wind profiles, also have a linked data series that provide the day-ahead forecast of those actual wind profiles. While Phase 1 used the actual wind profiles during both the commitment and dispatch portions of the simulation run, Phase 2 substituted in the day-ahead wind forecast when determining the commitment of thermal units.

This assumption change potentially results in a limited number of hours of additional wind curtailment (when the day-ahead wind forecast is too high), and can potentially create a small reduction in efficiency of system dispatch when actual hourly wind output during the dispatch turns out to be different from the level anticipated during the day-ahead unit commitment. This change likely creates a slight increase in EIM benefits, as the EIM can respond more easily to forecast errors due to renewable resource diversity and a deeper conventional resource stack.

2.4.7 GENERATOR CHANGES FOR PHASE 2

In the Phase 2 analysis, two generator changes were made based on feedback from local utilities:

- Generator data was updated to reflect coal retirements & fuel switching for PSCO's Front Range units, changes that were not incorporated into the TEPPC 2020 PC0 Case. The replacement plant additions were assigned characteristics from similarly-sized generic gas plants in the TEPPC 2020 PC0 case.
- Burrard generation was removed in BC after consultation with Powerex.

2.5 Other Phase 2 Inputs and Assumptions (Unchanged from Phase 1)

2.5.1 SELECTION OF 2006 AND 2020 MODEL YEARS

E3 selected the 2020 model year to be consistent with TEPPC's 2020 PC0 case. The generation additions included in TEPPC's 2020 PC0 case[4] create a high penetration of renewable resources, so this case provides an estimate of how an EIM would perform in the presence of a high level of renewables and the variability associated with those resources.

The TEPPC 2020 PC0 Case uses load and hydro shapes from the year 2006 (except for California hydro)—scaling and date shifting these shapes as appropriate for 2020. Similarly, the wind output shapes used in TEPPC 2020 PC0 are also based on the year 2006, as estimated in NREL's Western Wind Integration Study. E3 selected the 2006 model year to provide a comparable data point to estimate EIM benefits under a known set of historical conditions. Data availability for hourly historical path flows, loads and other information also made 2006 a suitable historical year selection.

2.5.2 NATURAL GAS PRICES

The 2020 Benchmark and EIM Cases use generator fuel prices from the TEPPC 2020 PC0 case. The 2006 Cases, however, required that E3 modify the natural gas prices to more accurately reflect actual seasonal and regional price

[4] Other than the PSCO and Burrard (BC) changes specifically identified above, the 2020 case included all generation and transmission facilities in the 2020 PC0 case, including TEPPC assumptions on the Foundational List and OTC replacements.

variations that occurred during the historical year. For example, some pairs of zones (e.g., the Northwest and Southern California) show regional basis spread for historical 2006 prices that are in the opposite direction as the basis differential used in the 2020 PC0 case.

Thus, E3 use the following steps to create an updated set of monthly gas prices specific to each TEPPC Load Area for the 2006 Cases:

1. Calculated monthly average prices for major Western natural gas hubs based on daily 2006 spot prices obtained from Platts.

2. Applied a local delivery charge (LDC) between the hub and the TEPPC Load Area. These LDCs were derived from estimates of natural gas delivery tariffs between each hub and electric generators within the TEPPC Load Area.

3. Inflation-adjusted the 2006 gas price to 2010 dollars (assuming an inflation rate of 2.5% per year) for consistency with the other costs in TEPPC database.

4. Applied a 5.6% tax surcharge on natural gas for zones located in Arizona.

The table below indicates the TEPPC Load Areas that were associated with each regional hub for calculating gas prices.

Table 4. TEPPC Load Areas Associated with Regional Hubs for Developing 2006 Natural Gas Prices

Regional Hub	TEPPC Load Areas Associated with Hub
AECO	AESO, AVA
Sumas	BCTC, BPA, CHPD, DOPD, GCPD, PACW, PGN, PSE, SCL, TPWR
Rockies	NWMT, WAUW, PACE ID, PACE WY, PACE UT, Idaho Power (FAR EAST, TREAS VLY, MAGIC VLY)
Northern California	PG&E_BAY, PG&E_VLY, SMUD, SPP, TIDC
Southern California	CFE, IID, LDWP, NEVP, SCE, SDGE, WALC
San Juan	PSC, WACM
Permian	APS, EPE, PNM, SRP, TEP

3 Phase 2 Hurdle Rate Benchmarking Process

3.1 Setting hurdle rates for Benchmark Cases

For Phase 2 E3 endeavored to identify and implement hurdle rates between the 24 modeled zones that would cause the GridView production simulation to result in modeled path flows that are similar to actual flows in the 2006 historical benchmark year. At a high level, this benchmarking process involved the following steps:

1. Start with OATT rate schedules & losses from transmission tariff schedules.

2. Run production simulation initially with these "tariff rate plus losses"-based hurdle rates.

3. In an iterative process, adjust certain hurdle rates so that simulated flows across major paths match historical flows to the extent possible given time and resource constraints. This process included comparing historical and simulated flows based both on the flow duration curves as well as the average seasonal patterns during heavy load hours (HLH) and light load hours (LLH).

After implementing this process, some of the final calibrated hurdle rates were larger than OATT rate schedules and some were smaller. Since powerflows within the Western Interconnection are heavily networked, all hurdle rates interact to affect the flow levels, so establishing individual hurdle rate levels involves a combination of art and science.

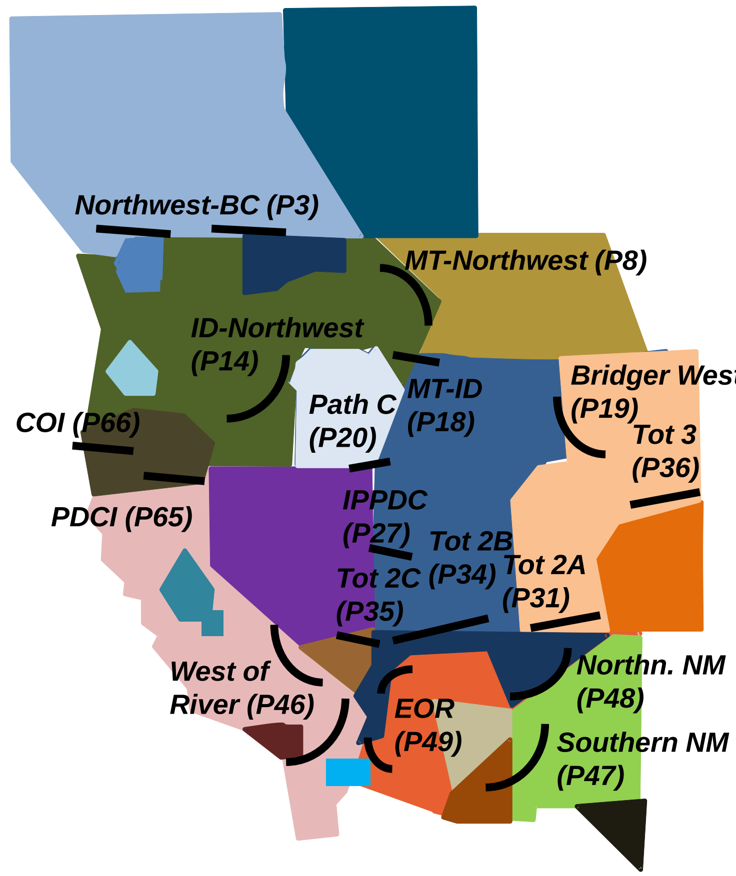
For the Phase 2 Benchmark Cases, this process resulted in development of direction-specific hurdle rates for each pair of zones that share a boundary, a total of 64 bi-directional interfaces (compared to 25 for the Phase 1 analysis). For the new interfaces in Phase 2 (esp. in the Northwest and Arizona) E3 stayed close to OATT tariff rates unless available flow results indicated a change was needed. For Phase 2, E3 also attempted to improve on the hurdle rate benchmarking performed in Phase 1, which showed higher simulated flows than historical levels on certain east side paths and paths into the Northwest.

