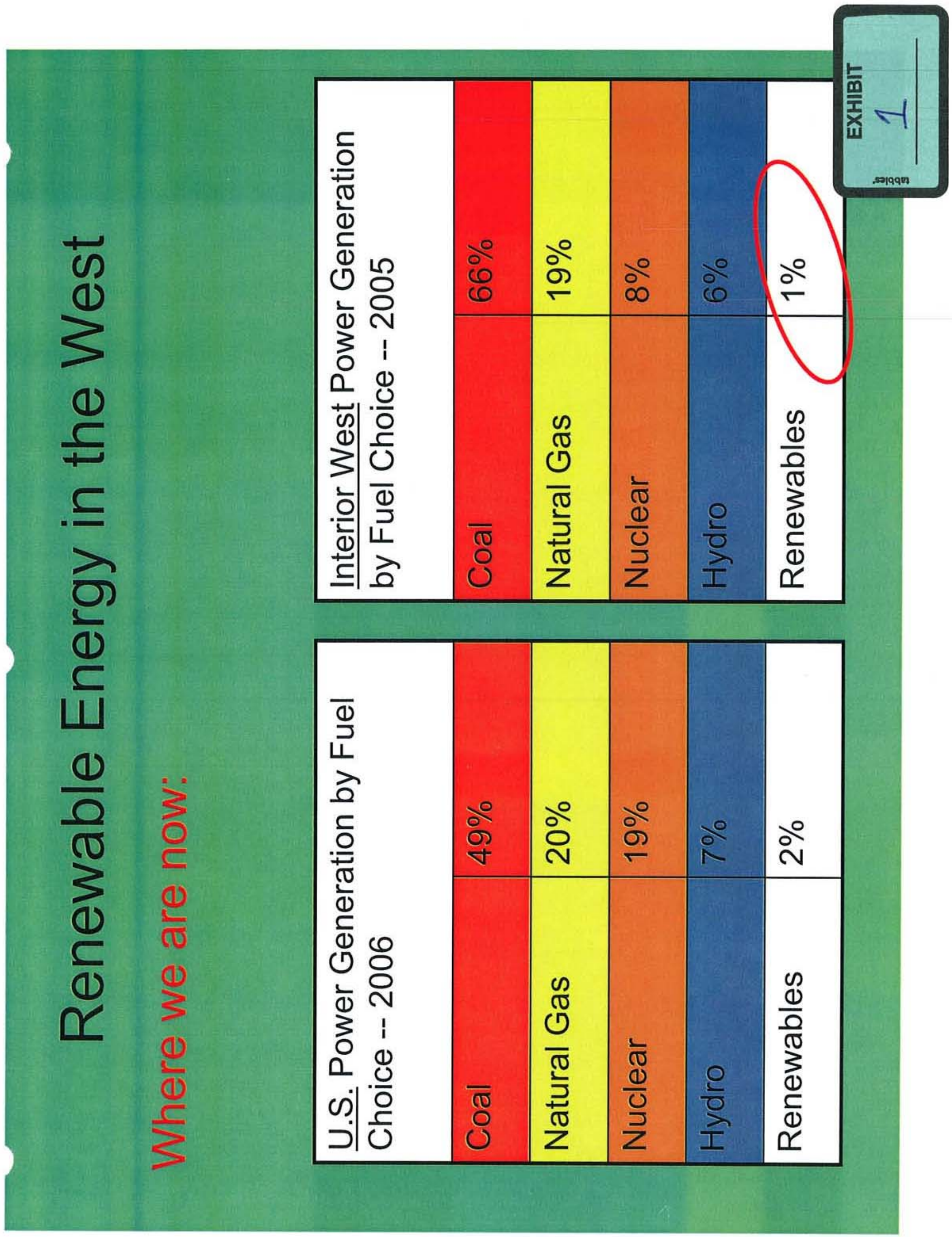
Attachments for WEC_50504

WEC_00101



Western Resource Advocates – May 2007

Comprehensive and Sequential Planning Steps For Energy Transmission Corridors on Public Lands

(1) Before looking to new bulk power generation sources to meet future load requirements, first analyze opportunities for energy efficiency, distributed generation, conservation, demand response and other technologies to address and lessen future load concerns.

(2) Focus on truly needed corridors by identifying key areas of transmission congestion, constraint or absence. In areas of documented congestion or constraint, first analyze opportunities to solve the constraint by redispatch, offering conditional firm service or other market, operational, tariff, or regulatory changes.

(3) Then, in order to avoid the impacts of new corridors, analyze opportunities to upgrade and expand existing transmission infrastructure through the application of state of the art technology, including new conductor materials, sensing and control systems, and improved transformer and system control technologies.

(4) Where the transmission need for new bulk power generation is established, then identify opportunities for renewable energy sources, such as wind, solar and geothermal – and associated transmission needs – to meet future load concerns and reduce air pollutants and carbon emissions. To reduce the need for long-distance and multi-state transmission lines, first identify for development those renewable energy resources that are in close proximity to major demand/load centers.

(5) Having demonstrated the need for these new energy transmission corridors (regardless of generation source):

First,

(a) avoid sensitive public lands recognized for scenic, natural, recreational, cultural or historic resources

Then,

(b) minimize impacts to affected public lands, wildlife and other resources through the adoption of Best Management Practices for right-of-way siting, construction, ongoing maintenance and reclamation

(6) Employ the concept of corridors. If planned and implemented properly, corridors create opportunities to harness multiple industry proposals for energy transmission into discrete, well-defined and studied areas to minimize adverse impacts.

(7) Finally, to the extent practicable, require the use of designated renewable energy transmission corridors for future right-of-way applications in order to avoid duplicative rights-of-way, unnecessary impacts and affecting key areas identified in (5)(a).

WEC_00101

Utility System Efficiencies, Inc.

EXPERT OPINION STATEMENT REGARDING POTENTIAL ENGINEERING SOLUTIONS TO ASSIST IN REGIONAL TRANSMISSION PLANNING

Prepared by Utility System Efficiencies, Inc. for Western Resource Advocates
February 11, 2008

INTRODUCTION

Utility System Efficiencies, Inc. (USE) was contracted to aid Western Resource Advocates (WRA) in developing an expert opinion statement regarding the draft programmatic environmental impact statement for the west-wide designation of energy transmission corridors. Ty Larson of USE is the principal author of this statement.

BACKGROUND OF TY LARSON

Ty Larson currently holds fifteen years of electric system utility experience - specializing in both transmission system planning & operations engineering. Mr. Larson possesses extensive experience and a strong working knowledge of the analytical tools that support the system performance evaluation and capital planning processes used by electric utilities. In recent years as an Operations Engineering Manager at the California ISO, Mr. Larson mentored and coached other engineers in power engineering analysis. More recently Mr. Larson has joined Utility System Efficiencies, Inc. (USE) in July of 2005. Mr. Larson's employment resume spans over several sectors of the electric utility industry, and he is qualified to discuss material with this expert opinion statement.

THE ROLE OF ENGINEERING SOLUTIONS IN COMPREHENSIVE REGIONAL TRANSMISSION PLANNING TO ASSIST IN ASSESSING ENERGY CORRIDOR NEEDS AND POTENTIAL OPTIMAL PLACEMENT

In the context of regional planning for the optimum location for energy corridors for the future location of thousands of linear miles of power lines in the Western United States, the following paper outlines a methodology that focuses on: (1) maximizing the use of the existing transmission infrastructure and utilizing the existing transmission/transportation rights-of-way; and (2) determining suitable locations for the construction of new transmission corridors for use in future transmission planning. While employing this methodology is one of several potential approaches to developing solutions for energy needs, the methodology discussed herein contains important steps in comprehensive regional transmission planning that may better inform both the need for and location of energy corridors for the future location of new or upgraded power lines. This expert opinion focuses on both the <u>need</u> for proposed energy corridors that may contain power lines in the future, as well as the review of a <u>proposed solution</u>. It is not the authors intent to infer that this proposed methodology is the only process or strategy to aid in this type of review, but rather to impart simply a method that could be used to help aid any existing process that may be currently engaged in finding a solution via regional transmission planning and the need for and location of energy transmission corridors.

From an engineering perspective, this paper focuses on opportunities to reduce the overall need for new power lines and thereby corridors and rights-of-way in which to locate them, namely by identifying potential engineering solutions and methodologies to follow in order to optimize components of the existing western power grid and enhance the current electric system's overall power carrying capacity to meet future power transfer needs. Employing these methodologies and applying technological engineering solutions in this fashion is a widely recognized industry practice as one component of transmission planning that in some instances may reduce or eliminate the need for new power lines and the impacts associated with associated rights-of-way and/or corridors.

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Project/Corridor Need

Project need is typically at the very core of all regional transmission planning issues and it is usually well documented in a power engineering study. Few good engineers would dispute that accurately understanding the driver for project need is critical in developing the best and correct project solution. Project need is usually conveyed through a series of well documented power engineering studies. A very basic question is does one really need this project? What is driving this need? Importantly, there is a direct correlation between project need – i.e., the need for an upgrade or addition to the electric power infrastructure – and rights-of-way and corridors in which to "house" a potential project. By first taking a hard look at whether a potential or specific project is needed, this may in turn answer a related question of whether the related ROW/corridor is also needed.

Power Engineering Studies

The detailed modeling and measure of transmission system performance outlines the major role of most power engineering studies. Once the true performance of a particular transmission system is known, then one can attempt to improve or optimize transmission performance. Many power engineering experts consider this first phase of analysis very important for it can shed light on where and what criteria violations may surface ultimately yielding weaker area of the overall transmission grid. Once this information is known, the engineer can start to model various changes that could potentially be made to the transmission system. This could be considered phase 2; ultimately modeling and measuring transmission performance of various transmission solutions. All portions of the power engineering studies are based on a set of assumptions which ultimately can impact modeling accuracy.

Power Engineering Assumptions

Most power engineering studies make a certain set of assumptions for various grid conditions that are to be represented in the study. It is safe to say that the overall transmission model accuracy is greatly improved with assumptions that best resemble accurate real life transmission grid conditions. It should be know that just minor changes in assumptions can have major impacts on the overall transmission grid performance. The role of assumptions should not be played down in their overall potential to influence power engineering studies results. Therefore it is in everyone's best interest to make sure that all study assumptions are reasonably accurate and their sources and values are well documented in power engineering studies. The following list-of-assumptions are but just a few, but the strategy of Q & A regarding them could be applied to many different assumptions. The principles are the same. This information is readily available in transmission planning circles and a rigorous examination of the following factors is an important preliminary step in terms of identifying current and future power grid needs including anticipated needs for new or expanded ROW and corridors.

Key Assumptions

Load Growth is an example of one key assumption that will typically influence the measure of power-grid performance under various conditions. Interested parties may ask many different questions regarding load growth, for if load growth is inaccurately modeled the effects may throw off the timing of the project need. This could result in project solutions being proposed late or too early. The following are good rule of thumb questions that I typically ask regarding a studies load growth projections.

1. What was the focal area of studies load growth?
2. How were the load growth projections done?
3. What data was used in calculating load growth projections?
4. How was the data collected?
5. What load growth was actually measure for the last 10 years?
6. When was it measured (Peak, Partial Peak, etc.)

7. What type of customer load does this represent (Residential, Commercial, and Industrial)?
8. What is the average Power-Factor for the loads represented in the study area?
9. To what extent have future load growth assumptions factored in efficiency gains in the residential and commercial sectors that can reduce overall load growth? Reducing load through efficiency gains, as well as the application of distributed power sources, can result in reductions in the amount of generation needed to meet future load growth, which may in turn affect and possibly lessen overall transmission and corridor needs.

Generation Pattern modeled in the study is another key assumption that can affect the modeling and measure of power-grid performance. Understanding the modeling of both existing and planned future generation commitment and output levels in a power engineering study is important. Inaccurate key assumptions regarding a studies generation pattern can skew power study results and ultimately impact timing of project need. The affects of inaccurate timing again can result in project solutions being proposed late or too early. The following questions are aimed at understanding the generation pattern modeled in the power engineering study.

1. What was the breakdown of all existing resources? Are these levels of commitment and output truly realistic?
2. What output levels and commitment strategy was used when modeling hydro generation? Does this pattern represent actual witnessed grid conditions?
3. How was the data collected?
4. What output levels and commitment strategy was used when modeling wind generation? Does this pattern represent actual historic grid conditions?
5. How was the data collected?
6. How are future new generation interconnections modeled in this study? Was all queued generation modeled? Was a cluster study involved? What was the overall strategy of new generation commitment and level of output based on?

Load growth and the generation pattern modeled in a power engineering study are just some of the assumptions that can easily influence the timing and outcome of a project need. Many other power-engineering study assumptions not listed in this section also require the same level of understanding to allow the engineer to obtain the best most accurate study results that ultimately can lead to accurately determining project need and timing. Fleshing out good project solutions, including the need for any expanded or new ROW or corridors for power line location, typically comes after understanding detailed project need and timing.

