

UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security  
Constrained Economic Dispatch

Docket No. AD05-13-000

SUPPLEMENTAL NOTICE OF SECOND WEST JOINT BOARD MEETING

(February 10, 2006)

On January 6, 2006, the Commission announced that it planned to hold further joint board meetings and that these meetings would take place at the Hyatt Regency on Capitol Hill, 400 New Jersey Avenue, N.W., in Washington D.C. Take notice that the joint board meeting for the West region is scheduled to take place on Monday, February 13, 2006, from 9:45 a.m. to 12:15 p.m.(EST) in the Yorktown Room.

These meetings are held pursuant to section 1298 of the Energy Policy Act of 2005, Pub. L. No. 109-58, § 1298, 119 Stat. 594, 986 (2005). Section 1298 adds section 223 to the Federal Power Act, 16 U.S.C. §§ 824 *et seq.* (2000), requiring the Commission to convene joint boards on a regional basis pursuant to FPA section 209 “to study the issue of security constrained economic dispatch for the various market regions,” “to consider issues relevant to what constitutes ‘security constrained economic dispatch’ and how such a mode of operating . . . affects or enhances the reliability and affordability of service,” and “to make recommendations to the Commission.”

Take further notice that attached are: (1) an agenda for the meeting, (2) a draft study previously circulated to the board members, and (3) recommendations to be considered by the board.

Take further notice that the following changes have taken place to the West Joint Board membership: Ms. Rolayne Ailts Wiest was replaced by Commissioner Dustin (Dusty) Johnson of the South Dakota Public Utilities Commission, and Chairman Paul Hudson was replaced by Commissioner Barry Smitherman of the Public Utility Commission of Texas. A complete and updated list of board members is available at [www.ferc.gov](http://www.ferc.gov).

For more information about the meeting, please contact Sarah McKinley at 202-502-8004 or [sarah.mckinley@ferc.gov](mailto:sarah.mckinley@ferc.gov).

Magalie R. Salas  
Secretary



Attachment B: Draft Study

**DRAFT**

**Study and Recommendations  
to  
The Federal Energy Regulatory Commission  
by  
The Joint Board on Economic Dispatch for the West Region**

**January 30, 2006**

## **I. Introduction**

This report of the West Joint Board for the Study of Economic Dispatch presents the results of the Joint Board's study of Security Constrained Economic Dispatch (SCED) issues, and provides recommendation to the FERC. The West Joint Board is one of four joint boards designated by the Commission under EAct2005, Section 1298 Economic Dispatch.

As the Commission noted in the initial order convening the joint boards:

Each joint board is authorized: (1) "to consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

This report contains three sections in addition to this introduction: Section II provides a description of the basic concept of Security Constrained Economic Dispatch used in the study; Section III describes background on the variations in dispatch procedures in the west, and Section IV gives a summary of the issues raised and considered by the board, together with any recommendations made to address these issues. The principal sources for these sections are presentations to the board and written comments submitted, discussions among the Joint Board members, the DOE report under EAct 2005, Section 1234, the responses to the DOE survey of economic dispatch under Section 1234.

## **II. Security Constrained Economic Dispatch: the Basics**

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."<sup>1</sup> This definition describes the basic way all utilities in the region dispatch their own and purchased resources to meet electricity load. The basics of security constrained economic dispatch are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand, demand varies greatly over the course of a day, week, and seasons, the costs of generation from different types of units vary greatly, and expected

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<sup>1</sup> September 30, 2005 order at P 14.

and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. Security constrained economic dispatch is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance. Operators must also consider other factors that may affect what resources should be included in the next day dispatch, such as environmental limits on annual unit output, non-power uses of hydro resources. These factors can affect the eventual cost of utilizing the resource, but cannot be easily translated into daily or hourly production costs.

In addition, forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace cheaper units.<sup>2</sup> Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In

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<sup>2</sup> This is known as "out of merit" dispatch.

addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes.

