Arnold Schwarzenegger
Governor

RENEWABLE ENERGY AND ELECTRIC TRANSMISSION STRATEGIC INTEGRATION AND PLANNING

Interstate Generation and Delivery of Renewable Resources into California from the Western Energy Coordinating Council States

IN SUPPORT OF THE 2005 INTEGRATED ENERGY POLICY REPORT

DRAFT CONSULTANT REPORT

Prepared for:
California Energy Commission
Public Interest Energy Research Program

Prepared by:
Center for Resource Solutions Davis
Power Consultants
Electranix Corporation
Kema-Xenergy

APRIL 2005
CEC-500-2005-064-D

Prepared By:
Center for Resource Solutions
Ray Dracker
San Francisco, CA
Contract No. 500-01-042

Ron Davis – Davis Power consultants
Dennis Woodford – Electranix
Ryan Wiser – Wiser Associates

Prepared For:
California Energy Commission

Val Tiangco
Project Manager

George Simons
Manager
PIER Renewable Energy Program

Martha Krebs
Deputy Director
Energy Research Development Division

Scott Matthews
Acting Executive Director

Table of Contents

BACKGROUND AND OVERVIEW

Goals and objectives of this report are to examine the magnitude, locations and characteristics of renewable resources outside of California in the Western Electricity Coordinating Council (WECC) region, examine existing transmission corridors that could bring this renewable power into California, the physical and contractual constraints of the existing transmission network, and possible opportunities to enhance the system to enable California to better avail itself of these potentially important resources. The work also examines, on a preliminary basis, the technical feasibility of importing renewable power from a representative set of concentrated renewable energy resource areas in nearby states and the potential impacts on California's electricity system.

While there are adequate renewable energy resources within California to serve most of the current renewable portfolio standard (RPS) objectives of the State (20%), it is important to understand how renewable resources outside of California could support the expanded RPS goals (33%) currently under consideration.

This report examines, on a preliminary, conceptual basis, specific concentrations (500 MW or greater) of renewable energy resources that are in regions that are either close in proximity to California or along major transmission corridors that could plausibly be expanded to accommodate significant additional energy and capacity flows. The analysis also examines potential scenarios and opportunities for enabling renewable power flows from these far west resource centers into California load centers. While renewable energy and associated transmission planning and development occurs across a continuum of time, this evaluation examines two snapshots in time to identify what options could be pursued in the near-term (by 2010) and over the mid to longer term (2017). The purpose of this work is to provide a context for more detailed planning and analysis in this subject area by the Energy Commission, California Independent system Operator (CA ISO), California Utilities, and renewable energy developers.

SECTION 1: RENEWABLE ENERGY RESOURE OVERVIEW

Renewable Energy Resources Throughout the Far West

In 2003, the Energy Commission assembled raw renewable resource data throughout the western US states as part of the early planning process for the State's Renewable Portfolios Standard. These results were subsequently published in the 2003 Renewable Resources Development Report[1], which concluded that the technical potential for renewable generation both within California and throughout the WECC far exceeded the generation required to meet California RPS requirements. A summary of these data is summarized in Tables 1 and 2.

Table 1
Technical Potential (GWh/year) in Other WECC states
(Wind, Geothermal, Biomass, and Solar)

State	Wind	Geothermal	Biomass	Solar	Total
AZ	5,000	5,000	1,000	101,000	112,000
CO	601,000	-	4,000	83,000	688,000
ID	49,000	5,000	9,000	60,000	123,000
MT	1,020,000	-	6,000	101,000	1,127,000
NM	56,000	3,000	500	104,000	163,500
NV	55,000	20,000	1,000	93,000	169,000
OR	70,000	17,000	10,000	68,000	165,000
UT	23,000	9,000	1,000	69,000	102,000
WA	62,000	-	11,000	42,000	115,000
WY	883,000	-	-	72,000	955,000
Total	**2,824,000**	**59,000**	**43,500**	**793,000**	**3,719,500**

Source: ***Renewable Energy Atlas of the West***

While many WECC states have since developed their own renewable energy targets to serve native load, the renewable resource in most of the states continues to far exceed the potential indigenous demand. In fact, many of these states have begun developing energy infrastructure development strategies that target California export markets as a key opportunity.

Estimates of renewable energy technical potential are approximations of the amount of energy that could technically be generated from each resource type, based on a current set of data on resource availability and assumptions about generation technologies. It is important to note that these estimates ignore the obstacles of getting that supply to market (e.g., transmission constraints), as well as certain siting and permitting issues. Furthermore, future technology improvements or regulatory constraints (e.g., new permitting restrictions) could significantly alter future estimates of gross technical potential. Not all of the technical potential, or even a significant fraction of it, is likely to be realized.

A vast high quality solar resource exists throughout much of the desert southwest. Within California, it is estimated that over 100 GW of power generation potential exists in the southern end of the state. In addition, 600 GW of solar resource exists in other WECC states. The solar resource is important in that it can provide reliable capacity and has an energy production profile that is well matched to system peak demand.

---

[1] http://www.energy.ca.gov/reports/2003-11-24_500-03-080F.PDF

While costs of solar power are expected to continue to fall over time, costs today are significantly higher than power from wind and geothermal resources. Given the vast solar resource that exists in California, it is useful to focus on renewable resources outside of California from the other renewable resource categories.

Table 2
Renewable Energy Technical Potential (GW)
Western US outside of California
(Wind, Geothermal, Biomass)

State	Wind	Geothermal	Biomass	Total
AZ	1.6	0.6	0.14	2.3
CO	196	-	0.6	197
ID	16	0.6	1.3	18
MT	332	-	0.9	333
NM	18	0.4	0.1	19
NV	18	2.5	0.1	21
OR	23	2.1	1.4	27
UT	7.5	1.1	0.1	9
WA	20	-	1.6	22
WY	288	-	-	288

Source: ***Renewable Energy Atlas of the West***
Note: A high quality solar resource, with a technical potential in excess of 600 GW, also exists throughout Western States outside of CA

Of particular note is the large wind resource in nearby states of Oregon, Nevada and Washington, as well as the significant geothermal resource in Nevada and Oregon. Also notable is the almost limitless wind resource in Wyoming and Montana.

Renewable Energy Resource Needs throughout the West

There is an appreciable and growing need for new renewable power throughout all of the Western states. It is reasonable to assume that many of the most attractive resources (from a cost, value and location perspective) will be reserved for use within those states.

To better understand these emerging market needs, the Energy Commission has evaluated the state-by-state renewable energy procurement targets driven by RPS mandates and Utility Integrated Resource Plans (IRP), and other identified project developments over the next decade. A summary of this estimate is illustrated in Figure 1.

Figure 1
Planned Renewable Resource Additions Throughout the West

Note: Estimates based on the technical potential, utility IRPs, RPS mandates, and proposed projects, with consideration of existing transmission constraints.

The largest portion of these estimates is driven by current RPS legislative mandates. These percentages represent percent of electricity sales by state:

- California RPS 20% by 2017
- Arizona 1.1% between 2007-2012, 60% from solar – solar set aside
- Colorado 3% by 2007, 6% by 2011 and 10% by 2015
- New Mexico 5% by 2006, 10% by 2011. Solar sales count 3 to 1 compared to wind
- Nevada 5% in 2003; 2% every 2 years through 2013, 5% required to solar

Of the total new deployment of over 17 GW, 10 GW is targeted to meet these RPS legislative goals.

Remaining WECC states, Mexican and Canadian estimates are based on:

- Individual utility announcements of planned renewable contracts and development over the next decade
- Technical potential by state
- Energy Commission staff estimate of plausible future, including transmission upgrades after 2010

One important caveat regarding the RPS data is that state requirements have flexible compliance mechanisms that offer the utilities various ways to meet both the requirements for renewable generation and the deadlines for meeting those levels of generation. Assumptions for technology choice, project location, credit multipliers, and other factors will also influence how much renewable energy will be required to meet the RPS requirements. In some states, RPS mandates may not be entirely achieved. Thus, the projections provided here should be considered indicative of the increase in renewable generation supply over time, but not determinative of the annual amounts of additional capacity and generation driven by the RPS requirements. Also note that these data do not include the possibility of other states developing RPS policies in the future, or of existing state RPS policies being revised to strengthen their renewable energy requirements.

Renewable Energy Production Costs

Bringing new renewable energy and capacity into California in any significant quantity will require expansion of the existing regional power grid. Costs associated with such expansion could be significant. To better understand the potential merit of including renewable resources from outside of California in planning and procurement processes, it is necessary to characterize the costs, or cost ranges, of the various supply options. The Energy Commission is in the process of developing estimates of the anticipated electricity costs for the wide range of renewable resource types along with the relatively broad range of resource quality in the regions of interest. This data will be available in the future to support a more comprehensive evaluation of the resource-transmission alternatives.

Subject to the important caveats described above, the following observations are made concerning the relative renewable energy supply and demand outlook for WECC:

- The combined demand for new renewable power generation created by RPS requirements and integrated resource plans is expected to lead to approximately 17,000 MW of new renewable capacity throughout the WECC by 2016.

- With about 2,273 MW of installed non-hydro renewable capacity in the WECC (outside of California) in 2004, the combined demand created by non-California RPS and IRPs could lead to a five fold increase of existing capacity by 2016.

- Notwithstanding the large percentage increases in capacity and generation between now and 2016, all of this additional generation capacity represents a small fraction of the technical potential. In 2016, more than 90 percent of the renewable energy technical potential in the WECC will remain untapped, even if current RPS and IRP driven renewable energy demand is met in full.

- On a state-by-state basis, no state is expected to tap more than 10% of its technical potential by 2016, based on current generation and capacity additions expected under current RPS policies and IRP plans.

Other Regional Resource and Transmission Planning Perspectives

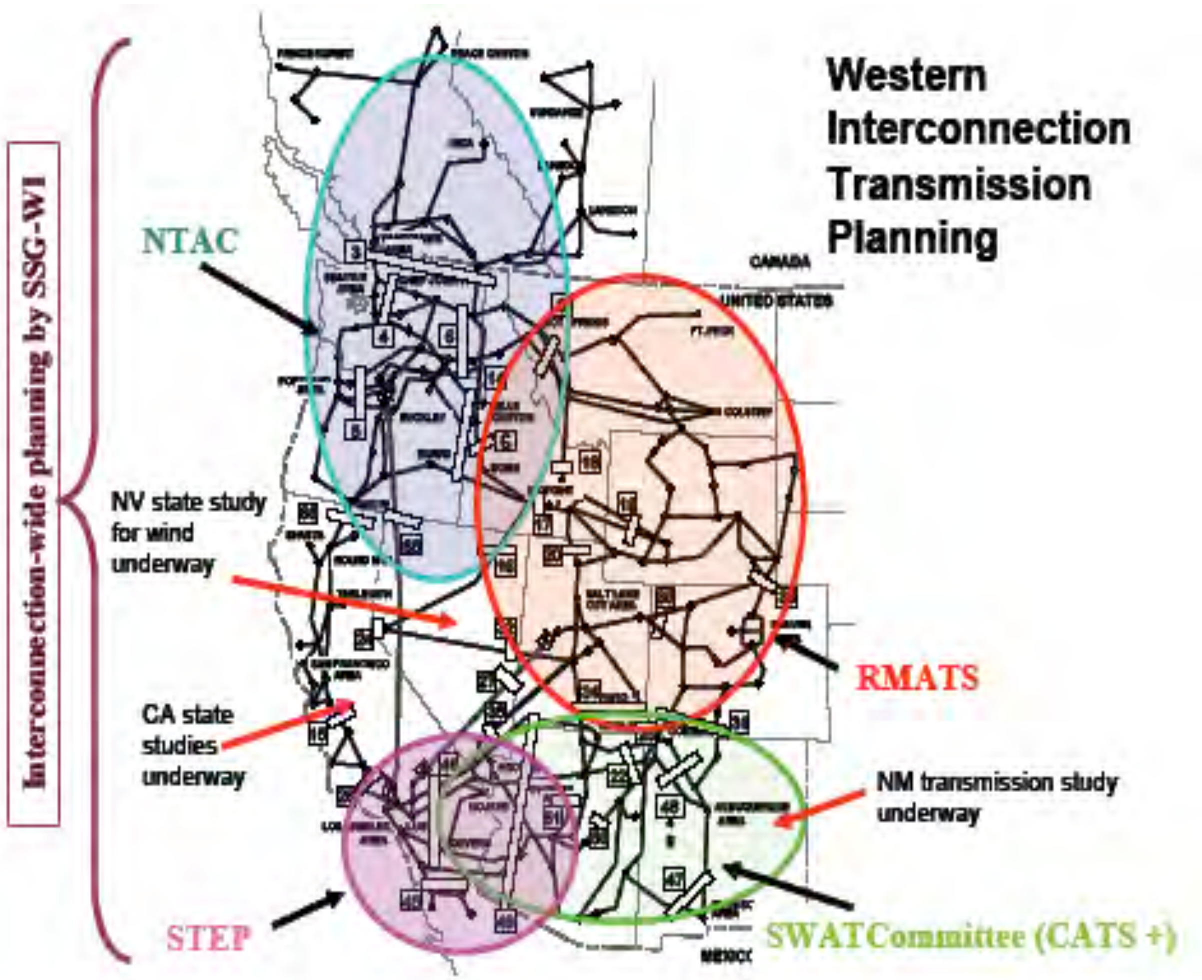
Several regional transmission planning initiatives are underway across the west. These include:

- Northwest Transmission Assessment Committee (NTAC)
- Rocky Mountain Area Transmission Study (RMATS)
- Southwest Transmission Expansion Plan (STEP)
- Southwest Area Transmission Study (SWAT)

Each of these regional studies is examining the potential transmission needs stemming from new renewable energy development, including the potential for developing renewable energy capacity for export into California. The geographic scope of these regional assessments is highlighted in Figure 2.

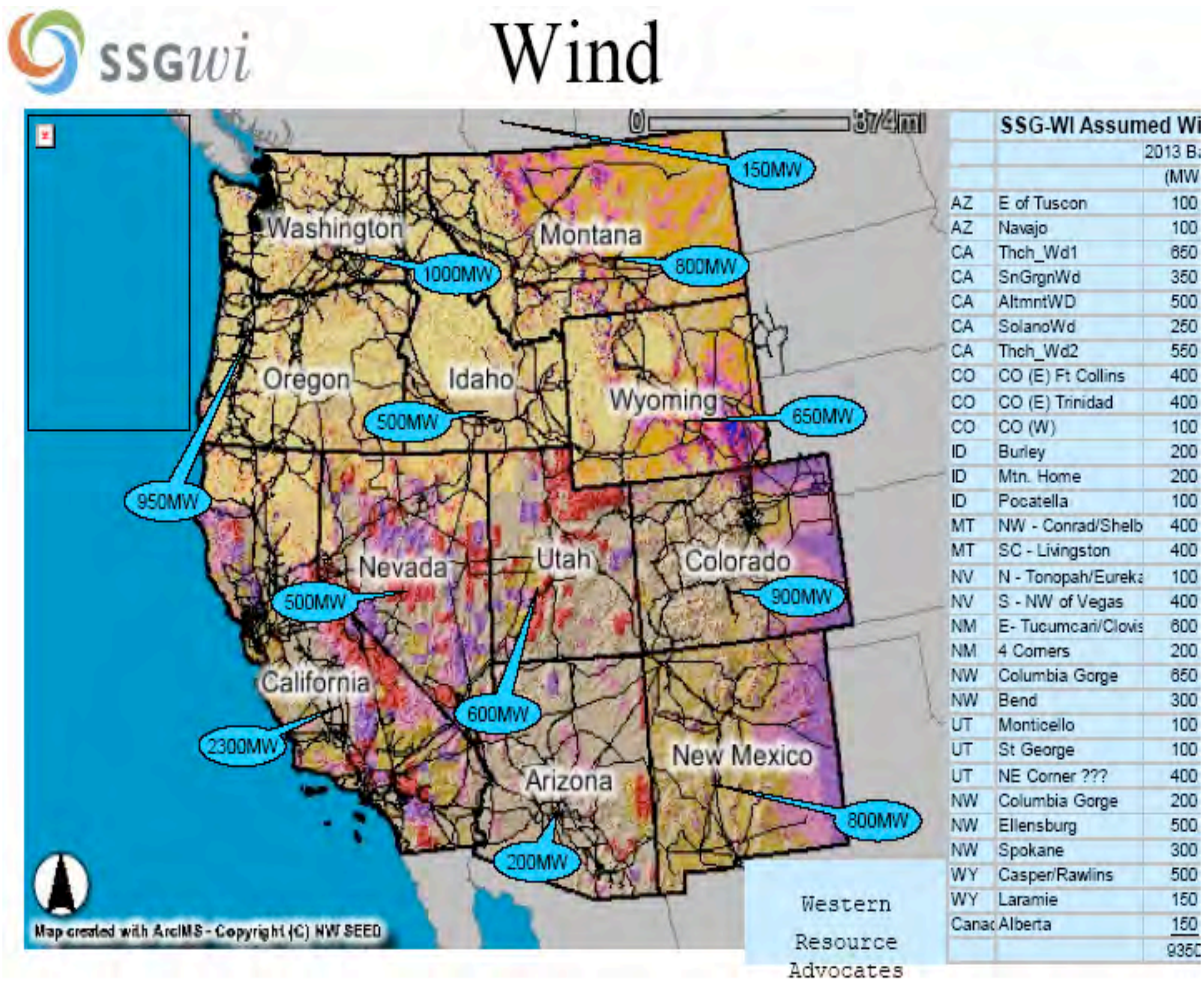
The Seam Steering Group – Western Interconnection (SSG-WI), is an initiative involving transmission planning and management staff from control regions throughout WECC that is working to evaluate inter-regional transmission issues and needs.

Figure 2


Western
Interconnection
Transmission
Planning
Interconnection-wide planning by SSG-WI
NTAC
NV state study
for wind
underway
CA state
studies
underway
STEP
RMATS
NM transmission study
underway
SWATCommittee (CATS +)
CANADA
UNITED STATES

SSG-WI has also conducted a preliminary analysis of renewable resources throughout WECC for which preliminary transmission interconnection planning might occur. The summary of those resources is illustrated in Figure 3.

Figure 3
Seams Steering Group – Western Interconnect
Estimate of Wind Resource Subject to Early Transmission Planning



	SSG-WI Assumed Wi	
		2013 B
		(MW
AZ	E of Tuscon	100
AZ	Navajo	100
CA	Thch_Wd1	650
CA	SnGrgnWd	350
CA	AltmntWD	500
CA	SolanoWd	250
CA	Thch_Wd2	550
CO	CO (E) Ft Collins	400
CO	CO (E) Trinidad	400
CO	CO (W)	100
ID	Burley	200
ID	Mtn. Home	200
ID	Pocatella	100
MT	NW - Conrad/Shelb	400
MT	SC - Livingston	400
NV	N - Tonopah/Eureka	100
NV	S - NW of Vegas	400
NM	E- Tucumcari/Clovis	600
NM	4 Corners	200
NW	Columbia Gorge	650
NW	Bend	300
UT	Monticello	100
UT	St George	100
UT	NE Corner ???	400
NW	Columbia Gorge	200
NW	Ellensburg	500
NW	Spokane	300
WY	Casper/Rawlins	500
WY	Laramie	150
Canac	Alberta	150
		9350

Conclusions and Perspectives

- The combined demand of Renewable Portfolio Standard requirements and Integrated Resource Plans are driving a significant increase in renewable generation across the WECC over the next decade.

- California is by far the largest component of that demand.

- Although the increases in renewable generation resources are expected to be significant over the next decade, they are still quite minor compared to the overall technical potential.

- Proposed project data and responses to Request-for-Proposals (RFPs) suggest that the supply of renewable energy in the WECC, in the near term, is relatively deep, but is dwarfed by the technical potential. Transmission issues and other factors will ensure that realistically available supply will remain well below the technical potential.

- Many western states appear to be interested in examining opportunities to export renewable energy into California markets.

- Resource procurement and transmission planning activities throughout California could benefit by including high quality renewable resources from neighboring western states in baseline planning processes.

SECTION 2: TRANSMISSION OVERVIEW

The use of the electric transmission grid across North America has changed dramatically in the last decade. Following the passage of the Energy Policy Act of 1992 and subsequent Federal Energy Regulatory Commission orders, the U.S. wholesale power market was altered significantly. Marketers and new owners of power plants gained new abilities to sell power to distant buyers over the existing transmission system. Power flow patterns changed as utilities relied increasingly on market purchases from distant sellers.

California has a long history of importing electric power from neighboring states. Major high voltage interties exist between California and Oregon, Nevada and Arizona, with substantial quantities of energy and capacity originating in Utah and New Mexico as well. California's transmission network is contained within the Western Electricity Coordinating Council (WECC). The WECC represents a physical infrastructure and collaborative management practice that, in theory, enables loads residing throughout the system to be served by supply resources located throughout the system

Western Electricity Coordinating Council Overview

The Western Electricity Coordinating Council (WECC) was formed in 2002, by the merger of Western Systems Coordinating Council, Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). The formation of WECC was accomplished over a four-year period through the cooperative efforts of WSCC, SWRTA, WRTA, and other regional organizations in the West. WECC's interconnection-wide focus is intended to complement current efforts to form Regional Transmission Organizations (RTO) in various parts of the West. The reliability standards of the electric power system in western North America are defined by WECC. The states and provinces covered by the WECC are shown in Figure 4.