Engineering Solutions to Address Needs: Maximizing the Power Transfer Capacity of the Current Grid System through Engineering Analyses and Capacity Upgrades

The implementation of project solutions to upgrade a transmission grid typically involves a broad spectrum of approaches to solve a transmission grid challenges. One could add new equipment (build new lines/install new substations) or leverage or upgrade existing transmission assets, including the utilization of some of the new technologies that are now becoming available, as possible solutions. The approach followed – including the preceding two scenarios that are poised at opposite ends of the transmission planning spectrum – may result in reducing or eliminating the need for new transmission ROW/corridors and their attendant impacts on the natural environment. The bottom line is that some project solutions are more elegant than others. Cost and actions with the least amount of impact are usually at the top of most transmission planning engineer's lists when it comes to attempting to compare or optimize different project solution options. The selection of a good project solution is critical and will ultimately impact a variety of variables that go beyond project cost. Experience has shown that typically solution projects are more cost effective and less environmentally invasive on many levels if the project solution employs leveraging or upgrading an existing grid asset.

Power Engineering Project

From an interested party perspective, understanding why different study project solutions or alternatives are proposed is important. It is good to know why and how the favored project solution was arrived at. The following set of questions can be beneficial to verifying if the best project solution was truly chosen while reviewing engineering studies. At times the following through the actual process of Q and A of the following question tree can expose some low-lying fruit that may be beneficial in fleshing out an even a better project solution then was listed in the most current engineering studies or reports.

While there are many different approaches one can take in terms of finding a solution for an anticipated need, my professional expertise is that a rigorous examination of the following questions is an important initial step in transmission planning that first seeks optimization of existing electric grid assets before turning to higher-impact solutions such as new power lines and associated ROW/corridors. In other words, optimization of current electrical grid assets, i.e., the major components of substations, transformers, conductors (lines) and other equipment, particularly through the use of state of the art electrical engineering analysis and solutions, can address additional power transfer needs by using/upgrading the existing transmission system which has the environmental benefit of utilizing already-impacted areas.

1. **Existing grid assets leveraged** -are they leveraged to their fullest capability? Examples of leveraging existing grid assets are:
    a. ***Equipment Re-rates*** – The re-rating of existing grid equipment (examples may be transmission line or transformer bank) may be an answer to solving criteria violation(s) or grid issue(s) resulting from excessive flows over existing equipment ratings. My experience has shown in the past that the re-rating existing equipment is typically cheaper then installing new equipment, so the leveraging of existing grid assets in this manner can be very cost effective.
        i. What is the current position of the utility or system operator in the study area in regards to administering existing grid equipment re-rates?
        ii. Is there a written policy regarding the re-rating of existing grid equipment?
        iii. Has the utility or system operator already set a precedent by re-rating existing grid equipment in the past?
        iv. Has the solution option of re-rating of existing grid equipment been evaluated in the engineering study?
        v. What is the condition of the existing grid equipment?
            1. Transformer banks:
                a. When was the last time a dissolved gas analysis was performed on the transformer?
                b. What is the status of the last dissolved gas analysis of the bank?
                c. What are the historic temperature trends of the transformer bank (Top winding)?
            2. Transmission lines:

a. When was the last time the line underwent maintenance?
b. Is the line current in its maintenance cycle?
c. What is the practice of the utility or system operator regarding transmission line maintenance?
d. What are the surrounding ambient air conditions of the line?
e. Is the line located in an air district where insulator contamination is an on-going concern?
f. Is there an insulator wash cycle?
g. When was the last time the line was patrolled?
h. How is the visual inspection of the line?
i. What is the status of all insulators, shoes, clamps, sleeves and connectors?
j. Is there appropriate ground clearance during peak-loading of the line?
k. When was the last infrared scan done on the transmission line?
l. Did the scans reveal any hot spots or outline any concerns regarding risk to line integrity?
m. What is the written policy or practice of the utility or system operator regarding transmission line ratings?
n. What are the engineering assumption with regards to ambient temperature and wind-speed (2 ft/sec, 3 ft/sec or 4 ft/sec)?

b. ***SPS or RAS*** - Can the criteria violation or grid issue(s) driving the need and timing of the project be solved by installation of a special protection scheme (SPS) or remedial action scheme (RAS)? If the criteria violation or grid issue(s) are due to excessive flows over existing emergency equipment ratings, then one example in solving the problem may be to have an automatic scheme ramping back or tripping generation or even tripping customer load.
   i. What is the current position of the utility or system operator in the study area in regards to employing the use of an SPS or RAS?
   ii. Is there a written policy?
   iii. Has the utility or system operator already set a precedent by using other SPS or RAS?

2. **Upgrading Existing Grid Assets** –in a lot of cases existing assets can be partially upgraded to see some real gains in overall increased capability. The upgrade of existing transmission lines are strong examples of this.

   a. **Circuit Re-conductoring with Conductor of Higher Capability** – Re-conductoring limiting circuits with larger conductor will in most cases upgrade circuit transfer capability. The right of way and corridor are already in use. In many cases, this simple fact can make the process of re-conductoring faster and more cost effective, and at times more environmentally friendly then embarking on the construction of a new line.

i. In places where criteria violation or grid issue(s) driving the need and timing of the project, will re-conductoring of existing transmission line(s) with higher ampacity conductor help increase transfer capability in solving the transmission need?

ii. Has the utility or system operator compared transmission solutions that employ the re-conductoring of existing circuit(s)?

b. **Adding an Additional Circuit to Existing Towers** – At times inspection of existing towers along an existing critical transmission rout may have a circuit vacancy. For example if a visual inspection reveals that there is no second circuit on the existing tower, this would lead to analyzing whether a second circuit would be a sensible solution. Or minor tower modifications can enable the addition of another circuit. This can equate to a real gains! The right of way and corridor are already in use – which would result in confining impacts to an already-disturbed area. In many cases, this simple fact can make construction faster and more cost effective, at time more environmentally friendly then embarking on the construction of a new line.

i. In places where criteria violation or grid issue(s) driving the need and timing of the project, is there a vacancy on the existing towers that can be leveraged help increase transfer capability in solving the transmission need?

ii. Has the utility or system operator compared transmission solutions that employ the addition of a second circuit?

c. **Upgrading the Voltage of an Existing Transmission line** – Upgrading voltage class of an existing transmission line can also yield possible increases in circuit capability. Again as in the above example, the right of way and corridor are already in use. In many cases, this simple fact can make construction faster and more cost effective, at time more environmentally friendly then embarking on the construction of a new line.

i. In places where criteria violation or grid issue(s) driving the need and timing of the project, is there a lower voltage circuit that could be upgraded with minor tower modifications to help increase transfer capability in solving the transmission need?

ii. Has the utility or system operator compared transmission solutions that employ the change in circuit voltage class?

3. **Employing the use of new technologies**–in a lot of cases existing assets can be partially upgraded with newer technologies to see some real gains in overall increased capability. The re-conductoring of existing transmission lines with composite conductor are strong examples of utilizing the new technologies available currently today.

a. **Composite Conductors** – Over the years vast improvements have been made in the construction of newer high-tech composite conductors. There are many different designs that can show as much as a threefold ampacity increase in circuits that have been re-conductored with this new material.

i. In places where criteria violation or grid issue(s) driving the need and timing of the project, will re-conductoring of existing transmission line(s) with higher ampacity composite conductor help increase transfer capability in solving the transmission need?

ii. Has the utility or system operator compared transmission solutions that employ the re-conductoring of existing circuit(s) with composite type conductor?

b. **Series Reactors or Series Capacitors** – In places where it makes sense to increase or limit flows on large transmission corridors. The use of reactive or capacitive devise can be used. These devices do have the side of effect of changing voltage, but in the correct applications they can be used to influence the overall flow of power.

i. Has the utility or system operator compared transmission solutions that employ the series reactors or series capacitors?

c. **Phase Shifting Transformers** – In places where it makes sense to increase or limit flows on large transmission corridors. The use of phase shifting transformer has been employed. Transformers are able to manipulate the power angle by changing the setting and ultimately allowing more or less power to flow.

i. Has the utility or system operator compared transmission solutions that employ the phase shifting technologies?

Applying Engineering Solution Transmission Planning Principles to One Area in Southern Arizona and New Mexico

The current west-wide corridor effort seeks to designate energy transmission corridors in 11 western states, including Arizona and New Mexico. My professional opinion is that employing the above analyses including a rigorous examination of system needs and potential engineering solutions would have been helpful in determining the optimum number, potential width and location of transmission corridors for the future location of power lines. In addition to the current status of electrical system components, comprehensive planning for new power line corridors could also incorporate available lands and wildlife constraints and proposals for new generation sources seeking grid interconnection. Indeed, this type of grid interconnection "queue" information that is readily available in the public domain can also shed light if one has a particular focus on adding generation sources of a particular type. This type of planning can be useful into addressing multiple concerns in a comprehensive fashion by incorporating information about generation type (e.g., renewable sources), corridor needs and locations and lands and wildlife concerns.

Attached as Exhibit A is a map of Arizona and New Mexico. This mapping effort contains information readily available, in the public domain, to combine the geographic features including: land status, public interest group priority conservation areas, existing power lines and substations, and current interconnection queue data points, broken down by resource type and anticipated megawatts of newly installed capacity.

Attached as Exhibit B is a more specific map that zooms in on an area straddling the AZ/NM border in the Tucson AZ to Deming, NM general location. In addition to the above geographic features, proposed corridor 81-213 is depicted that would likely serve future power line needs between the Tucson and Deming locations. Between the Luna, Greenlee, Redtail substations and the Tucson area, numerous queue interconnections are shown, including 120 MW of solar power near Luna. For purposes of this demonstrative exercise in transmission planning, we are assuming that the "unknown" queue requests of 300 MW and 1000 MW in Greenlee and northeast of the Redtail substation are all for renewable energy resources. Accordingly, in this general location as depicted on the Exhibit B, approximately 1,420 MW of renewable energy resources are seeking grid access. One further assumption is that this power can flow at time from east to west to potentially help serve growing load needs in the Tucson population center.

Employing the recommended engineering analyses and potential solutions outlined above as a demonstrative exercise yields the following qualitative assessments. After closing inspecting this potential future project from a comprehensive vantage, it would appear that leveraging or upgrading an existing 345kV transmission line between Luna New Mexico, Greenlee Arizona and Tucson Arizona might be another more cost effective and less environmentally invasive approach than building a new power line to carry this power in proposed corridor 81-213.

Answers to important questions would need to be assessed in a properly conducted power flow analysis to determine what capacity upgrades and technological solutions could possibly enable the current grid asset of the 345kV line to handle the proposed MW additions to the system. In other words, this would be the point where the above-enumerated methodologies and technological/engineering solutions would shed light on the ability of adding a second circuit, moving to a higher voltage class or re-conductoring or other solutions could allow for these proposed energy additions to be handled by upgrading existing grid assets.

The current corridor designation process could be improved upon by addressing these issues in a comprehensive fashion and employing these engineering-solution methodologies. In the current example, while, proposed corridor 81-213 does coincide with the existing 345 kV for approximately 30 miles west of the Luna substation, about 10 miles east of the Hidalgo substation, however, the power line departs the proposed corridor. From this point on all the way to the Tucson area, proposed corridor 82-213 appears to not follow areas containing existing power line and ROW infrastructure. From the point of departure with the existing 345 kV line, proposed corridor 81-213 appears to also bisect citizen proposed wilderness areas as well as high priority conservation areas identified by The Nature Conservancy. Accordingly, comprehensive transmission planning that combines geographic features with engineering analyses and solutions, may in this one example suggest other alternatives to transfer proposed power additions to the grid system other than any use of a new power line through proposed corridor 81-213. While this analysis is mostly qualitative, the purpose in this instance is not to provide a definitive engineering solution, but rather, to suggest in this example that employing these comprehensive transmission planning principles might obviate the need for this proposed corridor altogether and keep future impacts in already-impacted areas and outside of potential environmental constraints.

Additionally, upgrading the ties to Greenlee Arizona could provide potential additional benefits in a strengthened source to two northern 345kV ties from Greenlee Arizona to the Springerville and ultimately Four Corners. Also additional planned queued interconnection projects such as the proposed solar power plant located at in the Luna could be effective in feeding both Luna and Tucson loads. Other queued projects may site in this are due to high solar gain. While the Exhibit B shows the current snapshot in time concerning proposed additions to the grid system, high industry interest in this area for its solar potential and potential future projects also needing grid access would be relevant in terms of whether to upgrade the current line to a double-circuit 345 kV or moving to a higher voltage class (500 kV) or even possibly double-circuit 500 kV, as well as other new technologies that could be employed to increase the transfer capacity of the current system.