### **III. Economic Dispatch in the West**

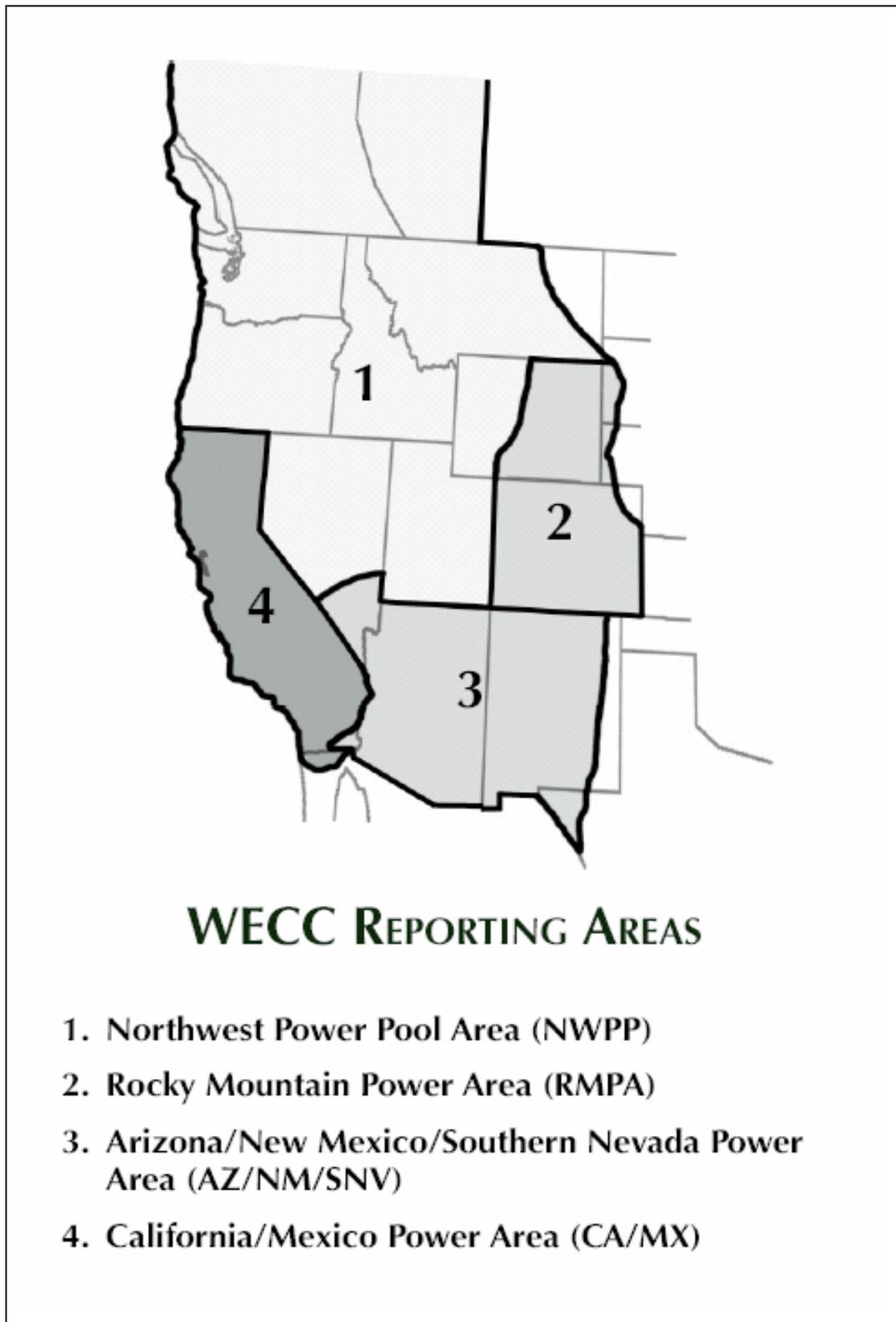
The practice of Economic Dispatch in the West varies by area. For purposes of this report, we will organize the discussion around the four areas used by the Western Electricity Coordinating Council (WECC). These regions are shown in Figure 1 and are as follows:

- Northwest Power Pool Area (Northwest)
- California-Mexico Power Area (California)
- Arizona-New Mexico-Southern Nevada Power Area (Southwest)
- Rocky Mountain Power Area (Rockies)

The overall pattern of dispatch in the west depends to a large extent on differences between the resources and loads in each area. The Northwest has an abundance of hydropower and a load that peaks during the winter, while the Southwest has a load that peaks during the summer. As a result, a historical pattern of flows has developed where power in the summer flows from available hydropower in north to peak loads in the south, while power in the winter flow from south to north to meet the peak loads in the northwest. The overall north-south transmission system has developed to support this pattern, and provides for overall economic utilization of generation resources. In a similar way, the main fuel sources for thermal power generation, coal and natural gas, tend to be in the in the Rockies or to the east in Texas and Oklahoma, while the major population centers are to the west, in California and the Pacific Northwest. The electric transmission systems reflect the need to move power west from coal generation; this movement of power is less seasonal than the north-south movement, as much of the power come from baseload plants that run year round.

The CAISO is the one multi-utility area market in the west that is centrally organized and dispatched. The remainder of the areas in the west perform economic dispatch on a decentralized basis, with a form of control area or utility dispatch similar to the basic dispatch described in the previous section. However, there is considerable variation in individual practices in each area that distinguish the way economic dispatch is practiced. The variations in regional practice are discussed briefly below.

Figure 1. Western Regions for Economic Dispatch Discussion



## A. Northwest

Although significant hydropower resources exist throughout the west, they dominate power generation in the Northwest. Fifty eight percent of capacity in the Northwest is conventional hydropower; seventy nine percent of the total western hydropower resources occur in the Northwest.<sup>3</sup> In the west as a whole, hydropower accounts for 34 percent of the total capacity.<sup>4</sup> This level of hydropower resources alters the way economic dispatch is performed in the Northwest and in the entire west, making the western dispatch issues significantly different from the Eastern Interconnection or from ERCOT.

Several characteristics of hydropower have direct implications for dispatch in the Northwest:

- Economic dispatch needs to consider the overall optimization of hydropower and thermal resources, making the problem of resource optimization much more difficult than it is in a power system based exclusively or primarily on thermal resource capacity.
- Hydropower generation resources in the Northwest are highly interdependent, so that they need to be dispatched as a coordinated system for power generation, rather than as separate, independent power sources.
- Conventional hydropower is generally limited by the total available energy stored in the water behind the dams, not by the total generating capacity of the resource.
- Hydropower can generally be dispatched very quickly when available, providing an abundance of low cost, rapidly dispatchable capacity to an extent not present in the other North American interconnections.

These characteristics have led to a long history of coordination in the Northwest, beginning around 40 years ago with the Columbia River Treaty with Canada and the Pacific Northwest Coordination Agreement (PNCA), and including the Mid-Columbia Hourly Coordination Agreement (MCHA). The PNCA enables both Federal and Non-Federal projects to operate as a single utility owner to optimize power and nonpower river demands, while the MCHA optimizes the hydraulic

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<sup>3</sup> WECC, 2005 Information Summary, Total Existing and Planned Generation, p. 6.

<sup>4</sup> *Id.*

operation of seven dams on the Columbia river. The MCHA permits hydropower resources to provide load following for much of the Northwest load, and hydropower resources also provide regulation and reserves at a low cost.

