REVISED METHODOLOGY TO ESTIMATE THE GENERATION RESOURCE MIX OF CALIFORNIA ELECTRICITY IMPORTS

Update to the May 2006 Staff Paper

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REVISED METHODOLOGY TO ESTIMATE THE GENERATION RESOURCE MIX OF ELECTRICITY IMPORTS TO CALIFORNIA

Introduction and Summary

This paper presents a revised method to estimate the resource mix and associated greenhouse gas (GHG) emissions of electricity that is generated out-of-state to serve California's load. Some method is needed to help set the historic and current resource mix, so that load-serving entity (LSE) responsibility for GHG targets may be set and progress traced.

Establishing a consistent emissions counting convention for the historic sources of generation is necessary to implement AB 32. A statewide control total will help set the starting point for allocating responsibility for emissions to individual LSEs. Implementation of AB 32 will attribute responsibility to individual electric LSEs for the GHG emissions associated with the electricity generated to serve their load.

Estimating the resource mix of imports is important because out-of-state generation plays a significant role in the sources of California's electricity. Approximately 22 to 32 percent of electricity consumed in California is generated out-of-state with about one-quarter coming from the Northwest and three-quarters coming from the Southwest. Electricity imported into California is generated by coal, natural gas, hydroelectric power, nuclear energy, and renewables. Coal-based generation is of particular interest because conventional coal produces significantly more greenhouse gases per unit of energy than do most other generation sources.

Staff's existing method assigns an average regional system mix to all imports from the Northwest and the Southwest. This method assumes that all electricity imported into California's control areas is the same. The revised method disaggregates imports into specified ownership or contracts and market purchases. The specified purchases are assigned to the specific resource type and the market purchases are assigned an estimated resource mix. This revised method grew out of research following a June 7, 2006 Energy Commission public workshop commenting on staff's original May 2006 draft update to its existing method.

The method would apply to 2001 through the transition to AB 32 counting conventions that will be developed in the next year. Those more detailed reporting requirements will replace the need to estimate unspecified resources. It is not necessary to revise the method for 1990 through 2000, because during that time the regulated system produced traceable purchases and exchanges. The methodology could also be considered as a method for assigning resource types to the generation used by individual LSE imports.

At the June 7, 2006, workshop, parties supported the proposal to separately track individual ownership shares and contracts with identified generation. In our example year of 2005, this category of specified resources accounted for 56 percent of imported electricity. Parties had more questions about how to characterize the remaining 44 percent of unspecified generation. In this paper staff has expanded the analytic base regarding unspecified imported resources.

Staff developed this method because a disaggregated tracking approach is superior to using regional system averages. It:

- More closely tracks with ownership shares and purchase patterns.
- Accounts for the increased role of natural gas as the marginal resource.
- Can record how California LSEs change the sources of their generation purchases.
- Fits better into AB 32 GHG accounting, which will track whether California LSEs are reducing the carbon content of their generation. Under the average system mix approach, the only way an LSE could reduce its out-of-state carbon content would be to cut its imports.

This paper will be discussed at an April12 public workshop held by the Energy Commission and the California Public Utilities Commission. After that workshop, decisions will be made on next steps. The proceeding will need resource mix totals for Northwest and Southwest imports for 2001 through 2006. Future statewide control totals for imports could be computed annually. These can serve as control totals for assuring that all GHG emissions from California-caused generation have been accounted for.

The revised method presented in this paper is to

1. Use the annual net electricity imports measured at California control area borders as a control total. This is not changed from the existing method.
2. Adjust import totals so that units located in California control areas but outside the state's border (for example, Intermountain and Mohave) are counted as imports. This change to accounting on a geographic basis is more compatible with how other states track generation.
3. Subtract the generation produced by resources owned by or under specified contracts to California LSEs and attribute that nuclear, coal, hydro, and natural gas generation directly to the LSE. Specified resources accounted for 71 percent of Southwest imports and 12 percent of Northwest imports in 2005. This change helps link the statewide total to the known purchases of LSEs and is similar to the approach used by Washington and Oregon.
4. Allocate the remaining unspecified resources based on a marginal generation analysis for the Southwest and on a hybrid method of marginal analysis and sales assessments for the Northwest. For the Southwest, the, unspecified imports would be allocated to 4 percent coal and 96 percent natural gas. This method change reflects the increasing role of natural gas as the marginal

resource, while retaining the role of Northwest hydro power as a key swing resource.

The resulting resource mix for all Southwest imports in 2005 is: 57.4 percent coal, 11.4 percent nuclear, 3.4 percent hydropower and 27.9 percent natural gas. The resulting resource mix for all Northwest imports in 2005 is: 10.5 percent coal, 2.3 percent nuclear, 65.3 percent hydropower 2.4 percent renewables, and 19.4 percent natural gas.