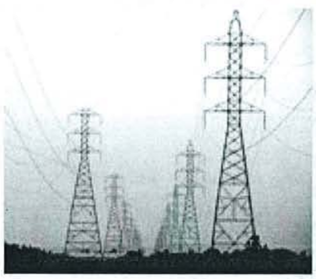
WEC_00101

Report of the

Transmission Task Force

May 2006

Western Governors' Association
Clean and Diversified
Energy Initiative



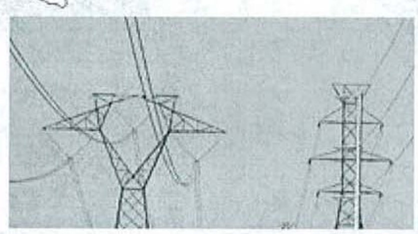


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EXHIBIT

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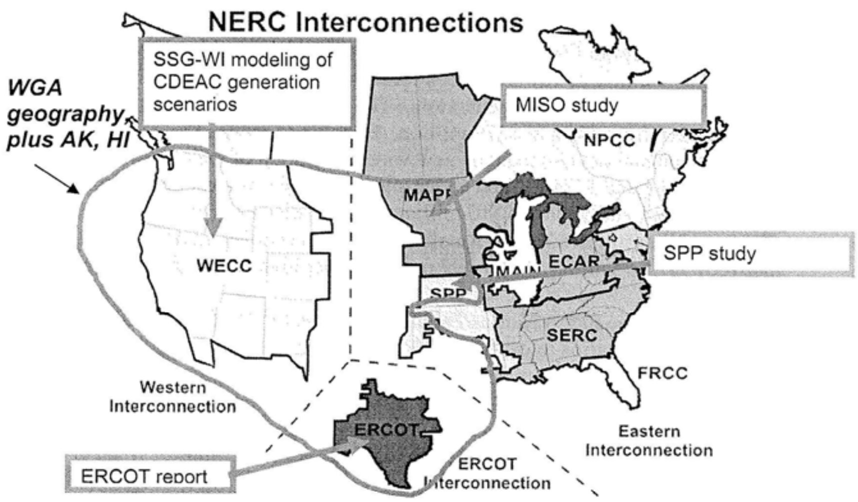
May 30, 2006
This document is intended as background information for the Clean and Diversified Energy Advisory Committee. It does not represent the adopted policies and views of the Western Governors' Association.

I. TRANSMISSION OPPORTUNITIES TO SUPPORT CDEAC GENERATION

The following map shows that the geography of the WGA region spans all three interconnections in North America, as well as Alaska and Hawaii.

Figure 1



The Task Force finds that even with improvements in operation of existing transmission grids, new transmission will be needed to move CDEAC's postulated new clean and diversified generation to markets.

To estimate the transmission requirements to move the postulated clean and diversified energy resources to market, the Task Force used existing studies by the Midwest Independent System Operator (MISO), the Southwest Power Pool (SPP), the Texas Legislature and the Electric Reliability Council of Texas (ERCOT) for the eastern part of the WGA region. In the Western Interconnection, the transmission needs associated with scenarios identified by the CDEAC Integration Subcommittee was modeled using a production cost model and compared with a reference case developed by the Seams Steering Group-Western Interconnection. No estimates of transmission needs were made for Alaska or Hawaii.

A. TRANSMISSION IN THE EASTERN INTERCONNECTION AND ERCOT

Based on existing studies by the Midwest Independent System Operator, the Southwest Power Pool and the Texas Legislature, the Task Force believes it is technologically feasible to expand the transmission system to support the levels of clean energy contemplated to be developed by the CDEAC fuel task forces.

MISO. The MISO Transmission Expansion Plan 2003 (MTEP-03)[2] evaluated transmission to support a high wind generation scenario of 8,640 MW and additional coal generation across nine Midwestern states, including 2,900 MW in North Dakota and 2,900 MW in South Dakota. The MTEP-03 analysis examined two plans that generally reduced constraints at key bottleneck locations in the region, and improved capacity utilization of wind and coal generators. The annual levelized cost of the two transmission plans ranged from $132 to $379 million. Benefits of reduced energy costs from new transmission and development of new wind generation of the high wind scenario were between $444 and $478 million under high natural gas price assumptions ($5.00/million Btu in $2001), and $303 to $316 million under a reference case gas price assumptions ($3.34/million Btu in $2001). An alternative high coal/balanced scenario yielded benefits between $1,166 million and $1,197 million under high natural gas price assumptions.

SPP. The SPP's Kansas/Panhandle Expansion Plan examined multiple transmission scenarios to export 2,500 MW of wind energy and 600 MW of coal energy out of the SPP system from Kansas and the Texas Panhandle.[3] Two alternative plans with several new 345 kV lines ranged from $458.7 million to $477 million. Annual production cost savings for the two plans were estimated at $60 and $72 million. Over ten years, the preferred plan yielded savings of $490.7 million.

ERCOT. A joint industry and ERCOT White Paper[4] evaluated the transmission needed to support significant increases of renewable energy across Texas. The Texas White Paper examined transmission to meet two goals: (1) 3,641 MW of new wind energy in West Texas; and (2) 8,641 MW of additional wind energy throughout Texas across both ERCOT and SPP regions. For the first goal, the White Paper proposed a plan to build a series of 345 kV upgrades in West Texas deliver 3,641 MW of wind energy at a cost of $1.0 billion for transmission expansion. For the second goal, two different options were evaluated to develop 8,641 MW of additional wind energy. One option contemplated a series of 345 kV upgrades in ERCOT, a new 345 kV loop in SPP, and a new DC tie or switchable facilities to connect ERCOT and the Panhandle region of SPP. Total cost for the first option is between $1.7 and $2.1 billion. The second transmission

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[2] Midwest ISO Transmission Expansion Plan 2003, June 19, 2003, (http://www.midwestiso.org/plan_inter/documents/expansion_planning/MTEP%202002-2007%20Board%20Approved%20061903.pdf).

[3] The SPP website provides information the Kansas/Panhandle Expansion Plan at http://www.spp.org/Objects/Engineer.cfm.

[4] Transmission Issues Associated with Renewable Energy in Texas, Informal White Paper for the Texas Legislature, 2005, March 28, 2005. http://www.ercot.com/AboutERCOT/TexasRenewableWhitePaper2005/RenewablesWhitePaper.htm

option entails a 765 kV line along with 345 kV additions that would cost from $2.5 to 3.0 billion.

B. TRANSMISSION IN THE WESTERN INTERCONNECTION

For the Western Interconnection, a collaborative modeling project evaluated transmission to support generation contemplated by the Clean and Diversified Energy Advisory Committee (CDEAC).[5] This project modeled an initial reference case and three bookend scenarios:

- High efficiency scenario;
- High renewables scenario; and
- High coal scenario.

The purpose of modeling these scenarios is to explore the potential implications from a menu of resource options. It is likely that the best or preferred option would include features from a combination of three CDEAC scenarios. This project provides a high level analysis with preliminary findings. Future studies will hopefully build upon this work with further iterations on the three scenarios.

The CDEAC modeling project builds upon the transmission modeling by the Seams Steering Group-Western Interconnection (SSG-WI). In 2005, SSG-WI updated its model of the Western Interconnection with the 2015 Reference Case.[6] The SSG-WI Reference Case serves as the foundation for constructing and evaluating the three CDEAC scenarios.

Generation and Load Assumptions. The SSG-WI Reference Case assumes incremental generation by 2015 that incorporated utility integrated resource plans (IRPs) and compliance with state Renewable Portfolio Standards (RPS). Over the period 2004 to 2015, the SSG-WI Reference case adds over 61 GW of generation capacity in the Western Interconnection that includes 30 GW from natural gas, 9.6 GW of coal, and 19.6 GW of renewables. The SSG-WI 2015 Reference Case provides the baseline from which all the CDEAC scenarios were constructed and evaluated. See Table 1 below for generation assumptions of the SSG-WI 2015 Reference Case and the CDEAC scenarios.

The High Efficiency scenario assumes that states in the Western Interconnection fully implement best practice policies and programs as recommended by the Energy Efficiency Task Force. These policies produce a 10% drop in energy use (87,714 GWh) and a 9% reduction in peak load (15.3 GW) in 2015 relative to the loads specified in the SSG-WI Reference Case.

The High Renewables scenario postulates an aggressive development of renewable resources based on assessments by the Biomass Task Force, the Geothermal Task Force,

[5] See Appendix A for more details of the assumptions and findings of the modeling project.
[6] For a description of SSG-WI modeling assumptions about the 2015 Reference case, see the website of the Western Electricity Coordinating Council (WECC). http://www.wecc.biz/

the Solar Task Force, and the Wind Task Force. The High Renewable scenario added 43 GW of nameplate renewable capacity on top of the 19.6 GW added in the Reference case by 2015. Combined with existing renewable generation, these additions yield an aggregate renewable nameplate capacity of 68.4 GW in the Western Interconnection.

The High Coal scenario expands new coal generation to a level more than double the amount assumed in the SSG-WI Reference Case. The High Coal scenario adds 11.3 GW of coal generation that includes 5 GW of advanced coal technologies with cleaner emissions.

Table 1

Generation Assumptions for SSG-WI Reference Case and CDEAC Scenarios
(Nameplate MW)

Total Generation 2015

	Natural Gas	Coal	Oil	Hydro	Nuclear	DSM DR	Other	Wind	Biomass	Geo	Solar CSP	Solar PV	Solar CSP & PV	Renew-ables	Total
SSG-WI Reference Case	106,084	48,490	1,703	66,017	9,637	724	561	17,933	2,187	4,021			1,483	25,624	258,838
CDEAC Scenarios:															
High Efficiency	99,785	42,440	1,703	66,017	9,637	16,068	561	17,933	2,187	4,021			1,483	25,624	261,835
High Renewables	93,703	40,911	1,703	66,017	9,637	724	561	43,457	9,326	8,243	2,677	3,250	7,410	68,436	281,692
High Coal	99,624	59,790	1,703	66,017	9,637	724	561	17,933	2,187	4,021			1,483	25,624	263,680

Incremental Generation 2004-2015

	Natural Gas	Coal	Oil	Hydro	Nuclear	DSM DR	Other	Wind	Biomass	Geo	Solar CSP	Solar PV	Solar CSP & PV	Renew-ables	Total
SSG-WI Reference Case	30,412	9,608	-320	1,745	0	680	0	16,273	1,006	1,362			1,023	19,664	61,786
CDEAC Scenarios:															
High Efficiency	24,113	3,558	-320	1,745	0	16,024	0	16,273	1,006	1,362	0	0	1,023	19,664	64,784
High Renewables	18,031	2,029	-320	1,745	0	680	0	41,797	8,145	5,584	2,677	3,250	6,950	62,476	84,641
High Coal	23,952	20,908	-320	1,745	0	680	0	16,273	1,006	1,362	0	0	1,023	19,664	66,629

CDEAC Scenario Additions and Removals to SSG-WI Reference Case

	Natural Gas	Coal	Oil	Hydro	Nuclear	DSM DR	Other	Wind	Biomass	Geo	Solar CSP	Solar PV	Solar CSP & PV	Renew-ables	Total
High Efficiency	-6,299	-6,050				15,344									2,995
High Renewables	-12,381	-7,579						25,524	7,139	4,222	2,677	3,250	5,927	42,812	22,852
High Coal	-6,460	11,300													4,840

Transmission for CDEAC Scenarios. This project relied on the SSG-WI Transmission Subgroup[7] to develop recommendations for new backbone transmission to support the CDEAC scenarios. The final transmission recommendations represent one portfolio of potential transmission projects to accommodate the CDEAC scenario generation and load assumptions. These recommendations are based on a high level analysis and do not represent the optimal solution on technical or economic grounds.

The SSG-WI Transmission Subgroup proposed a new transmission reference case ("CDEAC Reference case") that added three new transmission projects to the original SSG-WI Reference Case. The CDEAC Reference case consists of 21 projects (additions and upgrades) with about 3,956 miles of new lines and a cost of nearly $8.4 billion. See Table 2 below.

[7] The SSG-WI Transmission Subgroup is a committee of transmission experts who developed transmission recommendations for the SSG-WI 2015 Reference case. Members of the SSG-WI Transmission Subgroup met in Portland on February 22, 2006 to consider transmission for CDEAC scenarios. The group collaborated over the following two weeks on iterative modeling runs and developed a set of transmission recommendations.

The High Efficiency scenario featured reduced loads, less generation, and a reduced demand for transmission. The SSG-WI Transmission Subgroup recommended omitting three transmission project additions and 1150 miles of lines for a cost savings of almost $2.2 billion relative to the CDEAC Reference case. If time had permitted for further analysis, it is possible that additional transmission projects would have been removed for the High Efficiency case.

The High Renewables scenario required new transmission to support significant new renewable generation across the Western Interconnection including the Pacific Northwest, Wyoming, Montana, Nevada and New Mexico. Based on the SSG-WI Transmission Subgroup recommendations and additional modifications, the High Renewables scenario transmission features nine projects and about 3,578 miles of new lines at a cost of nearly $6.8 billion above the CDEAC Reference Case.

The High Coal scenario needed new transmission to integrate significant new coal generation in Wyoming, Montana, Nevada and Utah. The SSG-WI Transmission Subgroup proposed 11 projects and about 3,903 miles of new lines with costs of almost $7.0 billion. There is considerable overlap in the transmission recommendations between the High Coal and High Renewables scenarios. In addition to the three projects in the CDEAC Reference Case, the High Coal and High Renewable scenarios share five common projects covering approximately 2,021 miles of new lines for a cost nearly of $3.6 billion.