In addition to promoting a reliable electric power system in the Western Interconnection, WECC supports efficient competitive power markets, assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the ten regional councils of the North American Electric Reliability Council (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. Transmission lines span long distances connecting the verdant Pacific Northwest with its abundant hydroelectric resources to the arid Southwest with its large coal-fired and nuclear resources. WECC and the nine other regional reliability councils were formed due to national concern regarding the reliability of the interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization.

Membership in WECC is voluntary and open to any organization having an interest in the reliability of interconnected system operation or coordinated planning. The Council provides the forum for its members to enhance communication, coordination and cooperation – all vital ingredients in planning and operating a reliable interconnected electric system.

WECC members have long recognized the many benefits of interconnected system operation. During the mid 1960s, expansion of interconnecting transmission lines among systems in the western United States and western Canada resulted in the complete interconnection of the entire WECC region. As this expansion was taking place, systems generally adopted the Operating Guides of the North American Power Systems Interconnection Committee (NAPSIC) to promote consistent operating practices within the region. NAPSIC later became the NERC Operating Committee.

Figure 4:
States and provinces covered by the WECC

(Source: http://web.wecc.biz/maps_diagrams/

Major Transmission Corridors into California

California receives electric energy from outside the state from the major sources of energy on the Columbia River in the north over the Pacific SC Intertie (PACI) and the Pacific HVDC Intertie (PDCI).

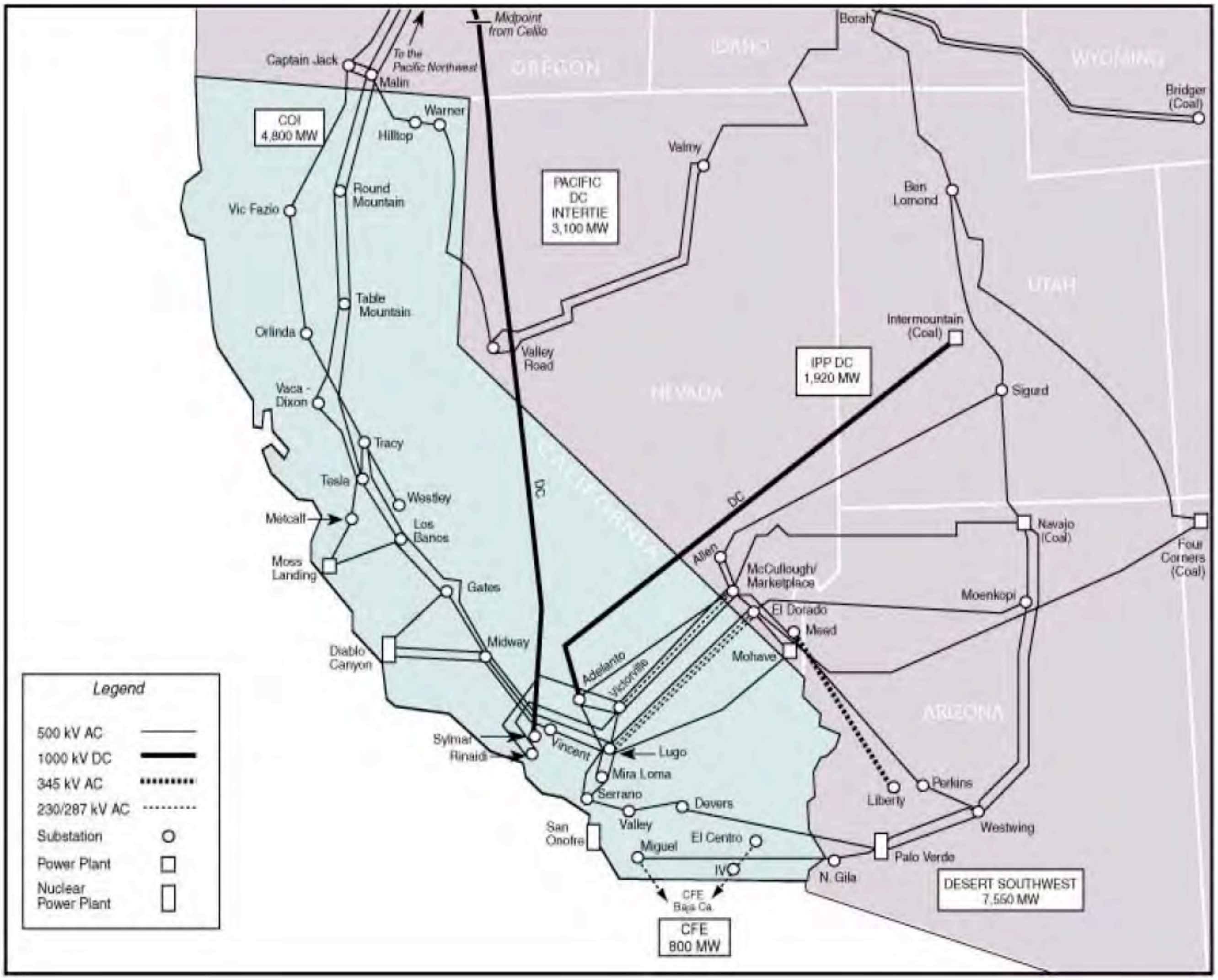
From the west, coal fired generation in Utah feeds into southern California over the Intermountain Power Project (IPP).

From the desert southwest, southern California receives hydroelectric power from Hoover Dam, and thermal energy from the large coal fired power plants of Navajo in Arizona, and Four Corners and San Juan in New Mexico. There is also power received from the Palo Verde nuclear power station in southwest Arizona.

From the Comisíon Federal de Electricidad (CFE) in Mexico, some electric energy is imported into California that is derived from natural gas.

These major transmission interconnections into California are shown in Figure 5.

Figure 5:
California's Major Transmission Interconnections.



Source: Upgrading California's Electric Transmission System: Issues and Actions for 2004 and beyond, Prepared in support of the 2004 Integrated Energy Policy Report Update Proceeding (03-IEP-01), California Energy Commission, July 2004.

The power transmission limits on the transmission corridors into California in MW as defined by the WECC for the year 2009 are presented in Figure 6. Also included are three smaller transmission interconnections out of Nevada that include:

- The 300 MW Alturas line that has a transmission path from Sierra Pacific Power (SPP) into northern California through southern Oregon.

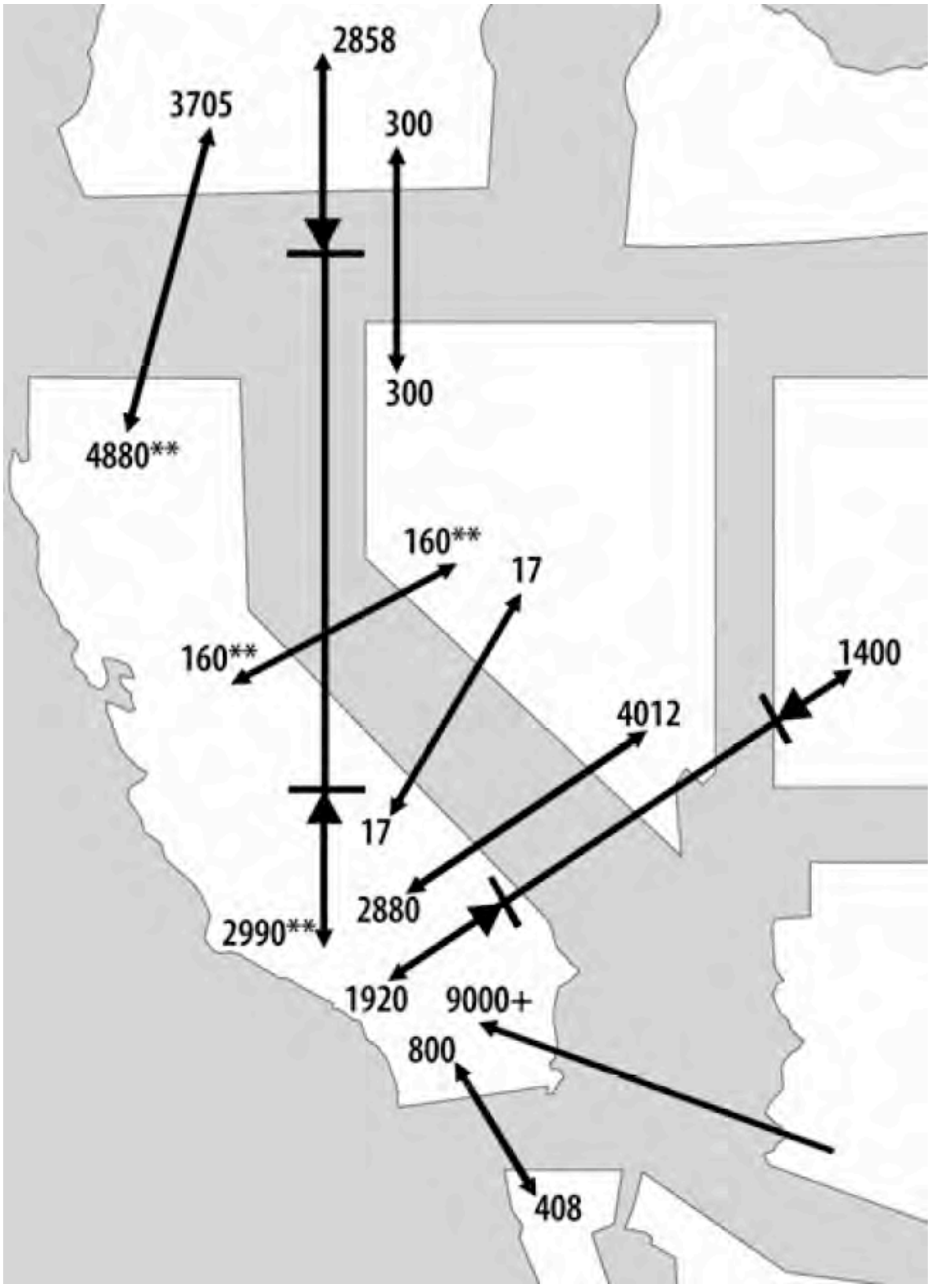
- The 160 MW transmission path from SPP across the Sierra Nevada mountains through the Donner Pass.

- The Dixie Valley transmission line bringing power in from SPP in Nevada.

Figure 6 illustrates the comparative capacities of the transmission corridors into California.

Figure 7 shows the major transmission lines and interconnections from California, with the congestion paths shown. The congestion limits shown are for the pre-Path 15 upgrade.

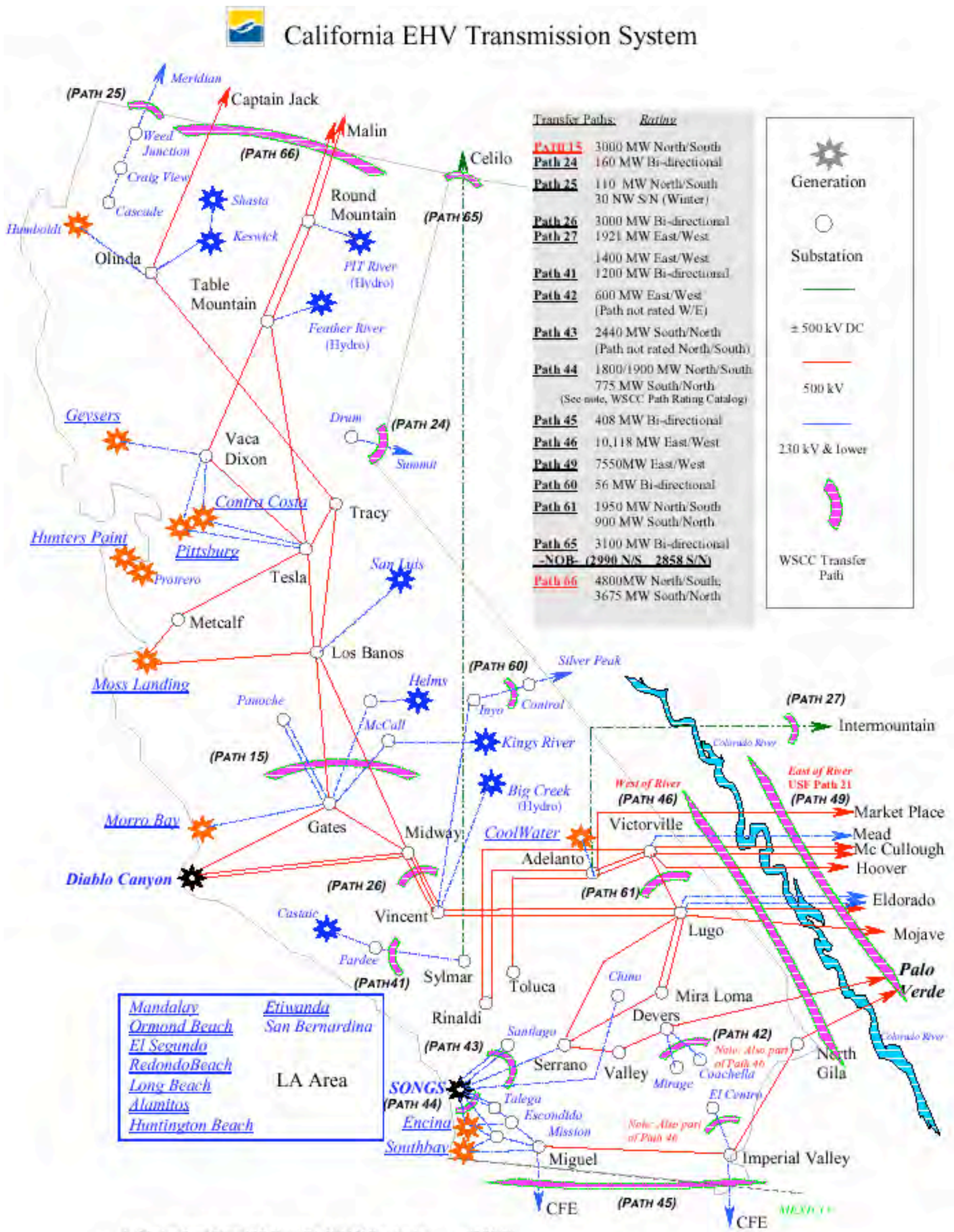
Figure 6:
Non-simultaneous power transfer capabilities into or out of California. 2009.



** Currently being operated at a lower limit depending on the operating season

(Source: Western Electricity Coordinating Council, 10-Year Coordinated Plan Summary, Planning and Operation for Electric System Reliability, September, 2004)

Figure 7
California EHV Transmission System (Source CA CA ISO).



Major Transmission Corridors to the North – the Pacific AC and DC Interites

PACI-COB

The Pacific AC Intertie (PACI) across the California – Oregon border (COB) is a major transmission path that could potentially be used to bring new renewable energy into California. PACI across COB is shown in Figure 3 to have a power transfer limit into California of 4880 MW. The reality is that it is usually operating at 4000 MW or less. Figure 8 shows the power flows on PACI at COB for a week in January 2003, and Figure 9 shows the power flows 6 months later in July 2003.

Figure 8: Power flow on the Pacific AC Intertie across the California – Oregon Border for the week 19 – 25 January, 2003.

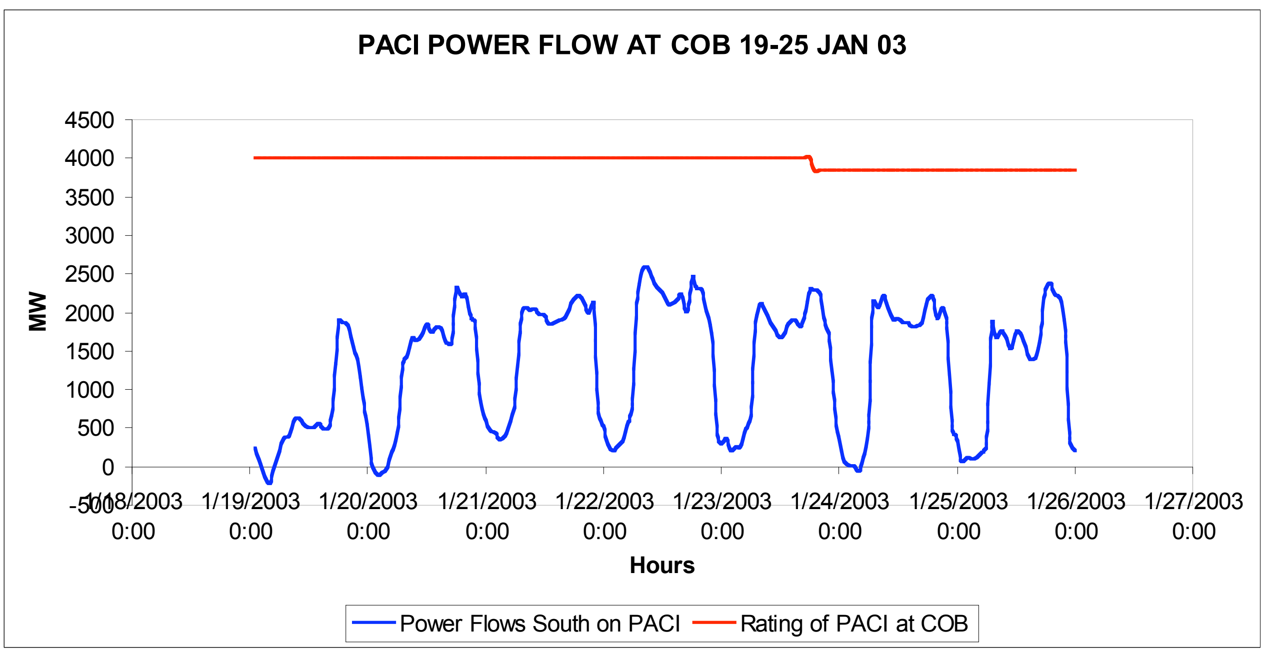
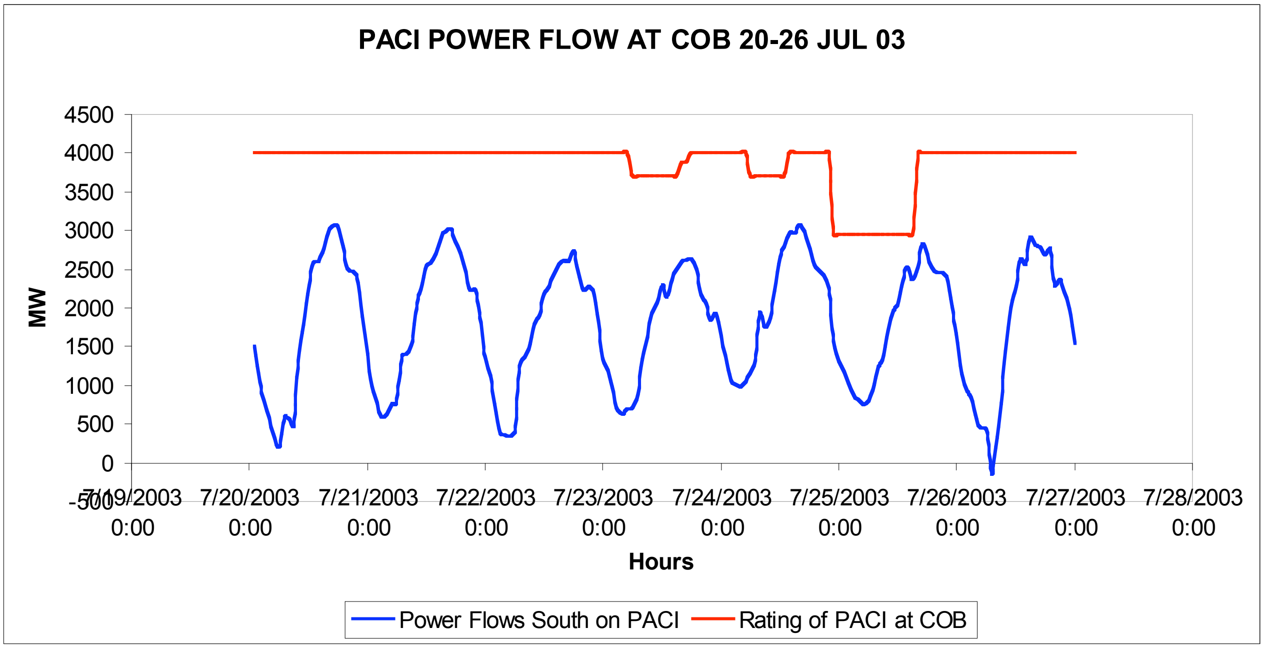


Figure 9: Power flow on the Pacific AC Intertie across the California – Oregon Border for the week 20 – 26 July, 2003



PDCI – Dalles to Sylmar

The other major interconnection into California from Oregon is the PDCI whose operational rating is also reduced from time to time from its maximum limit shown in Figure 3 to be 2990 MW into southern California. Figure 10 shows the historical power flow on PDCI for the week in January 2003 and Figure 11 shows the flows for the week in July 2003.