Staff engaged in an extensive and continuing dialogue with Washington and Oregon energy staff regarding how to compare and coordinate our tracking systems. The exchange has produced a better mutual understanding of the purposes, strengths and weaknesses of our tracking systems and a shared frustration over data gaps. The staffs have noted inconsistent accounting rules for our voluntary reporting systems, and agreed that further regional cooperation and analysis is needed. The Energy Commission staff will continue to work with other Western states to reconcile differences between different tracking methodologies. A consistent western methodology will avoid the possibility of double-counting or the use of innovative accounting practices to shift the attribution of GHG emissions when implementing global climate change programs in one state or the other.

This research has identified some difficulties with all current tracking systems. Tracking electricity generation from source to use is complicated by both actual market operations and data availability. While the system is dispatched on a least-cost, transmission-constrained basis, buyers and sellers engage in multi-year, seasonal, daily and hourly sales and exchanges. Energy may be sold multiple times and may be a financial settlement rather than an actual dispatch. Tracking of generation currently doesn’t account well for gross exports across state lines or trading. It also doesn’t account for the different voluntary conventions now being used to report an LSE’s generation footprint through the purchase of ‘green energy credits”.

Background: Reasons to Revise the Existing Methodology

Currently there is no public, western-wide system that identifies the generation source of the electricity imports that are delivered to specific population centers in California. In the past, the Energy Commission staff has estimated this resource mix using simplistic assumptions that allocate the amount of imported electricity to specific fuel types. The annual average power mix in different Western Electricity Coordinating Council (WECC) regions was used to represent the assumed generation source for imports. The resulting resource mix estimates are reported in the Energy Commission’s *Net System Power Report*, published annually since 1997.

The Energy Commission requires California control area operators to report the annual amounts of metered electricity flows through the major transmission lines that cross the State line. This represents the amount of electricity imports and exports, but is not specifically linked to transactions. Electricity imports and exports are grouped into two regions, the Pacific Northwest and Desert Southwest. For simplicity, the Energy Commission staff assumed that the annual average power mix in each region was representative of the generation source for imports from each region. This approach was based on the theory that the generation was built to serve California and native load equally.

In the 1990s, staff was able to collect detailed reports from all California utilities and to trace much of their fuel sources. The switch to a hybrid competitive market added many more sellers and buyers, as well as introducing many more types of transactions. The investor-owned utilities sold portions of their generation, so the role of market purchases increased. After electricity restructuring commenced in the late 1990s and electricity markets expanded, tracking sources of imported power became more difficult. There were more LSEs to track, less detailed interchange information, many more types of contract products in the market, and an expanded set of sellers.

As described in Appendix A and in more detail in the May 2006 Energy Commission staff paper *Proposed Methodology to Estimate the Generation Resource Mix of California's Electricity Imports* (CEC 700-2006-007), staff previously calculated the fuel mix of all imported resources, whether owned by California utilities or purchased from out-of-state suppliers, using the average generation mix percentages of the Pacific Northwest and the Southwest. These percentages were applied to the annual import totals obtained from California control areas. The results were used in the annual Gross System Power estimate and the Net System Power Label required by SB 1305 (Sher, Chapter 796 of the 1997 statutes).

Stakeholders have agreed that assigning a uniform profile to every imported electron is misleading. When staff knows that a power plant is owned or contracted for by a California LSE, that power plant's fuel type and emissions should be attributed to California. If the "average mix" approach is used to estimate the GHG emissions associated with imports, then LSEs will have no incentive to import from less carbon-intensive resources. Changing the types of out-of-state investments would be diluted by being included in the regional average.

The "average mix" methodology also ignores the likelihood that electricity from low-cost baseload power plants owned by out-of-state utilities is primarily dispatched to serve their own local customers. Regulated utilities, including the owners of out-of-state coal, have the fiduciary obligation to provide electricity to their ratepayers from the lowest cost resources. Coal-fired power plants in the West are owned by utilities (92 percent) and independent power producers that have long-term contract commitments (8 percent). The average mix methodology instead assumes that out-of-state generators export a portion of their baseload generation to serve California consumers. It also treats generation owned by California LSEs as if it was part of the undifferentiated energy provided in the Northwest and Southwest regions.

With the new need to establish a rigorous statewide baseline for tracking GHG emissions and with detailed data that could improve the accuracy of the estimates, staff decided it was time to update the “average mix” approach. Since data was available directly for all coal, nuclear and hydroelectric units owned or directly contracted for by California LSEs, that fuel mix could be established with greater certainty. This narrowed the amount of power that still needed to be estimated to that which came from undisclosed sources, approximately half of total imports during the 2001–2005 study period.