Another factor affecting Northwest dispatch is operation of the transmission system of BPA, which is closely connected to the operation of hydropower resources. Historically, the coordinated operation of the system of dams meant that all power was treated equally regardless of location on the system, so that a megawatt had the same value at any location. Until relatively recently, there were few constraints on the BPA transmission system, so there was sufficient transmission capacity to ensure that coordination would work successfully. In the last few years, there have been an increasing number of internal constraints and BPA is now moving toward a power flow based methodology to more accurately capture transmission effects in dispatch.<sup>5</sup>

The coordination of power and non-power uses leads to determining the optimum power operation *within* the non-power constraints. This optimum operation is distinct from the objective of minimizing short term operating costs, and may not be compatible where hydropower is low cost to produce in the short term, but high value if stored for subsequent use. In any case, the valuation of hydropower resources for short term dispatch presents unique challenges when such a high percentage of resource is low cost in the short term and potentially high (and uncertain) value over the longer term.

Although the presence of hydropower in the Northwest significantly affects the overall operation and dispatch of the power system, the basic dispatch remains decentralized and economic dispatch is conducted on a utility by utility basis rather than coordinated centrally. Plans for the development of an RTO in the Northwest are no longer being considered Northwest utilities are proceeding with the development of GridWest, a proposal for regional grid scheduling, real-time balancing and market monitoring, even though BPA recently decided not join.

Based on the responses to the DOE survey and the utility presentations at the initial meeting of the West Joint Board, utility dispatch in the Northwest is similar to the basic model described in the Section II, once operations are adjusted for the presence of hydropower. The main differences are less emphasis on day-ahead unit commitment of thermal resources to provide load following and reserves, because hydropower is generally the lowest cost alternative for these functions and will be used when available. Utilities report dispatching a mix of their own generation,

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<sup>5</sup> BPA, Economic Dispatch in the Pacific Northwest, presentation to the meeting of the West Joint Board for the Study of Economic Dispatch, Palm Springs, CA, November 13, 2005. (FERC Docket No. AD05-13-000)

independent generation committed under contract, and wholesale spot market purchases, combined to achieve the lowest cost from the resources available. These dispatch decisions are generally made before the operating day, either in the day ahead planning or earlier, and take into account factors other than strict operating costs, such as environmental limits, fuel contract terms, opportunity cost of company-owned hydropower, and similar factors.

Although planning for dispatch may take into account a wider range of sources, hourly or real time adjustments are often restricted to company owned resources or resources under contract that permit the utility sufficient flexibility in the terms of the dispatch.

## **B. California**

The California ISO (CAISO) performs an economic dispatch covering most of California, with the exception of some control areas.<sup>6</sup> Formed in 1998, the CAISO dispatches a single control area, corresponding to the former control areas of the three largest Investor Owned Utilities. Prior to the formation of the CAISO, each of the three control areas performed single utility economic dispatch, by dispatching their own resources and other resources under their control. This dispatch was similar to the basic dispatch process described in Section II, using the costs of the generation resources to establish the order of the dispatch and running the lowest cost resources available, given the security constraints of the system.

The CAISO consolidated the dispatch of the three utilities into a single dispatch for approximately 45,000 MW of California peak load, by balancing generation and load every 10 minutes based on market bids from generation resources. This balancing market was similar to the previous control area balancing function, in that lower cost generation resources were dispatched before higher cost resources; however, the traditional utility costs were replaced by bids to the CAISO. This change altered the economic dispatch process in two fundamental ways: all resources capable of being dispatched were eligible to submit bids on an equal basis, and the market bids that replaced the utility production cost estimates were no longer required to be tied to actual production costs of the utility.

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<sup>6</sup> Examples of control areas inside California, but not included in the CAISO dispatch are the Los Angeles Department of Water and Power in Southern California, Sacramento Municipal Utility District in Northern California, and a few others throughout the state.