Table 2

CDEAC Scenario Transmission Expansion

Scenario	Line Miles	Capital Costs (million$)
CDEAC Reference Case	3,956	8,382
CDEAC-High Efficiency	2,807	6,231
CDEAC-High Renewables	7,535	15,167
CDEAC-High Coal	7,860	15,363
Difference from CDEAC Reference Case		
CDEAC-High Efficiency	-1,150	-2,151
CDEAC-High Renewables	3,578	6,786
CDEAC-High Coal	3,903	6,982

C. LONG TERM OUTLOOK

1. Transmission Adequacy Beyond 2015

Determining the adequacy of transmission must be the product of an on-going process that regularly reassesses uncertainties such as the economics of alternative generation technologies, fuel costs, the preferred location for generation, changes in demand and energy growth rates, and new transmission technologies. The further into the future one attempts to look, the greater these uncertainties. Thus, the Task Force recommends that the Governors encourage industry and regulators to maintain a robust holistic process for evaluating transmission needs that systematically reexamines these uncertainties. Typically long-term transmission planning looks at most 10 years into the future because that provides sufficient time to construct needed transmission.

The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location. The Task Force also believes it is important to identify and preserve transmission corridors in advance of urban development. Adding transmission in developed urban and suburban areas is extremely difficulty and costly. Similarly, preservation of corridors to energy rich geographic areas with location-constrained resources, such as areas with good wind or geothermal resources, is important to assuring future transmission adequacy. Finally, the Task Force observes that transmission costs are less than 10 percent of the delivered cost of energy and thus the economic penalty of making poor transmission investments is small relative to costs of uneconomic generation investments. However, the environmental and social cost of transmission lines needs to be considered when evaluating the cost of potentially over building transmission .

2. Non-Wires Alternatives

Transmission is one type of input to the electrical system. Other inputs to the system include different types of generators, distribution facilities, and end-use products. New investments in certain types of inputs can function as a complement or substitute for new transmission. For example, development of new coal generation or wind generation located far from loads will require new transmission to deliver electricity to load centers. In contrast, the continued reliance of gas-fired generation located near loads would reduce the need for significant new transmission facilities. Similarly, investments in demand-side management and distributed generation provide alternatives to increase the capacity of the electrical system without a corresponding increase in transmission investment. Non-wires alternatives should be considered as an option in the process of evaluating potential transmission investments.[8]

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[8] See for example, Bonneville Power Administration's Non-Wires Solutions program. The Non-Wires Solutions Round Table consists of 18 leaders in the Northwest that advise the agency on alternatives to building transmission lines and other facilities. The roundtable helps BPA determine whether non-wires solutions can be employed as viable alternatives to transmission expansion. Non-wires solutions include

Demand side management refers to measures designed to change the amount (energy efficiency) or timing (demand response) of electricity consumption. Energy efficiency investments enable the consumer to utilize less electricity to attain the same level of services from such tasks as lighting the home or office, operating appliances, and running electrical equipment. Demand response investments decrease consumption of electricity during peak hours and shift consumption to off-peak periods to decrease the use of expensive peak load generation. Energy management control systems can be used to switch electrical equipment on or off to reduce peak loads. Some energy management control systems allow off-site control by local utilities to alter timing of air conditioning, heating and lighting loads to reduce peak loads. Leveling load and reducing peak demand levels reduces a utility's need to use higher cost peak generation resources and invest in new peak generation. Many demand side management investments provide rates of returns that are competitive with supply side investments. The CDEAC Energy Efficiency Task Force report provides more detail on potential energy savings and economic benefits of demand management systems in WGA states. Reducing future demand provides an alternative to building new power plants and their associated transmission lines.

Distributed generation denotes small, modular electricity generators sited close to customer loads that are interconnected to the existing grid. Generator technologies for distributed generation systems include small scale wind, photovoltaic solar, biomass, gas microturbines, and heat and power systems. The Department of Energy's Distributed Energy Resource program has the long-term goal that distributed generation will achieve a 20% share of new electrical capacity additions by 2010. Strategically placed distributed resources can be used to defer or eliminate the need for new transmission and distribution line upgrades that would be needed for large centralized generation resources.

3. Technological Innovation for Transmission

Emerging technologies in the electrical system continue to increase the transfer capability of existing lines, enable more power to be delivered in existing rights-of-way, provide greater flexibility to site lines underground and in water, and improve overall power system utilization. Specific technologies that may lead to changes in transmission systems over the next twenty five years are described below.[9]

- Innovative new materials and methods can potentially increase the amount of electricity over transmission lines.
    - High-Temperature Superconducting (HTS) cables have advantages of low resistance and capability to carry more current than standard wires of the same size. HTS cables would allow more power to flow on existing rights-of-way. The refrigeration system to reach superconductivity

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pricing strategies, demand reducing strategies, and strategic placement of generators. http://www.transmission.bpa.gov/PlanProj/nonwires.cfm.

[9] Rocky Mountain Area Transmission Study, 2004, Appendix C.3.b; J. Hauer, T. Overbye, J. Dagle, and S. Widergren, Advanced Transmission Technologies, Issue Papers, 2002.

conditions, however, carries higher fixed and variable costs than conventional cable technology. This technology is currently limited to short distance applications making it less usable in the West.

- Advanced transmission conductors with composite cores are lighter and have greater carrying capacity than current steel core conductors. These advanced composite conductors enable more power to flow across existing rights-of-way for short distance applications and in systems without voltage stability limitations.
- Many of the new technologies like superconducting cables or advanced conductors that increase power transfer capability also consume significant amounts of reactive power. Reactive power consumption is proportional to the square of the current (or power) – thus doubling the current in a device will quadruple the reactive power consumption. This reactive power consumption must be managed by adding reactive compensating devices – an additional cost.

- Underground cables provide a transmission alternative in areas where overhead lines are physically impractical or publicly undesirable. Underground lines cost five to ten times the cost of overhead lines.

- Compact transmission line configurations based on computer-optimized transmission line tower designs enable some additional power to flow over existing rights-of-ways.

- Increased phase transmission line configurations from three phases to six or twelve phases for AC high voltage power transmission enables greater power transfer in a given right-of-way. Expanded phase lines reduce electromagnetic fields from lines due to greater phase cancellation.

- Ultra high voltage lines would enable more power to be transmitted over paths that are currently carried over conventional transmission lines such as 230 kV, 345 kV and 500 kV. The highest transmission voltage line in North America is 765 kV. Ultra high voltage lines are technologically possible but would require larger rights-of-way, generate stronger electromagnetic fields, and produce much more reactive power (which must be managed by adding reactive compensating devices).

- High-Voltage Direct Current (HVDC) provides an economic alternative to long-distance AC transmission lines. HVDC lines can be used to link asynchronous systems, and applied to long distance transmission in the air, underground, or in water. Disadvantages of DC lines are the additional costs of converting from AC to DC and then back to AC. To date, there are several thousand miles of HVDC transmission lines in North America.

- Flexible AC Transmission Systems (FACTS) devices use power electronics to improve power system control and thereby increase power transfer levels without new transmission lines.

- Energy storage devices enable greater flexibility to utilize low cost energy generated during off-peak hours to meet consumption during peak hours and improve power system operations. Energy storage technologies for electrical systems include pumped hydro storage, compressed air energy, superconducting magnetic energy storage (SMES), flywheels, and batteries. These devices are typically expensive and have limited capability to impact the transmission system. To date, for large scale energy management, only pumped storage hydro has been and is commercially viable.

New technologies that connect to the grid must meet NERC and WECC Planning Standards. The value of these additions must be analyzed in the context of what each brings to the capability of the grid within these standards. Unless properly planned, new technology additions may add little if any capability to the grid.

Additionally, technological innovation in the broader electrical system (not transmission specific) may create new opportunities that effect future decisions on transmission investments.[10]

- New information technology has the potential to profoundly transform the planning and operation of the power grid. Information technology will become the "nervous system" that integrates distributed resources, passive grid generation, transmission, and new types of active grid technologies.

- The management of end-use resources in factories, commercial buildings, and residential facilities offer a great potential for enhancing grid operations. Advances in load-control technology will allow end-use systems to play a more active role in the day to day operations of the electric system and more flexible responses to emergency systems.

- Advanced meter technology will not only measure total energy usage, but also provides flexible interval monitoring and real-time power measurement. These new meters support advanced billing and create schedule options that are used to promote demand response and collaborative operation of customer-owned distributed generation. They can also provide additional data for grid operations such as voltage, current, and phase angle.

- New retail and wholesale market operations will develop in the future at many levels in the power grid and facilitate the operation of assets under control of multiple entities. For example, market operations software can link and integrate

[10] Comments from GridWise Alliance, December 30, 2005 and January 31, 2006.

distributed resources and demand response to manage peak demands and provide ancillary services.

- Grid Friendly Appliance (GFA) technology allows household appliances and other small equipment to automatically detect and respond to frequency disturbances on the grid. GFA controllers autonomously recognize a disturbance and turn off the appliance for short periods (2-5 minutes) to reduce the demand for electricity. GFA technology can be installed into air conditioners, electric heaters, heat pumps, washers, dryers, dishwashers, and water heaters.

APPENDIX A

Transmission Analysis in the Western Interconnection

Note: The modeling analysis presented below was prepared by the individuals identified in footnote 1 and was not reviewed in-depth by the Transmission Task Force.

In the Western Interconnection, a collaborative modeling project identified and evaluated transmission for new clean and diversified generation resources. This project modeled the Western Interconnection under an initial reference case and the following three scenarios specified by the Clean and Diversified Energy Advisory Committee (CDEAC):

- High Efficiency scenario;
- High Renewables scenario; and
- High Coal scenario.

The CDEAC scenarios represent three alternative bookend strategies. This study does not attempt to identify the most efficient or cost-effective portfolio of generation resources. The purpose of modeling these scenarios is to explore the potential implications from a menu of resource options. It is likely that the best or preferred option would include features from a combination of three CDEAC scenarios. This project did not have the time or resources to pursue subsequent iterations on the three scenarios. We hope the project yields insights that advances the discussion of ideas and provides a foundation for future research.

CDEAC and SSG-WI Modeling In the Western Interconnection

The project to model the CDEAC scenarios in the Western Interconnection was a collaborative ad hoc effort that relied on numerous individuals and organizations.[97] The CDEAC modeling builds upon modeling work by the Seams Steering Group-Western

[97] Doug Larson and Thomas Carr (Western Interstate Energy Board, CDEAC Transmission Task Force) organized and coordinated the project, provided oversight, and drafted the findings. Donald Davies (Western Electricity Coordinating Council) coordinated the flow of generation and transmission assumptions to the modeling team. The CDEAC Quantitative Task Force, Doug Arent (National Renewable Energy Laboratory) and Dick Watson (formerly Northwest Power and Conservation Council), provided quality control oversight and identified the generation removed in scenarios. Howard Geller (Southwest Energy Efficiency Project, Energy Efficiency Task Force) identified the load reductions for the High Efficiency case. A team from the National Renewable Energy Laboratory (Ron Benioff, Michael Milligan, Mark Mehos, Ralph Overend, Martin Vorum, Donna Heimiller, and Laura Vimmerstedt) developed the High Renewable scenario assumptions for wind, biomass, geothermal and solar. Jerry Vaninetti (Trans Elect, and Advance Coal Task Force) specified the technologies and plants of the High Coal scenario. Transmission additions based on the recommendations of the SSG-WI Transmission Subgroup: Jeff Miller (PacifiCorp), Dean Perry (SSG-WI), Marv Landauer (Bonneville Power Administration), Ray Brush (NorthWestern Energy/RMATS), Chris Reese (Puget Sound Energy/NTAC), Peter Krzykos (Arizona Public Service/SWAT), Irina Green (California ISO), Roger Hamilton (Wind on the Wires) and William Pascoe. A team of modelers from ABB, Inc. (Henry Chao, Lan Trinh, Maria Moore) operated the GridView computer model.

Interconnection (SSG-WI).[98] In 2003, SSG-WI developed a database and modeled the Western Interconnection as a tool to assess future transmission congestion. In 2005, SSG-WI updated its model of the Western Interconnection with a Reference Case reflecting projections of loads and generation for the year 2015.[99] The SSG-WI Reference Case assumed incremental generation to 2015 based on existing utility integrated resource plans (IRPs) and compliance with state Renewable Portfolio Standards (RPS).[100] Given the IRP/RPS parameters, the SSG-WI Reference Case represents the region's current planning path and provides the baseline to compare CDEAC scenarios.

Generation and Load Assumptions

The SSG-WI Reference Case assumes 258,838 MW of total generation nameplate capacity in the Western Interconnection by 2015. Over the period 2004 to 2015, generating capacity increases by 61,786 MW primarily from natural gas (30,412 MW), coal (9,608 MW), and renewables (19,664 MW). The largest source of renewable energy will come from wind (16,273 MW), followed by comparable amounts of geothermal (1,362 MW), solar (1,023 MW), and biomass (1,006 MW). See Table A-1 below for the SSG-WI Reference Case generation assumptions.

The SSG-WI Reference Case load assumptions are presented in Table A-2. The maximum seasonal peak load (summer) is 186,130 MW. The planning margin is an indicator adequate generating capacity by comparing peak seasonal load to the total discounted generating capacity. [101] The SSG-WI 2015 generation and load assumptions yield a planning margin equal to 29%. In contrast, more common observed planning margins in the West are typically in the range from 10% to 15%. A planning margin around 30% suggests there is excess generating capacity in the system. Market conditions would probably discourage investors from building new generation in regions with excess capacity.