During the 2006 term of this research activity, the Energy Commission needed to publish a historic baseline of greenhouse gas emissions from all California sources. That December 2006 report, *Inventory of California Greenhouse Gas Emissions Sources and Sinks:1990 – 2004* (CEC 600-2006-013), used a hybrid method to estimate the emissions, taking some of the lessons from this research and indicating that future modifications would be made when a revised method was completed. This hybrid method is described in Appendix B and is relevant for parties who wish to understand how the revised method would affect the overall electricity sector GHG totals in the inventory.

Framework of Analytic Issues

The remainder of this paper uses a question and answer format, largely based on the questions raised in public comment at the June 2006 workshop. The report addresses Southwest imports and Northwest imports separately. These two regions function differently in the California market. Due to the doughnut-like nature of the West’s transmission grid, power flow dynamics and transmission costs to import electricity from remote generation facilities, it is not economic, except in highly dysfunctional market conditions, to purchase power in Oregon and ship it all the way around the West to enter California at the southern border.

As Table 1 shows, 75 percent of imports (22 percent of total generation) comes from the Southwest and that only 25 percent (7 percent of total) comes from the Northwest. It also shows that 56 percent of total imports comes from firm, known generation sources.

Table 1: 2005 Net Electricity Imports (GWhs)

Import Type	NW	SW	Total	% of Total
Specified Imports	2,404	44,159	46,563	56%
Unspecified Imports	17,882	18,083	35,965	44%
Total Imports	20,286	62,242	82,528	
Regional %	25%	75%		

Source: California Energy Commission

Southwest

Southwest: Coal as a Marginal Resource

Staff's initial proposal was that Southwest imports could be split into firm and nonfirm imports. Specified imports are mostly baseload coal, with some nuclear and hydropower. Unspecified imports were estimated to be primarily short-term purchases from the market marginal resource. Modeling showed the Southwest's marginal resource to be natural gas.

Question 1: Is it correct that if natural gas is setting the marginal price in the Southwest import market that all imports are from natural gas? Couldn't sellers be generating from lower-cost coal and selling it at the higher natural gas price?

Ms. Devra Wang, Natural Resources Defense Council (NRDC), stated at the 2006 workshop that

> (NRDC) acknowledges that the current methodology for estimating the generation resource mix of electricity imports might overestimate the amount of coal-fired generation. However, the (NRDC) analysis suggests that the proposed methodology may be overly conservative and appears to underestimate the amount of coal-fired generation that is actually imported.

NRDC suggested that the market clearing price analysis approach might underestimate the amount of coal-fired generation since California could be purchasing electricity from both coal and natural gas resources during the same period even though natural gas would be setting the market-clearing price.

Answer 1: Staff concurs with NRDC that the May 2006 market clearing price analysis did not document that all generation sold at the market-clearing price was the generation which set the market-clearing price. In response, staff conducted a new analysis, simulating the Western Energy Coordinating Council (WECC) electricity system to investigate how the out-of-state generation resources would be dispatched if California imports declined. The thesis being tested in the study was:

> If California is indeed importing coal-fired generation, then total generation from this resource should decline when California electricity import levels are lowered. If Southwest coal generation does not decline when California reduces import levels, then that coal is being used to serve non-California customers.

Using a simulation for 2008 Western electricity market performance, the staff developed three scenarios, each reducing the amount of electricity that could be delivered over the Southwest transmission lines. Normally, electricity is imported when it is cheaper than in-state generation resources, as long as transmission reliability constraints are satisfied.

While the Southwest transmission lines are rated at a 13,000 megawatts (MW) transfer capability, in reality imports are limited by Southern California import constraints to about 11,500 MW. Of this amount of transfer capability, approximately 4,500 MW is dedicated to imports from coal, hydro, and nuclear generation that is owned or contracted by California LSEs. The electricity imports from these resources represent about 71 percent of the total Southwest deliveries, with the balance coming from system purchases. To test the hypothesis that natural gas is the resource used to fuel system purchases, the staff reduced the remaining transmission transfer capability.[1]

Three cases were tested:

- Case 1, the transfer capability was reduced by 3,300 MW.
- Case 2, the transfer capability was reduced by 3,800 MW.
- Case 3, the transfer capability was reduced by 4,600 MW.

The simulation results show, for a constant level of demand, how the mix of generation changes within the Southwest and California, when the amount of transmission is reduced along the various import paths. Firm imports do not change; what changes is the amount of marginal generation available for unspecified imports and which generation types are turned on or backed down.