3.2 Selected monitored paths for benchmarking inter-zonal transfers using hurdle rates

During each run of the iterative process to develop hurdle rates, E3 compared path flows results from the GridView simulation to historical 2006 hourly flow data on 17 selected monitor WECC paths, as illustrated by the black lines in the figure below.

Figure 4: Monitored Paths for Benchmarking Inter-zonal Transfers

	Zone Name	Zone Description
1	BC	British Columbia
2	AB	Alberta
3	BPA	BPA + SCL + TWPR + GCPD + CHPD + DOPD
4	NWE	Northwestern Energy + WAUW
5	NNV	Northern Nevada (Sierra Pacific Power)
6	PACE	PacifiCorp East
7	WACM	WAPA Rocky Mts.
8	PSCO	Xcel Colorado
9	CA	CAISO + CFE
10	NEVP	NV Energy
11	AZPS	APS
12	NM	New Mexico
13	PSE	Puget Sound Energy
14	AVA	Avista
15	PGN	Portland General Electric
16	PACW	PacifiCorp West
17	IPC	Idaho Power
18	WALC	WAPA Lower Colorado
19	SRP	Salt River Project
20	TEP	Tucson Electric Power
21	BANC	BA of N. CA+ Turlock ID
22	EPE	El Paso Electric
23	LADWP	LA Dept. of Water & Power
24	IID	Imperial Irrigation District



E3 chose to benchmark to historical flows on these WECC paths because historical 2006 path data were available for these paths. These particular paths were selected primarily because their locations provide an indication of flows that are likely occurring across many of the relevant zonal interfaces for Phase 2.

3.3 Model changes for each Phase 2hurdle rate benchmarking simulation run

The iterative process for benchmarking hurdle rates built off the Phase 1 benchmarking work and required development and evaluation of 6 new GridView simulation runs for the 2006 Benchmark Case. The table below summarizes the major incremental changes made with each run. Some of the changes do not directly involve hurdle rate adjustments; rather, they were performed to reflect other assumption updates for Phase 2, or to remove other types of differences between the simulation case and historical 2006 operations that also could cause differences in simulated vs. actual path flows.

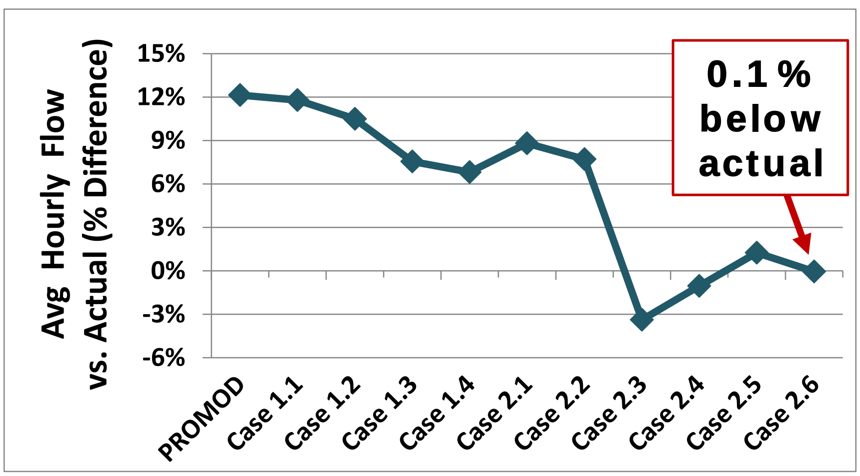
Table 5. Incremental Model Changes for Hurdle Rate Benchmarking Simulation Runs

Simulation Run	Details and Incremental Changes
Case 1.4	**Final Phase 1 2006 Benchmark Case Run**
Case 2.1	**Initial Phase 2 Case** • Used final hurdle rates from Phase 1 • Added paths for embedded CA zones • Modified conventional reserve requirements and zone definitions • Incorporated HTC hydro model
Case 2.2	• Added hurdle rates on new paths not in Phase 1 based on OATT tariff rates plus losses
Case 2.3	• Increased hurdle rates to reduce E-W flows from MT/ID into NW; flows into CA; East side N-S flows
Case 2.4	• Further hurdle rate adjustments
Case 2.5	• Further hurdle rate adjustments
Case 2.6	**Final Phase 2 2006 Benchmark Case Run** • Small hurdle rate adjustment; removed planned Shiprock-Glade 230 kV line for 2006; removed Burrard

3.4 Results of Phase 2 Hurdle Rate Benchmarking Process for 2006

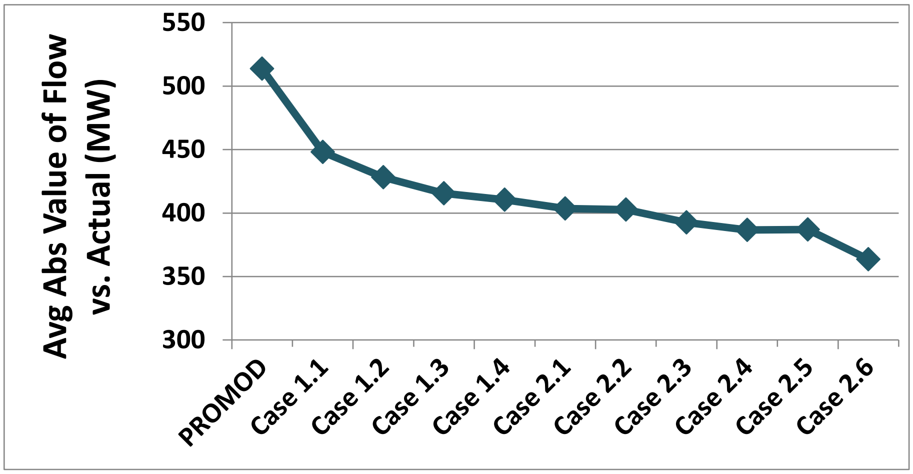
The sequential benchmarking simulation runs for Phase 2 resulted in incremental improvement in the difference between simulated path flows and 2006 historical flow data. The overall average level of flow on the monitored paths from the final Phase 2 2006 Benchmark Case (Case 2.6) was 0.1% below the historical actual flow (compared to 7.0% above historical for the Phase 1 2006 Benchmark Case).

Figure 5: Percent difference from Actual Average Hourly Flow over 17 WECC Paths (MW)



The chart below shows the average absolute value of differences in hourly path flow between the simulated cases and historical 2006 data, averaged over the selected 17 monitored paths. The Phase 2 iterations show continued improvement relative to the Phase 1 flow results.