Figure 10:
Power flow on the Pacific DC Intertie for the week 19 – 25 January, 2003

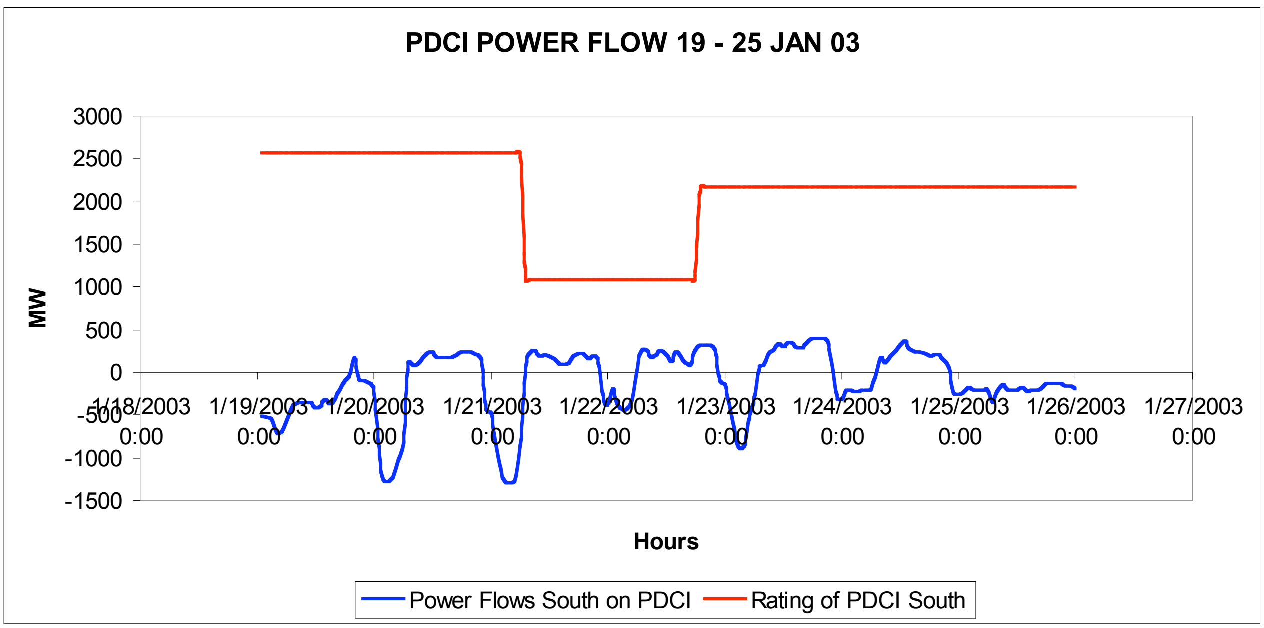
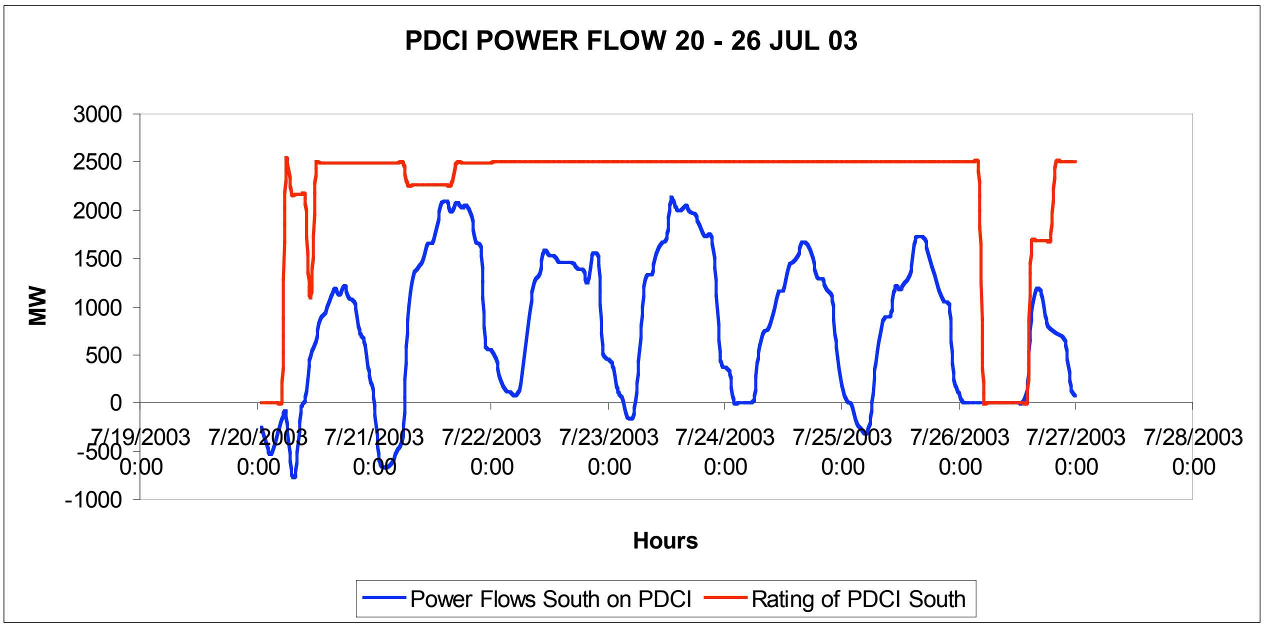


Figure 11:
Power flow on the Pacific DC Intertie for the week 20 – 26 July, 2003



The power flows over both PACI and PDCI often reflect the daily load following or peaking regulation of electric power derived from the hydroelectric power plants of the Columbia River. Grand Coulee provides most of this regulation service. Figures 12 and 13 show the power generated at Grand Coulee for the same weeks in January and July as shown for the transmission over PACI and PSCD in Figures 8 through 11.

Figure 12:
Power generated at Grand Coulee for the week 19 – 25 January, 2003

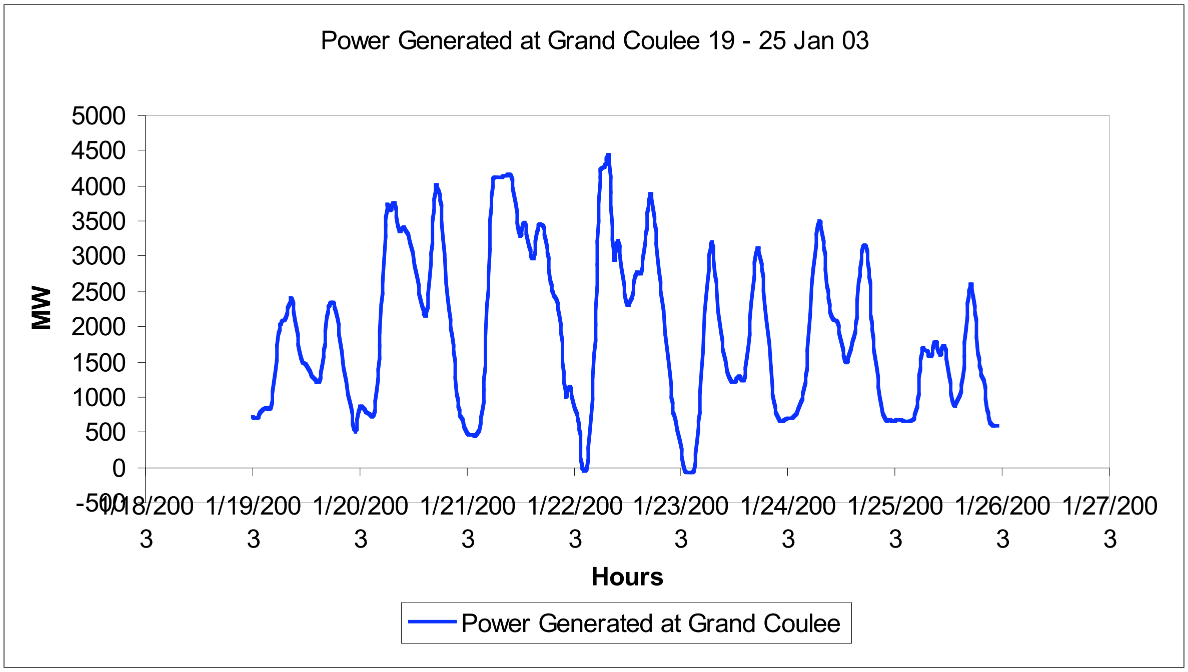
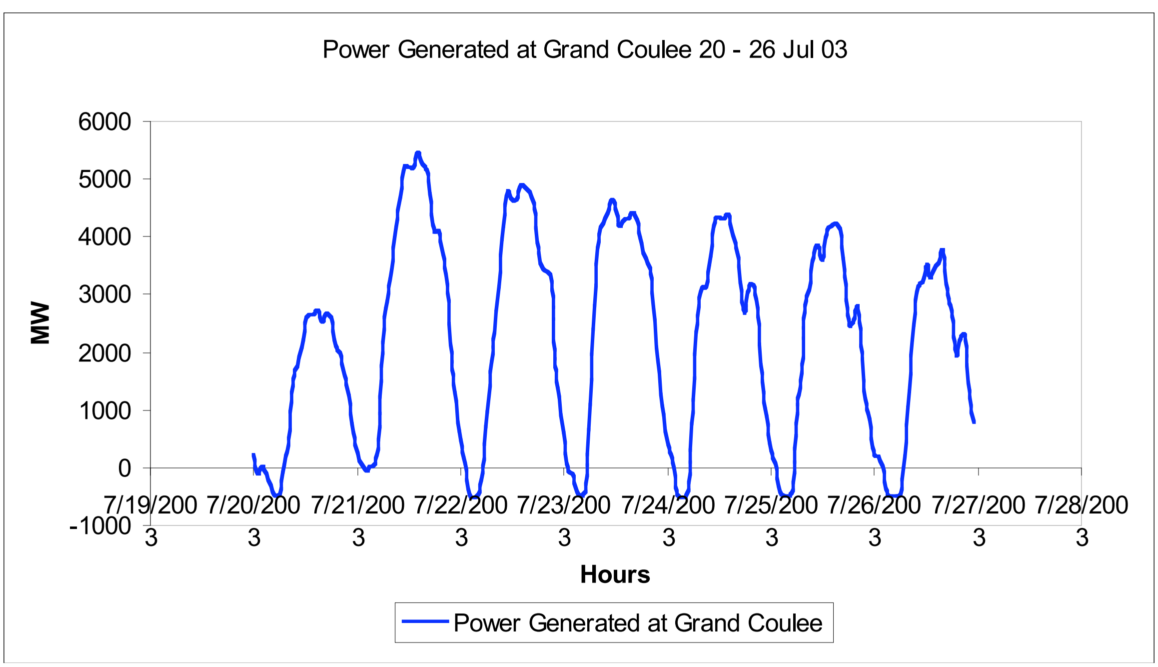


Figure 13:
Power generated at Grand Coulee for the week 20 – 26 July, 2003



The implication of the loading on both the PACI and the PDCI is that its regulation through each daily load cycle is much tied to the amount of regulation from the generation at Grand Coulee. Grand Coulee is a load following or peaking plant serving California and the Pacific Northwest. Other generators in the region, such as the northern California hydroelectric power systems also provide load following service.

On the average, the amount of load regulation into California on both PACI and PDCI is about the same as the load following regulation provided from Grand Coulee. This does not mean that Grand Coulee is devoted only to the California load, as there are other hydroelectric generators in the Pacific Northwest including from Canada that do provide this service.

PDCI has multiple transmission rights stakeholders with LADWP and BPA jointly operating the facilities and controlling their respective portions south and north of the NOB. LADWP has not become a CA CA ISO Participating Transmission Owner (PTO) and as such has not transferred operations and control of the PDCI to CA CA ISO.

Firm scheduling rights on the PDCI are held by several California IOUs and other municipal utilities, through which CA CA ISO retains scheduling rights. CA CA ISO has an effective PDCI scheduling allocation of 66.72%.

The question of transmission rights on PACI and PDCI for bringing power from new and large renewable generation from the Pacific Northwest or Nevada into California is a key consideration.

There are two ways renewable power can be transferred over PACI and PDCI. The first is to get access to the Available Transmission Capacity (ATC) and Existing Transmission Contracts (ETC) available.

At any given time, the Existing Transmission Contracts (ETC) on PACI and PDCI may not be fully scheduled leaving unused ETC rights. There may also be Available Transfer Capacity (ATC). If there is any ETC available, this capacity is generally not accessible for use by any without rights, whereas any ATC is accessible for a transmission use charge. The difference between the transmission ratings on PACI and PDCI (shown in red in the graphs above) and the power flowing (shown in blue in the graphs above) consists largely of ETC available and ATC.

The second way renewable power can be transferred over PACI and PDCI is with hydro/wind integration contracts between load following Columbia River hydroelectric generators (principally Grand Coulee) and the renewable energy plants that might connect to the system further south.

Other Existing Transmission Paths into California

The other transmission paths into California are shown in Figures 6 and 7. The discussion on use of PACI and PDCI for renewable energy imports is pertinent so far as these other transmission lines are concerned. Similar impediments to access to ATC and ETC available exist on these lines too, which include:

1. Las Vegas – LA (Mead, Marketplace, Eldorado – Victorville, Lugo)

2. Phoenix – LA/San Diego (Palo Verde – Devers & Miguel)

3. Parker – Mojave Region

4. Mexico – Tijuana, La Rosita

5. Alturas

6. Dixie Valley

7. Donner Pass (Path 24)

The Dixie Valley, Alturas and Donner Pass corridors could be important paths for future geothermal power. The Las Vegas, Phoenix and Parker corridors could be important paths for future wind and solar power.

SECTION 3: INTERSTATE TRANSMISSION TO SUPPORT NEW RENEWABLE ENERGY FLOWS

Introduction

This section focuses on the incremental interstate transmission import capability to support new renewable energy flows into California. The analysis evaluated the existing transmission network as well as several selected interstate high voltage transmission upgrades. It provides a conceptual evaluation of the interstate transmission system from a 50,000 foot level and seeks to provide sufficient information to determine which transmission corridors appear to provide sufficient import capability and reliability at a relatively economical perspective. The results of this evaluation could lead to future, in-depth studies of selected interstate transmission corridors.

This study seeks to quickly and efficiently estimate how much additional power could be imported from anticipated new out-of-state renewable projects. The study considers incremental transfers from specific projects, in addition to the anticipated flow on tie-lines from other planned imports. This study focuses on technical feasibility, without regard to the cost of the upgrades or how they will be financed. It provides a quantitative measure of the improvement in import capability achieved by each planned interstate EHV transmission upgrade.

The capacity of the transmission system to import proposed out-of-state renewable resources under 2005, 2010, and 2017 summer peak load scenarios is evaluated. A base case import capability is established for each period with all proposed out-of-state resources operating simultaneously over the existing interstate transmission system, with a few currently approved transmission upgrades. Next, the study examines all proposed out-of-state resources operating simultaneously, with additional proposed transmission upgrades. Finally, it evaluates several independent scenarios coupling specific out-of-state renewable projects with specific proposed transmission upgrades intended to increase import capability from those resources.

Available Transfer Capability (ATC) Analysis

The study considered summer peak load flow cases for 2005, 2010, and 2017 developed in prior analysis. These cases incorporate transmission upgrades, load growth, new permitted power plants and the expected retirement of several power plants. The study thus independently evaluated the impacts of transmission upgrades and load growth on the ATC. The study considered several scenarios combining newly proposed transmission upgrades and proposed out-of-state renewable resources.

The ATC analysis used linear sensitivities to identify which transmission elements limit the incremental transfer of power from the proposed out-of-state renewable resources to the California system. The study identified multiple limiting factors, each consisting of an overloaded transmission element and a line-outage contingency. In the context of this project, the ATC can also be referred to as the ITC (Incremental Transfer Capability) as the quantitative results reflect the *additional* transfer capability above the existing transfers. The incremental transfer capability was calculated for each such pair of transmission element and contingency. Thus the study revealed multiple limitations of the transmission network, providing an understanding of the incremental benefit of alleviating individual limitations with further upgrades to the transmission network or operational grid management practices such as remedial action schemes.

The calculations utilized linear power injection and line outage sensitivities from the solved AC cases. However, the available documentation and study time necessitated that DC methods be used to estimate available transfer capability. A full AC analysis would require significant detailed information describing voltage control upgrades throughout the grid, including the low voltage sub-transmission network. As a result, the study considers only the thermal limitations of the network and not voltage limitations.

Representative Out-of-State Renewable Resources

Out-of-state renewable resources were modeled as lumped generators in eight regions as shown in Figure 14, distributed across high voltage substations based on anticipated interconnection points. These resource areas are have not been selected as the only, or best, renewable resource areas, but more as a representation of regions that plausibly represent future supply opportunities for California. This aggregation of renewables is consistent with the most likely interstate transmission corridors that would be used to import the energy. The study results were not significantly influenced by the exact out-of-state connection points, as only in-state transmission elements were monitored.

Figure 14 - Representative Out of State Renewable Resources[2]

The out-of-state renewable resource groups consisted of:

- Northwest Source
  - Columbia Valley Wind – 3000 MW
  - Southern Oregon Wind – 2000 MW
  - Southwest Idaho/Northern Nevada Wind – 1000 MW
- Reno Source
  - Reno Wind – 1000 MW
  - Reno Geothermal – 600 MW
  - Dixie Geothermal – 500 MW
- Southern Source
  - Las Vegas Solar – 1000 MW
  - Arizona Solar – 1000 MW

[2] Overview of Renewable Energy Resources in Select Western States

Representative Transmission Network Upgrades

The study independently evaluated upgrades to five interstate transmission corridors as follows, in addition to the base transmission topology.

- COI/PACI/Alturas Transmission Network
  - New 500kV line from Captain Jack through Olinda to Tracy (CA), parallel to existing 500kV lines
  - Extend 345kV Alturas line to Captain Jack
  - New 60kV transmission line from Fredonyer Hills wind farm into Honey Lake
  - Convert 60kV circuit to 230kV circuit from Honey Lake to Caribou

- Trans Sierra Transmission line around Susanville
  - New Valley Road 500kV bus
  - New 345/500 kV transformer at Valley Road
  - New Valley Road to Table Mountain 500kV Line
  - New 500kV line from Table Mountain to Tracy/Tesla

- Trans Sierra Transmission line around Truckee
  - New Valley Road 500kV Bus
  - New 345/500kV transformer at Valley Road
  - New 500kV line from Valley Road to Tracy (CA)

- DC Intertie to southern California: new taps into PDCI in NV from Valley Road and Tracy

- Transmission Intertie to Arizona
  - Add new 500kV circuit from Palo Verde to Devers
  - Reconductor 230kV lines from Devers to Vista
  - Reconductor 230kV lines from Devers to San Bernardino
  - New 500kV circuit from Devers to Miguel

The study also incorporated n-1 transmission contingencies on the EHV grid (100 kV and above). It was assumed that existing base case and contingency MW overloads would be alleviated by congestion management and other grid planning measures. The study identified the next most limiting EHV transmission elements and the incremental transfer those elements allow.

Study Scenarios

The study methodology involved increasing the output of out-of-state resources in proportion to each resource's MW capacity. The renewable resource groups were examined both individually and simultaneously. The simultaneous aggregation of all resource groups is termed the "aggregate source". The aggregate source approach is a reasonable scenario of California importing from all modeled sources as a group, in proportionate amounts. The transfer capability analysis using the aggregate source approach results in transfer limitations identified state-wide as power is imported from all directions, and the variations to those state-wide limitations as the various transmission upgrades were examined.

In addition to the aggregate source analysis, the study also looked at transfer capability limitations for a more specific import scenario related to each expansion project.

The results for the specific source transfer capabilities provide a localized look at the transmission elements impacting the transfer capability into California along the specific expansion path, assuming the transfer comes from the "nearest" out-of-state renewable resource locations. This helps draw conclusions about how the expansion projects affect the surrounding system for the nearest renewable sources, versus the overall affect of the expansion project from a state-wide point of view assuming that California would in fact be importing power from all out-of-state renewable resources concurrently.

In all source scenarios, out-of-state resources displaced in-state fossil fuel generators. Nuclear, baseload units, reliability-must-run (RMR) units, and in-state renewable units maintained constant power output within each study year and were not displaced by out-of-state renewable units. Units identified by the CA CA ISO as current or potential retirements[3] were displaced, regardless of other status.

Results Summary

Results vary across years and transmission upgrades as different transmission elements were the most limiting under different loading profiles. In many cases, the in-state transmission lines near the terminating end of the proposed transmission upgrades became limiting. This suggests that these transmission upgrades should be continued along the EHV paths to the load centers. Negative ATC values imply that a transfer in the opposite direction (from California to the out-of-state renewables) is required to relieve existing overloads. In some cases, the

[3] http://www.CA CA ISO.com/docs/2001/06/25/20010625134406100.pdf, California CA ISO, April 16, 2004.

transmission upgrades and resulting lower impedance induced enough additional flow that other lines in the vicinity became overloaded before any new imports were considered. Summary results showing ATC and the transmission elements that were most limiting to the transfer for each resource group, transmission topology, and study year are shown in the table below. The most limiting conditions occurred during n-1 contingencies, except where “Base Case” is noted.