The simulation results measure the difference in annual generation mix for the three cases, compared to a business-as-usual base case. As Table 2 shows, in all three

[1] The transmission paths modeled were: Palo Verde to Imperial Valley (1,383 MW), Southern Nevada to SCE (3,000 MWs), Palo Verde to SCE (1,800 MWs), Utah to LADWP (1,900 MWs), Southern Nevada to LADWP (3,800 MWs) and LADWP to SCE (3,600 MWs). This totals 15,483 MWs because it had to also look at Northwest import paths to ensure that staff wasn’t artificially forcing power to flow over the D.C. intertie.

cases, reducing the import levels causes the output of natural gas-fired generation facilities in the Southwest to decline. The coal-fired generation operating levels change less than 0.1 percent. These coal units are still dispatched, just sold to non-California consumers. In-state gas-fired generation also increases to compensate for the loss of imported energy.

Case 1 reduces the transfer capability by 3,300 MW for electricity imports into Southern California. Coal-fired generation declines by 56 GWh from a base case level of 109,815 GWh. This is a change of less than 0.07 percent, an insignificant amount. Net Southwest natural gas generation declines by 647 GWh out of 63,853 GWh, 1 percent compared to the base case. The generation from many of the new natural gas generation facilities located in Arizona and New Mexico declines in the simulation but increases in Southern Nevada. This is a result of the price differentials among various regions in the WECC. In-state natural gas increases to make up the difference.

Case 2, restricting the transmission import capability by 3,900 MW, is a repeat of the Case 1 scenario, just with a more pronounced reduction of Southwest gas generation. There is no significant change in Southwest coal generation, and there are increases in compensating California natural gas. This again illustrates that when imports into California are constrained, it is Southwest gas and not Southwest coal that is turned off. Southwest coal continues to generate, presumably to serve Southwest needs.

Case 3, restricting import capability by 4,600 MW, shows that coal generation is reduced by 59 GWh, 0.1 percent. In this most restricted import case, a very small amount of coal is backed down. This 59 GWh would have been imported if there were transmission available.

The results from these simulations indicate that Southwest coal, other than that owned by California LSEs, is most likely not the marginal resource imported to California in unspecified contracts. The scenario simulations and the earlier marginal pricing analysis support the original proposal on the resource mix of the electricity imports from the Southwest.

Staff notes that there is a limitation to modeling hydro-generation, but this does not appear to be of major concern to the Southwest. An ideal model should also redispatch the hydro system. ProSym and other generation simulation tools lack this capability. The hydro-generation systems are characterized in the model to match the generation profiles under different water conditions.

Table 2: Reduced Imports: Case Study Results

Transmission Area	Fuel	Case 3 Generation Changes (GWh)	Case 2 Generation Changes (GWh)	Case 1 Generation Changes (GWh)	Basecase Total Generation (GWh)	Percent Change of Case 3 compared to Basecase
Arizona	Coal	3	(4)	(4)	41,003	0.0%
New Mexico	Coal	(33)	(40)	(43)	27,425	-0.1%
So Nevada	Coal	(0)	(2)	(1)	4,330	0.0%
Utah (Intermountain)	Coal	(29)	(7)	(7)	37,058	-0.1%
Total Southwest Coal Changes From Basecase		(59)	(53)	(56)	109,815	-0.1%
Arizona	Natural Gas	(557)	(512)	(454)	23,004	-2.2%
La Rosita	Natural Gas	(34)	(25)	(33)	2,500	-1.0%
Baja	Natural Gas	37	13	36	4,133	0.3%
New Mexico	Natural Gas	(84)	(99)	(140)	4,710	-2.1%
Palo Verde	Natural Gas	(577)	(545)	(481)	13,778	-4.0%
Southern Nevada	Natural Gas	600	278	425	15,728	1.8%
Total Southwest Natural Gas Changes From Basecase		615	(890)	(647)	63,853	-1.4%
Imperial Valley	Natural Gas	(81)	(78)	(77)	7,552	-1.1%
Miguel	Natural Gas	1	1	0	283	0.4%
SP15	Natural Gas	346	278	188	39,411	0.9%
San Diego	Natural Gas	30	10	7	6,047	0.5%
IID	Natural Gas	5	(5)	6	184	2.7%
LADWP	Natural Gas	49	4	(15)	11,680	0.4%
Total Southern CA Generation Changes From Base-case		350	210	110	65,158	0.5%

Source: Energy Commission Staff and Global Energy

Southwest: Loads and Available Capacity

Question 2: Isn't there excess coal available in the Southwest?