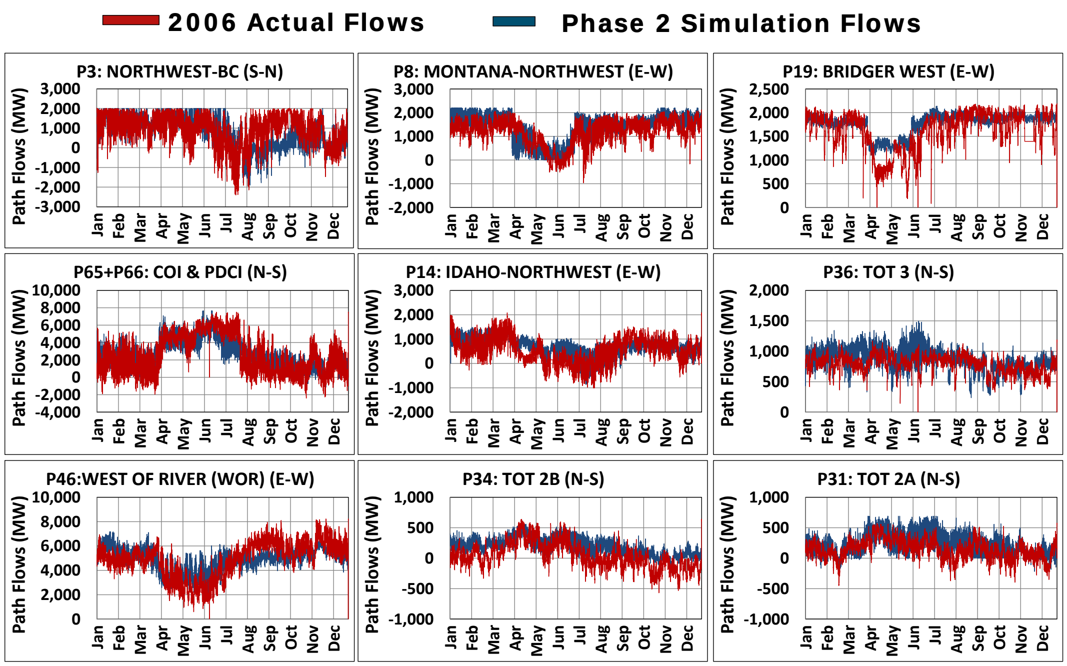
Figure 6. Absolute Value of Hourly Differences in Simulated vs. 2006 Historical Path Flow



Overall, Case 2.6 flows show a 29% average absolute value of hourly difference compared to the historical flows. While still significant, this error is a considerable improvement compared to previous iterations. The remaining differences are partially reflective of inherent challenges in precisely simulating historical operations on an hour-by-hour basis. Simulated flows can be higher than historical for some hours and lower in other hours due to a number of factors; resolving some of these differences would require data granularity beyond the level permitted by the inputs available for the simulation.

The figure below compares the chronological hourly flows for all 8760 hours from historical 2006 year with the final GridView simulation for the Phase 2 2006 Benchmark Case on a selected set of paths.

Figure 7. Chronological Hourly Path Flows in 2006 Simulated Benchmark Case vs. Actual



The figures below summarize the hourly paths flow comparisons by taking the average value of flows during heavy load hours (HLH) and light load hours (LLH) of each season. The figures show flows under both the final 2006 Phase 1 and Phase 2 Benchmark Cases, and highlight the improvements in flows, particularly on the east side paths.

Figure 8. Seasonal Average Heavy Load Hour Flows in 2006 Simulated Benchmark Case vs. Actual

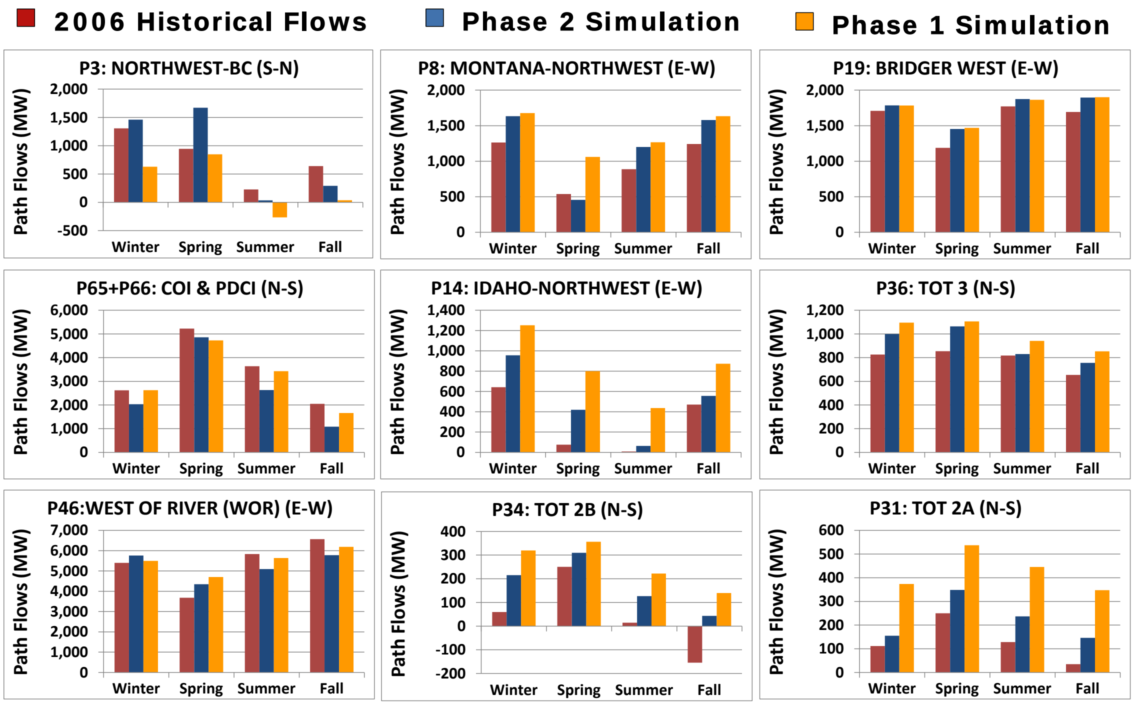
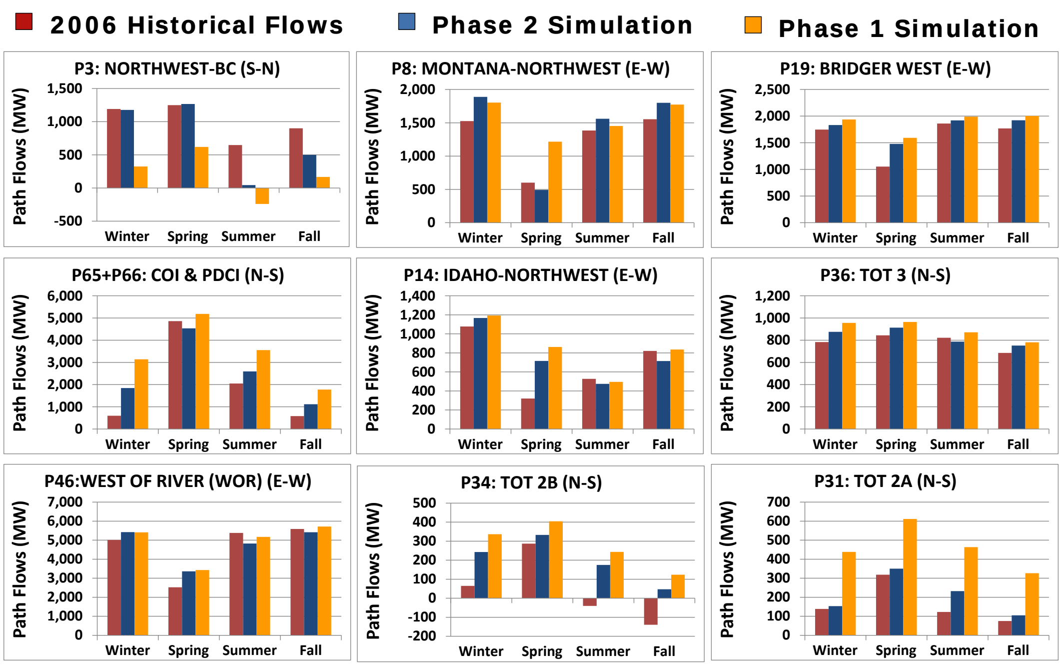