Table 3 - ATC Summary (figures in MW)

Resource Group	Transmission Topology	Transfer Capability and Limitation		
		2005	2010	2017
Aggregate Source	Base Topology	27 MW; *COI, Malin-Round Mountain*	221 MW; *COI, Malin-Round Mountain*	-683 MW; *Hassayampa – North Gila (Base Case)*
	COI/PACI/ Alturas Transmission Network	394 MW; *ADCC-Newark (Base Case)*	-113 MW; *ADCC-Newark (Base Case)*	-599 MW; *Hassayampa – North Gila (Base Case)*
	Trans-Sierra Transmission : Susanville	-56 MW; *COI, Malin-Round Mountain (Base Case)*	81 MW; *ADCC-Newark, Malin-Round Mountain (Base Case)*	-699 MW; *Hassayampa – North Gila (Base Case)*
	Trans-Sierra Transmission : Truckee	270 MW; *COI, Malin-Round Mountain*	308 MW; *ADCC-Newark, COI (Base Case)*	-679 MW; *Hassayampa – North Gila (Base Case)*
	PDCI to southern California	30 MW; *COI, Malin-Round Mountain*	252 MW; *COI, Malin-Round Mountain*	-736 MW; *Hassayampa – North Gila (Base Case)*
	Transmission Intertie to Arizona	-2182 MW; *Imperial Valley – Miguel (Base Case)*	254 MW; *COI, Malin-Round Mountain*	277 MW; *Imperial Valley – Miguel (Base Case), COI*
Northwest Source	Base Topology		175 MW; *COI, Malin-Round Mountain*	-890 MW; *Hassayampa – North Gila (Base Case)*
	COI/PACI/ Alturas		-100 MW; *ADCC-Newark (Base Case)*	-787 MW; *Hassayampa – North Gila (Base Case)*

Resource Group	Transmission Topology	Transfer Capability and Limitation		
		2005	2010	2017
Reno Source	Base Topology		333 MW; *COI, Malin-Round Mountain*	-913 MW; *Hassayampa – North Gila (Base Case)*
	Trans-Sierra, Susanville		93 MW; *ADCC-Newark, Malin-Round Mountain (Base Case)*	-1072 MW; *Hassayampa – North Gila (Base Case)*
	Trans-Sierra, Truckee		326 MW; *ADCC-Newark, COI (Base Case)*	-1051 MW; *Hassayampa – North Gila (Base Case)*
	DC Intertie (special case)		1248 MW; *Sylmar - Rinaldi*	-1562 MW; *Hassayampa – North Gila (Base Case)*
Southern Source	Base Topology		352 MW; *Mohave-Lugo*	-394 MW; *Hassayampa – North Gila (Base Case)*
	Arizona Intertie		682 MW; *Mohave-Lugo*	181 MW; *Imperial Valley – Miguel (Base Case)*

It should be noted that each transfer and scenario was bound by multiple transmission limitations, sometimes in the base case and under a variety of contingencies. Only the most limiting transmission paths are listed in this summary. Detailed results, discussed in the full report, show multiple transmission constraints that incrementally limit each transfer.

COI/PACI/Alturas Transmission Network

The primary piece of the COI/PACI/Alturas transmission expansion is the addition of a circuit that parallels COI from Captain Jack through Olinda to Tracy, CA. The impact of this circuit on the COI limitations seen in the base case transfer capability scenarios will be high. For the purpose of this study, the new Captain Jack – Olinda – Tracy 500kV circuit was <u>not</u> included as part of the COI interface for two reasons:

1) the new interface MW rating would not yet be known, and 2) keeping the COI definition the same as the base case will allow for easier identification of base case improvement, if any.

The COI flow in the peak-load cases analyzed in this study varied from 4698 MW in 2005 to 4398 MW in 2017. Loading in the study case decreased over time due to the methodology used to create the cases. As the loads for future years were scaled, imports were held approximately constant while in-state supply was increased at each available generator in proportion to its size. Most available in-state reserve margin was located in the south, causing the COI flow to decrease over time in the study cases. Even so, COI flow was very sensitive to increasing imports in this study due to the high concentration of proposed out-of-state projects in the north and the occurrence of loop flows during contingency outages.

Actual COI flow observed in July and August of recent years varies with time of day, but is almost always from north to south. The flow seen in 2001 and 2004 was sometimes erratic from hour to hour. The data suggest that the COI has import capacity during underutilized periods.

The scheduling data also reveals that the COI's MW capacity rating varies. External conditions such as overall system loading or forced outages may affect the rating. Any plans to schedule additional capacity from renewable resources would have to be coordinated with other transactions affecting the COI. The figures below show actual hourly COI usage and ratings for August.

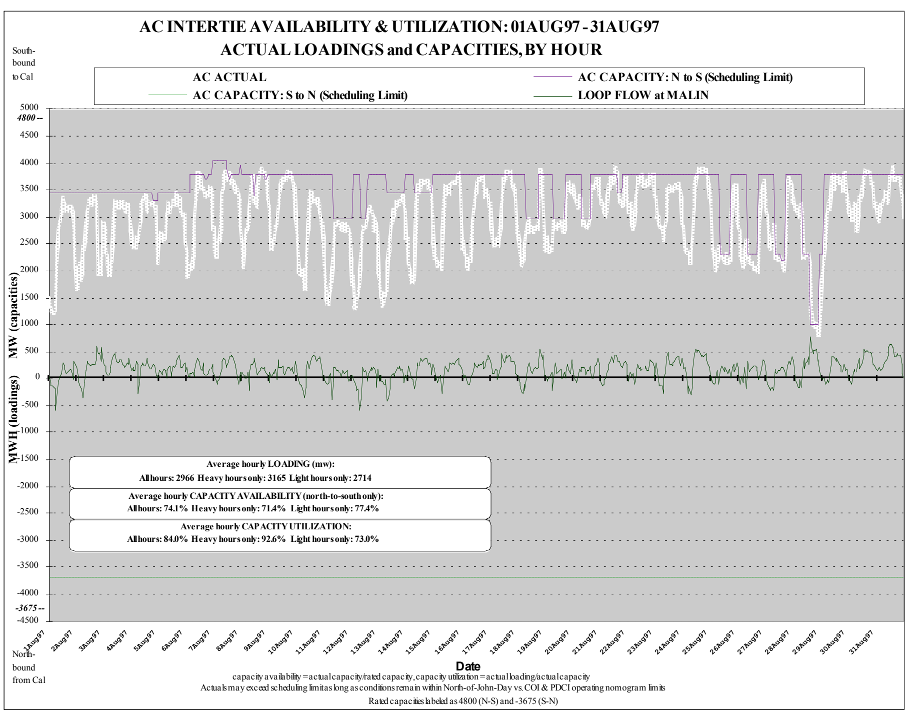


Figure 15 - August 1997 COI Utilization

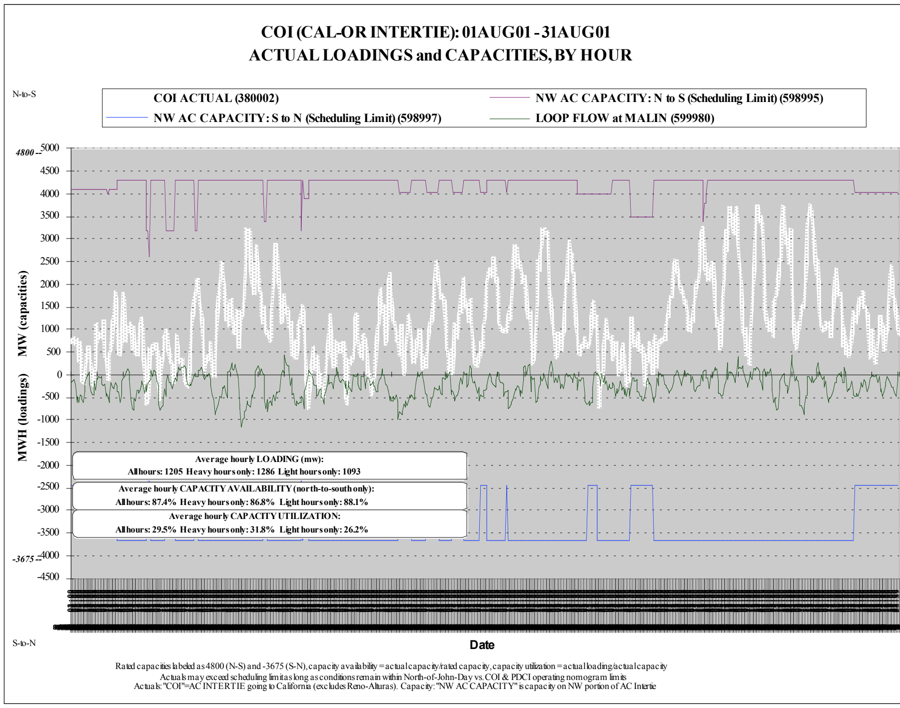


Figure 16 – August 2001 COI Utilization

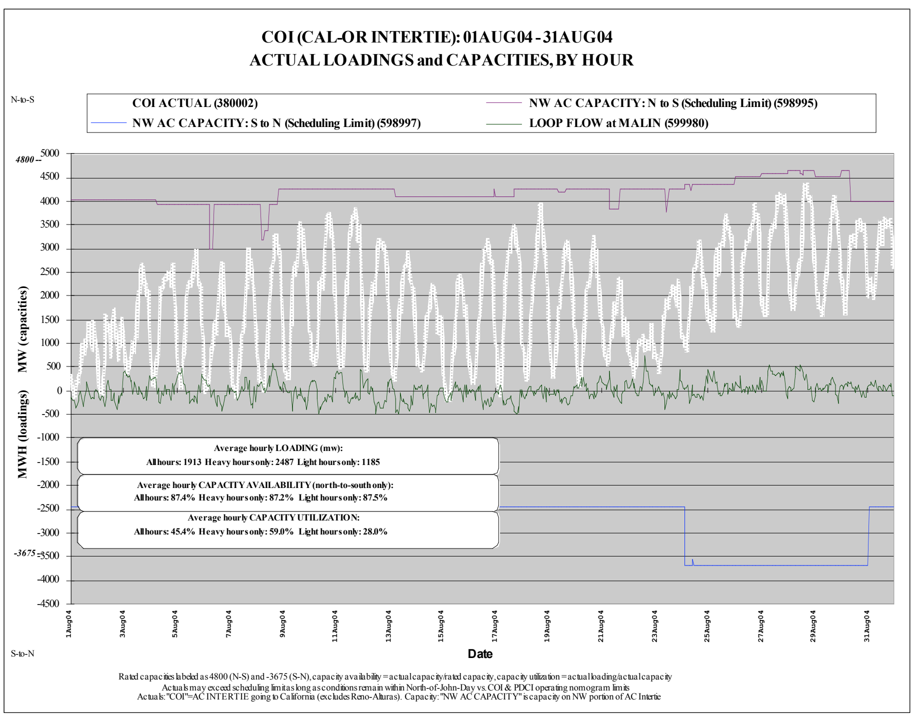


Figure 17 – August 2004 COI Utilization

2010 Northwest Import Capability: Base Transmission Topology

Figure 18 – 2010 Base Case PTDF Contour (Northwest Source)

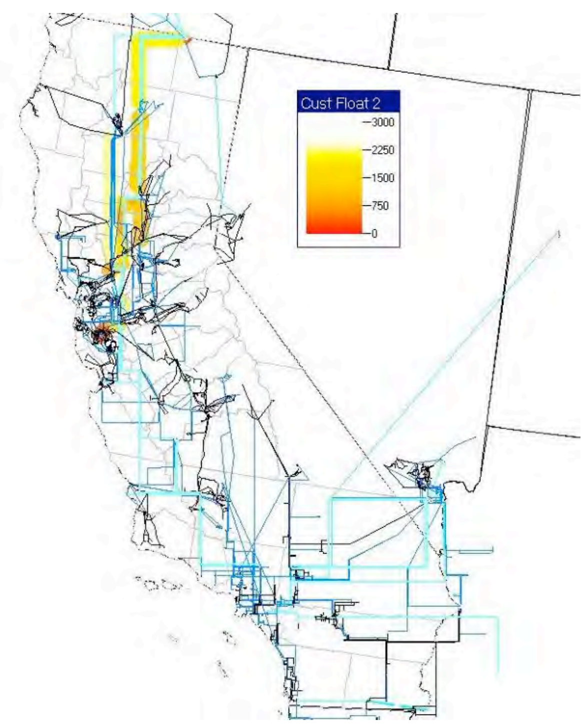


Figure 19 – 2010 Base Case Import Limiters (Northwest Source, Import Limitation in MW)

Table 4 – 2010 Base Case ATC (Northwest Source)

ATC	Overloaded Element	Contingency	Pre-Transfer Flow	PTDF	Flow Limit
175	Interface COI (N-S) (66)	T_24007ALMITOSW-24162ALAMT7GC1	4654	83.6	4800
176	Interface COI (N-S) (66)	T_24068HUNTGBCH-24169HUNT5GC1	4653	83.6	4800
176	Interface COI (N-S) (66)	L_24068HUNTGBCH-24197ELLISC1	4653	83.6	4800
180	Interface COI (N-S) (66)	L_36076BAFOOD1-36077BAFOOD2C1	4649	83.6	4800
184	Interface COI (N-S) (66)	L_32333PEASETP-32302YUBACITYC1	4646	83.6	4800
266	Branch MALIN (40687) TO MALROU21 (40692) CKT 2 [500.00 - 500.00 kV]	Base Case	1476	27.6	1550
430	Branch ADCC (30655) TO NEWARK E (30631) CKT 1 [230.00 - 230.00 kV]	Base Case	651	1.5	657
833	Branch TABVAC11 (30031) TO TABVAC12 (30032) CKT 1 [500.00 - 500.00 kV]	Base Case	1987	24.8	2194

The most limiting transmission path in the Northwest is the COI interface operating limit. The most severe transfer capability is 175 MW due to flows on COI under contingency situations. The transfer distribution factor on COI for flow from the Northwest Source to reducing generators in California is approximately 84%. For every 100 MW transferred from the Northwest Source to California, the flow on COI will change in the direction of the transfer by 84 MW.

Several n-1 contingencies can cause slight reductions in the import capacity of the COI relative to the base case. Several of the contingencies noted are seemingly minor generator step-up transformer outages in remote parts of the system. The individual listed contingencies themselves are not the root cause of the COI overload, but only a reflection of the fact that minor loop flows from outages can hasten overloads under peak conditions. Improving the base case import capacity will tend to simultaneously improve a large set of contingency import capacities.

2010 Northwest Import Capability: COI/PACI/Alturas Expansion

Figure 20 – 2010 PTDF Contour for COI/PACI/Alturis Expansion (Northwest Source)

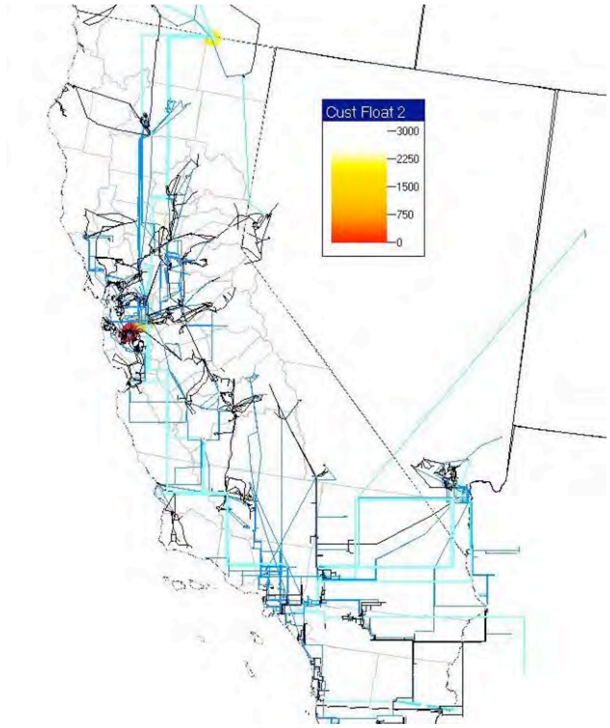


Figure 21 - 2010 COI/PACI/Alturis Expansion Import Limiters (Northwest Source, Import Limitation in MW)

Table 5 - 2010 COI/PACI/Alturis Expansion (Northwest Source)

ATC	Overloaded Element	Contingency	Pre-Transfer Flow	PTDF	Flow Limit
-100	Branch ADCC (30655) TO NEWARK E (30631) CKT 1 [230.00 - 230.00 kV]	Base Case	658	1.6	657
1089	Branch TESLA F (30640) TO ADCC (30655) CKT 1 [230.00 - 230.00 kV]	L_35209SANRAMN-35221EDUBLINC1	665	1.6	683
1110	Branch TESLA F (30640) TO ADCC (30655) CKT 1 [230.00 - 230.00 kV]	T_33463CARDINAL-33386STANFORDC1	665	1.6	683
1225	Branch ADCC (30655) TO NEWARK E (30631) CKT 1 [230.00 - 230.00 kV]	L_35209SANRAMN-35221EDUBLINC1	663	1.6	682
1245	Branch ADCC (30655) TO NEWARK E (30631) CKT 1 [230.00 - 230.00 kV]	T_33463CARDINAL-33386STANFORDC1	663	1.6	682
1561	Branch MIRALOME (25656) TO mirlom3i (24180) CKT 3 [230.00 - 13.80 kV]	Base Case	-1080	-1.8	-1109
2090	Interface COI (N-S) (66)	L_32333PEASETP-32302YUBACITYC1	3470	63.6	4800
2091	Interface COI (N-S) (66)	T_24007ALMITOSW-24162ALAMT7GC1	3470	63.6	4800
2091	Interface COI (N-S) (66)	T_24068HUNTGBCH-24169HUNT5GC1	3469	63.6	4800
2091	Interface COI (N-S) (66)	L_24068HUNTGBCH-24197ELLISC1	3469	63.6	4800
2095	Interface COI (N-S) (66)	L_36076BAFOOD1-36077BAFOOD2C1	3467	63.6	4800
4533	Branch MIDWAY (30060) TO MIDVIN31 (30068) CKT 3 [500.00 - 500.00 kV]	T_24007ALMITOSW-24162ALAMT7GC1	1161	15.0	1839
5058	Branch CAPTJACK (45035) TO CAPOLI11 (45036) CKT 2 [500.00 - 500.00 kV]	T_24007ALMITOSW-24162ALAMT7GC1	1244	20.9	2301

The proposed COI/PACI/Alturas transmission upgrade is shown to be effective at alleviating the COI as a limiting factor in import capacity. The COI limitations have moved down the list with the upgrade in place. The new parallel line from Captain Jack to Olinda to Tracy has allowed for the possible transfer capability limitations due to COI to greatly increase.

However, increasing the capacity of the COI actually puts more strain on the part of the network that delivers power from the southern COI terminals to the load centers in the San Francisco Bay area. The impedance reduction provided by the upgrade draws more of the import to the COI and reduces some of the loop flow on the other major import paths. Comparing the transfer limiter contours of the 2010 base case with the COI/PACI/Alturas upgrade shows that the upgrade relieves the limitations of the COI itself, but worsens the limitation of the lines leading to the Bay area load center.

The ADCC to Newark 230kV line is overloaded in the base case following the expansion resulting in a negative import capability. The 2010 ATC was actually higher without the expansion. The next transfer limitation is 1224 MW due to flows on the Tesla to ADCC element under contingency. The benefits of upgrading the COI can only be realized if the upgrade is continued beyond the Tracy substation to the load centers.

DC Intertie to Southern California

The main question regarding the Pacific DC Intertie and the relevance of the results discussed in this report depends on the conditions of the system and the purpose of the PDCI tap. If the PDCI is already operating at its limit in the system, then the issue becomes what the PDCI tap in Nevada will serve to do. It is likely that the PDCI tap in Nevada will serve the purpose of offsetting flow that was originally coming from the Northwest into California. This would be done by rescheduling hydro generation in the Northwest, and replacing it with renewable resource generation in Nevada. This then becomes an issue of energy, not instantaneous capacity, as the functional use of the PDCI would be no different as seen by the receiving end of the PDCI in California.

The transfer capability analysis that has been performed thus far is, however, studying instantaneous capacity issues by looking at the transfer capability limitations due to loading assumptions for summer peak conditions. The only usefulness that comes out of the transfer capability analysis for the PDCI is if we assume that either the PDCI is not operating at full capacity, or the PDCI would be upgraded (at least from the Nevada tap point into California) in order to deliver more instantaneous power into California. Given the nature of the current study, the previous assumption has been made. In general for all three years, the impact on the incremental transfer capability into California changed little from the base case to the expansion analysis for each year, when considering the source of the transfer being all available renewable resource locations modeled outside the state. This is indicative of most of the transfer occurring across the AC circuits, versus the controlled DC circuit. An analysis of the affects of increasing the PDCI injection into California by itself will be examined later.