At the workshop, NRDC noted that Figure 8 in the May 2006 staff report shows that coal capacity was projected to be available for part of 2008 and that it had been available for nearly half the year in 1993, as shown in Figure 7. Figure 8, "Arizona 2008 Loads and Supplies" (p. 18), shows a load duration curve and simplified stack of capacity resources. NRDC interpreted the 2008 chart to show that there is likely excess coal available for nearly half of the hours in the year. This suggested that excess coal is available during both the shoulder periods as well as during the off-peak periods. NRDC suggested that the system purchases may include coal for more than just the 4 percent of total annual hours that was reported in staff analysis.

Answer 2: Figures 7 and 8 are reproduced in Appendix A. NRDC's interpretation is not a correct interpretation of the figures. Figures 7 and 8 showed two things – first, how the formerly excess amount of coal has been consumed by growth in Arizona load, and, second, that the generation that has been added in Arizona and that is now on the margin is natural gas. Comparing the 1993 actual and 2008 estimated load duration curves illustrates that electricity demand growth has increased significantly over the last decade and now exceeds the old baseload generation capacity. There used to be a significant amount of excess coal-fired generation in Arizona during the 1980s and early 1990s, but electricity demand has almost doubled, and only natural gas-fired generation was added to meet load growth until 2006 when Springerville Unit #3 (400 MW) as added. The new natural gas-fired generation has now become the resource on the margin.

The figures are limited in that they illustrate only dependable capacity in Arizona. They do not reflect all Southwest generation, actual generation or how plants would be dispatched.

Southwest Off-Peak Power Purchases

Question 3: On what basis does staff assert that California does not need off-peak imports from the Southwest?

The May 2006 staff report states that California does not need to purchase energy during many of the off-peak periods. NRDC requested a discussion on why California does not have a need for off-peak imports, even though it would be cheaper to purchase out-of-state power during the off-peak periods.

Answer 3: California typically does not purchase imported electricity during off-peak hours because:

- There is less demand in these hours compared to peak periods,
- In-state generation is operating as "must-run" for system reasons,
- Qualifying facilities often operate as round-the-clock operations,
- As-available wind generation is frequently highest in the off-peak periods, and
- Baseload DWR must-take contracts are still in force.

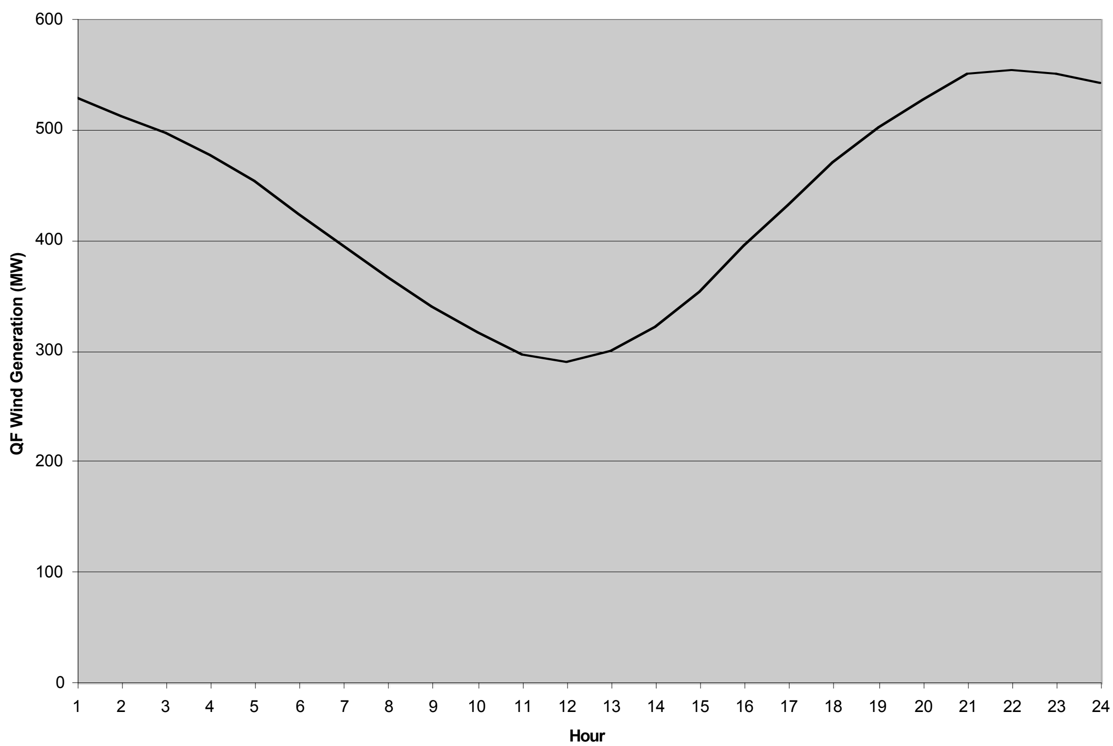
California loads are low in the off-peak hours. On a typical day, demand increases 60 percent from the midnight low to the afternoon high. On a hot summer day, this swing can be as much as 85 to 90 percent from early morning to afternoon peak. We have hourly load data from the California Independent System Operator for 2005. In that year, 36 percent of all energy was consumed during the 41 percent of hours defined as off-peak by WECC.