Figure 9. Seasonal Average Light Load Hour Flows in 2006 Simulated Benchmark Case vs. Actual



3.5 Final Hurdle rates used for Phase 2 Benchmark Case

The table below contains the final hurdle rates developed and used in the Phase 2 Benchmark Cases. The “Forward” rate in the 3rd column indicates the hurdle rate applies to power flows originating in the “From” zone in column 1 and terminating in the “To” zone in Column 2. The “Backward” hurdle rate is applied to power flows originating in the “To” zone. So, for instance, power that flows from the NWE zone to BPA incurs a $14.72/MWh hurdle rate, while power flowing from the BPA to NWE incurs a $3.26 rate. The rows shown in gold text represent the paths for which hurdle rates are maintained in both the

Benchmark Case and the EIM Case. To indicate the manual adjustments made for Phase 1 hurdle rate calibration, the last two columns list of the table shows any adjustments made to the calculated OATT transmission service rate plus losses. The majority of the adjustments made to the hurdle rates involve increases of $2-8/MWh on north to south path flows on the East side (e.g., WACM->WALC, PSCO->WALC) and for east to west paths (e.g., IPC->BPA, NWE->BPA).

Table 6. Hurdle Rates used for Phase 2 Benchmark Cases

		Benchmark Case Hurdle Rates (2010$/MWh)		Difference from Tariff Rates + Losses	
From	To	Forward	Backward	Forward	Backward
AB	**BC**	**$4.72**	**$3.63**		**($5.98)**
BPA	BC	$3.26	$3.63		($5.98)
NWE	BPA	$14.72	$3.26	$7.50	
IPC	BPA	$11.36	$3.26	$7.50	
BPA	NNV	$6.44	$6.04		
BPA	**CA**	**$11.44**	**$7.29**	**$5.00**	
NWE	WACM	$12.22	$7.27	$5.00	
PACE	NNV	$5.06	$6.04		
PACE	WACM	$10.06	$7.27	$5.00	
WACM	PSCO	$14.77	$4.22	$7.50	
NNV	**CA**	**$6.04**	**$3.88**		
PACE	AZPS	$12.56	$3.62	$7.50	($1.00)
PACE	LADWP	$40.00	$9.68	$34.94	
WACM	WALC	$14.77	$3.64	$7.50	
NNV	NEVP	$6.04	$3.03		
NEVP	**CA**	**$8.03**	**$3.88**	**$5.00**	
PACE	NEVP	$12.56	$2.03	$7.50	($1.00)
NEVP	WALC	$3.03	$3.64		
AZPS	**CA**	**$9.62**	**$3.88**	**$5.00**	

AZPS	NM	$2.12	$5.43	($2.50)	
PSCO	NM	$9.22	$5.43	$5.00	
NM	WALC	$5.43	$3.64		
AVA	BC	**$4.07**	**$3.63**		($5.98)
AVA	BPA	$4.07	**$3.26**		
IPC	AVA	$11.36	**$4.07**	$7.50	
NWE	AVA	$14.72	**$4.07**	$7.50	
AVA	PACW	$4.07	**$5.06**		
BPA	LADWP	$8.94	**$9.68**	$2.50	
WACM	NM	$14.77	**$5.43**	$7.50	
PACE	WALC	$12.56	**$2.64**	$7.50	($1.00)
PACE	IPC	$5.06	**$3.86**		
PSCO	WALC	$11.72	**$3.64**	$7.50	
WALC	**CA**	**$8.64**	**$3.88**	**$5.00**	
PACW	**CA**	**$10.06**	**$3.88**	**$5.00**	
PACE	**CA**	**$40.00**	**$9.68**	**$34.94**	
IID	**CA**	**$4.13**	**$3.88**		
LADWP	**CA**	**$9.68**	**$3.88**		
CA	**BANC**	**$3.88**	**$5.99**		
AZPS	IID	$2.12	**$4.13**	($2.50)	
AZPS	LADWP	$9.62	**$9.68**	$5.00	
AZPS	SRP	$2.12	**$2.98**	($2.50)	
AZPS	TEP	$2.12	**$4.88**	($2.50)	
AZPS	WALC	$2.12	**$3.64**	($2.50)	
BPA	PACW	$3.26	$5.06		
BPA	PGN	$3.26	$1.62		
BPA	PSE	$3.26	$0.96		
BPA	BANC	$8.94	$5.99	$2.50	
NM	EPE	$5.43	$5.63		
TEP	EPE	$4.88	$5.63		
IPC	NNV	$11.36	$6.04	$7.50	
IPC	PACW	$11.36	$5.06	$7.50	
IPC	PGN	$11.36	$1.62	$7.50	
NEVP	LADWP	$8.03	$9.68	$5.00	
NNV	LADWP	$40.00	$9.68	$33.96	
NWE	PACE	$14.72	$5.06	$7.50	
PACW	PGN	$5.06	$1.62		
AVA	PGN	$4.07	$1.62		
TEP	NM	$2.38	$5.43	($2.50)	

SRP	**CA**	$7.98	$3.88	$5.00	
SRP	TEP	$2.98	$4.88		
SRP	WALC	$2.98	$3.64		
WALC	TEP	$3.64	$4.88		
WALC	IID	$3.64	$4.13		
WALC	LADWP	$8.64	$9.68	$5.00	

The BC to BPA path hurdle rate was lowered considerably to reflect BC's likely use of non-firm, as-available transmission capacity for power exports.

The largest hurdle rate increase is for PACE to CA and PACE to LADWP. In the simulation database, the IPP coal units in Utah are considered part of the LADWP load area due to the presence of the IPP DC line. The 2006 historical data indicated that flows on the IPP DC line matched very closely to historical output from the IPP plant. In hours when certain units at the IPP plant were offline (for maintenance or other reasons), flows on the IPP line would drop considerably. In the early simulation cases, however, even with a relatively large hurdle rate of $10-15/MWh on the PACE to LADWP path, power would be imported from other parts of the PACE region to fill in any unused capacity on the IPP DC line when IPP generating units are offline, creating flows that are quite different from the historical pattern for 2006.

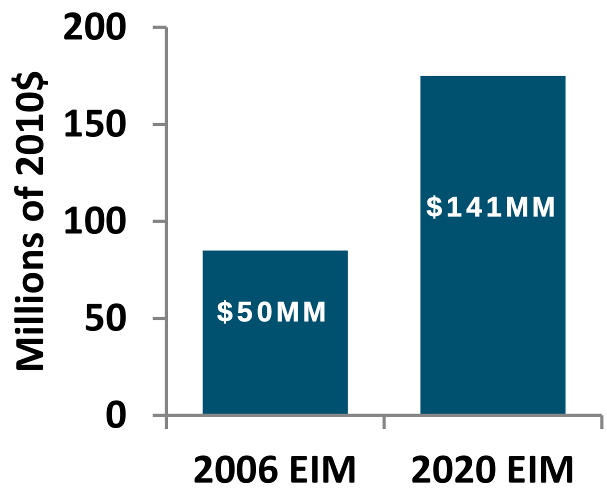
The PACE to CA and PACE to LADWP hurdle rates were increased to $40/MWh to essentially shut down this path of power imports when the IPP plant was offline to more closely approximate the historical flow pattern on the IPP DC line.