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[98] SSG-WI was an organization formed in 2001 by three proposed regional transmission organizations: the California ISO, WestConnect, and RTO West (later Grid West). SSG-WI supported an open stakeholder transmission planning process that included utilities, energy and transmission developers, state government regulators and energy policy officials.

[99] Key technical support for the SSG-WI 2005 project came from the PacifiCorp modeling team (Michael DeWolf, Jamie Austin, Clarissa Cooper, Dina Thompson) and Dean Perry (SSG-WI). Donald Davies (WECC), Mary Johannis (BPA), and Jeff Miller (PacifiCorp) chaired workgroups on loads, generation, and transmission, respectively.

[100] Other key assumptions of the SSG-WI 2015 Reference case: The GridView production cost model performs economic dispatch of generation resources given the specified transmission constraints. Loads in the database came from WECC's 2005 Load and Resources Report modified by data from NPCC in the Northwest, RMATS load forecasts in the Rocky Mountains, and the CEC load forecast in California. The model specified unit commitment parameters for generation resources based on actual data for some resources and generic data for other resources. Hydro and wind resources were hard wired into the model using data for the major western rivers and from the National Renewable Energy Laboratory. A complete description of SSG-WI 2015 Reference Case modeling assumptions will be available on the website of the Western Electricity Coordinating Council (WECC). http://www.wecc.biz/

[101] Planning margin equals the difference between the discounted capacity and peak load, divided by the peak load.

The CDEAC High Efficiency scenario assumes that states in the Western Interconnection fully implement best practice policies and programs as recommended by the Energy Efficiency Task Force. Energy savings in the High Efficiency scenario were modeled by reducing loads in the SSG-WI Reference Case. The amount of energy savings varied by region depending on the level of existing energy efficiency policies already in place. In the aggregate for all states in the Western Interconnection, the High Efficiency scenario energy savings amount to a 10% drop in energy use (87,714,948 MWh) and a 9% reduction in peak load (15,344 MW) in 2015 relative to the Reference Case.[102] The High Efficiency scenario paired the load reductions with the removal of power plants in the Reference Case fueled by natural gas (6,299 MW) and coal (6,050 MW) on a pro rata basis.

The High Renewables scenario represents an aggressive development of western renewable resources based on the analyses of the Biomass Task Force, the Geothermal Task Force, the Solar Task Force, and the Wind Task Force. The High Renewable scenario adds 42,812 MW of nameplate renewable capacity on top of the Reference Case incremental renewable generation 19,664 MW between 2004 and 2015. The resulting total renewable generation in 2015 is 68,436 MW of nameplate capacity in the Western Interconnection. The High Renewable generation additions were offset by removal of natural gas (12,381 MW) and coal (7,579 MW) generation resources.

The High Coal scenario adds new coal generation that includes some advanced coal technologies with lower emission rates. The High Coal scenario adds 11,300 MW of coal generation above the Reference case, and 5,000 MW would be from advanced coal technologies. The High Coal scenario additions were offset by reduced natural gas (6,460 MW) generation resources.

Table A-1 presents the three CDEAC scenario generation assumptions for the Western Interconnection grouped in terms of total generation in 2015, incremental generation from 2004 to 2015, and scenario additions and removals from 2004 to 2015. The bottom section of Table A-1 shows total net nameplate capacity additions are 2,995 MW for the High Efficiency scenario, 22,852 MW for High Renewables scenario, and 4,840 MW for the High Coal scenario. Table A-2 lists the total discounted capacity values for each scenario after adjusting for generation capacity assumptions. The corresponding planning margins for the CDEAC scenarios are 30% for the High Efficiency[103] scenario, 30% for the High Renewable scenario, and 31% for the High Coal scenario.[104]

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[102] The Energy Efficiency Task Force best practices case applied to the entire WGA region in 2020, not just the Western Interconnection in 2015, attains the goal of 20% energy efficiency.

[103] For purposes of deriving the planning margin and describing scenario generation assumptions, the High Efficiency load savings were treated as Demand Side Management (DSM) and Demand Response (DR) generating resources. In the production cost model, these load savings were represented as a reduction of loads in the system.

[104] As discussed above, the SSG-WI Reference Case had a 29% planning margin which is probably too high for conventional market practices. Accordingly, the CDEAC scenarios have a higher than optimum planning margin.

May 30, 2006

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Table A-1

Generation Assumptions for SGG-WI Reference Case and CDEAC Scenarios

(Nameplate MW)

Total Generation 2015

	Natural Gas	Coal	Oil	Hydro	Nuclear	DSM/DR	Other	Wind	Biomass	Geo	Solar CSP	Solar PV	Solar CSP & PV	Renew-ables	Total
SSG-WI Reference Case	106,084	48,490	1,703	66,017	9,637	724	561	17,933	2,187	4,021			1,483	25,624	258,838
CDEAC Scenarios:															
High Efficiency	99,785	42,440	1,703	66,017	9,637	16,068	561	17,933	2,187	4,021			1,483	25,624	261,835
High Renewables	93,703	40,911	1,703	66,017	9,637	724	561	43,457	9,326	8,243	2,677	3,250	7,410	68,436	281,692
High Coal	99,624	59,790	1,703	66,017	9,637	724	561	17,933	2,187	4,021			1,483	25,624	263,680

Incremental Generation 2004-2015

	Natural Gas	Coal	Oil	Hydro	Nuclear	DSM/DR	Other	Wind	Biomass	Geo	Solar CSP	Solar PV	Solar CSP & PV	Renew-ables	Total
SSG-WI Reference Case	30,412	9,608	-320	1,745	0	680	0	16,273	1,006	1,362			1,023	19,664	61,786
CDEAC Scenarios:															
High Efficiency	24,113	3,558	-320	1,745	0	16,024	0	16,273	1,006	1,362	0	0	1,023	19,664	64,784
High Renewables	18,031	2,029	-320	1,745	0	680	0	41,797	8,145	5,584	2,677	3,250	6,950	62,476	84,641
High Coal	23,952	20,908	-320	1,745	0	680	0	16,273	1,006	1,362	0	0	1,023	19,664	66,629

CDEAC Scenario Additions and Removals to SSG-WI Reference Case

	Natural Gas	Coal	Oil	Hydro	Nuclear	DSM/DR	Other	Wind	Biomass	Geo	Solar CSP	Solar PV	Solar CSP & PV	Renew-ables	Total
High Efficiency	-6,299	-6,050				15,344									2,995
High Renewables	-12,381	-7,579						25,524	7,139	4,222	2,677	3,250	5,927	42,812	22,852
High Coal	-6,460	11,300													4,840

Table A-2

Loads and Resources Balance

	Loads	
Summer Peak (MW)	186,130	
Winter Peak (MW)	155,151	
Max of Summer/Winter Peak (MW)	192,890	
Energy (MWh)	1,026,349,907	
	Discounted Capacity (MW)	**Planning Margin**
SSG-WI Reference Case	239,648	29%
CDEAC Scenarios:		
High Efficiency	242,643	30%
High Renewables	242,226	30%
High Coal	244,488	31%

The CDEAC scenario generation assumptions are summarized by state in the maps of Figures A-1, A-2, and A-3.

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Figure A-1

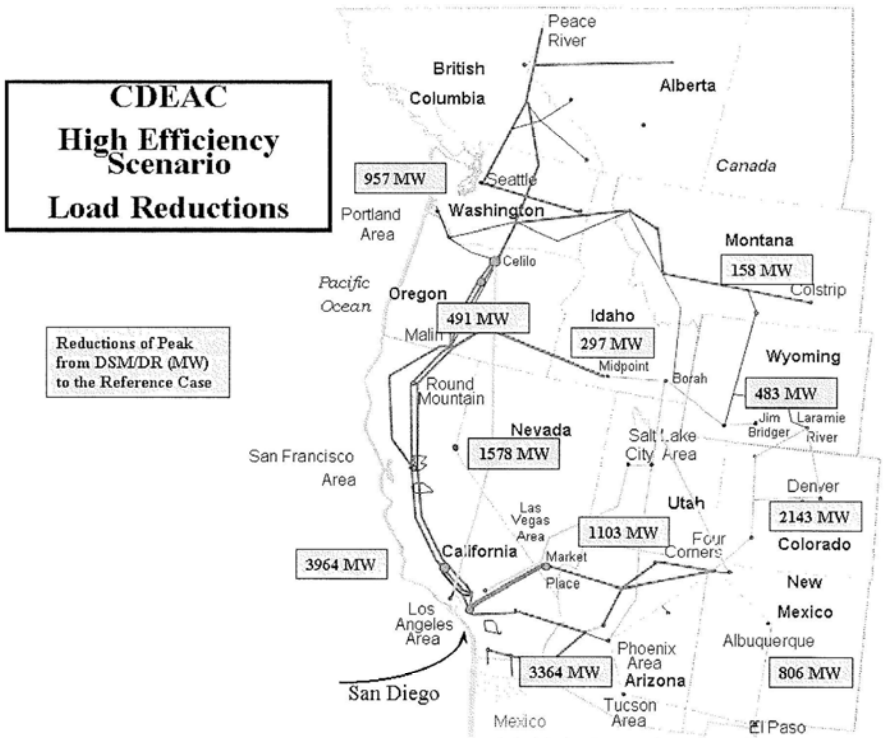

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Figure A-2

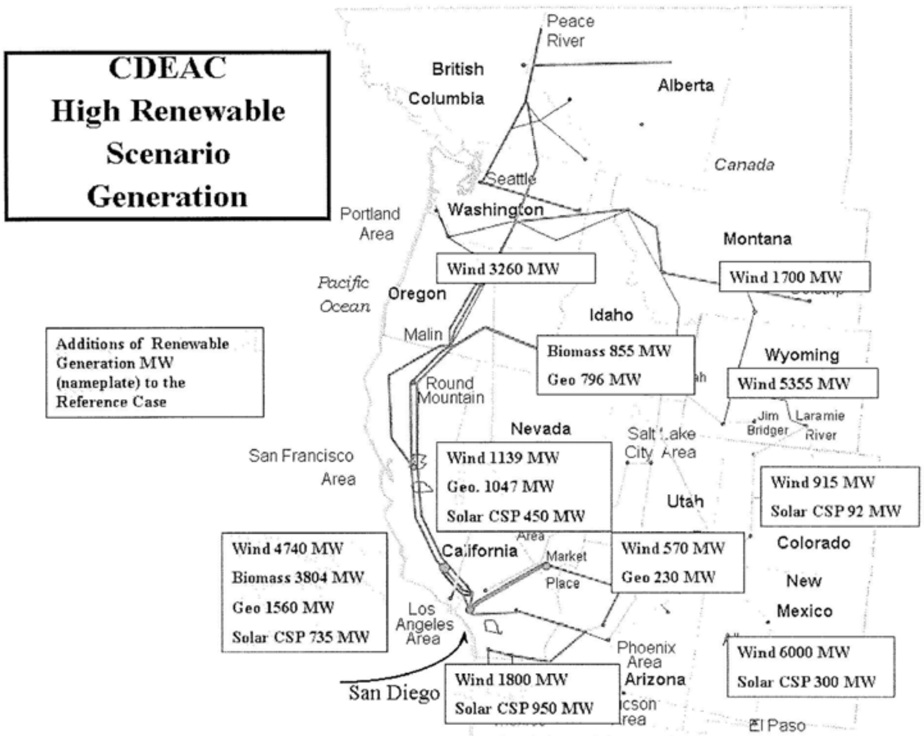

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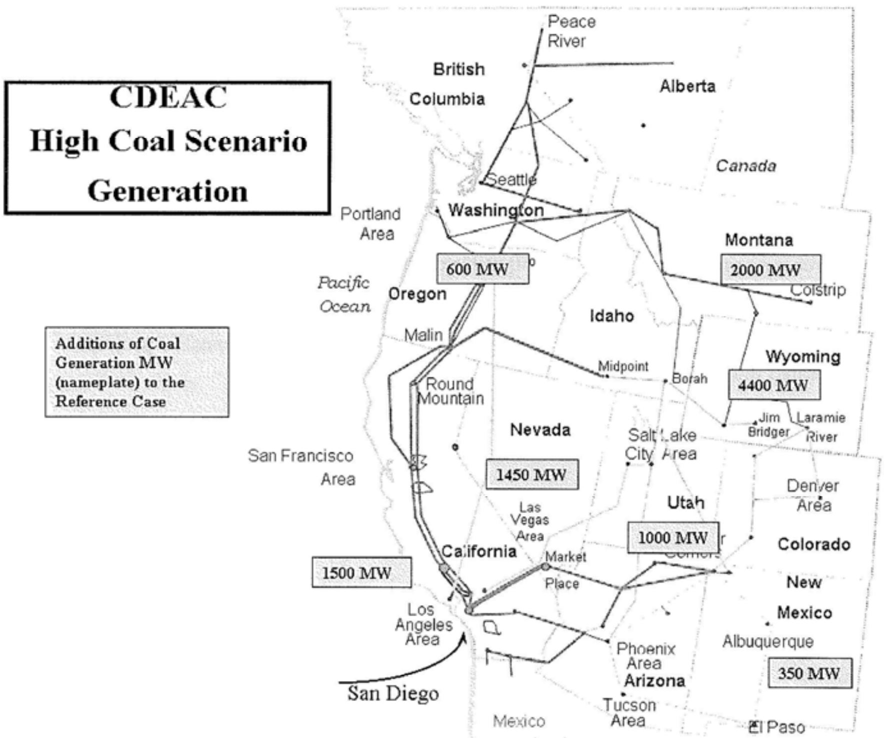
Figure A-3



Transmission for CDEAC Scenarios

The SSG-WI Transmission Subgroup is the committee of western transmission experts who developed recommendations on transmission for the SSG-WI studies. On February 22, 2006, the SSG-WI Transmission Subgroup met in Portland[105] to review an initial model run and identify potential transmission additions for the three CDEAC scenarios. Over the following two weeks, members of the SSG-WI Transmission Subgroup collaborated by email on iterative modeling runs and developed a set of transmission recommendations.