During off-peak hours, the California nuclear generation facilities, out-of-state ownership generation and a number of qualifying facilities are still operating at baseload profiles. There are also natural gas-fired facilities that will continue to spin at low levels in the evening just to be ready to operate during the higher load levels the next day.

The evening is also the time when wind generation typically increases. As a preferred resource, wind is taken whenever it is available and displaces the need to operate other thermal facilities and to import out-of-state power.

Figure 1 shows the average wind generation in California. The chart shows that wind generation is very cyclical, with wind generation at its lowest and highest levels during the noontime and late evening hours respectively. This cyclical pattern is present throughout all seasons of the year.

Figure 1: Average Wind Generation by Hour in California for 2003-2005



Source: Energy Commission staff data requests

Finally, some of the Department of Water Resources contracts have take-or-pay clauses that require generation to be accepted in the off-peak hours regardless of load. The utilities are actually selling the DWR must-take energy that exceeds demand during the off-peak

In sum, there is so much in-state generation that must run in the off-peak hours that California LSEs cannot take advantage of the lower price of Southwest resources during off-peak hours.

Southwest: Determining When Power Is Imported

Question 4: Does staff have more detailed information on the timing of imports than the quarterly information presented in the paper?

NRDC requested detailed profiles of the timing of the actual power flows on the transmission ties to the Southwest.

This information would help verify staff's contention that Southwest imports do not occur primarily in off-peak hours when coal generation is likely to be available and likely to be cheaper than natural gas-fired generation.

Answer 4: Energy Commission staff agrees this would be useful data but does not have this information. Unlike the Pacific Northwest, where the Bonneville Power Administration operates most of the transmission lines, the Southwest transmission ties are operated and controlled by several different entities, and obtaining quality data has proven to be a challenge. The Energy Commission staff has data from the California Independent System Operator but would need similar data from the Los Angeles Department of Water and Power and the Imperial Irrigation District control areas to compile a complete data set.

California ISO data alone isn't sufficient because it accounts for just half of the import capability. According to the WECC data for West of Colorado River entitlements, 5,419 MW out of a total of 10,118 MW are owned by Southern California Edison and San Diego Gas & Electric. These are controlled by the CALIFORNIA ISO. The remaining 4,699 MW are owned by LADWP, IID, the southern cities, and DWR. The Energy Commission staff will work with the various entities involved to obtain actual hourly imports and exports on paths from the Southwest into California.

Estimating Actual Dispatch of Contracted Generation

Question 5: Does tracing the resource mix of "contract path" purchases of electricity reflect the real-time flow of electrons?

Mr. Michael McCormick, with the California Climate Action Registry, requested clarification on the proposed accounting method as it relates to the actual physical flow of electrons. Mr. McCormick pointed out that the flow of electrons from Arizona to California is a homogenous mix of all the generation on the grid. He concluded that treating electrons as if they are coming from specific generation facilities clashes with the reality of homogeneous deliveries.

Answer 5: Mr. McCormick is correct that electricity does not actually flow on the "contract path" but follows the rules of thermodynamics. His observation is true for all systems that assign LSEs responsibility for generation, not just this method.

The goal is to assign to LSEs responsibility for the type of generation they purchase and the associated GHG emissions. Thus, we are tracking the flow of dollars and commitments between loads and sources. LSEs report that they had ownership shares or contracts, and EIA records that the power was generated. The tracking method assumes that the LSE caused the generator to operate, even if the actual electrons flowed into the overall grid.

Conclusions for Imports from the Southwest

Question 6: What is staff's recommended approach, and what is the result of applying it for the example year 2005?

Answer 6: Staff believes that its Southwest import methodology has been validated through the results of system modeling and market analysis. That methodology is to:

1. Use the net imports measured at California control area borders as a control total.
2. Adjust import totals so that units located in California control areas but outside the state's border (for example, Intermountain and Mohave) are counted as imports.
3. Subtract the generation produced by resources owned by or under specified contracts to California LSEs and attribute that nuclear, coal, hydro, and natural gas generation directly to the LSE. Specified resources accounted for 71 percent of Southwest imports in 2005 and are largely coal.
4. For the remaining, unspecified imports, use the results of marginal generation analysis to allocate 4 percent to coal and 96 percent to natural gas.