In October 2004, the CAISO began a new market application, the Real Time Market Application, that plans a 5 minute dispatch for 2 hours in the future, dispatches online resources on a 5 minute basis in real time, and starts “fast start” resources on a 15 minute interval. A Market Redesign and Technology Upgrade (MRTU), planned for early 2007, will include the use of market bidding for day ahead planning and unit commitment, and greater detail in representation of the transmission grid for more accurate representation of the security constraints in the economic dispatch decision. These changes will enhance the dispatch processes of the CAISO, but will not change the basic differences between the CAISO dispatch and dispatch in the rest of the west: CAISO will continue to perform the only centralized, multiple-utility, market-bid-based economic dispatch in the west. Although the CAISO is the only area with this type of dispatch, its operation has significant effects on dispatch in the rest of the west, because the total load in California is large (approximately 30% of the summer peak load for the west)<sup>7</sup> and because California relies on significant imports from the rest of the west. Because California is so closely dependent on imports from the rest of the west, and because long distance power transactions are an important factor in overall power flow, the impact of centralized dispatch in the CAISO has greater direct impact on other areas in the WECC than comparably-sized centralized dispatch in the Eastern Interconnection has on other areas in the east.

The CAISO dispatch includes all resources needed to serve the load, both those that can be dispatched on a 5-minute basis and those that are not capable of responding to 5-minute dispatch signals. The non-dispatchable resources include generating plants that must be run for longer time periods, such as nuclear plants, as well as imports into the CAISO control area. These imports follow scheduling procedures set for the WECC as a whole, and must conform to fixed hourly schedules for exchanging power between control areas. Although imports are eligible to bid into the CAISO market for dispatch in real time, they must do so on an hourly basis and cannot be varied in the real time dispatch.

The CAISO is still evaluating the current implementation of real time dispatch, the RTMA, but notes two changes from the previous economic dispatch.<sup>8</sup> First, prices have become more volatile and the fluctuation of the dispatch has increased. This result is consistent with the change in the design of the dispatch, which was intended to promote more frequent balancing of generation and load and produce market prices that more closely mirrored that balance. Second, RTMA has improved “start up”

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<sup>7</sup> Based on a summer peak load of 141,100 in 2004, *WECC, 2005 Information Summary*, p. 2.

<sup>8</sup> *Assessment of Economic Dispatch Practices at the CAISO*, initial Meeting of the West Joint Board on Economic Dispatch, November 13, 2005, p. 18.

problems, including improved pricing of imports/export bids. Coordination the balance of hourly export/imports and 5 minute generation dispatch continues to be a challenge, however, particularly when load is rapidly fluctuating.

### **C. Southwest and the Rockies**

Although the Southwest and Rockies are separate areas, they have a single reliability coordinator, located at the WECC Rocky Mountain Desert Southwest Reliability Center (RDRC) in Colorado. Both areas rely principally on thermal resources, but face somewhat different issues in performing economic dispatch. The Southwest has a larger amount of hydropower capacity in the generation mix, and has a significantly greater level trade with California.

Natural gas is the largest single source of generation in the Southwest, followed by coal and nuclear. Hydropower also plays a significant role, with slightly over 10 percent of the total area capacity. Dispatch throughout the area is by individual utilities that perform unit commitment and economic dispatch of the own resources, supplemented by resources controlled by contract and purchases from the spot market. This general pattern of utility dispatch is followed by large investor owned utilities such as Arizona Public Service, large projects such as the Salt River Project, and smaller cooperatives and public power entities. Thus the Southwest dispatch is similar to the basic model described in the Section II, and does not have the extensive procedures needed to coordinate the dispatch the hydropower resources of the Northwest, nor has it adopted the centralized dispatch procedures used in the CAISO. An active spot market exists at the Palo Verde hub, providing a basis for price discovery in the Southwest and a point of reference for including wholesale purchases in the economic dispatch.<sup>9</sup>

Like the Southwest, the Rockies generation resources are largely thermal, with coal being the largest generation resource, followed by natural gas, and dispatch follows the single utility approach, together with use of resources under contract and spot market purchases.

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<sup>9</sup> See DOE survey comments of APS, Salt River Project and Arizona Electric Power Cooperative on the use of wholesale spot purchases in the dispatch.