[105] SSG-WI Transmission Subgroup participants included: Jeff Miller (PacifiCorp), Dean Perry (SSG-WI), Marv Landauer (BPA), Ray Brush (NWE/RMATS), Chris Reese (PSE/NTAC), Peter Krzykos (APS/SWAT), Irina Green (CAISO), and Roger Hamilton (Wind on the Wires).

The CDEAC transmission recommendations added enough transmission to reduce congestion in the system to reasonable levels for each scenario.[106] Alternative configurations were possible but time constraints to the study prevented a more thorough comparison of all options. It should be emphasized that this was a high level analysis and the recommendations do not represent the optimal solution on technical or economic grounds.

The original SSG-WI Reference case assumed 18 transmission projects consisting of additions or upgrades to existing lines by 2015 for a total cost of $6.2 billion. See Table A-3. When the SSG-WI Transmission Subgroup re-examined the SSG-WI Reference case as the foundation for CDEAC scenarios, they decided to expand the Reference case with three new projects that added 1150 miles of lines. The cumulative sum of the SSG-WI Reference case 18 projects and the three new projects is deemed the "CDEAC Reference case." The CDEAC Reference case consists of 21 projects with about 3,956 miles of lines at a cost near $8.4 billion. See Table A-4 for the three specific projects incorporated into the CDEAC Reference Case.

[106] The GridView model calculates congestion costs in the transmission system for each specification of generation, loads and transmission facilities. The congestion costs for the initial model run of CDEAC scenarios without transmission additions to the system (Feb. 22, 2006) are significantly higher than the final model run with the final version of transmission additions (March 14, 2006). (Thousands $)

	First Run	Last Run
Reference Case:	$1,975,425	$1,012,671
High Efficiency:	$1,105,821	$1,105,821
High Renewables	$4,981,011	$1,786,070
High Coal	$3,710,000	$1,913,067

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Table A-3

SSG-WI Reference Case:
Transmission Additions and Upgrades

	Facility	Line Miles	Line Costs (million $)	Equip. Costs (million $)	Total Cap.Costs (million $)
	AZ-NM				
R-1	Four Corners-Pinnacle #1 (Phoenix) 500 kV	289	577.0		577.0
R-2	Navajo/Desert Rock; Four Corners-Moenkopi	220	560.0		560.0
R-3	Moenkopi to Market Place	218	436.0		436.0
R-4	Coronado to Silver King line including series comp			20.0	20.0
R-5	Pinal Project	60	204.6	52.6	257.2
R-6	Capacity upgrade at N. Gila			5.2	5.2
	CA				
R-7	Trans Bay Area Project	55	300.0		300.0
R-8	Palo Verde-Devers #2	230			628.0
R-9	Tehachapi Wind transmission -- 2 lines	72			94.0
R-10	West of Devers upgrade				101.0
R-11	San Diego Sunrise Link & Imperial Valley Central 500/230 kV	120			1,400.0
R-12	Imperial Valley Upgrade 500/230 kV	280	249.3	9.9	259.2
R-13	Otay Mesa	70			209.0
	CO				
R-14	Kansas-Colorado added lines to integrate 2-700 MW coal plants	830	747.0	11.5	758.5
	MT-NW				
R-15	Colstrip to Spokane Upgrade (series compensation)				142.0
	WY-UT				
R-16	Bridger-- Wasatch Front TX 345/230 kV	363	409.0		409.0
R-17	Path C Upgrade		65.0		65.0
R-18	Amps Phase Shifter (Mill Creek Phase Shifter)			10.0	10.0
	Total	2,807	3,548.0	109.2	**6,231.1**

May 30, 2006
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Table A-4

CDEAC Scenarios:
Transmission Additions and Upgrades

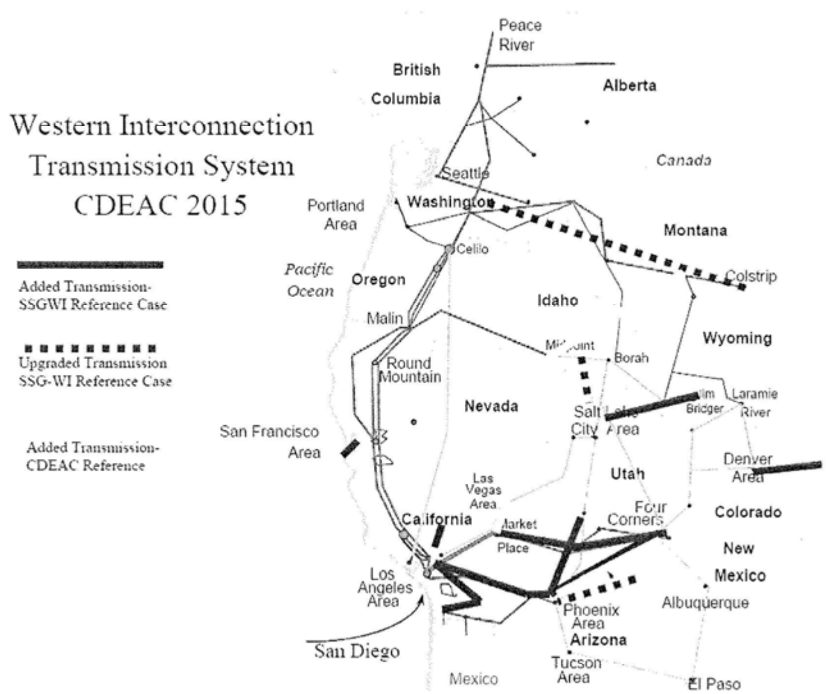
(million $)

	Facility	Ref Case	High Effic.	High Ren	High Fossil	Line Miles	Line Costs	Equip. Costs	Total Cap.Costs
	CDEAC Reference Case Additions								
1	SWP (Midpoint-Rocky Pk-Robinson-Crystal)	X		X	X	462	739.2	73.9	813.1
2	Broadview-Midpoint 500 kV (Broadview-Towns-Midpoint)	X		X	X	399	638.9	63.9	702.8
3	Four Corners-Pinnacle #2 500 kV	X		X	X	289	577.0	57.7	634.7
	Subtotal					1,150	1,955.1	195.5	**2,150.6**
	CDEAC Scenarios								
4	Dave Johnston-Bridger-Mona 500 kV			X	X	462	739.2	73.9	813.1
5	Mona-Crystal (Marketplace) 500 kV			X	X	319	510.4	51.0	561.4
6	Midpoint-Grizzly 500 kV			X	X	539	862.4	86.2	948.6
7	Midpoint-Tesla 500 kV			X	X	550	880.0	88.0	968.0
8	Grand Junction-Emery 345 kV			X	X	151	242.0	24.2	266.2
9	Upgrade thermal limits on 5 lines: Shasta-Flanagan; Silver Park-Silver PS; Ft. Chur-Ft. Ch.PS; Cal.Sub-Cal. S. PS; Flanigan-Keswich			X		20	13.0	40.0	53.0
10	Falcon to Robinson 345 kV added			X		133	213.0	21.3	234.3
11*	NM Wind Export Plan: 4 x 500 kv in NM			X*			1,441.0	300.0	1,741.0
	1 x 500 kV Route 1: ENM-Las Vegas-Taos-Ojo-San Juan-Four Corners					352	352.0		
	2 x 500 kV Route 2: ENM-West Mesa-Four Corners					308	616.0		
	1 x 500 kV Route 3: ENM-Amrad-Newman-Luna-Hildago-Saguro					473	473.0		
12*	Tehachapi Wind -- Phases 1-4			X*					1,200.0
	Phase 1: Antelope-Pardee, Antelope-Vincent, Antelope-Tehachapi					69			
	Phase 2: Antelope-Mesa					60			
	Phase 3: Tehachapi-Vincent, SCE & PG&E network upgrades					45			
	Phase 4: Tehachapi-PG&E Midway					97			
13	Dave Johnston-Mira Loma 3000 MW DC line				X	968	1,548.8	154.9	1,703.7
14	Colstrip-Dave Johnston 500 kV				X	218	348.5	34.8	383.3
15	Mona-Huntington-Four Corners 500 kV				X	297	475.2	47.5	522.7
16	Mohave-Lugo upgrade 500 kV				X			12.0	12.0
17	Eldorado-Lugo upgrade 500 kV				X			12.0	12.0
18	Reno to Sylmar 500 kV (Limit PDCI + fossil gen.added at Sylmar to 4330 MW total)				X	399	718.7	71.9	790.6
	Totals								
	CDEAC Reference Case					3,956	5,503.0	304.7	**8,381.7**
	CDEAC-High Efficiency + CDEAC Reference Case					2,807	3,548.0	109.2	**6,231.1**
	CDEAC-High Renewables + CDEAC Reference Case					7,535			**15,167.4**
	CDEAC-High Coal + CDEAC Reference Case					7,860			**15,363.4**
	Changes from CDEAC Reference Case								
	CDEAC-High Efficiency					-1,150			**-2,150.6**
	CDEAC-High Renewables					3,578			**6,785.7**
	CDEAC-High Coal					3,903			**6,981.7**

* Project added to list after modeling.

Figure A-4 presents a map of Western Interconnection transmission paths. The SSG-WI Reference case transmission projects are depicted by blue lines. Solid blue lines represent transmission additions and dotted lines denote transmission upgrades. The yellow lines illustrate the three additional lines added to the SSG-WI Reference Case that cumulatively make up the CDEAC Reference Case.

Figure A-4



The High Efficiency scenario featured reduced loads, less generation, and a reduced demand for transmission. The SSG-WI Transmission Subgroup recommended that the High Efficiency scenario omit the three new transmission projects and 1150 miles of lines added to the CDEAC Reference case for a cost savings of almost $2.2 billion. In Figure A-4, the yellow lines can be viewed as the potential savings of avoided transmission projects resulting from implementation of best practices energy efficiency policies. If time had permitted for further analysis, it is possible that fewer transmission projects would have been removed for the High Efficiency case.

The High Renewables scenario required new transmission to support significant new renewable generation across the Western Interconnection including the Pacific

Northwest, Wyoming, Montana, Nevada and New Mexico. The SSG-WI Transmission Subgroup recommended seven additional transmission projects with about 2,174 miles of new lines for the High Renewables case on top of the transmission in the CDEAC Reference case. These seven projects are listed in Table A-4 as projects numbered 4-10.

A subsequent review of the modeling assumptions prompted the inclusion of two additional transmission projects to the High Renewable case. These two projects drew upon existing transmission studies that identified transmission needed to tap 6,000 MW of wind resources in eastern New Mexico[107] and over 4,000 MW of wind in the Tehachapi region of California.[108] See projects numbered 11 and 12 in Table A-4. In total, transmission for the High Renewables scenario consists of nine projects and about 3,578 miles of new lines at a cost of nearly $6.8 billion above the CDEAC Reference case. Figure A-5 depicts the additional transmission for the High Renewables case in green.

[107] New Mexico Governor Richardson's Electricity Transmission Task Force Report, December 2004. Personal communications with David Eubank, PNM, April 2006.
[108] Tehachapi Collaborative Study Group, Second Report – Transmission in the Tehachapi Wind Resource Area, California Public Utilities Commission, April 19, 2006; First Report – Transmission in the Tehachapi Wind Resource Area, California Public Utilities Commission, March 16, 2005.