The resulting resource mix for test year 2005 is shown in Table 3 and is described in greater detail in Appendix C.

Table 3: 2005 Southwest Import Resource Mix Net Imports (GWh)

Resource Type	Specified	Unspecified	Unspecified Percent	Total	Percent mix
Coal	34,992	723	4%	35,715	57.4%
Nuclear	7,074	0	0%	7,074	11.4%
Hydropower	2,093	0	0%	2,093	3.4%
Natural Gas	0	17,360	96%	17,360	27.9%
Renewables	0	0	0%	0	0.0%
Total Imports	44,159	18,083	100%	62,242	100%
Percent Specified and Unspecified	71%	29%		100%	

Firm imports = California LSE ownership shares times total actual generation.
Nonfirm, market imports = 4 percent coal and 96 percent natural gas for total net imports less firm imports.
Source: California Energy Commission, May 2006 staff paper.

Northwest

Pacific Northwest Resource Mix

The May 2006 methodology proposed that for the Northwest, the percent of system imports attributed to hydropower in the 2001 to 2005 period should be reduced from 64 percent of imports to 50 percent, that coal be reduced from 24 percent to 8 percent, and that natural gas be raised from 9 percent to 44 percent.[2]

Question 7: Why is the Northwest analyzed using a different approach than the Southwest?

At the workshop, Chairman Pfannenstiel questioned the basis for the staff draft recommendation that 50 percent of the electricity imports from the Pacific Northwest are from hydro-generation resources. She would like to better understand the reasons for the staff assumptions, since they are not based on the same marginal generation simulations that support the Southwest resource mix proposal.

Answer 7: The Northwest hydropower system is a unique resource that serves as the foundation for the Northwest electricity system. It is managed first to serve local needs, including water, environmental protection, agriculture, recreation, and so forth. Because hydropower varies greatly from year to year, the system must be supplemented with other resources such as natural gas, nuclear, and coal. Both

[2] May 2006 paper, Table 4, page 6.

California and the Northwest built their generation to take advantage of hydro by pairing it with intermediate and shaping resources, especially natural gas, which needs to be turned on only when hydropower is not available.

Hydroelectric generation facilities are modeled as a must-take resource to match typical generator operating profiles at varying water levels. This modeling convention limits the simulations of hydroelectric generation compared to the manner that it is actually operated for spot market transactions in a marginal generation study. The hydroelectric generation resource assumption is instead based on how the Pacific Northwest generation system operates and the planning criteria that are used to define the availability of firm and non-firm energy.

In response to model limitations on hydropower flexibility, staff analyzed the Northwest loads and resource basis to estimate marginal generation for each quarter. The results are discussed in Question and Answer 14. This analysis supplements the information on the relationship between hydro availability and California purchases and information on the sellers of Northwest power.

Role of Hydroelectric Generation in the Northwest

Question 8: Why does staff believe that there is surplus hydropower to sell to California in most years? Why isn't all the cheap hydropower retained in the Northwest?

Answer 8: Surplus electricity is available most years because the Northwest system is designed to meet firm needs in even a critically dry hydro year. In all other years, excess nonfirm energy is available. The surplus electricity is typically sold on the spot market throughout the WECC region. Hydropower accounts for about 58 percent of the total installed generating capacity of British Columbia, Washington, Oregon, Idaho, Montana, and Wyoming[3] and in 2005 produced 64 percent of the energy In that region

The Northwest can't keep all the hydropower for itself because it can't store all the water, and its peak demand occurs in the winter while the peak run-offs occur in the spring. More than half of the annual hydropower production from the Pacific Northwest comes from natural stream flow, and the rest comes from reservoir storage. Only 40 percent of the average January to July runoff is storable in the system reservoirs. This means that large portions of the total annual water supply occurs during the spring runoff from April through July. Most of the water from the melting snow must pass through the generators or over the spillways if it cannot be used in the springtime because it cannot be stored for use in the following fall and winter, when energy demand is higher in the Northwest. This pattern benefits

[3] EIA, 2005 data, compiled by Energy Commission staff.

California, because the water is available when the California loads are increasing in the early summer and the winter-peaking Pacific Northwest loads are decreasing.

Question 9: How does the Northwest's planning criteria affect the availability of surplus hydropower to be sold into the spot market?

Answer 9: The Pacific Northwest Coordination Agreement (PNCA) guides operational planning for the United States portion of the region's hydro-generation system. The PNCA defines the level of risk to which regional utilities have contractually agreed for relying on hydro-generation to produce firm energy. The firm energy forecasts of the Pacific Northwest system reflect no more than that expected under critical water conditions. Surplus firm energy that is available after serving regional loads is available for spot-market sales. The excess electricity above critical water levels is available as non-firm electricity.