#### IV. Issues and Recommendations

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing these issues. Based on the discussion at the initial meeting, there appeared to be a consensus on two general features of any approach to issues relating to SCED. First, board members generally believed that there should not be a “one size fits all” approach to the use of SCED. Differences among the areas in the west, and often differences within each area, were felt to be too large to warrant recommending a single form of SCED for all areas or utilities. Second, the focus of changes from current practices should be at the state or local level. Regional changes should be based on collaborative efforts among utilities, other market participants and states, rather than on legislative or regulatory initiatives at the federal level.

Recommendations from the DOE report to Congress on the value of economic dispatch are discussed at the end of this section.

##### A. Observations

A number of issues have been raised about the nature of economic dispatch, its scope and uses, and implications for affordable and reliable service to electricity consumers. Some of these issues concerned general features of an economic dispatch that should be included in a report discussion, rather than specific issues for additional study. These general issues included:

- Relative importance of hourly dispatch costs
- Least cost production may not be lowest cost for the ratepayer
- The broad choice between cost-based and bid-based dispatch

*Relative importance of economic dispatch.* Some board members and market participants expressed the desire to put the implications of economic dispatch in an overall cost perspective. In terms of total overall cost, economic dispatch, when framed in terms of daily and hourly dispatch, was felt to be relatively unimportant compared to long term investment in generation and transmission.<sup>10</sup>

*Least cost production may not be lowest cost for the ratepayer.*<sup>11</sup> This issue was raised by several board members, in reference to environmental costs, the nonpower issues of hydropower scheduling, and other considerations. The concern was that many factors are considered in the unit dispatch decision that cannot be easily translated into short term

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<sup>10</sup> Commissioner Schneider, tr at 116.

<sup>11</sup> Commissioner Beyer, tr at 114.

monetary terms, so that exclusive emphasis on minimizing daily or hourly production costs could prove to be more expensive to the ratepayer in the long run.

*Choice of cost based versus bid based dispatch.* This issue focused on the idea that economic dispatch often arose in the context of choice between two different systems of dispatch. The cost-based system referred to the basic single utility dispatch where a utility dispatched its own units based on its own generation costs and other factors, and was compared to a system with a separate grid operator that dispatched generation resources based on bids to supply power and then set a market price for the power based on the bids. Each overall approach gave rise to different sets of specific issues regarding the factors to consider for security constrained economic dispatch. One board member noted the existence of these different approaches, and proposed that the board not recommend a single approach to this issue.<sup>12</sup>

## **B. Specific Dispatch Issues**

The specific dispatch issues that were raised at the initial meeting or in the DOE survey comments varied by subregion, with different issues raised in each of the areas of the west, and also varied by market segment within regions, with different issues raised by utilities, independent power producers, grid operators and state regulators. These specific issues are listed below, and discussed in the remainder of this section.

- Independence of dispatcher
- Complicated nature of SCED, particular when bid based
- Utility dispatch of third party power through contracts
- Transparency of dispatch information and processes
- Consolidation of control areas
- Regional scope benefits
- Import/export schedule changes within an hour

*Independence of dispatcher.* A representative from the independent power producers recommended that some type of independent transmission provided was needed so that independent power producer resources could be fully integrated in the hour-to-hour operation of the dispatch.<sup>13</sup> In discussion, the IPP representative stated that dispatcher independence was a prerequisite for merit order dispatch.<sup>14</sup>

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<sup>12</sup> Commissioner Campbell, tr at 110

<sup>13</sup> Mr. Kahn, tr at 91.

<sup>14</sup> Mr. Kahn, in response to a question from Commissioner Grueneich concerning whether a utility would always favor its own generation, tr at 94.