4 Phase 2 Key Findings

4.1 Overall Phase 2 EIM benefits for WECC in 2006 and 2020

For the simulation year 2020, the Phase 2 EIM Case resulted in $141MM of annual savings (in 2010 dollars) compared to the Benchmark Case throughout the Western Interconnection. This savings represents a 0.7% reduction of the overall total production cost from the Benchmark case. This total is lower than the Phase 1 estimate of $235MM, but Phase 1 assumed a large benefit from conventional reserve savings that is not included for Phase 2. The figure below shows the expected Phase 2 EIM savings for the 2006 and 2020 simulation years.

Figure 10. Phase 2 EIM Savings for 2006 and 2020 (MM 2010$)

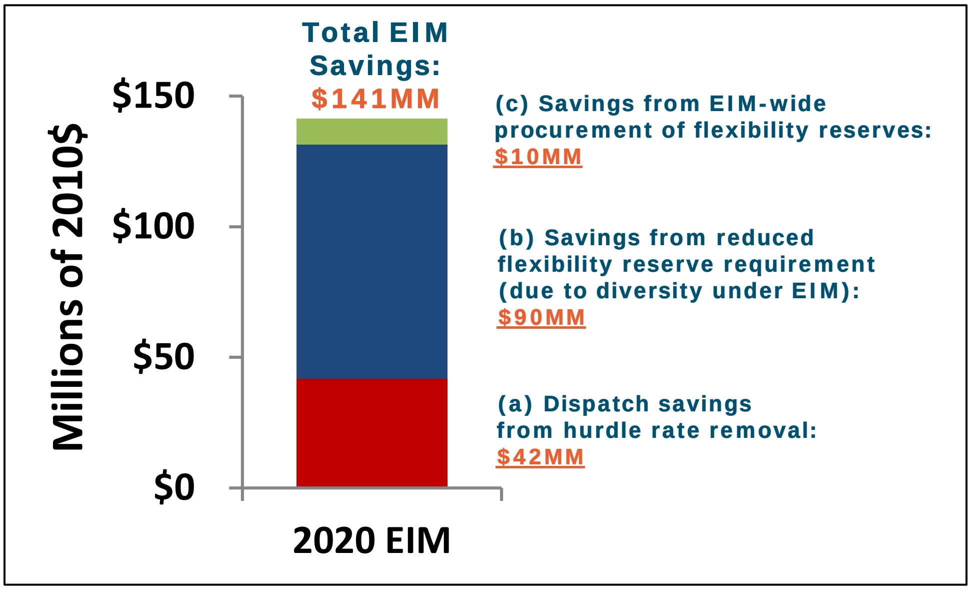


2006 EIM benefits for Phase 2 total $50MM, a modest increase compared to Phase 1. The most significant difference between the 2006 and 2020 set of cases is the addition of substantially more variable generation in 2020 to meet renewable policy goals in many Western jurisdictions. Due to the low level of variable generation in the 2006 Case, no flexibility reserves requirements were modeled in 2006, so the 2006 benefits are entirely dispatch-related.

4.2 Relative impact of dispatch and flexibility reserve-related benefits

In the 2020 case described above, the total EIM benefit amount has 3 primary components, related to three differences in EIM Case assumptions versus those in the Benchmark Cases. The figure below shows the amount of savings attributed to each component, which are then each discussed separately.

Figure 11. Components of Phase 2 2020 EIM Savings



1. **<u>Dispatch Savings from removal of hurdle rates</u>**. As described in previous sections, the Benchmark Cases used the benchmarked hurdle rates for power transfers between zones, while the EIM Cases removed the hurdle rates between zones within the EIM footprint. This hurdle rate removal alone resulted in $41.8 million in savings for 2020.

   Three primary factors explain why these dispatch savings are relatively small:

a. **Coal resources make up a relatively small share of generation in the West and already run at high capacity factors**. The largest dispatch benefits under the EIM result from displacement of gas generation with low cost coal generation. Unlike many other regions in North America, however, coal generation is a relatively small share of generation in the West and the coal units that are operating typically run at high capacity factors[5] even in the Benchmark Case. Therefore, removing hurdle rates can only enable a limited amount of additional coal to gas displacement.

b. Production simulation modeling does not fully capture the flexibility of hydro resources to respond to changes in market prices. Even with HTC modeling, hydro resources still show limitations in the model that they may be able to optimize around in actual practice.

c. **TEPPC database does not capture heat rate diversity among fleet of gas generators.** The heat rate curves used in the production simulation are simplified and do not reflect real data. These curves do not model factors that can affect real heat rates such as temperature, altitude, technology, and dry vs. wet cooling. The generic heat rates are identical between many generators and therefore do not capture some of the

[5] Annual capacity factor is the ratio of the actual output of a power plant over a year divided by the unit's output if it had operated at full nameplate capacity for the entire year.

incremental opportunities for gas-on-gas efficiency improvements that would add to the dispatch-related savings.

2. **Reduced Flexibility Reserve requirement.** The Phase 2 Benchmark Case used a separate flexibility reserve requirement for each of 24 zones, while the EIM Case used a single flexibility reserve requirement for the EIM footprint, which is nearly 1000 MW lower on average for each hour due to diversity of the aggregate signal of wind & solar generation in the EIM footprint. This reduction in reserve requirements allows the EIM to commit fewer conventional thermal units for reserve needs, and burn less fuel. Additionally, by committing fewer units, the model must go less deeply into the stack of generation resources, enabling greater use of lower cost generation for actual production. Overall, this reduced flexibility reserve requirement creates $89.8MM in savings for 2020.

   This reserve-related savings level implies a unit value of reserve savings of approximately $10-11/MWh, which is comparable to CAISO regulation and spinning reserve prices over the past several years. In practice, however, the mechanism for procuring these reserves is unknown at this time for both the Benchmark Case and the EIM Case, and the amount of reserve-related savings that could potentially be realized under an EIM would depend on the operational arrangement in either scenario.

3. **EIM-wide procurement of Flexibility Reserves**. After accounting for the hurdle rate removal and reduced flexibility reserve requirement, allowing EIM-participating zones to procure flexibility reserves from

across the EIM footprint results in an incremental savings of $9.9MM, compared to the case in which the flexibility reserve requirement quantity is reduced for the EIM footprint, but where the flexibility reserves must be procured from within the specific zones where the wind and solar are located.

4.3 EIM impact on changes to production cost by zone

The two figures below show the effect that an EIM has on 2020 generator output for each zone modeled in Phase 2. Positive bars indicate that the 2020 EIM Case resulted in a generation increase (compared to the 2020 Benchmark Case) for a particular zone. Negative bars indicate a decrease in generation under the EIM, and colors correspond to different types of generation technology. The zones are sorted from largest to smallest absolute change in generation under the EIM.

It is important to note that changes in production cost do not represent changes in overall cost because market costs and revenues are not included in production cost. Therefore, an increase in production cost for a certain zone does not necessarily imply an increase in overall cost for the zone, but rather an increase in *production*, which would be accompanied by either a reduction in imports or an increase in exports and associated market revenues.