This analysis and the ATC results reported herein do capture the limitations seen on the AC system, both in the vicinity of the terminal in southern California and the proposed terminal in Nevada, and throughout the California system. It should be noted that the PDCI was operated at full summer north to south capacity in the power flow cases used in this study. However, since the ATC study evaluated the capacity of the AC network, the results are independent of the present or future capacity of the PDCI. Further study of seasonal and off-peak cases would be necessary to draw conclusions about the ability of the AC system to accommodate additional PDCI schedules under these conditions.

Data for actual PDCI schedules in July and August of several recent years suggest that PDCI loading is sometimes erratic and can change significantly from hour to hour. It is assumed that hydro scheduling and reservoir conditions are an important factor in determining the PDCI load. According to the July and August schedules for 2001 and 2004, power was often scheduled from south to north during off-peak hours and north to south at other times. The 1997 schedule suggests a predominantly north to south flow, though the magnitude of flow varied with the time of day.

The scheduling data also reveals that the PDCI's MW capacity rating varies, sometimes drastically from hour to hour. Losses on the line can be as high as 27% for loading at the nominal capacity of 3100 MW. Consequently, the line is often operated under 2700 MW, making losses less severe. External conditions such as overall system loading or forced outages may affect the rating. Any plans to schedule additional capacity from a future Nevada tap would have to be coordinated and reconciled with injections at the other PDCI terminals and operating policies. The figures below show actual hourly PDCI schedules and ratings for August.

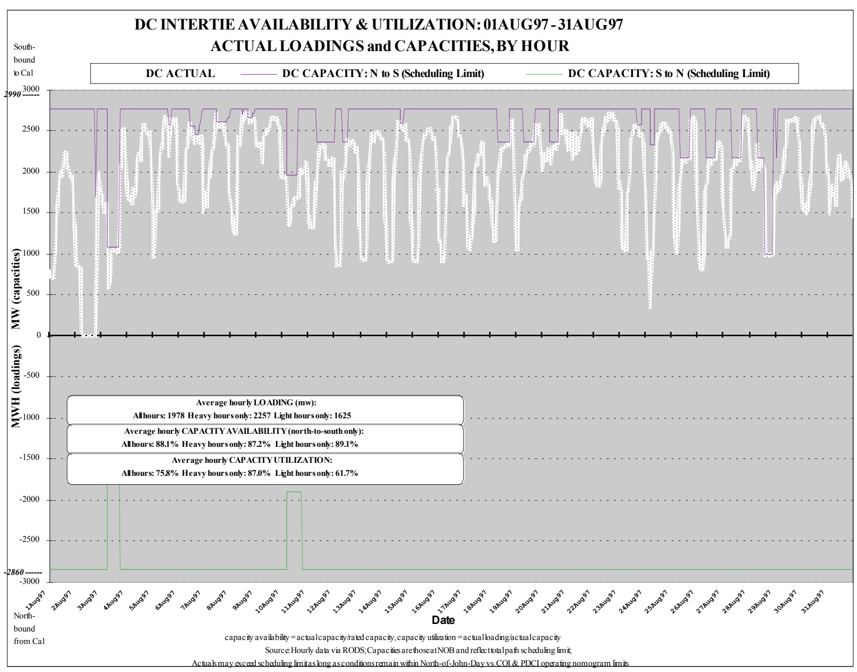


Figure 22 - August 1997 PDCI Availability and Utilization

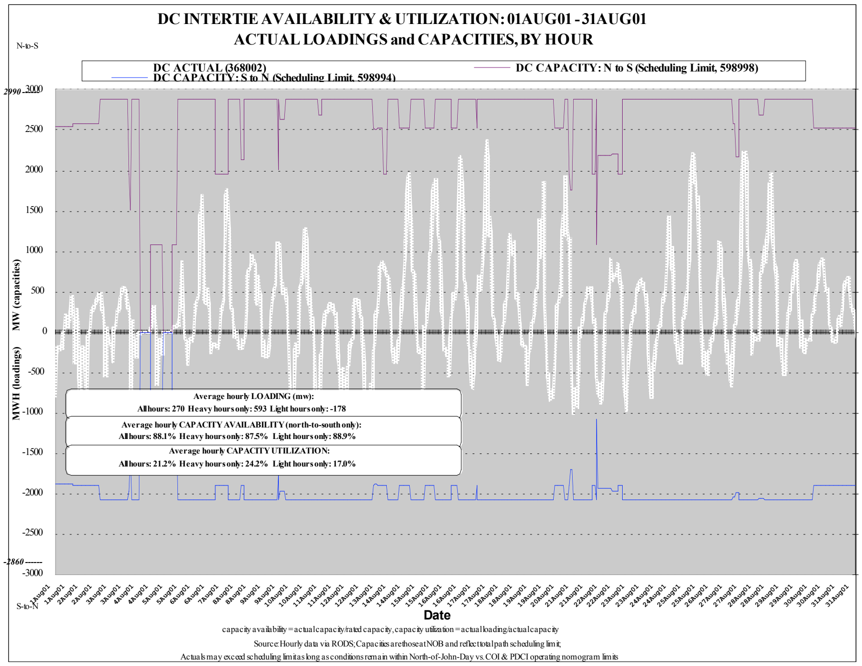


Figure 23 - August 2001 PDCI Availability and Utilization

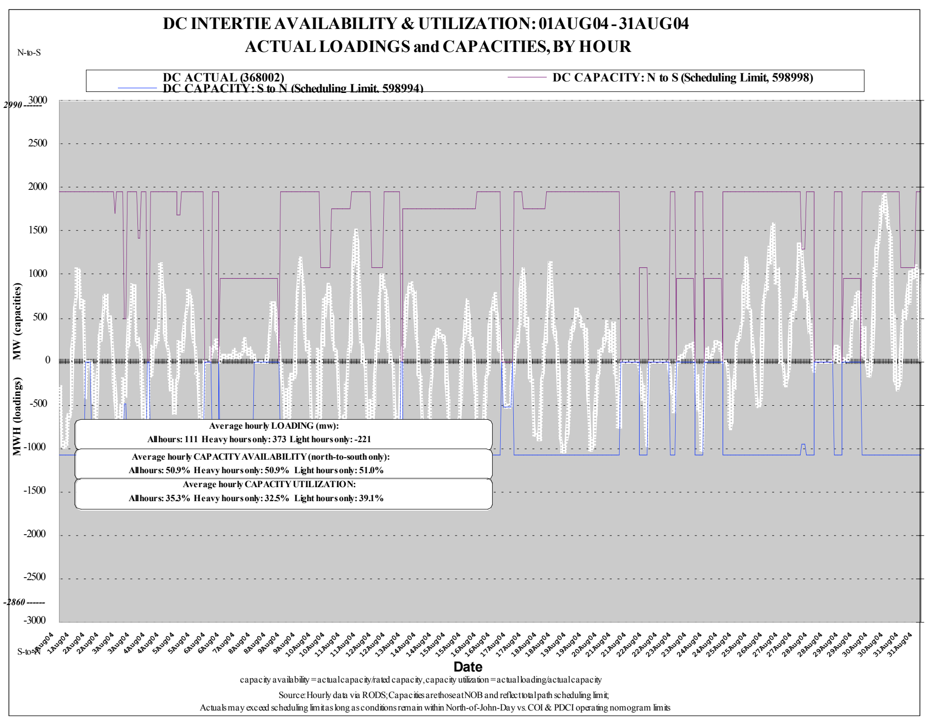


Figure 24 – August 2004 PDCI Availability and Utilization

Conclusions and Perspectives

The available transfer capability (ATC) analysis presented in this study revealed several capacity limitations of the in-state EHV transmission network in handling additional imports from proposed out-of-state renewable resources. Though the specific limiting transmission lines varied with transmission topology, out-of-state renewable resource group, and system load, a few common issues were observed across scenarios:

The COI interface operates very close to its limit and is very susceptible to overload under a wide range of contingencies.

- In-state transmission expansion is needed to sustain the California system through anticipated load growth, independent of the strategy for importing new power from out-of-state resources.

- Efforts to increase import capacity in 2010 should consider upgrades to the infrastructure at the EHV termination points to complement the proposed interstate transmission upgrades.

- The load growth projected for 2017 creates additional capacity limitations that require more study.

- Identifying specific solutions to in-state congestion limitations and priorities for additional transmission upgrades requires a detailed follow-up study.

Outage distribution factors (OTDFs) on the COI are very significant when other major transmission lines are forced out of service. Flow tends to concentrate on this path when transmission capacity in other parts of the system is reduced. Furthermore, the proposed generation expansions in the Reno Source group produce counterflow on the Alturas line, but much of the flow loops back into California on the COI.

Under peak-load conditions, the COI and PDCI become loaded at or near rated capacity. Actual hourly data suggest that there is capacity on both interties during some off-peak hours. Furthermore, dispatchers could relieve loading on the COI without impacting imports by increasing the scheduled flow on the PDCI, provided capacity is available. Any plans to schedule additional capacity on the PDCI or the COI would have to be coordinated and reconciled with other network flows. New incremental transactions utilizing these interties could be subject to curtailment during peak load unless the intertie ratings are increased and the in-state transmission network is also upgraded to handle the additional flows.

The in-state transmission network still requires upgrades to sustain load growth, even if major interstate paths are upgraded. Analysis of several proposed transmission upgrades revealed that overloads occurred between the receiving end of the upgrade and the in-state load centers. Some scenarios even revealed a reduction in ATC after the interstate upgrade. This often occurs because the interstate upgrade reduces the impedance along an existing EHV path, drawing more power into some high voltage bulk substations and overloading the EHV and sub-transmission networks between the bulk substations and the load centers. For example, the COI/PACI/Alturas upgrades actually decreased ATC in 2010, in part because they forced more flow onto the 230 kV and 115 kV network around Tracy and Tesla.

Follow-up studies should consider the interaction between planned in-state and out-of-state renewable resources. Optimal power flow analysis could reveal specific dispatch patterns and resource mix which would be most beneficial to reliving transmission congestion. Specific upgrades to in-state transmission paths could also be studied. Additional voltage stability analysis could determine whether the COI path rating could be increased with planned interstate upgrades. Detailed information about the timing of deployment and the minimum and maximum output capacities for in-state and out-of-state each resource would enhance the study.

The limitations of peak power flow analysis in the context of this study should also be recognized. All study scenarios evaluated capacity on a stressed transmission network, prior to increasing the imports from out-of-state sources. The ATC limitations noted in the results do not imply that renewable energy could not be imported during off-peak, spring, and autumn periods. A comprehensive energy analysis and seasonal load flow study could better help determine the ability of the transmission network to support renewable energy goals.

Potential Alternatives for 2010

The potential operating alternatives for 2010 are listed below. The conclusions are based on the transmission power flow data sets developed by the California utilities. The utilities model maximum loading on the COI and PACI interconnections to stress the system for reliability and stability. Even though the two transmission paths may not have been loaded to maximum delivery in the recent past, the assumption that the lines would be close to full load by 2010 for power purchases and renewable energy deliveries make the following conclusions valid.

- Preliminary ATC results indicate that up to 220 MW of new renewable resources could be imported across all of the interconnections in aggregate. The limiting element is the COI under contingency conditions.

- If power was delivered only on the PDCI, the ATC results indicated that up to 250 MW of new renewable resources could be imported into California.

- Load flow results indicate that up to 85 MW of new renewable resources could be imported over the 60 kV transmission line that serves the Susanville area. If the line was converted to 230 kV, then the imports could be increased to 220 MW.

Potential Alternatives for 2017

- Another 500 kV transmission line will be needed from the Pacific Northwest to PG&E service area to relieve the continued overload of the COI/PACI lines. Additional studies will be required to determine whether the connection should be in Oregon or Nevada.

- The biggest obstacles are the selection of the termination point (Tesla, Tracy or another point) and the upgrades to the 230 and 115 kV system to transport the power to the load.

SECTION 4: USING WESTERN HYDRO RESOURCES TO ENDHANCE RENEWBALE ENERGY INTEGRATION OPPORTUNITIES

Hydro Re-dispatch Issues and Impediments

Re-dispatching hydroelectric generation to firm up the intermittent generation of power from wind or other renewable energy resources is a relatively new issue that has not been embedded into operating strategies and procedures. The Bonneville Power Administration (BPA) has undertaken and study to evaluate the costs and opportunities associated with integrating wind energy into the Federal Columbia River Hydroelectric System (FCRPS). In March 2004, BPA announced two new services. These are; the Network Integration Service and the Storage and Shaping Service.

The Network Integration Service will be charged to customers in the BPA Control Area at a fee of $4.50/MWh (subject to annual escalation).

The Storage and Shaping Service is designed to serve the needs of utilities and other entities outside the BPA Control Area who have chosen to purchase the output of a new wind resource but do not want to manage the hour-to-hour intermittency associated with wind. To facilitate the service, BPA's Power Business Line will take the hourly output of new wind projects into the BPA Control Area, integrate and store the energy in the Federal hydro system, and re-deliver it a week later in flat peak and off-peak blocks of power to the purchasing customer. To help reduce transmission costs, return energy will be capped at 50 percent of the participant's share of project capacity. The base charge for storage and shaping service is $6.00/MWh, escalated annually at the GDP Implicit Price Deflator.

BPA's Storage and Shaping Service is illustrated in Figure 25. This service is an example of what might be applied to the Federal Hydro system in California, as well as the Feather River, Hetch Hetchy, Pit River and Colorado River hydro systems. It is recognized that management of water with these hydro systems are less flexible than the FCRPS due to constraints imposed by water use for irrigation, fishing and recreation. Nevertheless, each hydro system should be investigated to see what energy storage and release services might be possible, and what fees might apply for it to be profitable for all concerned. Such studies and recommendations could be completed by 2010.

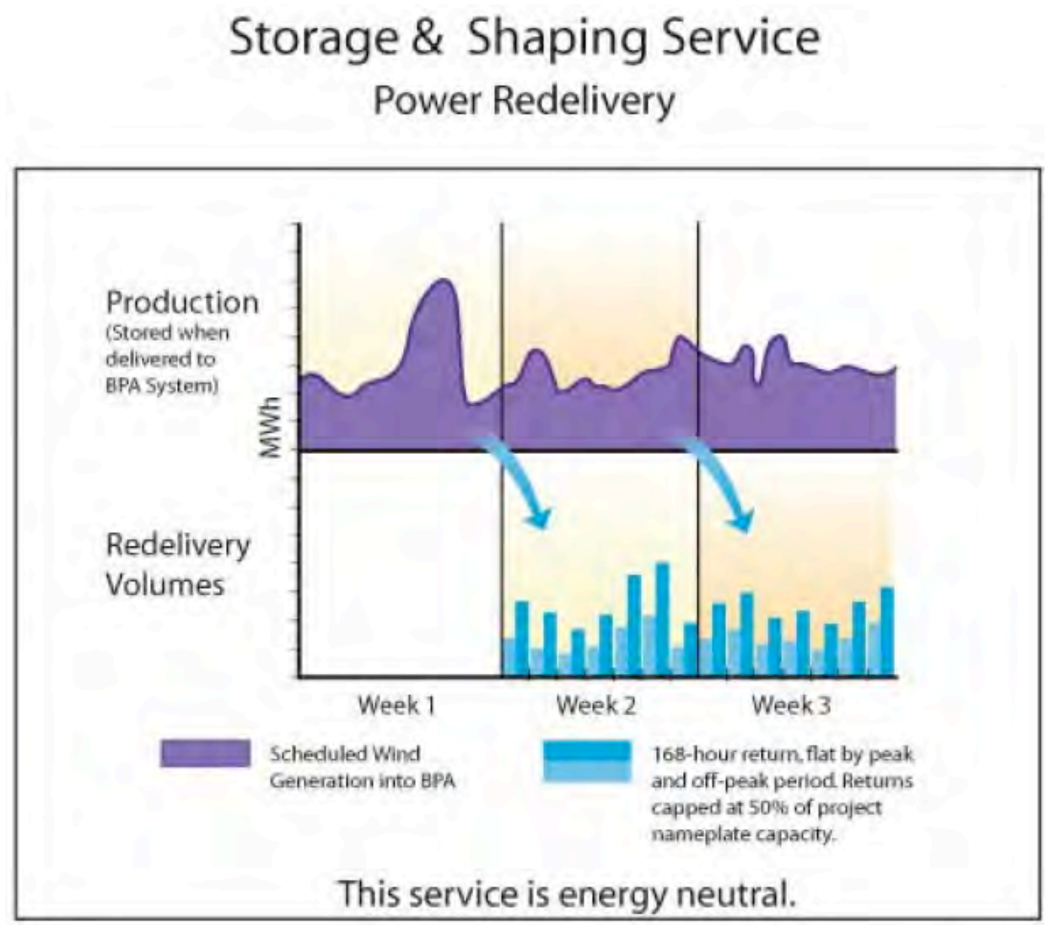


Figure 25: BPA's wind energy Storage and Shaping Service
Source:
http://www.bpa.gov/Power/PGC/wind/BPA_Wind_Integration_Services.pdf

The ability of existing hydroelectric plants to be used to firm or shape intermittent renewable energy may be more or less depending on the flexibility available to re-schedule water release, the water storage capacity of reservoirs and whether or not the river system is in flood. For run-of-the-river plants there may be no firming capability available because of limited reservoir capacity.

An initial screening of western hydroelectric facilities has been made to identify those that could plausibly be used for the purposed outlined above. These are listed in Table 5.

Table 6
Western Hydroelectric Generating Plants

Hydroelectric System	**Capacity (MW)**
Pit River & James E. Black	682
Federal Hydro (Keswick, Judge Francis Car, Trinity, Spring Ck, Shasta)	1,250
Tuolumne (SFCPUC - Moccasin, Kirkwood, Holm), (Don Pedro, New Melones)	852
SMUD plants	710
Feather River (Butt, Bucks, Cresta, Caribou, Rock, Belden, Poe, Thermalito, Hyatt)	718
Mokelumne River (Hydro Project 1, Collierville)	502
Big Creek (Big Creek, Mammoth Pool)	804
King River (King River, Pine Flat, Kerchoff2 Haas)	516
Upper Columbia River (Grand Coulee, Chief Joseph)	8,563
Hoover Dam	2,074
Total	16,671

Conceptual Estimates of Transmission Upgrade Scenarios

Tapping the PDCI in Northern Nevada

The studies undertaken on this subject conclude that a viable tap to the PDCI can only be accomplished with a solid ac transmission base to anchor the tap to in northwestern Nevada [2]. The alternative to this is to radially feed onto the tap without any connection to the network of Sierra Pacific Power resulting in a non-firm interconnection.

There will be need to integrate the renewable power fed onto the PDCI at the tap with the hydroelectric power from the Columbia River. Under these conditions, the electric power fed into southern California network from the PDCI will be no greater than the system is designed for. Consequently no new facilities are required in the receiving system network other than what is already recognized as needed.

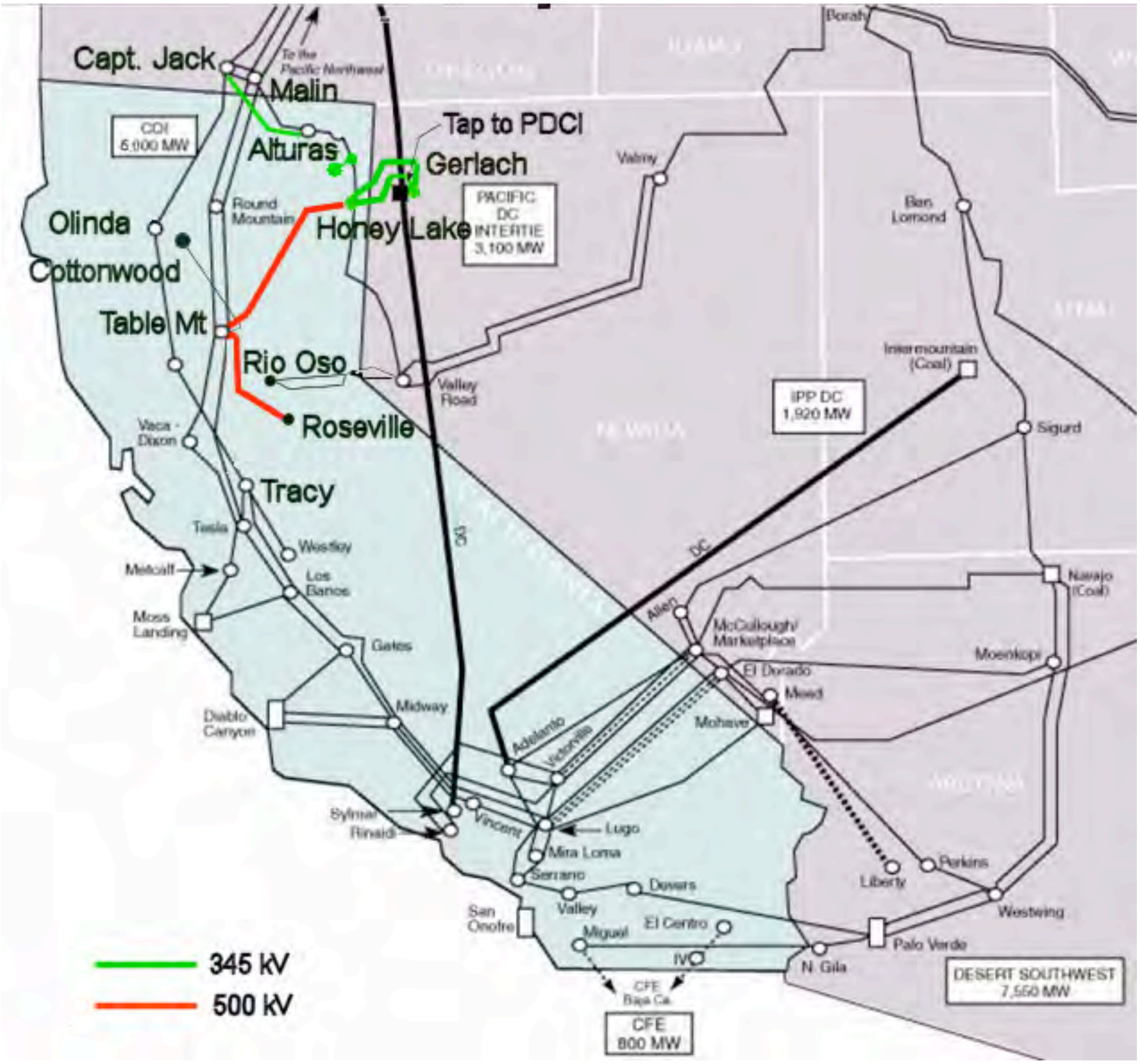
To get access to 2000 to 3000 MW of developable renewable power from northern Nevada in the period up to 2017, significant new transmission facilities must be constructed. If the collector lines for all the renewable generators (geothermal and wind) can be brought to a common point at the transmission line to PDCI, then an interconnection to the PDCI could be affected. A reasonable size for the interconnection is 1500 MW.