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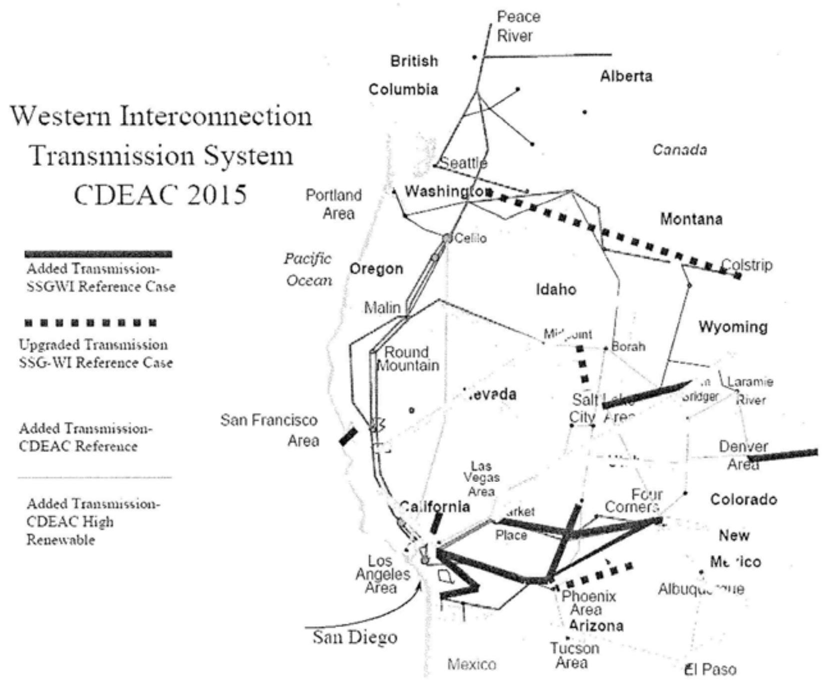
Figure A-5



The High Coal scenario integrates significant new coal generation in the Western Interconnection including large concentrations in Wyoming, Montana, Nevada and Utah. The SSG-WI Transmission Subgroup proposed 11 transmission projects and about 3,903 miles of new lines with costs of almost $7.0 billion. The High Coal transmission projects in Table A-4 are listed as projects 4 through 8, and projects 13 through 18. Figure A-6 shows High Coal scenario additional transmission lines in red.

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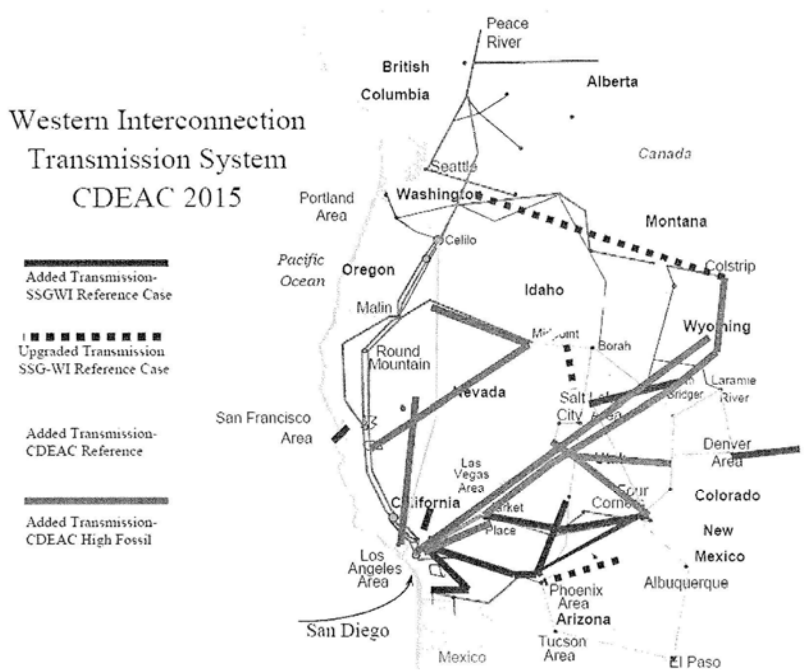
Figure A-6



A comparison of the High Coal and High Renewables transmission maps shows a number of common transmission paths. In addition to the three projects in the CDEAC Reference Case, Table A-4 shows that the High Coal and High Renewable scenarios have five common projects (numbers 4 through 8) covering approximately 2,021 miles of new lines for a cost nearly of $3.6 billion.

WEC_00101

DRAM

DEMAND RESPONSE *and* ADVANCED METERING *Coalition*

DEMAND RESPONSE AND ADVANCED METERING FACT SHEET

DEMAND RESPONSE INCLUDES TIME-BASED PRICING AND INTERRUPTIBLE AND CURTAILABLE PROGRAMS

Demand response is when energy users lower energy consumption during peak periods in return for receiving savings on their bills. Those savings can be a result of energy prices that are higher during peak hours (via Time-Based Pricing) or through payments made in return for specific actions, such as reducing energy use to a lower, agreed-upon usage threshold (via Interruptible and Curtailable Programs). These programs require the participation of end-use, retail customers, but can be implemented by load serving entities such as utilities or by wholesale exchanges, such as Regional Transmission Organizations (RTOs).

WE CAN SAVE BILLIONS

According to McKinsey Consulting, Princeton University, the California Energy Commission, and others, Americans can save from $10 billion to $19 billion every year by balancing investment in new power plants with demand response programs. Most of the savings comes from reduced costs to build power plants and transmission lines and to purchase electricity in wholesale markets.

DEMAND RESPONSE MEANS FEWER POWER PLANTS

Demand response is a lower-cost and environmentally-friendlier option to building more power plants and transmission lines. None of us wants blackouts, so we need to be sure that enough plants and lines are available to meet the highest demands of the year. We can achieve this goal either through spending billions on more resources or turning off a few lights, appliances, and other equipment on those few days a year when energy usage is extremely high. Building power plants to meet peak loads costs $600 per kilowatt-demand response costs only one-sixth as much as peakers, or $100 per kilowatt! These figures are from the California Energy Commission.

DEMAND RESPONSE LOWER WHOLESALE PRICES

Demand response reduces prices in wholesale power markets, too. This is because wholesale prices rise when supplies are short as a result of heavy demand during peak hours a few days each year. At such times, wholesale prices spike up as much as 1,000 percent. End users reducing consumption during those hours eliminate the supply shortage, reducing wholesale prices – and creating savings for all electricity users, not just demand response volunteers.

SMART METERS MAKE IT POSSIBLE

Today's electric meters, with a few exceptions, use 100-year old technology and record energy usage only once a month. Consumers must pay for high-cost peak power even if they are not using energy during the peak hours. Smart, or advanced, meters record energy usage throughout the day, every fifteen minutes or every hour. And they send their data in every day. This lets consumers choose when they use power and save on their bills if they can use less during the peak hours. Whether demand response discounts are given in the price of power or through payments for curtailment, smart meters are needed to record the peak load reductions.

RESIDENTIAL CUSTOMERS ARE KEY

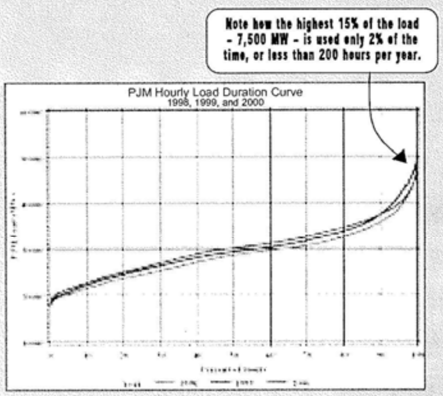
Residential consumers deserve the same chance to lower their bills as businesses. Also, today's solid-state meters and information systems make it nearly as easy to operate millions of advanced meters as it is to operate hundreds of thousands. Moreover, even though they consume only 40% of electricity, residential users would provide 53% of the demand response savings according to McKinsey. This is because residential consumers are better at managing their energy budgets; they have what economists call a higher price elasticity of demand.

Giving residential consumers demand response choices should be done, can be done, and is cost-effective.

WE NEED DEMAND RESPONSE ONLY A FEW HOURS PER YEAR

One reason demand response is a good choice is that we need it only a few days per year. The chart on the next page, a ***Load Duration Curve***, shows the amount of time that total electricity use, or demand, is required during the year. Most of the year, less than 45,000 megawatts are needed in the Pennsylvania-New Jersey-Maryland (PJM) area. But two percent of the time – less than 200 hours – demand spikes

EXHIBIT
4.1



SOURCE: *PJM Interconnection, State of the Market Report 2000,* June 2001.

up as much as 7,500 megawatts. If power consumers reduced their usage during these few hours, we would need 15 percent fewer power plants!

WE KNOW IT WORKS

Matching supply and demand works well wherever consumers are allowed to choose the prices they pay – from advance airline tickets to long distance calls on nights or weekends. In electricity, Puget Sound Energy has led the way. In May 2001, Puget placed over 300,000 volunteers on a time-of-use rate (the customers were switched automatically, and less than one percent chose to go back to flat rates). Since then, on average, these residential consumers reduced peak demand by six percent and total power usage by five percent. And 90 percent said they would recommend the program to a friend.

SMART METERS MAKE IT BETTER

California implemented the 20:20 Program in the summer of 2001. In return for 20 percent discounts, a third of Californians reduced energy use by over 20 percent. It was highly successfully in reducing wholesale prices and preventing rolling blackouts that had been widely expected. However, the state was paying consumers the equivalent of 28 cents per kilowatt-hour to turn lights off at 2 a.m., when load reductions were needed only on weekday afternoons. The solution: smart meters would have given discounts only when the demand reductions were needed. Same results, lower cost.

SMART METERS CAN BE CHEAP

In the past, smart meters have cost up to $3,000 or more for a single customer. The cost is now as low as $50 for a meter and less than $50 for all of installation, information systems, implementation, and other expenses – a total cost of less than $100 per smart meter. The keys to achieving these numbers are large volumes – millions of meters – and scale economies – installing smart meters on every customer in a geographical area. One-by-one installation of meters can cost, according to the New York Public Service Commission, seven times as much as installation in a large-scale deployment.

SMART METERS ENHANCE ENERGY EFFICIENCY AND DISTRIBUTED GENERATION

By giving consumers the full benefit of energy conservation during peak hours, smart meters and time-based pricing make energy efficiency a better deal. Efficient air conditioners, programmable thermostats, even insulation become more cost-effective. In the same way, distributed generation, particularly solar power, becomes more economic when used to displace higher on-peak energy prices (or, better yet, selling power back to the grid!).

VOLUNTARY PARTICIPATION PROTECTS ALL

Time-of-use, peak-day, and real-time prices must be provided only to volunteers among small commercial and residential customers. Voluntary participation delivers peak reductions without imposing hardships on small users who would pay higher bills on time-based rates. All consumers should always have the choice of a flat rate.

Voluntary demand response programs are still cost effective, since volunteers take the actions needed (as in Puget's time-of-use program and California's 20:20 program). And existing programs, including Puget's and Pacific Gas & Electric's, have found that, in spite of perceptions to the contrary, volunteers for time-based rates do not have less on-peak usage to start with.

TIME-OF-USE, PEAK-DAY, AND REAL-TIME PRICING

Time-based pricing can take many forms. Wholesale electricity costs typically vary each hour. To make it easy for small consumers to remember and respond to prices, these hourly costs are typically grouped into time-of-use periods, usually no more than four peak or off-peak periods per season (weekday afternoons in summer usually being peak, with nights, weekends, and all winter usually being off-peak).

With another simple option, peak-day pricing, extra discounts can be offered to customers on those 10 to 20 days per year when demand peaks would otherwise hit critically high levels (think of a California-type 20:20 program offered to all customers for, say eight hours, on 20 peak days per year).

Real-time pricing usually has prices that change each hour, like the wholesale markets. Such prices are best suited for large and sophisticated customers – or customers, including even residential customers, that have devices that can automatically turn appliances or equipment on or off to respond to changing hourly prices.

CURTAILABLE AND INTERRUPTIBLE PROGRAMS

In addition to simple, time-based pricing, demand response can be achieved through centralized control of customer loads or dispatch of load reduction orders. Customer loads such as industrial processes, air conditioners, or other uses, can be automatically turned off centrally by a utility or other entity. In curtailments, the central entity orders participants to reduce load to an agreed-upon level that is lower than the customer's usual load. Participants receive incentive payments for agreeing to reduce their loads in this fashion. These programs are typically used, or "dispatched", only 10 to 20 days per year.

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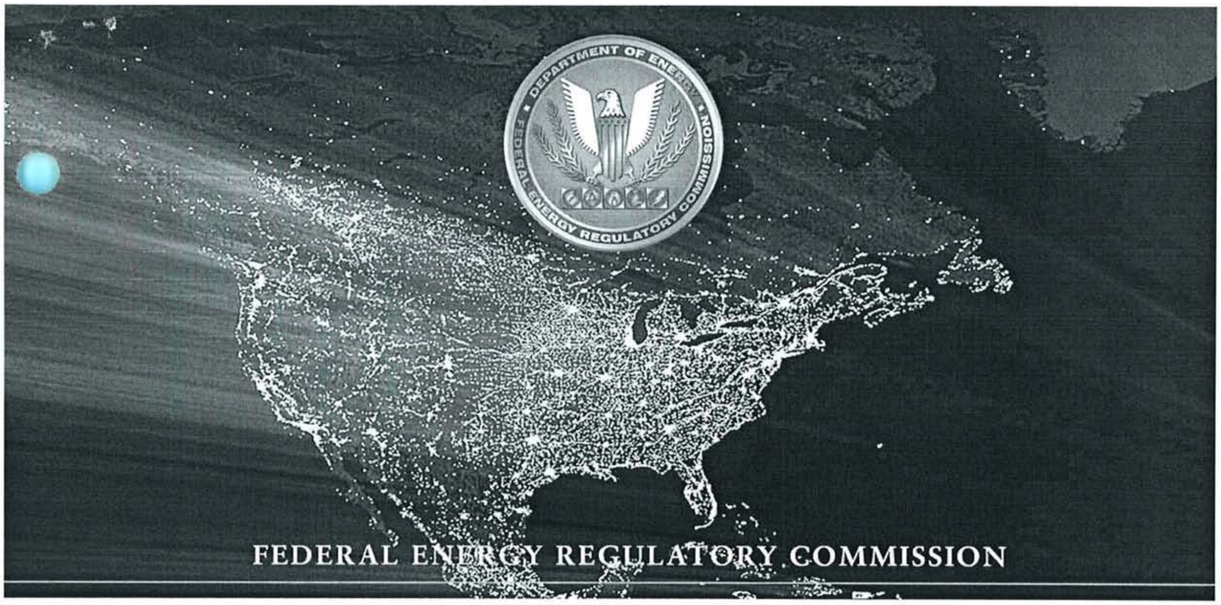

ASSESSMENT OF

Demand Response & Advanced Metering

2007

Executive Summary

The level of and interest in electric demand response and advanced metering increased significantly beyond the activities discussed in the first report by the staff of the Federal Energy Regulatory Commission. The Commission staff's first report, *Assessment of Demand Response and Advanced Metering*, August 2006,[1] presented the results of a comprehensive nationwide survey of these activities. This year's report provides an informational update on developments and reflects on activity since issuance of the 2006 report.