Figure 12. Phase 2 EIM Impact on Generation: Net Change in 2020 Production (GWh), Part 1

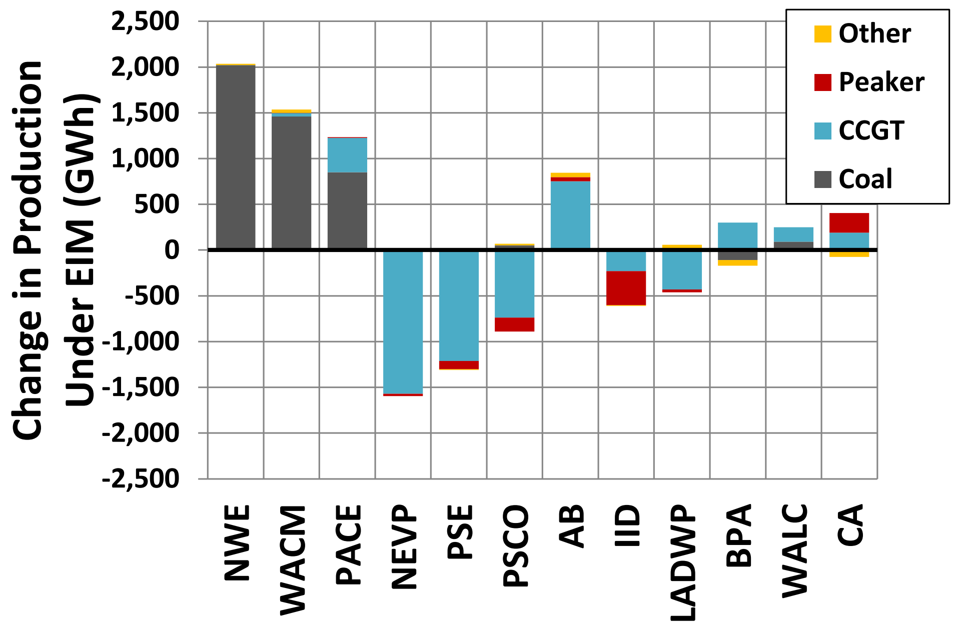
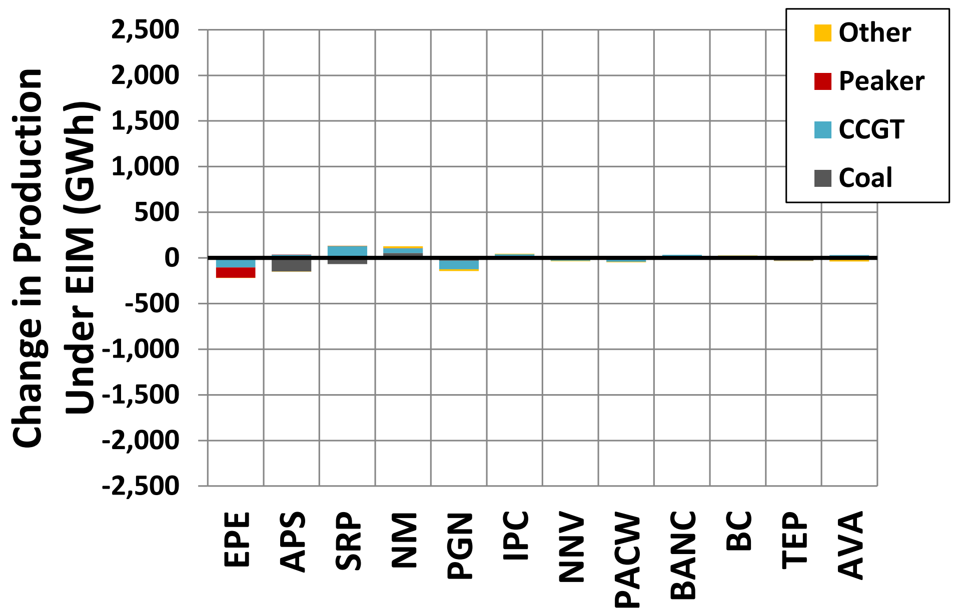


Figure 13. Phase 2 EIM Impact on Generation: Change in 2020 Production (GWh), Part 2



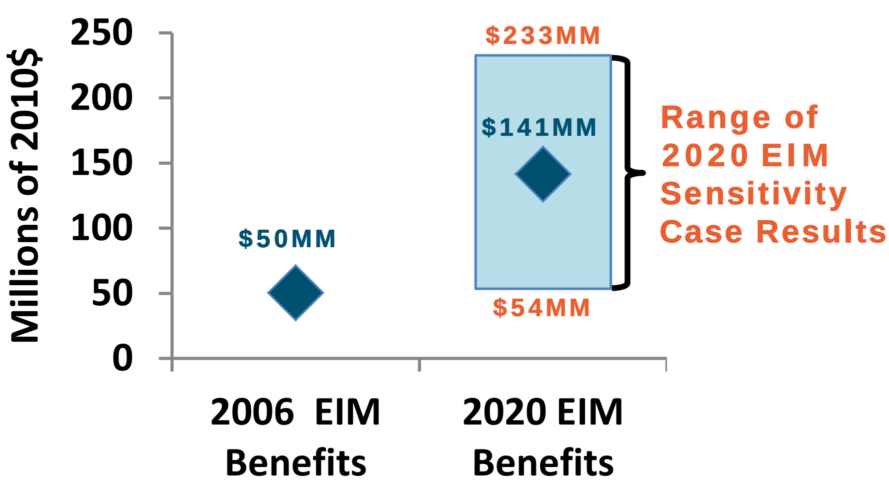
The figures highlight many of the key dispatch changes under the Phase 2 EIM case. The EIM creates an increase in coal generation in PACE, NWE, and WACM of approximately 4,300 GWh. This generation displaces local CCGT and peaker generation largely in PSCO, NEVP, PSE, and LADWP. In the EIM case, lower hurdle rates reduce the cost of importing low cost coal generation from adjacent zones. The lower procurement requirement for flexibility reserves in EIM case also reduces need to commitment as much local gas generation.

5 Phase 2 Sensitivity Case Results

5.1 Sensitivity Case Overview

In addition to the 2020 and 2006 EIM and Benchmark Cases, Phase 2 included a number of sensitivity cases for 2020. Overall, the benefits resulting under the sensitivity cases ranged from $54MM to $233MM.

Figure 14. Range of Results for Phase 2 Primary and Sensitivity Cases



The table below shows a high-level summary of the sensitivity case results, which are then discussed individually in the remainder of this chapter.

Table 7. 2020 Production Cost Savings under EIM Case and Sensitivities

Sensitivity Cases	$MM Savings vs. Benchmark Case
0. Phase 2 2020 EIM Case (Primary EIM Case)	$141.4
1. Reduced BA Participation in EIM	$53.6
2. Market-to-Market Coordination with CAISO	$182.1
3. Low Gas Price Cases ($4.50/MMBtu Henry Hub)	$226.7
4. High Gas Price Cases ($10/MMBtu Henry Hub)	$156.6
5. CO2 Price Case ($36/ton C02)	$232.6
6. NW flexibility reserve requirement shared with CA	$141.6
7. Assume “learning” results in more efficient unit commitment	$178.9

5.2 Alternative Participation Cases

The EIM benefits are significantly affected by the level of BA participation. Case 1, which excludes BPA, PSE, PGN, Avista, PACW, BANC, BC, WACM and WALC, results in total savings of $54MM. The excluded zones together represent a 47% reduction in total load compared to the Primary 2020 EIM Case. This case shows a reduction in the amount of flexibility reserve requirement savings relative to the Primary Case EIM as fewer zones with variable generation are participating in the EIM. Additionally, hurdle rates are maintained between the EIM and the non-participating zones, resulting in reduced dispatch benefits.