It would be possible to interconnect from the collector system of renewable energy generators in northwest Nevada to the PDCI with a non-firm connection to the Sierra Pacific Power (SPP) grid. If the interconnection is lost, the non-firm connection to SPP limited to just several 100 MW would open up to protect SPP's power system from the loss. This is not a satisfactory way to tap the PDCI.

It is preferable to have a firm connection to PDCI from the tap to SPP to strengthen SPP and provide opportunity for SPP to trade energy reliably. With a rating of the tap at 1500 MW, this can be achieved with additional trans-Sierra transmission from the vicinity of the tap to the 500 kV transmission grid of California. This is shown in Figure 26 where a 500 kV ac transmission line traverses the Sierra Nevada Mountains to terminate at Table Mountain substation. In addition the 345 kV Alturas line is extended to Captain Jack substation in southern Oregon.

To relieve some of the congestion south of Table Mountain with the 500 kV trans-Sierra transmission line terminating there, one option is to feed the Western Area Power Administration's 230 kV transmission line from Cottonwood to Roseville substations in at Table Mountain and rebuild the section from Table Mountain to Roseville at 500 kV.

Figure 26
Tap of the PDCI near Gerlach



Tap of the PDCI near Gerlach, with 500 kV trans-Sierra ac transmission line from new Honey Lake substation to Table Mountain substation, with the 230 kV transmission line from Cottonwood to Roseville upgraded to 500 kV. The Alturas 345 kV line is extended to Captain Jack substation.

New HVAC Transmission: COB to Sacramento/Bay Area

There are wind energy developments in southern Oregon that could feed into California. However, developments of significant size (250 to 2000 MW) are limited by available transmission capacity. The main 500 kV transmission lines across COB into northern California are often de-rated and would be subject to congestion, particularly if competing with renewable power from northeast California and northwest Nevada.

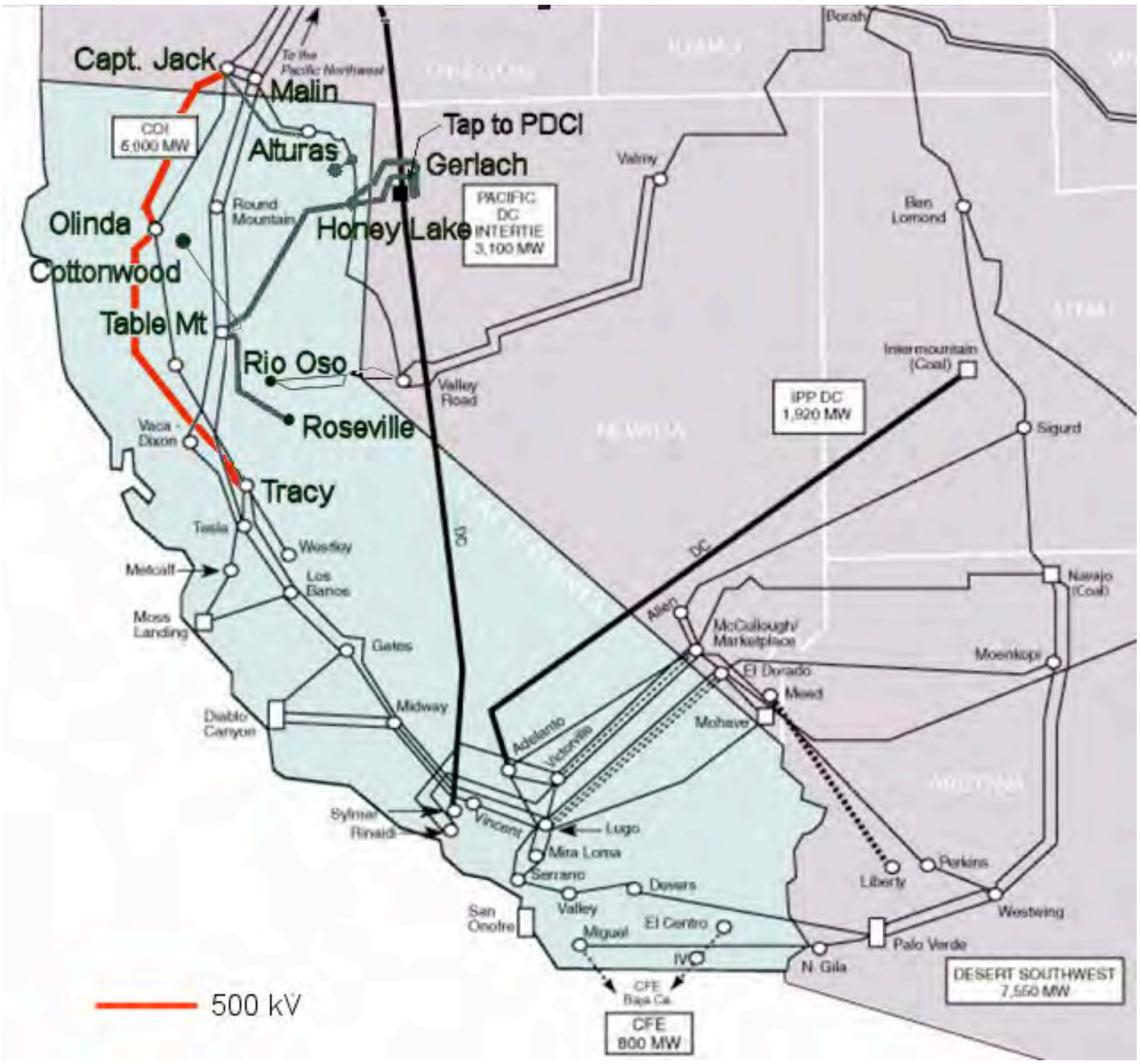
One potential option solution to accommodate up to 2000 MW of northern renewable energy into northern California is to build another 500 kV transmission line across COB and into Tracy or Tesla substations. This line could be ac or dc, but for the purpose of this assessment, only ac is considered.

Of the many options for a fourth 500 kV transmission line, one is to parallel the existing Captain Jack – Olinda – Tracy 500 kV transmission line as shown in Figure 19. This option will utilize the 345 kV extension of the Alturas line to Captain Jack, and the 500 kV trans-Sierra transmission line.

There are potential benefits to integrating a fourth 500 kV transmission line across COB with the 345 kV extension of the Alturas line from Captain Jack, along with new 500 kV Trans-Sierra transmission as shown in Figure 16. The obvious benefit is improved reliability for the northern California transmission system, but also for increased access to northern hydroelectric generation, including the Colombia River system and BC Hydro.

To add a fourth 500 kV transmission line from COB to the Sacramento/Bay Area may require upgrading of the sending end and receiving end ac systems. Any transmission reinforcements at or into the terminating substations will require additional study not included herein.

Figure 27
A new 4th 500 kV transmission line across COB



A new 4th 500 kV transmission line across COB, with the tap of the PDCI and the 500 kV trans-Sierra ac transmission line. The Alturas 345 kV line is extended to Captain Jack substation.

Capital Costs for the Transmission Upgrades

Conceptual budget capital costs of electric power transmission for staged development of renewable energy in northeast California and northwest Nevada are summarized in Table 6. The main assumptions upon which this cost analysis is based are as follows:

1. Transmission and substation component capital costs are based on the Western Area Power Administration's 2003 manual "Conceptual Planning and Budget Cost Estimating Guide," which was provided for this project. The costs are in 2003 dollars.

2. Costs are escalated from 2003 to 2005 at 2.5% pa. The costs are if constructed in the year 2005.

3. Major transmission only is considered. Collector system transmission and added receiving end distribution costs are not included.

Table 6
Conceptual capital cost (in 2005 $) of transmission for NE California and NW Nevada

Description	Possible in-service date before Year	Capital Cost $\$M_{(2005)}$		
		Transmission	Substations	Total
Extend Alturas 345 kV Line to Capt. Jack. Build New Gerlach and Honey Lake Substations (560 MW)	2012	90	40	130
Construct a Trans-Sierra ac transmission line at 500 kV from Honey Lake to Table Mountain substation, and upgrade Table Mt. to Roseville 230 kV line to 500 kV (720 MW)	2015	250	95	345
Build a 1500 MW tap to PDCI	2017	20	260	280
Construct a 500 kV ac transmission line from Capt. Jack to San Francisco Bay Area (1500 MW)	2017	470	30	500

Other Options: New DC Line – Southern California to Rockies Wind Region

A number of projects have been proposed by various developers to bring largely coal-generated energy into California with some portion allocated to wind energy.

Permitting the transmission lines for such projects is challenging, and if successful, could be in place by 2017. Several of these options have been conceptually evaluated through SSG-WI and are illustrated in Figures 28.

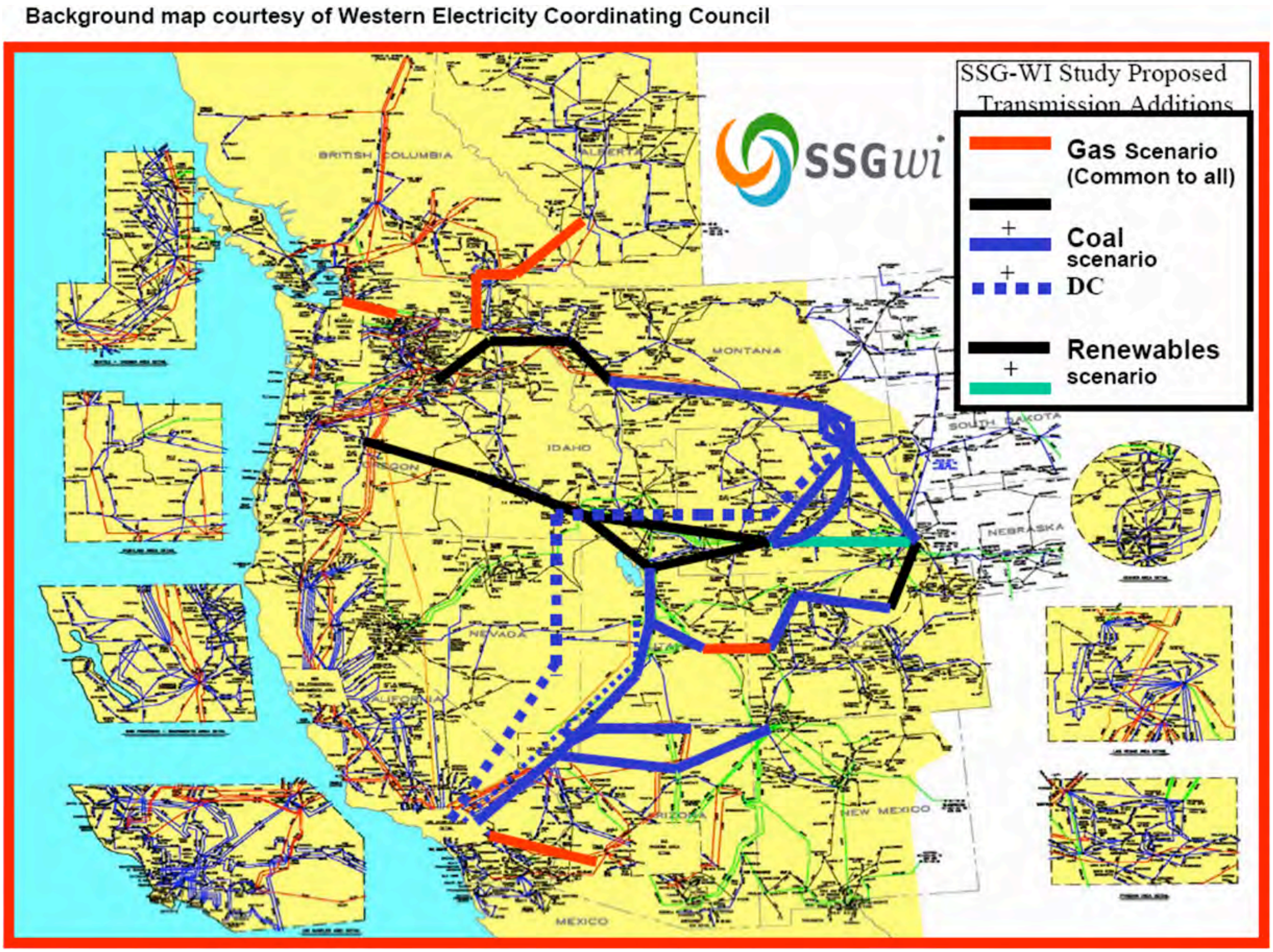


Figure 28: Major interconnections proposed by SSG – WI Study

SECTION 5: TEMPORAL PRODUCTION PROFILES FOR WIND POWER PROJECTS LOCATED IN THE WEST

Introduction

As larger quantities of wind power are considered for supply to the California electricity system, it is important to better understand its potential operating characteristics. Depending on wind power production correlates to system loads, wind power can have a wide range of capacity value. Where wind power plants across a wide geographic area are serving a particular utility load or control area, it is important to understand the aggregate production profile or those plants. Where wind power from a concentrated geographic area is serving load through a particular transmission line that is also supporting other generating resources, it is important to be able to plan for the integrated operation of the generating plants with the line. It is therefore, important for power and transmission planning efforts to fully understand the anticipated seasonal and diurnal production profile characteristics of major wind resource areas.

Wind power production experiences diurnal and seasonal variations that vary among different resource areas and sites. As a result, some wind power sites may have temporal wind patterns that better match electrical load or wholesale market prices than others.

The California Energy Commission is interested in temporal wind production patterns for sites located both within and outside of California for two distinct reasons:

1. to inform an understanding of whether wind sites outside of California – but able to deliver their output into California – are a better, or worse, match to California's electricity load and prices than are sites located within the state, and

2. to help develop hourly wind power production data that might be used in modeling work that the Energy Commission is currently involved in.

In the work reported here, we present data and analysis that informs both of these needs, though our focus is more on the former than the latter. We first present preliminary results from a study being conducted by Berkeley Lab that evaluates how temporal wind production patterns from the Pacific Northwest and California match Northwest and California electricity loads and prices. As detailed later, the Berkeley Lab work uses three difference sources of wind production data: actual wind power production from specific wind sites, anemometer-derived production estimates, and modeled wind production from AWS Truewind.

In addition to briefly reviewing the Berkeley Lab results, this work also sought to compile additional sources of wind speed and production data from the WECC. Some of these data come in the form of actual hourly wind speed or production values, while other data come in more aggregated form. This paper reviews the results of our data collection effort, and an associated Excel workbook provides the data that we were able to collect.

As shown in the pages that follow, we find that wind sites with the most favorable temporal patterns may have a wholesale market value that is as much as 15% higher than those sites with less favorable characteristics (assuming a $40 per megawatt-hour (MWh) average wholesale market price, this equates to ~$6/MWh). Similarly, sites with more favorable characteristics will often have much higher production during the hours of highest customers load (a loose correlate for capacity value). Variations in temporal production patterns among sites are therefore significant, though perhaps not overwhelmingly so.

We further find that many California wind power sites experience reasonably consistent patterns of high production in the spring and early summer months, with diurnal patterns during this period that peak at ~12:00 midnight and fall to a low at ~12:00 noon. At other sites throughout the West, seasonal production variations are less uniform. Many sites experience production peaks in the winter months, while others experience either less-pronounced seasonal variations or – in a limited number of circumstances – spring and summer peaks similar to California resource areas. Diurnal patterns outside of California are often less-pronounced, as many of these resource areas are driven by storm fronts, not temperature-driven pressure differences.

Overall, we find little evidence that wind sites located outside of California will be a significantly better match to California load or prices. If anything, the California sites appear to have higher production during the summer months on average, and therefore more closely match California's summer peak load, although production often appears to peak in July and has begun to drop off in the high-load months of July – September. Despite this, it deserves note that most California sites do not have particularly favorable diurnal patterns, at least relative to some of the other Western resource areas, which may diminish the wholesale market value of these sites, and weakens the correlation between wind production and high levels of electrical load.

Overview of Draft Berkeley Lab Report

Berkeley Lab's report, "Analyzing the Effect of Temporal Wind Patterns on the Value of Wind-Generated Electricity at Different Sites in California and the Pacific

Northwest", remains in draft form. A final review draft is expected to be completed within a month, and the final report is likely to be completed within two months. Here we present the preliminary results of that work.

Methods

Berkeley Lab uses wind power production data from California and the Pacific Northwest (Oregon, Washington, Idaho, Montana, and Wyoming). These data derive from three sources:

- AWS Truewind: High resolution wind maps have been produced by AWS Truewind for California and the Northwest. These maps, which typically report wind speeds and wind densities on an annual average basis, are built from more finely-tuned estimates of seasonal/monthly and diurnal wind speeds. Because data provided for California and the Northwest differ somewhat, some data manipulation was required to put that data on a comparable basis. These temporal pattern estimates have not been used in the public domain, and have not been validated to any significant degree. A key purpose of the Berkeley Lab report is to assess whether these temporal estimates provide useful information.

- Anemometers: The Berkeley Lab study uses actual hourly wind speed measurements from 103 anemometers in the Northwest and 82 anemometers in California, transformed into hypothetical wind power production using standard techniques. The anemometer data were originally collected by the Kenetech Corporation, by the Bonneville Power Administration, and by the DOE's Candidate Site program.

- Metered Production: Actual metered production from wind farms is not often available publicly. However, the Berkeley Lab study uses actual hourly metered production from California's three major wind power resource areas, as well as monthly production data from most of the new wind facilities in the WECC (this data come from forms submitted to the EIA and FERC). Actual metered production data, especially on a diurnal scale, is limited, and these data are therefore use sparingly in the Berkeley Lab report.

To various degrees, the data above had to be manipulated to ensure comparability. For example, a wind turbine power curve had to be used in some cases, and different height adjustments had to be applied. These methods, though necessary, make the reported results somewhat uncertain. The full Berkeley Lab report, still in draft form, provides more details on the methodology used, and limitations therein.

The wind production data are then correlated with historical 2000 – 2003 load in California (and the Northwest), and to historical and forecasted wholesale electricity prices in California (and the Northwest). Hourly load data derives from data submitted to FERC through Form 714. Historical California prices come from the Power Exchange (July 1998 – June 1999), as an average of the day-ahead hourly zonal prices for NP15 and SP15. Forecasted prices are the average of hourly forecasts for all California hubs for 2006-13, provide by Joel Klein of the Energy Commission. This forecast was part of the baseline case for the Energy Commission's 2003 "Electricity and Natural Gas Assessment" report.

Monthly/Seasonal and Diurnal Production Profiles

For a number of the prominent or possible wind resources areas in California and the Pacific Northwest, Figures 27 and 28 provide the monthly wind production profiles derived from the three data estimates above.

As shown here, California's major current wind resource areas (Solano, Altamont, Tehachapi, San Gorgonio) all experience similar seasonal trends, with peaks in late spring to early summer. Other not-yet-developed wind sites experience different patterns. In the Pacific Northwest, seasonal production variations are less uniform. Many sites experience production peaks in the winter months, while others experience either less-pronounced seasonal variations or – in a limited number of circumstances – spring and summer peaks similar to California resource areas. Also note that, while there is a reasonable amount of agreement among the three data sources used to derive wind production patterns for some of the resource areas shown in Figures 29 and 30, there are also significant differences in some cases (see, e.g., Tehachapi and San Gorgonio in Figure 27).