*Board response/recommendation:?*

*Complexity of SCED.* The issue of the complexity and potential for unintended consequences of SCED was raised by the representative from City of Anaheim.<sup>15</sup> Security constrained economic dispatch was viewed as a complicated process from an engineering and cost point of view, but much more complex combined with the intricacies of a market. In addition to general caution regarding significant changes to the dispatch, two recommendations were put forward: (1) keep any structural changes flexible and sensitive to the needs of the states” and (2) to make changes voluntary wherever possible.<sup>16</sup> Several board members cited this issue in their summary remarks.<sup>17</sup>

*Board response/recommendation:?*

*Utility dispatch of third party power through contracts.* This issue was cited by both utilities and non-utilities, with utilities sometimes arguing that it was difficult to obtain sufficient performance and reliability from third party contracts. One utility stated that the primary difficulty with incorporating non-utility generation in their dispatch was their “inability to complete alternative actions in a swift and economic manner.”<sup>18</sup> Independent power producers stated the opposite position, arguing that their generation was flexible and capable of being very responsive, but that they were often denied the ability to dispatch power by utility generation owners who controlled the dispatch, particularly in the case of hourly dispatch and ancillary services.<sup>19</sup>

*Board response/recommendation:?*

*Transparency of dispatch information and processes.* One of the benefits cited for an independent entity dispatching all resources in a region was the ability to provide a transparent process for the dispatch. One utility representative argued that full value economic dispatch would not be fully realized without this transparency.<sup>20</sup> Without the independence condition, sharing sensitive real-time information between a utility transmission provider and third parties can be as an impediment to dispatching

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<sup>15</sup> Ms. Edwards, tr at 68.

<sup>16</sup> Ms. Edwards, tr at 73.

<sup>17</sup> Commissioner Greuneich, tr at 111; Commissioner Beyer, tr at 115.

<sup>18</sup> Portland General Electric response to DOE survey, p. 2.

<sup>19</sup> Mr. Kahn, tr at 88.

<sup>20</sup> Mr. Larson, tr at 49.

economically.<sup>21</sup>

*Board response/recommendation:?*

*Consolidation of control areas in a region.* The current single-utility dispatch means that each utility first determines a dispatch for its own area with only limited knowledge of conditions in other areas. Coordination is therefore based on more limited information on generation availability in other areas, and on available transmission constraints for imports and exports between control areas, compared to the information available within each control area. The larger the number of areas, the greater potential benefit of consolidating control areas, in principle, arising from better information available to the dispatch and greater control over generation and transmission resources. Some presenters recommended that control areas be consolidated, citing the large number in an area like the Northwest.<sup>22</sup> Others argued that there were potential benefits to SCED from consolidation, without taking a position on whether the benefits of consolidation would exceed the costs.<sup>23</sup>

*Board response/recommendation:?*

*Increased Regional Scope.* Increasing the size of the dispatch region, even without consolidating regions into a single control area, can lead, in principle, to a lower cost dispatch through inclusion of more generation and transmission resources. However, there appeared to be no consensus on whether such regional benefits exist in practice. Some cited regional benefit studies that concluded there were positive net benefits; for example, the representative from the Independent Power Producers cited a recent study for Grid West as demonstrating benefits.<sup>24</sup> One utility representative stated that there were potential benefits from regionalization, without citing a specific study. However, at least some board members felt the current system of utility dispatch coupled with spot and short term market purchases worked efficiently. One board member cited the adage, "If it ain't broke, don't fix it."<sup>25</sup>

*Board response/recommendation:?*

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<sup>21</sup> Discussion between Commissioner Smith and Mr. Larson, tr at 53 and 54.

<sup>22</sup> Mr. Kahn, tr at 89.

<sup>23</sup> BPA in comments submitted in the docket.

<sup>24</sup> Mr. Kahn, tr at 90.

<sup>25</sup> Commissioner Baca, tr at 119.