The Commission staff intends to publish another comprehensive report on demand response and advanced metering in 2008 and every even year thereafter, with informational update reports in the intervening years.

Demand Response

An electric demand-response activity is an action taken to reduce electricity demand in response to price, monetary incentives, or utility directives so as to maintain reliable electric service or avoid high electricity prices. Demand reduction activities occur principally during the summer when electricity demand is highest in most regions, and demand reductions from these demand-response activities proved crucial to the reliable operation of electric markets during the record-setting peaks that occurred in July and August of 2006. Estimates of demand reductions in Regional Transmission Organization (RTO) and Independent System Operator (ISO) regions with organized wholesale markets lowered system peaks between 1.4 and 4.1 percent on these peak days. These demand reductions resulted from a combination of RTO/ISO demand-response programs, utility retail demand response, and voluntary customer demand reductions.

Several states and individual utilities took actions to introduce more opportunities for demand response and price-responsiveness. These actions include the adoption of time-based rates and the adoption of demand-response policies (which includes deployment of enabling technologies such as advanced metering). States such as California, Connecticut, Illinois, Maryland, and Michigan have encouraged more demand response and customer access to information about their energy consumption. Utilities like Pepco and Wisconsin Public Service introduced or revised demand-response programs.

Two important new developments since the 2006 report at the wholesale level are the inclusion of demand resources in forward capacity markets and ancillary services markets at RTOs and ISOs and the development of new reliability-based demand-response programs.

The Commission in the past year has actively encouraged the use of demand response in several ways. It has encouraged organized wholesale power markets to use demand response as they would use generation where it is technically capable. Over the last year, it addressed demand response in a number of orders addressing wholesale market design proposals filed by the various RTOs and ISOs. The Commission revised its Open Access Transmission Tariff regulations in Order No. 890 to require transmission service providers to incorporate demand response into their transmission planning

[1] The Energy Policy Act of 2005 (EPAct 2005) section 1252(e)(3) requires the Federal Energy Regulatory Commission (Commission) to prepare and publish an annual report that assesses electric demand-response resources and advanced metering. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAct 2005 section 1252(e)(3)). The first report is available on line at http://www.ferc.gov/legal/staff-reports/demand-response.pdf.

processes and to require them to allow demand resources to provide certain ancillary services, where appropriate, on a comparable basis to generation resources. It also directed that NERC's mandatory reliability standards, addressed in Order No. 693, be revised to incorporate demand response. A recently issued Advance Notice of Proposed Rulemaking by the Commission proposed several measures to enhance competition in organized wholesale markets, including demand-response enhancements.

In addition to its direct regulatory actions, the Commission has encouraged demand response through public conferences and collaborative efforts with its state regulatory colleagues. Among other activities, the Commission held a technical conference on April 23, 2007 to examine problems and possible solutions for increased use of demand response in wholesale markets. In November of 2006, the Commission and the National Association of Regulatory Utility Commissioners began a demand-response collaborative effort, co-chaired by Commissioner Jon Wellinghoff, to coordinate the efforts of the state and federal electric regulators to integrate demand response into retail and wholesale markets and planning.

Based on this review of various demand-response activities in the last year, Commission staff has identified the following demand-response trends:

- Increased participation in demand-response programs
- Increased ability of demand resources to participate in RTO/ISO markets
- More attention to the development of a smart grid that can facilitate demand response
- More interest in multistate and state-federal demand-response working groups
- More reliance on demand response in strategic plans and state plans
- Increased activity by third parties to aggregate retail demand response.

Advanced Metering

A number of utilities are planning an installation of advanced metering in the next several years; and indications from state regulatory proceedings suggest that the interest in advanced metering will continue. Although not all announced plans will necessarily go into effect, in the last year utilities announced new deployments of more than 40 million advanced meters between 2007 and 2010. Advanced metering refers to technologies and communications systems necessary to record customer consumption at least hourly and allow for daily or more frequent retrieval of the consumption data. Advanced metering can enhance an electric customer's ability to reduce demand in response to a higher price and an electric utility's ability to meter and monitor the customer's electricity use. Such metering can also allow an electric utility to provide a variety of innovative services to benefit customers and to reduce the utility's costs of operations.

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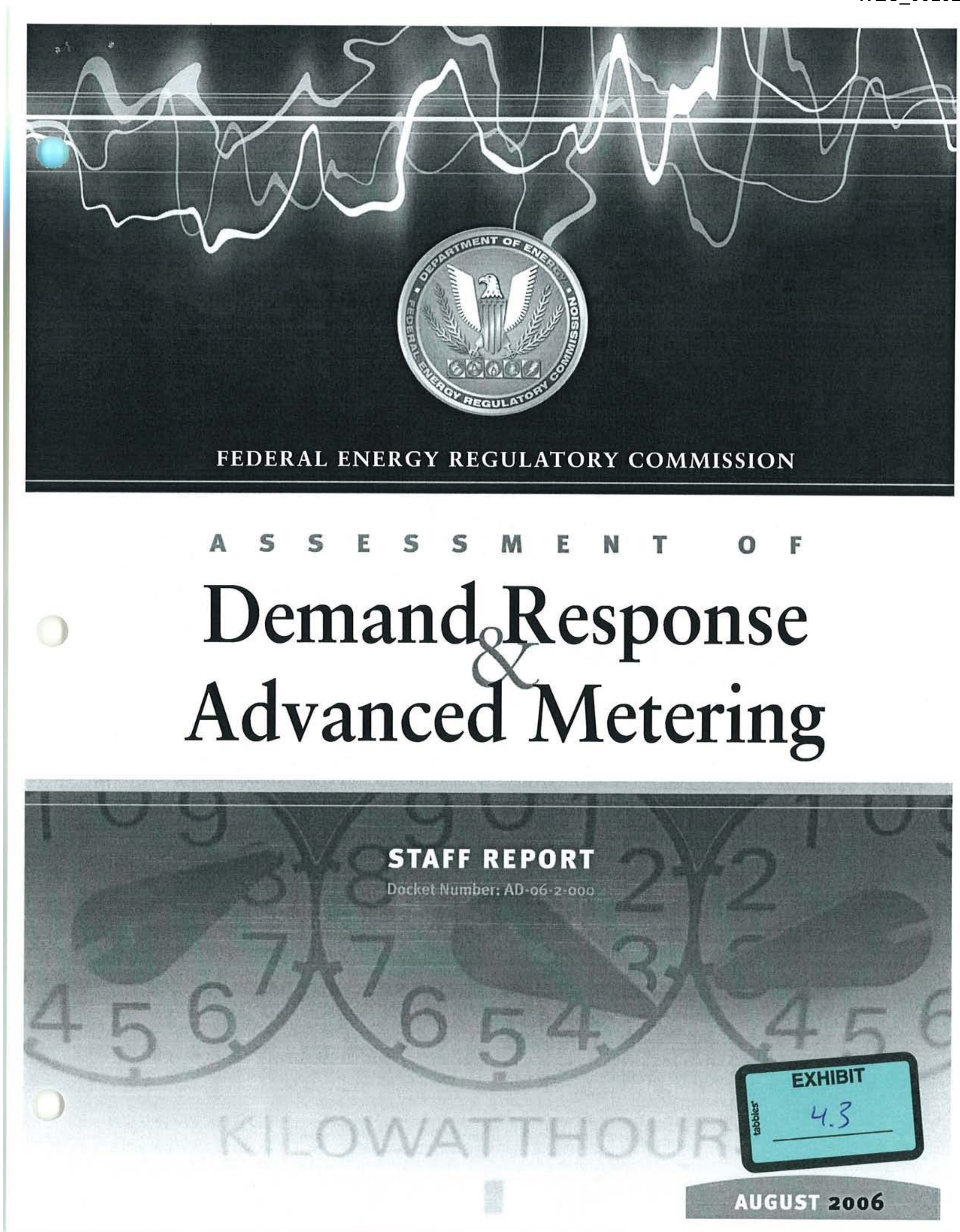

FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF Demand & Response Advanced Metering

STAFF REPORT

Docket Number: AD-06-2-000

EXHIBIT 4.3

AUGUST 2006

Executive Summary

Energy Policy Act of 2005

Section 1252(e)(3) of the Energy Policy Act of 2005 (EPAct 2005)[1] requires the Federal Energy Regulatory Commission (Commission) to prepare a report by appropriate region, that assesses electric demand response resources, including those available from all consumer classes. Congress directed that this report be prepared and published not later than one year after the date of enactment of the EPAct 2005, and specifically to identify and review the following for the electric power industry:

- saturation and penetration rate of advanced meters and communications technologies, devices and systems;
- existing demand response programs and time-based rate programs;
- the annual resource contribution of demand resources;
- the potential for demand response as a quantifiable, reliable resource for regional planning purposes;
- steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and
- regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

Commission Staff Activities

In preparing this report, Commission staff undertook several activities:

- Developed and implemented a first-of-its-kind, comprehensive national survey of electric demand response and advanced metering. The FERC Demand Response and Advanced Metering Survey (FERC Survey) requested information on (a) the number and uses of advanced metering, and (b) existing demand response and time-based rate programs, including their current level of resource contribution.
- Requested and received written comments from interested persons on a draft version of the FERC Survey, and on key issues and challenges that Commission staff should examine. Thirty-one entities provided written comments to the proposed survey.
- Held a public technical conference on January 25, 2006 at Commission headquarters in Washington, D.C.; obtained comments from five panels with over 30 participants.
- Surveyed 3,365 organizations in all 50 states representing every aspect of the electric delivery industry: investor-owned utilities, municipal utilities, rural electric cooperatives, power marketers, state and federal agencies, and unregulated demand response providers. The voluntary survey had a response rate of about 55 percent.

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[1] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAct section 1252(e)(3)). The full text of section 1252 is attached as Appendix A.

- Collected information on the role of demand resources in regional transmission planning and operations through review of regional transmission documents, and through interviews with regional representatives.
- Conducted a detailed review of the literature on and experience with advanced metering, demand response programs, and time-based rates.

Advanced Metering

By specifically designating saturation and penetrations rates of advanced meters and communication technologies, devices and systems as a matter to be covered in this report, Congress in section 1252 (e)(3) of EPAct 2005 recognized that the penetration of advanced metering[2] is important for the future development of electric demand responsiveness in the United States. In studying this issue, Commission staff examined the state of the technology and the market penetration of advanced metering.

One result of the FERC Survey is that advanced metering currently has a penetration of about six percent of total installed, electric meters in the United States. An analysis of market penetration by region indicates that there are differences in how much advanced metering has been adopted across the United States (see Figure ES-1). The parts of the United States associated with the ReliabilityFirst Council (RFC)[3] and Southwest Power Pool (SPP) had the highest regional overall penetration rates of 14.7 percent and 14 percent, respectively. Advanced metering penetration for the remaining regions in the United States is lower than the national average.

Commission staff also developed estimates of the penetration of advanced metering by state. These state-by-state estimates should provide a useful baseline in the state deliberations on smart metering required by EPAct 2005[4] and any future state proceedings on advanced metering. Table ES-1 displays the penetration rate of advanced metering in the ten states with the highest penetration. The remaining states reported lower penetration rates.

Market penetrations also differ by type of organization. The estimate of market penetration of advanced metering is highest among rural electric cooperatives at about 13 percent. Investor-owned utilities have the next highest penetration at close to six percent. This suggests that small, publicly-owned entities such as electric cooperatives have been actively pursuing automated and advanced meter reading.

Existing Demand Response Programs and Time-Based Rates

In this report, Commission staff adopted the definition of "demand response," that was used by the U.S. Department of Energy (DOE) in its February 2006 report to Congress:

[2] For purposes of this report, Commission staff defined "advanced metering" as follows: "Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."
[3] Reliability*First* Corporation (RFC) is located in the Mid-Atlantic and in portions of the Midwest.
[4] EPAct 2005 section 1252(b)