Figures 31 and 32 provide the diurnal profiles associates with these same wind resource areas, for both January and July. Here we again see that the three wind production data sets do not perfectly agree. Note, however, that because we have limited actual wind production on an hourly time scale, most of these plots are only comparing the AWS Truewind and anemometer data. Nonetheless, for the four current major California wind resource areas, we see that in the high-wind month of July, wind production is expected to peak at ~12:00 midnight and then reaches a low at ~12:00 noon. In the Northwest, we see far less diurnal production variation, on average, with some sites experiencing generally flat production throughout the day, and others experiencing late-evening peaks.

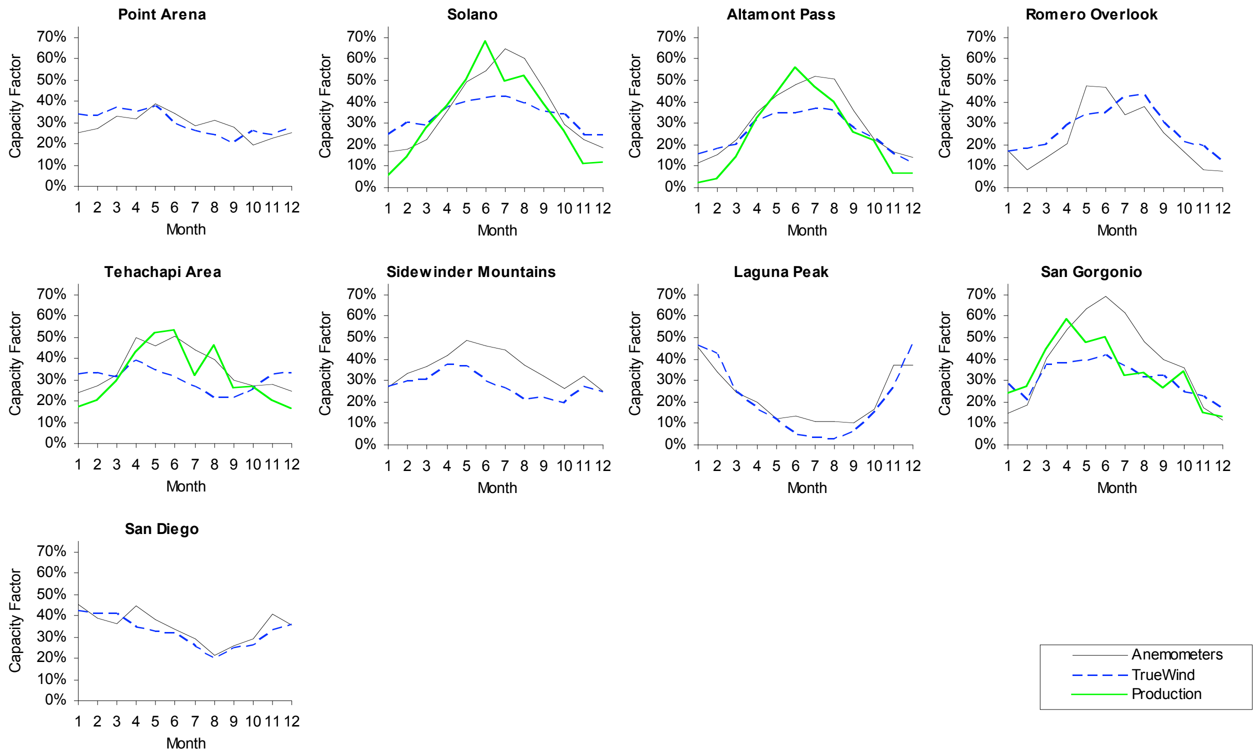


Figure 29. Monthly Average Capacity Factor for Selected Possible Resource Areas (California)

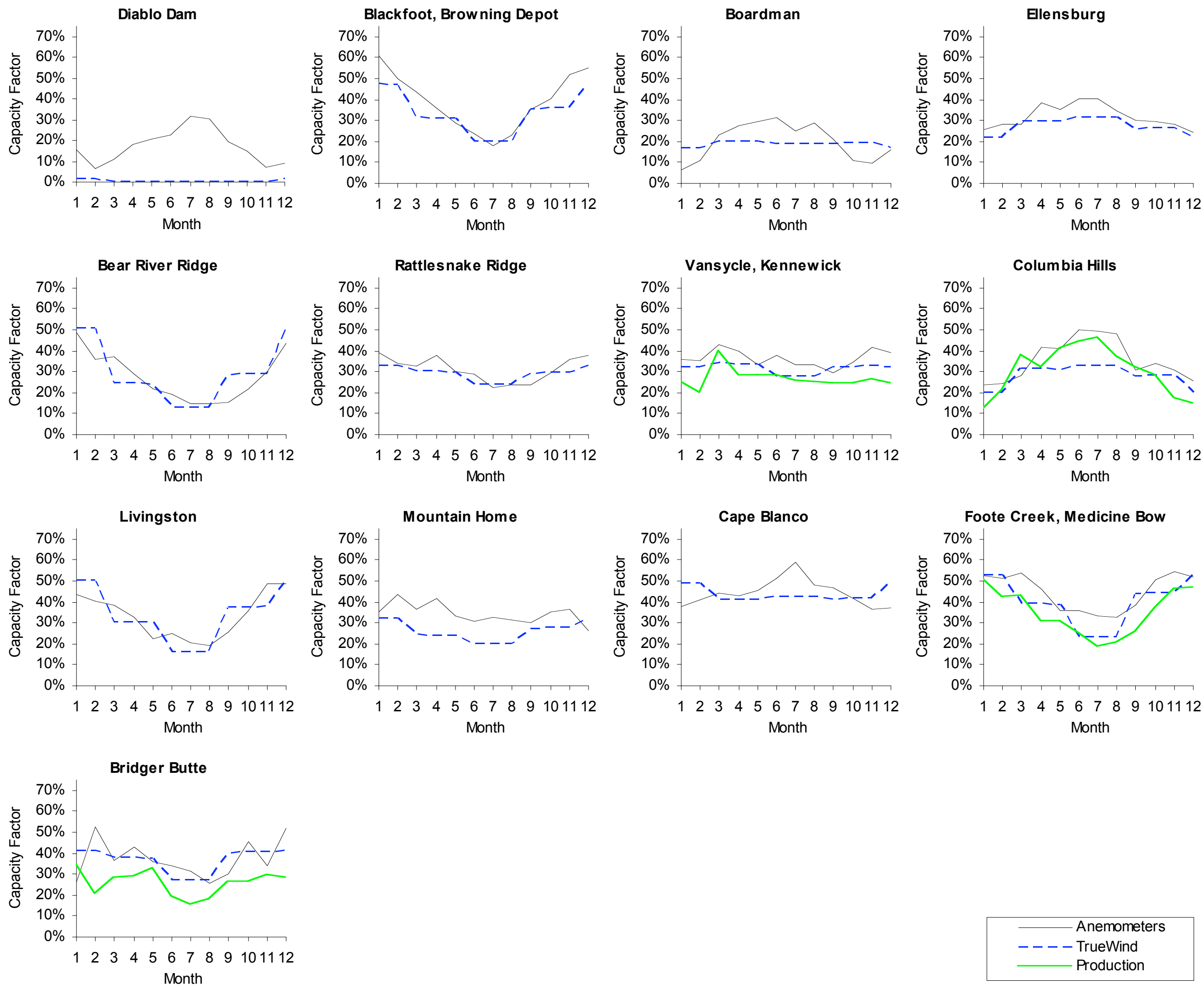


Figure 30. Monthly Average Capacity Factor for Selected Possible Resource Areas (Northwest)

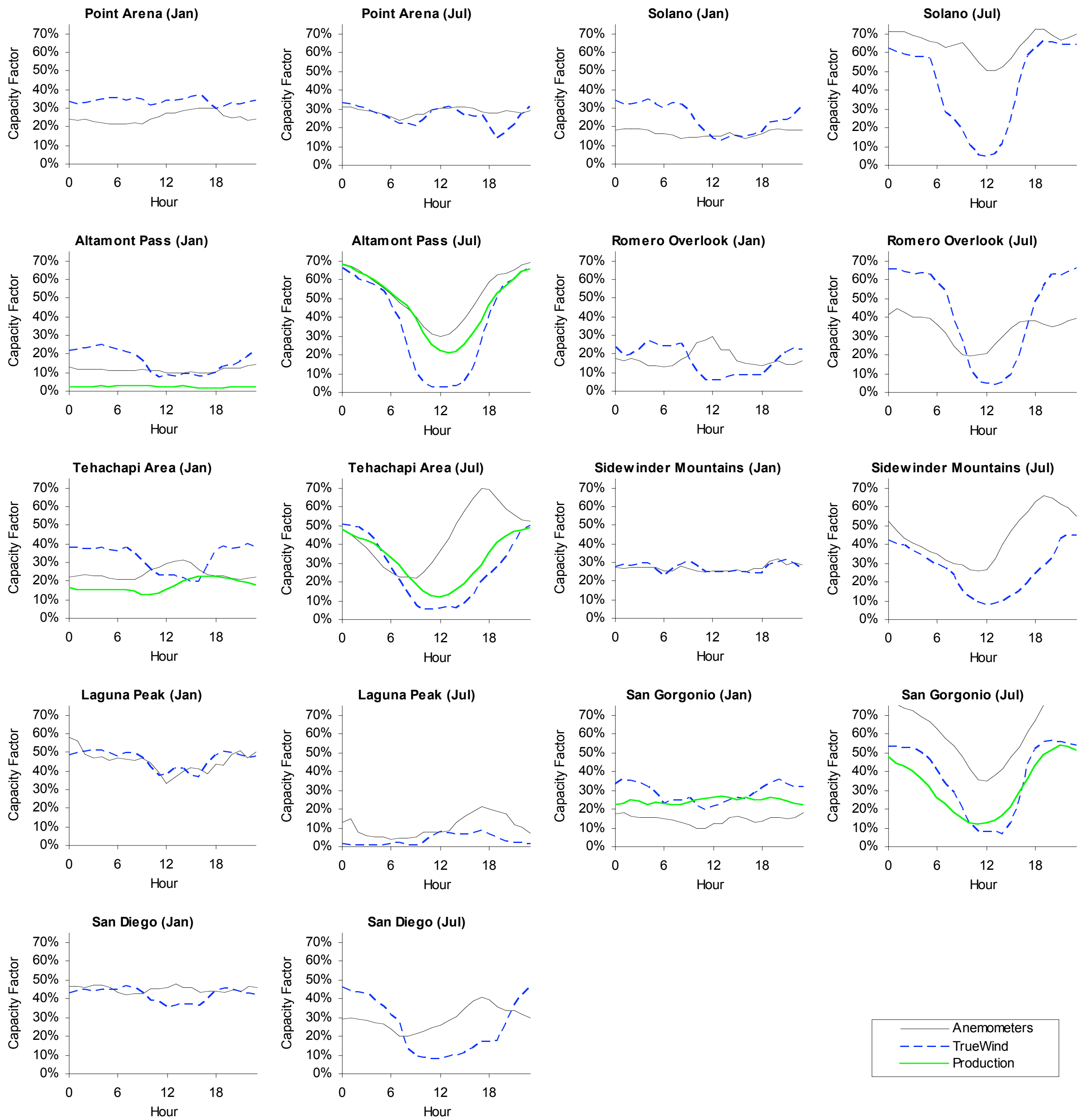


Figure 31. Diurnal Average Capacity Factor for Selected Possible Resource Areas (California)

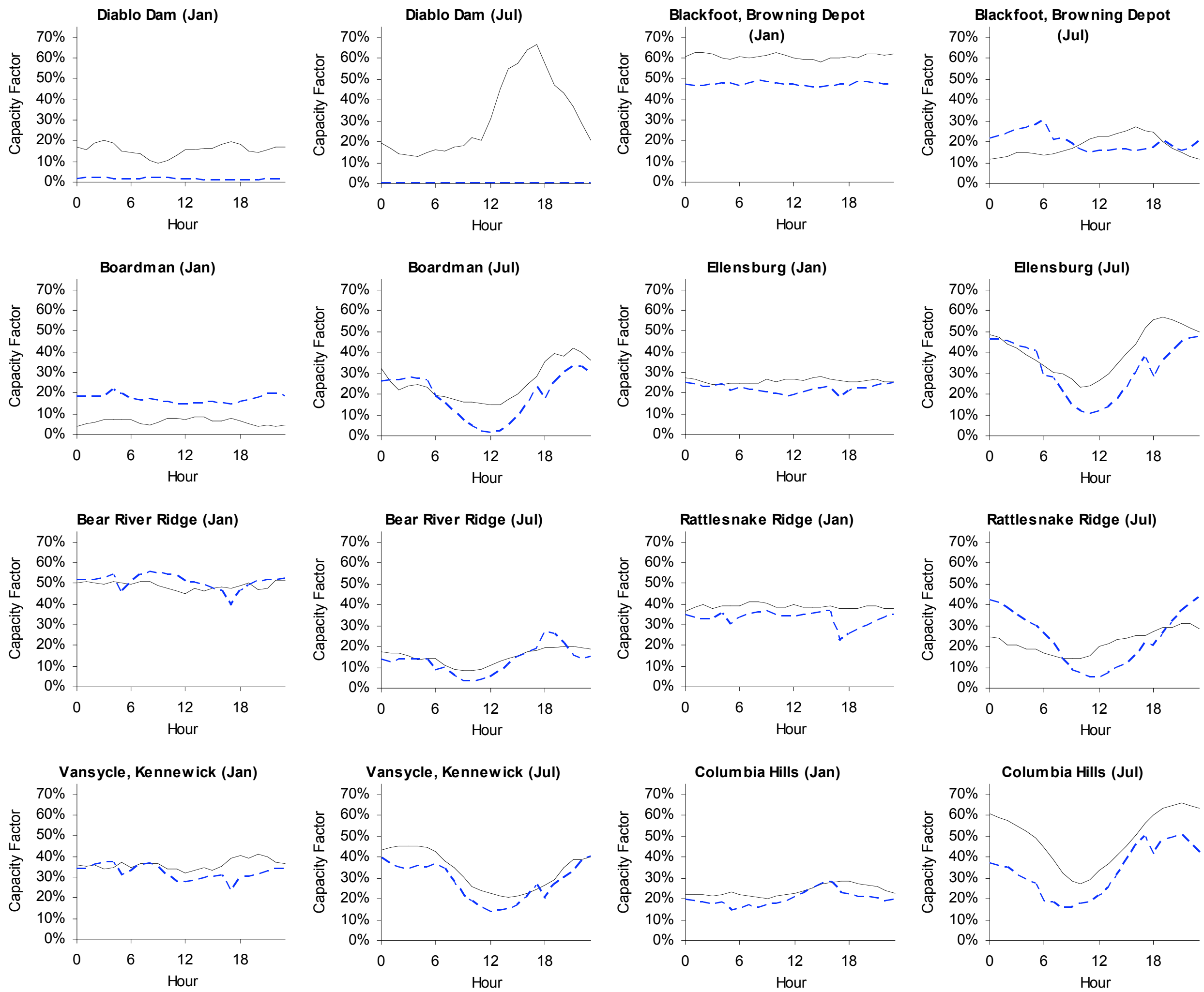


Figure 32 Diurnal Average Capacity Factor for Selected Possible Resource Areas (Northwest)

Comparing Wind Production to Wind Value Metrics

In addition to providing the wind power production profiles, these profiles were compared with historical load and historical and forecast wholesale market prices in California (correlations with Northwest value metrics was also conducted, but is not reported here). There is quite a lot of disagreement among our three wind production data sets, especially for California. The reason for these differences is unclear, but may relate to the gross assumptions that had to be made to scale wind speed data at lower elevations to estimates of wind production at higher elevations.

Figures 33, 34 and 35 provide the results of this analysis, focusing again on a select group of major current or possible future wind resource areas.

- **Historical Load:** Figure 33 presents data on the correlation of wind production in California and the Northwest with California's electricity load. Here we focus on the expected capacity factor of a wind site in the top 10% of California's load hours, an imperfect proxy for wind's capacity value. The median effect of wind timing shows the percentage increase or decrease in the capacity factor in these top 10% of load hours, compared to the annual average capacity factor. For example, results for Tehachapi using anemometer data show that in the top 10% of California's load hours, the median capacity factor for a Tehachapi wind project will be perhaps 45% above its annual average. Using AWS Truewind data, however, suggests that the capacity factor during these top 10% of load hours will be perhaps 70% below the annual average. Actual Tehachapi wind production data show that the capacity factor in the top 10% of load hours may be approximately the same as the annual average. Though Tehachapi is a particularly acute case of disagreement among our three wind production data sets, there is significant disagreement in other cases as well. All else equal, more confidence should clearly be placed on the actual wind production data than AWS TrueWind estimates or anemometer data (though production data is only available for three California wind resource areas). Overall, we find that different sites perform very differently in the top 10% of load hours, but that California sites in general are neither clearly superior to nor clearly inferior to Northwestern sites.

- **Historical Prices:** Figure 34 presents data on the correlation of wind production in California and the Northwest with California's historical wholesale electricity prices. Here the median effect of wind timing shows the median percentage increase or decrease in wholesale market value derived from the wind site, relative to a wind site that experienced flat production on a seasonal and diurnal basis. In San Gorgonio, for example, all three wind production data sets generally agree: median temporal wind patterns will decrease market value by ~3-7% relative to a project that provides power on a flat basis 24x7. For some other sites, there is greater disagreement among our three wind production data sets. Overall, we find that temporal wind patterns can affect wholesale market value by as much at 5% over a flat block of power to as little as10% lower than such a flat block. Said a different way, the best temporal wind resource areas may have a wholesale market value that is ~15% higher than the worst wind areas. However, neither Northwestern nor California sites appear systematically more valuable than the other.

- **Forecast Prices:** Figure 35 presents the same results, but with forecast wholesale electricity prices. Here we again find that temporal wind patterns can affect wholesale market value by as much at +5%/-10%, with the best sites performing ~15% better than the worst sites. With a base wholesale price forecast of $42/MWh, this means that the difference between the best and worst wind sites may see a difference in wholesale market value of ~$6/MWh. In this case, Northwestern sites appear, on average, to be a slightly better match to California wholesale market prices than California sites.