*Import/export schedule changes within an hour.* The CAISO identified large hourly schedule changes as a problem for their dispatch. The source of this problem for the CAISO dispatch stems from the fact that schedules between control areas change at the beginning of each hour and remain constant for the hour. Because the CAISO often has large amounts of imported power at the same time that it has large changes in load over the hour, it becomes difficult to accommodate these large blocks of hourly imports while following a volatile load.<sup>26</sup> To address this issue, CAISO recommended spreading the changes out over the hour to decrease the magnitude of each change.<sup>27</sup> Scheduling could still occur on an hourly basis, but each hourly schedule could increase or decrease on a less than one hour basis, for example, on 15 minute intervals. Because scheduling imports and exports between control areas in the west follows a standard protocol, developing the ability to provide schedule varying on 15 minute intervals would require coordinated development of such a change throughout the west.<sup>28</sup> One board member cited this recommendation positively, but there was no further comment from other board members at the initial meeting.<sup>29</sup>

*Board response/recommendation: ?*

### **C. Recommendations from the DOE Report to Congress**

The DOE Report to Congress, *The Value of Economic Dispatch*, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

- FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct ED.<sup>30</sup> These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time

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<sup>26</sup> Mr. Rothleder, tr at 38.

<sup>27</sup> Mr. Rothleder, tr at 41.

<sup>28</sup> Mr. Rothleder, tr at 39.

<sup>29</sup> Commissioner Campbell, tr at 110.

<sup>30</sup> *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 52.

dispatch. The reviews should distinguish entity-specific and regional business practices should from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow NUGs and other resources to compete effectively and serve load.

*Does the Joint Board wish to pursue this recommendation?*

- FERC and DOE should explore EPSA and EEI proposals for more standard contact terms and encourage stakeholders to undertake these efforts.<sup>31</sup> Specifically, the EEI proposed that NUGs should commit to provide energy at specified price for specified time to meet unit commitment schedule and there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

*Does the Joint Board wish to pursue this recommendation on a regional basis or does it wish to recommend that FERC and DOE pursue it on a national basis?*

- Current economic dispatch technology tools deserve scrutiny.<sup>32</sup> These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

*Does the Joint Board wish to pursue this recommendation?*

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<sup>31</sup> *Id.* at p. 51.

<sup>32</sup> *Id.* at p. 53.

## Attachment C

### **RECOMMENDATIONS FOR CONSIDERATION BY THE WEST JOINT BOARD**

#### **Recommendations Found in the Record of the West Joint Board**

- Establish an independent operator with a security constrained economic dispatch. (Mr. Larson transcript at 49, Mr. Kahn transcript at 91)
- Encourage contractual commitments by independent producers to provide energy in a manner consistent with the utility's dispatch, but do not require utilities to purchase non-utility power. (Mr. Larson transcript at 49)
- Consolidate control areas in the Northwest (Mr. Larson transcript at 49, Mr. Kahn transcript at 90.)
- Spread import/export schedule changes out over the hour to decrease the magnitude of each change (Mr. Rothleder transcript at 41.)
- The current system of utility dispatch works well and should be kept without major changes (Commissioner Baca transcript at 119)
- Ensure that changes in the dispatch are voluntary and flexible, and sensitive to the needs of the states (Ms. Edwards transcript at 73.)
- Review selected dispatch entities, including some investor-owned utilities, to determine how they conduct economic dispatch. These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, and distinguish entity-specific and regional business practices from regulatory, environmental and reliability-driven constraints. (DOE Report, The Value of Economic Dispatch at 52)
- Recommend that FERC and DOE explore Electric Power Supply Association (EPSA) and Edison Electric Institute (EEI) proposals for more standard contract terms and encourage stakeholders to undertake these efforts. (DOE Report at 51)
- Review current economic dispatch technology tools. These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions. (DOE Report at 53)

### **Additional Recommendations by Joint Board Members**

- Explore ways to include renewables in the economic dispatch (Commissioner Grueneich in comments on draft study.)
- Recognize the importance of a portfolio of diverse resource types, in order to accommodate state policy preferences for resource diversity and to help reduce volatility arising from over-reliance on a limited number of resource types (Commissioner Grueneich in comments on draft study.)