Conversely, Case 2 simulates one potential result of market-to-market coordination between the CAISO and the full EIM (together representing a 43% increase in total load versus the Primary Case EIM). The case assumes no change in flexibility reserve requirements, but removes hurdle rates between the CAISO and EIM to allow greater opportunity for dispatch efficiency improvements and savings, and results in total benefits of $182MM. It is important to note that this value represents a bookend case, as a market-to-market coordination arrangement may potentially be able to reduce, rather than fully remove, transactional costs and friction between the CAISO and EIM.

5.3 Gas & CO2 Price Sensitivity Cases

Cases 3, 4 and 5 together show that the EIM benefits are relatively robust to a range of natural gas and CO2 prices. The High Gas Price Case (Case 4) adjusts all gas prices in both the Benchmark and EIM Cases to reflect a $10/MMBtu Henry Hub price for 2020, in 2010$ (compared to $7.28/MMBtu for the Primary Benchmark and EIM 2020 Case, and in TEPPC PC0). This increase in gas prices slightly raises the overall EIM benefits for 2020 to $157MM. The Low Gas Price Case assumes a $4.50/MMBtu Henry Hub gas price for the EIM and Benchmark Cases and results in an increase in EIM savings to a total of $227MM.

At some level, the increase in EIM benefits under the Low Gas Price Case may at first appear counterintuitive, but is largely the result of the interaction of hurdle rates and gas-to-coal spreads in the Benchmark Case. The Low Gas Case reduces the price spread between coal and gas in the Benchmark Case. The combination of lower commodity price spreads plus hurdle rates in the Low Gas Price Benchmark Case together causes a net reduction in the utilization of remote coal plants compared to the Primary Case Benchmark Case, as the coal to gas price spread is no longer large enough in many hours for certain zones to justify importing remote coal generation and incurring hurdle rate costs. **In other words, with hurdle rates in place, it is less expensive in the Low Gas Price Case to run local gas generation than to purchase remote coal generation plus incur the cost of the hurdle rate**.

However, when the hurdle rates are removed under the Low Gas Price EIM Case, it again becomes economic to import remote coal to capture the savings from displacing local gas with remote coal generation. While the saving per MWh from displacing coal with gas is lower in the Low Gas Scenario, the larger potential for differences in the MWh of generation shifted between the EIM and Benchmark Cases (due to more unutilized coal capacity under the Benchmark Case) more than compensates, resulting in higher overall savings.

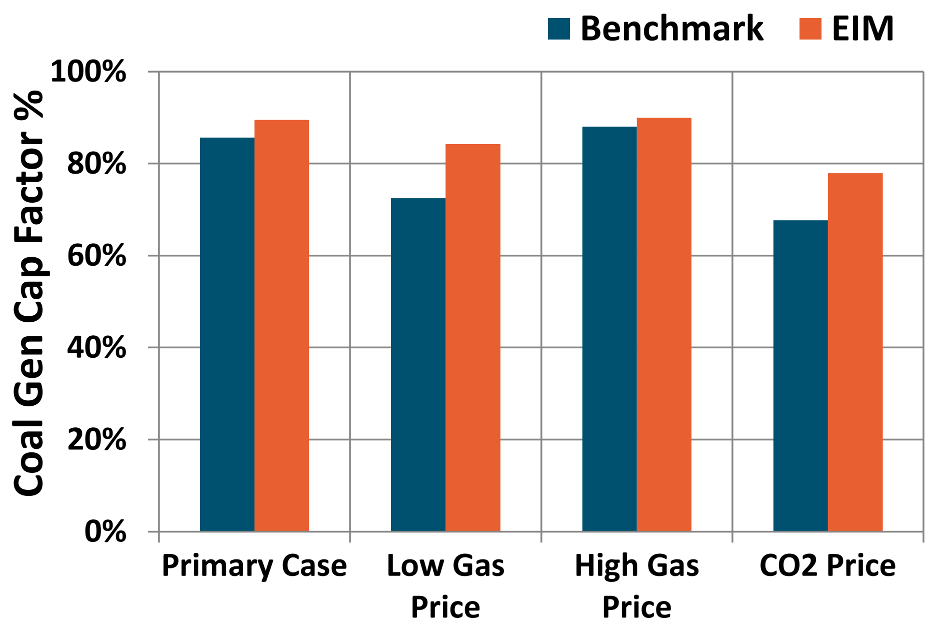
The interaction of price spreads in these cases is somewhat similar to what would occur if a person were choosing whether to buy groceries from a local store with higher prices (local generation) or from a generic low-cost store (remote low cost generation) located on the opposite side of a river that requires crossing an expensive toll bridge (hurdle). If the price difference between the stores is relatively high, the consumer would almost always be willing to cross the bridge to shop at the generic store, even if he had to incur the toll (equivalent to the Benchmark Case). As a result, if the bridge operator were to remove the toll (equivalent to the EIM Case), it would cause minimal change in the person's behavior as he already almost always crosses the bridge for groceries anyway. While the person would likely spend less on tolls, he would see minimal effective change in the amount he spends in stores for groceries after the toll is removed (which is analogous to showing small changes in generation production cost under the EIM).

By contrast, if the price difference between the two stores were smaller (equivalent of the Low Gas Price Case), the presence of a toll could create a large difference in the person's decision where to shop. Depending on the toll cost relative to the store's price differential, the person may choose to shop at the more expensive local store if the toll is in place (Benchmark Case). This means, however, that when the toll is removed (EIM Case), the person would switch stores and begin using the more distant, lower cost store, resulting in a larger change in his costs spent at the stores on groceries (EIM Production Cost Savings under the Low Gas Case).

Under the High Gas Price scenario (Case 4), by contrast, larger price spreads between gas and coal result in higher coal utilization under the Benchmark Case, even with hurdle rates in place. This change leave less remaining coal capacity available for increased use after hurdle rates are removed in the EIM case. This effect partially offsets the additional savings per MWh (due to the higher fuel price) that results when the EIM creates more efficient dispatch of gas generation and reduced fuel burn for generators committed to provide flexibility reserves.The CO_2 price scenario (Case 5) assumes a $36/ton CO_2 price for the 2020 Benchmark and EIM Cases compared to $0 in the Primary Case. The CO_2 price has a similar upward effect on the EIM benefits as the Low Gas Price Case. In the CO_2 price scenario, the effective $/MWh cost of coal generation increases relative to gas prices, shrinking the gas-to-coal price spread, and again reducing coal plant utilization under the Benchmark Case. Again, the removal of hurdle rates in the EIM Case of the CO2 price scenario results in a larger increase in gas-to-coal displacement than under the Primary EIM Case versus the Primary Benchmark Case.

The figure below compares the capacity factors under each scenario for coal plants located in the three zones with largest export increases under the EIM (PACE, NWE, and WACM). These data confirm the description of the effects of the gas and CO2 price scenarios above. Namely, the low gas price and CO2 price cases reduce the capacity factor of coal in the Benchmark Case, allowing a larger amount of unutilized coal capacity available for dispatch in the EIM after hurdle rates are removed. Importantly, the total level of coal utilization in the CO2 Price and Low Gas Price cases is lower than under the Primary case, but the differential between the EIM and Benchmark Cases is larger, creating a higher level of overall EIM savings.