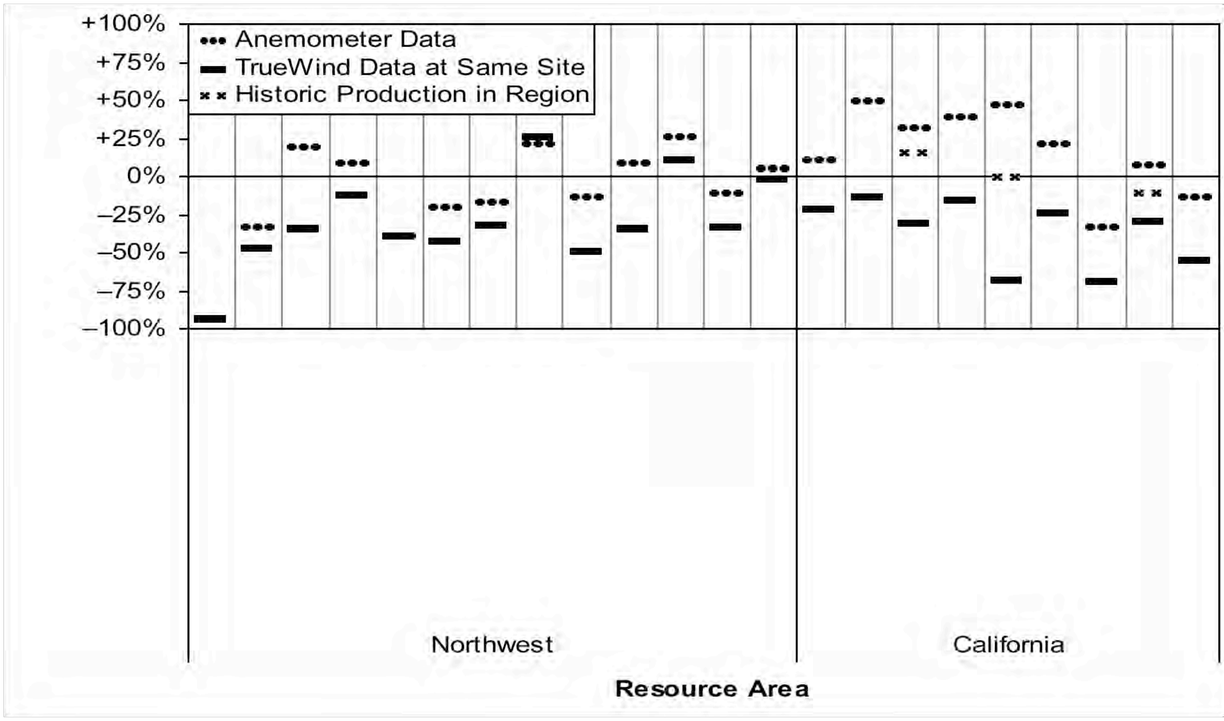


Figure 33. Median Effect of Timing on Load-Weighted Capacity Factor at Selected Resource Areas, Based on Historic California Load

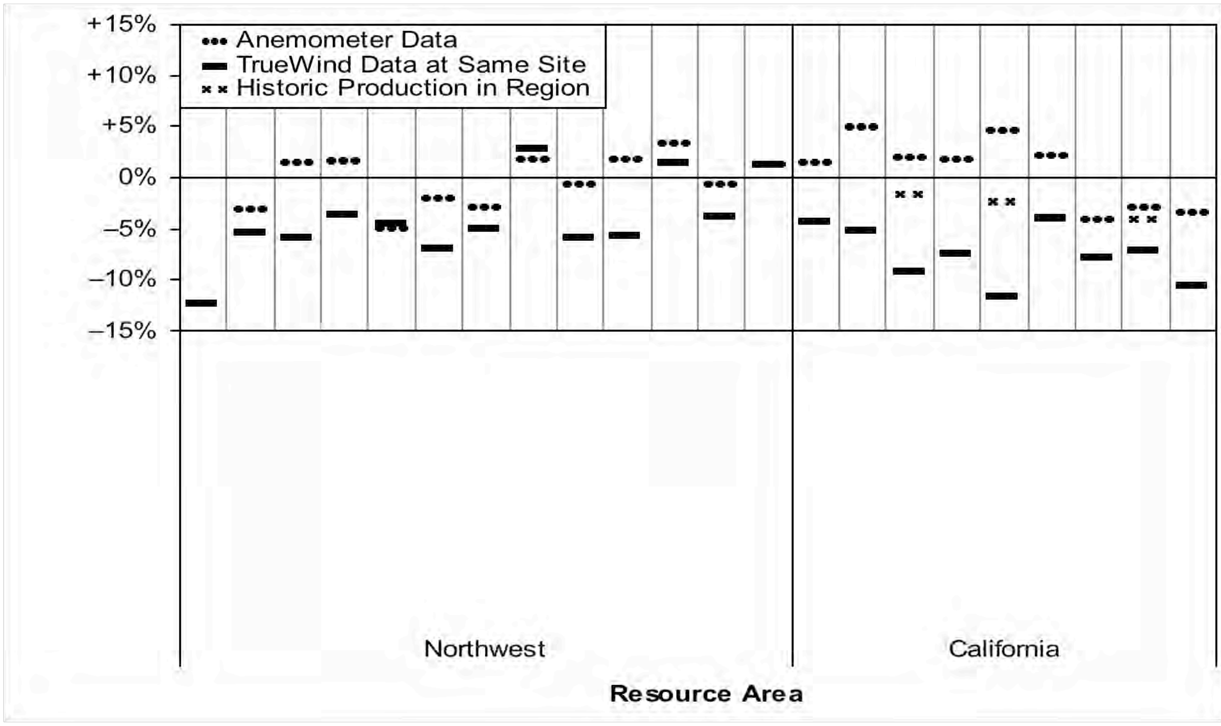


Figure 34. Median Effect of Timing on Market Value at Selected Resource Areas, Based on Historic California Prices

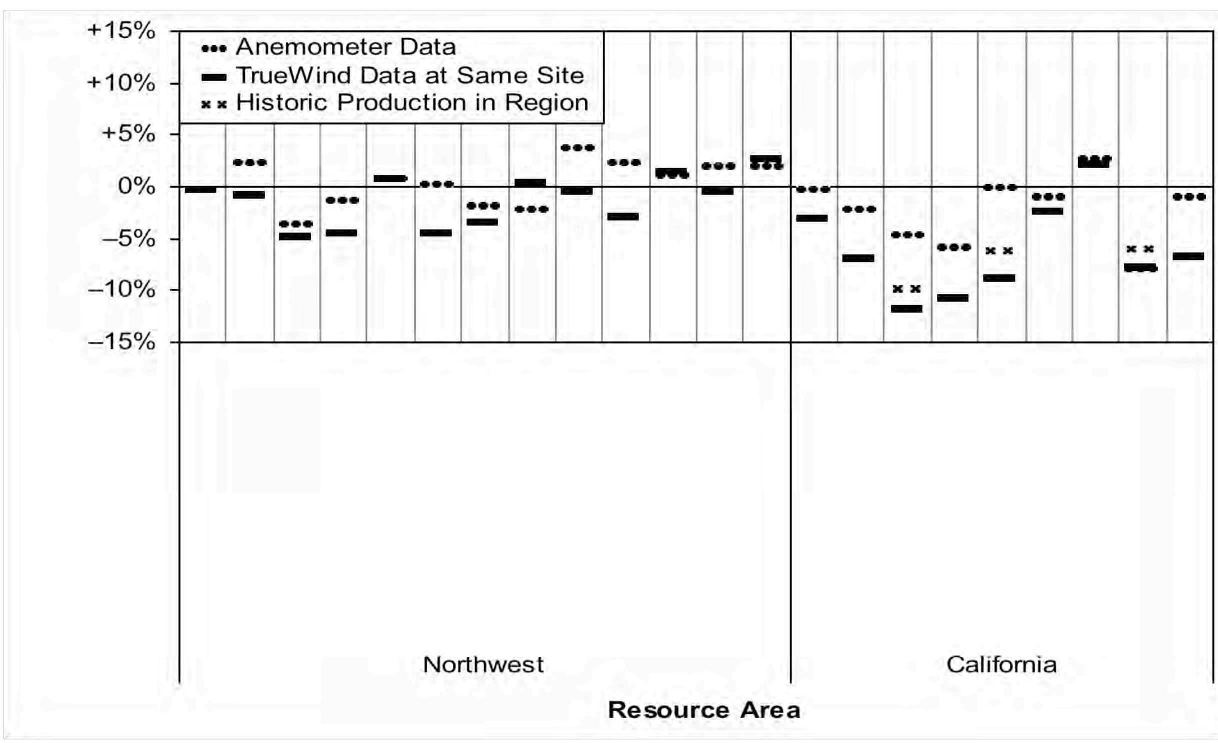


Figure 35. Median Effect of Timing on Market Value at Selected Resource Areas, Based on Forecast California Prices

Other Data Sources for Temporal Wind Profiles

Data Sources That Were Used

In addition to the data embedded in the Berkeley Lab analysis, we also sought other publicly available wind profile data. The results of those efforts are provided in a supplemental Excel workbook. This workbook contains data from the following sources:

- **Actual Monthly Production Data, by Project:** Many wind power projects are required to report temporal wind production to FERC (through quarterly reports) and to the Energy Information Administration (EIA) (Form 906). Much of this data is provided on a monthly basis, but some is only provided on a seasonal basis and in a very few cases information is provided on an hourly (or even 10-minute) basis. Data gaps and other problems are an issue with these sources. In the Excel worksheet, we sought to merge the EIA and FERC data, to fill gaps or resolve data problems, where they existed. The data represent up to 4 years' worth of monthly net generation from more than 1,600 MW of actual wind projects built in the WECC since 1999.

- **Actual Hourly Production Data, by Project:** Actual hourly production data was available from the three major wind resource areas in California (2002 data from Altamont, Tehachapi, San Gorgonio, all from the same sources as those used by the California Wind Energy Collaborative in their recent wind integration work), and from the 16.5 MW FPL Green Power project built in 1999 in the San Gorgonio area (2004 production data, from FERC quarterly reports). These hourly data, and associated monthly and diurnal graphs, are presented in the Excel workbook.

- **Utility Integrate Resource Plans (IRP):** Western utility IRPs sometimes provide wind profiles. In a review of twelve recent Western utility IRPs, we were able to identify four IRPs in which wind profiles were provided. Of these, Sierra Pacific provides wind profile data consistent with that in a recent power purchase agreement that it signed with a wind developer (and that data is presented elsewhere in the workbook). Idaho Power, PSE, and Avista all use monthly wind production profiles generated by the Northwest Power and Conservation Council for six different general resource areas throughout the Western U.S. It is these data that are presented in the Excel workbook.

- **Power Purchase Agreements (PPAs):** Power purchase agreements for wind power also sometimes provide monthly and/or diurnal wind profiles, typically created by the developer's meteorologist. Upon review of publicly available wind

PPAs in the West, we identified six such PPAs that contained wind profile information. These include projects in Nevada (2), Washington (1), Wyoming (1), Idaho (1), and Montana (1).

- **Other Anemometer Profiles:** The Berkeley Lab work, reported earlier, used anemometer data from California and the Pacific Northwest. The Kenetech and DOE Candidate Site program also had anemometers in other Western states. Here we report monthly and diurnal profiles from 14 such anemometers in Nevada, 3 in New Mexico, and 1 in Colorado.

- **RMATS Data:** A number of transmission planning studies have been conducted in recent years, and others are underway. These studies have sometimes used wind profiles, typically created by the National Renewable Energy Laboratory. Here we present the profiles created by NREL for the Rocky Mountain Area Transmission Study (RMATS). These data provide hourly wind production estimates for fourteen different general wind resource areas in Idaho, Wyoming, Montana, Colorado, and Utah. These data are also transformed into monthly and diurnal profiles. The wind speed data used to construct these estimates come from anemometer data – collected in different years – available through the Utility Wind Resource Assessment Program (Colorado East and West), Utah Energy Office (Utah), and Kenetech (Montana, Wyoming, Idaho).

Data Sources Not Used

In addition to these sources, we identified several other possible sources for which data are not presented here, for a variety of reasons. These data include:

- **EIA Form 906 Data for Older California Projects:** California projects built prior to 1999 also report monthly production data to the EIA. These data are publicly available, but we do not report on these data here because the data from the aggregate sum of these projects is effectively provided through the actual hourly production data for Tehachapi, San Gorgonio, and Altamont, discussed earlier.

- **Actual Hourly Production Data, by Project, NREL:** NREL receives data on actual hourly production (and production on an even finer time scale) from a number of wind projects in the Western U.S. These data are not publicly available, but may be available to the Energy Commission depending on the need and level of data confidentiality that could be maintained. If the Energy Commission is interested in these data, we recommend contacting NREL directly.

- **Other Transmission Studies:** Other completed and planned transmission studies are using or are developing wind profiles for modeling purposes. The SSG-WI modeling efforts, for example, used a wider range of wind profiles, generated by NREL, in their first modeling effort. In their current modeling efforts they are expecting to again use wind profile data from NREL. We have not sought to obtain these data, but they should be available through NREL. These profiles are generated using a combination of anemometer data (Kenetech, DOE Candidate Site, BPA, other) and actual project-specific output (see previous bullet). In addition, transmission planners are expecting to evaluate a 4000 MW wind export case out of New Mexico and into California (perhaps through SSG-WI). Wind profiles have apparently been created for that effort, based on AWS Truewind analysis, but we have not yet been able to receive those data in a readable format.

- **Other Anemometer Data:** Several other sources of anemometer data exist that might also be used, beyond those used here.

Select Results

Figure 36 reproduces the monthly profiles of 1,600 MW of actual wind projects located throughout the WECC (based on FERC and EIA data). The California projects show the most pronounced late spring, early summer peak. The Wyoming projects are winter peaking, as are many of the projects in Colorado and New Mexico, while the Oregon and Washington projects are mixed: some are spring/summer peaking, while other are winter peaking.

The actual hourly production data, by project, show similar monthly profiles for California, illustrated in Figure 37. On a diurnal basis, the peaks are typically around midnight, with a low point in and around noon. The diurnal profiles of the California wind projects are not particularly favorable, given peak loads in the afternoon period.

Though not shown here, the other data included in the Excel workbook demonstrate that the diurnal profiles of wind resource areas outside of California are sometimes more favorable relative to a mid-afternoon peak load. However, in many instances, these projects have monthly profiles that are poorly matched to California's summer peak.

Overall, it would appear that these results do not fundamentally alter the findings of the draft Berkeley Lab study: California's wind resource areas appear, in general, to have a superior monthly profile relative to California load and prices, compared to many of the wind resources in the rest of WECC, but California's diurnal profile is somewhat less favorable than some of those in other Western states. On net, though certain resource areas may be more favorable than others, resources areas outside of California do not, in general, appear to be significantly more or less favorable than California resource areas.

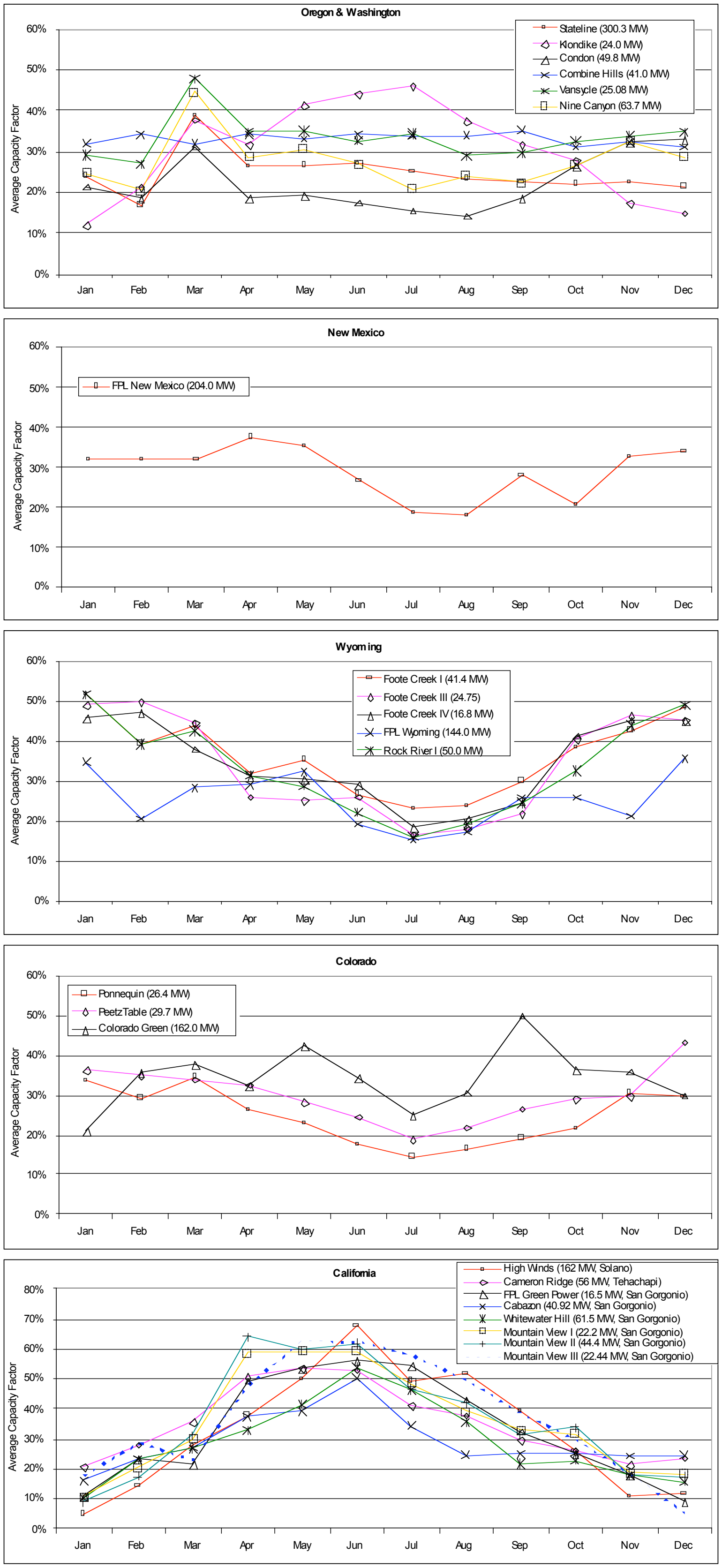


Figure 36 Monthly Profiles of Actual Wind Projects in WECC

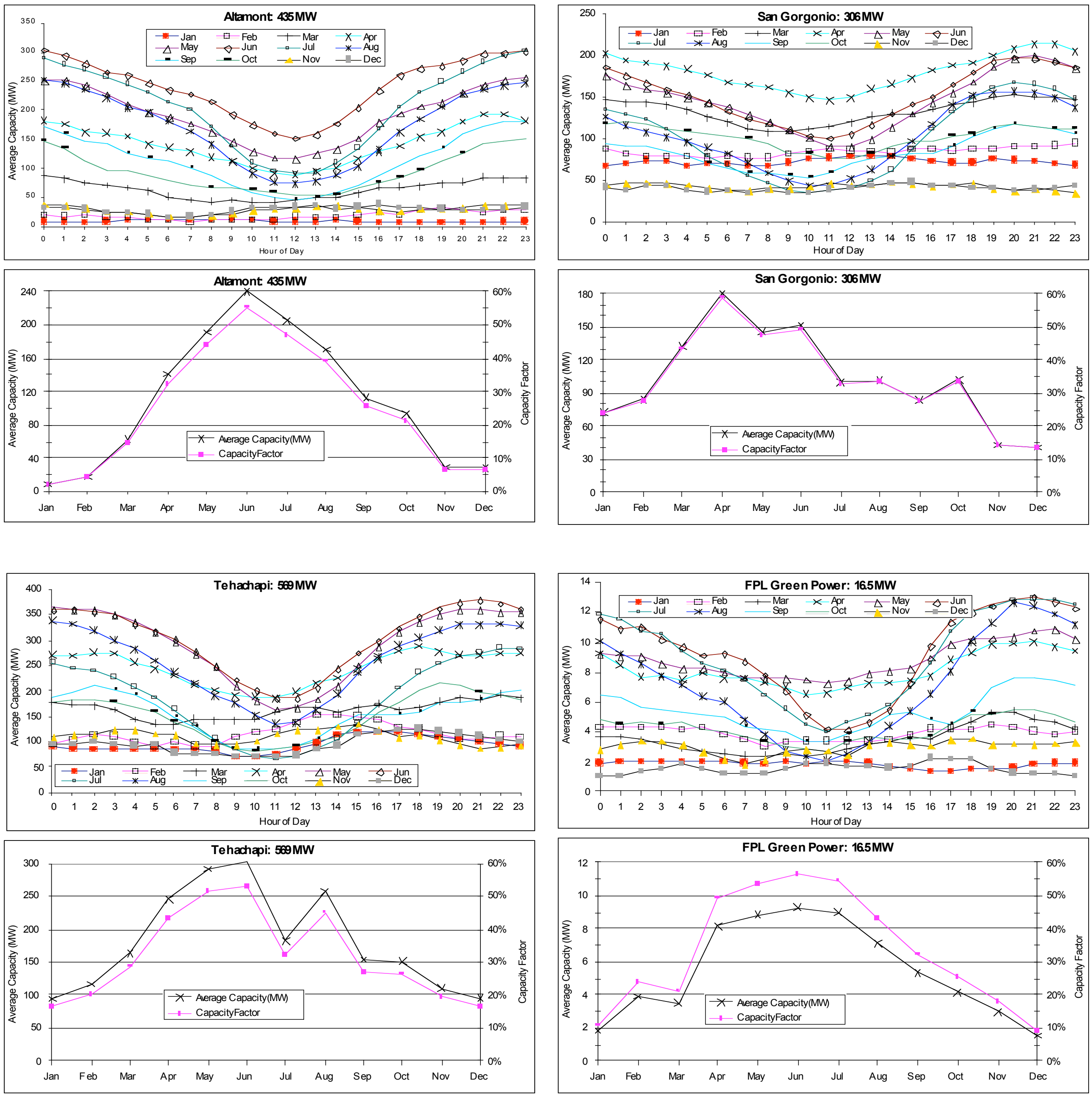


Figure 37 Monthly and Diurnal Profiles of California Wind Sites

REFERENCES

[1] Hetch Hetchy/SFPUC Programmatic Renewable Energy Project, Deliverable D1.1.1.1 Report on a Recommended List of Transmission Options. April 10th, 2003.

[2] Hetch Hetchy/SFPUC Programmatic Renewable Energy Project, Deliverable D1.1.2.1 Interconnection Model Development Report. May 17th, 2004.

[3] Hetch Hetchy/SFPUC Programmatic Renewable Energy Project 1.2: "Wind Site Identification and Qualification."

[4] California Energy Commission, Draft Staff White Paper, "Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond," Prepared in support of the 2004 Integrated Energy Policy Report Update Proceeding (03-IEP-01), July 2004, 100-04-004D.

[5] Hetch Hetchy/SFPUC Programmatic Renewable Energy Project 1.3: "New Geothermal Site Identification and Qualification."

[6] Hetch Hetchy/SFPUC Programmatic Renewable Energy Project Deliverable D1.1.3.1 Report on the Feasibility of AC Transmission Interconnections.

[7] http://www.3m.com/market/industrial/mmc/accr/

[8] http://www.compositetechcorp.com/

[9] John Vithayathil, "AC-DC Converters with Bi-directional Thyristor Valves," US Patent 6,587,362, July 1, 2003.

[10] Lionel O. Barthold "Current Modulation of Direct Current Transmission Lines" U.S. Patents 6,714,427 B1, and 6,804,128.

[11] Hetch Hetchy/SFPUC Programmatic Renewable Energy Project 4.3, Energy Storage for Renewable Generation.