Figure 15. Change in 2020 Coal Generation Cap Factor for PACE, NWE, and WACM zones



5.4 Other Sensitivity Cases

The calculated EIM Benefits also showed relatively low sensitivity to operating assumption changes made in Sensitivity Cases 6 and 7. Per EDTTRS member requests, Case 6 explores the effect of CAISO using dynamic transfers to import wind and solar from adjacent zones. The case thus assigns CAISO responsibility for meeting the flexibility reserve requirements associated with the imported power. The model implements this scenario in both the Benchmark and EIM cases by scaling CAISO flexibility reserve requirements proportionally to reflect 2167 MW of imported wind from BPA and PACW and 300 MW of imported solar from NEVP. These values are based on renewable generators identified for export to CAISO in TEPPC 2020 PC0. The local zones where the wind and solar is located also are also given a proportional reduction in the flexibility reserve requirements. Limitations to production simulation functionality prevented the modeling of dynamic transfer of the actual energy from the imported wind in addition to the reserve requirements.

This scenario results in a negligible net effect on EIM savings, which increase by less than $1MM (to $142MM of total savings for 2020). In this scenario, less wind and solar are ultimately balanced by zones inside the EIM footprint, so there is a slightly smaller savings in flexibility reserve requirements under the EIM relative to the Benchmark Case. This downward effect on EIM savings is offset because the lower thermal generation commitment for reserves inside the EIM results in to less thermal capacity available for gas-on-gas dispatch efficiency improvement and less dispatch-related savings.

Finally, Case 7 explored the effect of removing hurdle rates during unit commitment to simulate “learning” of generators and other market participants who may partially anticipate the ultimate dispatch prices under the EIM. In the Primary EIM Case, it is assumed that generators commit units as they would if they faced the Benchmark hurdle rates between zones. In this Sensitivity case, certain generators as able to make more efficient unit commitment decisions based on what the ultimate dispatch price signals will be under the EIM, resulting in a net increase in EIM savings to $179MM for 2020. This improved unit commitment represents an $30MM increase in EIM savings relative to the EIM benefits in the Primary Case EIM, in which the hurdle rates were maintained during unit commitment and only removed during the dispatch phase.

Stakeholders had proposed a number of other sensitivity cases that could not be included in this study due to data or time limitations. These cases include:

- **Hydraulic model** for dynamic hydro simulation
- **High/Low hydro** availability sensitivity cases
- **Reduced generator participation** in the EIM
- **Reduced BA participation beyond** removal of BPA, BC, & WAPA

6 BA Level Benefits Assessment

The primary focus of this analysis has been to calculate the societal, West-wide benefits resulting from an EIM. The way in which these benefits might be distributed among participants is dependent on the detailed nature of any potential EIM arrangement.

Despite these caveats, some comparable studies, such as CRA's analysis of an Energy Imbalance Service (EIS) market for the Southwest Power Pool (SPP) have endeavored to generate a proxy indication of the potential benefits for individual participating BAs.[6] The primary approach for this development is to calculate a "Modified Generation Cost" for each BA, which is equal to:

- the ***sum of generator production costs*** within that zone
- ***plus*** any net imports (in MWh) into the zone in each hour, priced at the load-weighted locational marginal price (LMP) for that zone
- ***minus*** any net exports (in MWh) from the zone in each hour, priced at the generation-weighted LMP for that zone.

[6] Charles River Associates Cost Benefit Analysis Performed for the SPP Regional State Committee, 2005. (Available at: http://www.spp.org/publications/CBARevised.pdf)

Using this methodology, the EIM benefit for any BA would then be calculated as reduction in Modified Generation Cost under the EIM Case versus the Benchmark Case. This approach is better than a simple sum of generator production costs because it accounts for a change in the cost of net imports and for the revenue create from net exports, rather than simply treating a change in energy generated as a benefit or cost. This method, however, is potentially misleading as it does not account for remote Generation owned by a particular BA but located outside of that BAA, or for multiple generation owners inside of a single zone.

E3 is currently developing a "Roadmap" for potential EIM participants to adjust this Modified Generation Cost calculation to account for their own remote generation. When completed, the roadmap will be presented in a separate document.

Glossary

Term	Use in Context of Phase 1 Report
Balancing Area (BA)	An entity that is responsible for integrating resource plans for a particular geographic area ahead of time, maintaining the area's load-resource balance, and supporting the area's interconnection frequency in real time.
Balancing Authority Area (BAA)	An area comprising a collection of generation, transmission, and loads within metered boundaries of a ***Balancing Area (BA).***
Benchmarking	The iterative process of using sequential production simulation runs to calibrate ***hurdle rates*** so that simulated hourly flows on monitored WECC path match more closely to historical hourly flows.
Capacity Factor	The ratio of the actual output of a power plant over a year divided by the unit's output if it had operated at full nameplate capacity for the entire year
Conventional Reserves	Generation capacity and ancillary services that a ***BA*** must traditionally procure for a given duration of time in the near future and have available to support unscheduled changes in load or unplanned outages of conventional generation resource or transmission facilities. May include specific sub-categories such as contingency reserves and regulation.
Energy Imbalance Market (EIM)	A voluntary, 5-minute market run by a central market operator that would supplement today's system of bilateral energy trading among multiple ***BAs*** in the Western Interconnection. The primary benefit of an EIM would be to create a more efficient dispatch of existing generation.
Flexibility Reserves	A new category of reserves that a system may need to hold for accommodating the variability and unpredictability of increasing penetrations of ***variable generation***. Flexibility reserve requirements would be additive to procurement requirements for ***conventional reserves.*** (May also be referred to as ramp capability.)
Hurdle Rates	Price adders (in \$/MWh) that are imposed on power flowing across zonal boundaries in a production simulation run to impede power transfers between ***zones***. Hurdle rates reflect a number of real-life impediments to trade, including point-to-

	point transmission rates across interfaces, pancaked losses, inefficiencies due to illiquid markets, and BAs' need to use resources to serve native load.
Hydro Thermal Coordination (HTC)	A production simulation technique used to model partial responsiveness of hydro generation output (from particular units) to nodal market prices.
Interface	A collection of all transmission facilities that connect the transmission busses in one ***zone*** to busses located in an adjacent ***zone***. In production simulation runs, ***hurdle rates*** can be applied to each interface.
Proportional Load Following (PLF)	A production simulation technique that shapes the output of hydro units that have sufficient flexibility. Under the PLF method, a hydro unit's available energy in a month is generated in a shape that is proportional to the aggregate hourly load within a certain geography that contains the hydro unit. The PLF method can be based on the gross load shape or may first subtract hourly output of wind, solar and other types of uncontrolled ***variable generation*** from the load shape. Higher or lower levels of hydro flexibility for following load can be controlled using a ***k-factor***.
TEPPC Load Area	A collection of busses in the TEPPC database topology that are assigned to one of 39 geographic groupings. TEPPC Load Area boundaries approximately correspond to the geographies of most ***BAAs*** within the Western Interconnection, but some TEPPC Load Areas represent aggregations of multiple ***BAAs*** and other TEPPC Load Areas represent sub-areas within a single ***BAA*.**
Unit commitment	The process for determining which generators in an area will be operating to meet the expected load over a given time period. This analysis assumes that units decide on a day-ahead basis whether to commit to operate or not operate in a given hour, but their final hourly dispatch level can be subsequently increased or lowered subject to ramping rate constraints.
Variable Generation (VG)	Generation technologies such as wind and solar that exhibit greater output variability and uncertainty than do conventional types of generation. The output of variable generators typically cannot be easily controlled by the system operators, and the presence of high VG penetrations may increase the need to procure ***flexibility reserves***.
Zone	An aggregation of one or more ***TEPPC Load Areas***. The Phase 1 analysis creates 12 zones and imposes hurdle rates on flows across transmission ***interfaces*** between each adjacent zone in the Benchmark Cases.