The firm hydro-based energy amounts to about 12,000 average megawatts[4] (aMW)), which is the equivalent of about 105,000 GWh per year. Because water conditions for most years will be greater than critical flows, the hydropower system typically will produce more than its firm energy generating capability. The average annual electricity hydro-generation, based on 50 years of historical water flows, is approximately 17,000 aMW (149,000 GWh/year). The difference between the average annual hydro energy production and firm energy generating capability (44,000 GWH/year), is referred to as non-firm energy. The non-firm energy pool that is available in any given year may be higher or lower, depending on water conditions.

For example, the hydroelectric generation in 2005 was 99 percent of normal availability, thus having about 44,000 GWh of surplus hydropower. California imported about 22,000 GWh from the Northwest In 2005 from nonfirm sources. This forms the basis of staff's conclusion that there is a high likelihood that a significant portion was from hydro-generation resources.

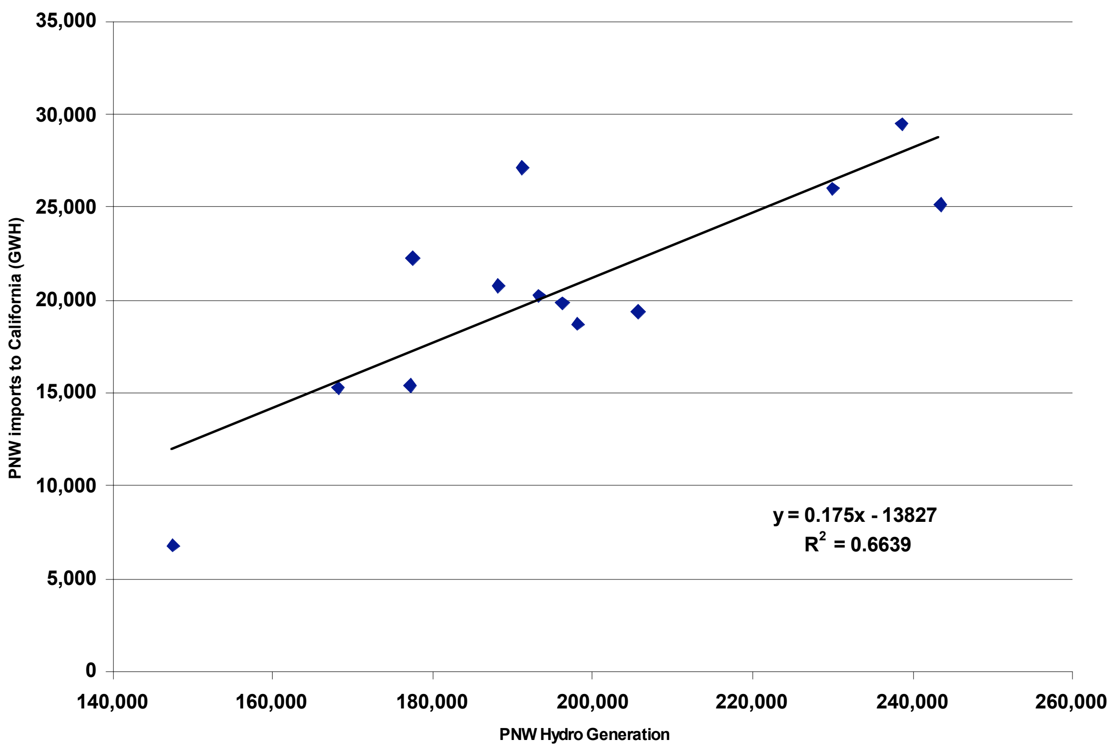
Question 10: Is there evidence that the total amount of generation imported from the Northwest varies from year to year and is correlated to the amount of hydropower available?

Answer 10: There is a measurable relationship between the amount of hydro-generation in the Pacific Northwest and Northwest electricity delivered to California. Figure 2 shows a positive correlation between the Pacific Northwest electricity imports and amount of generation from the hydro-generation facilities in the region over 1993-2005. The 66 percent R-squared coefficient of determination represents the strength of the correlation.

[4] Average megawatts is a unit of electricity measurement equaling the total electricity generated in the region divided by the number of hours.

The outlier data points that diverge from the trend line represent market fluctuations beyond the other correlated points. For example, the lowest data point (about 7,000 GWh of imports and 148,000 GWh of hydro-generation) represents the 2001 drought that occurred in the Pacific Northwest. The electricity imports rebounded to a high point in 2002 to create another outlier point (27,000 GWh of imports and 190,000 GWh of hydro-generation). The third outlier point occurred in 2003 when 6,600 MW of new gas-fired generation came online in California.

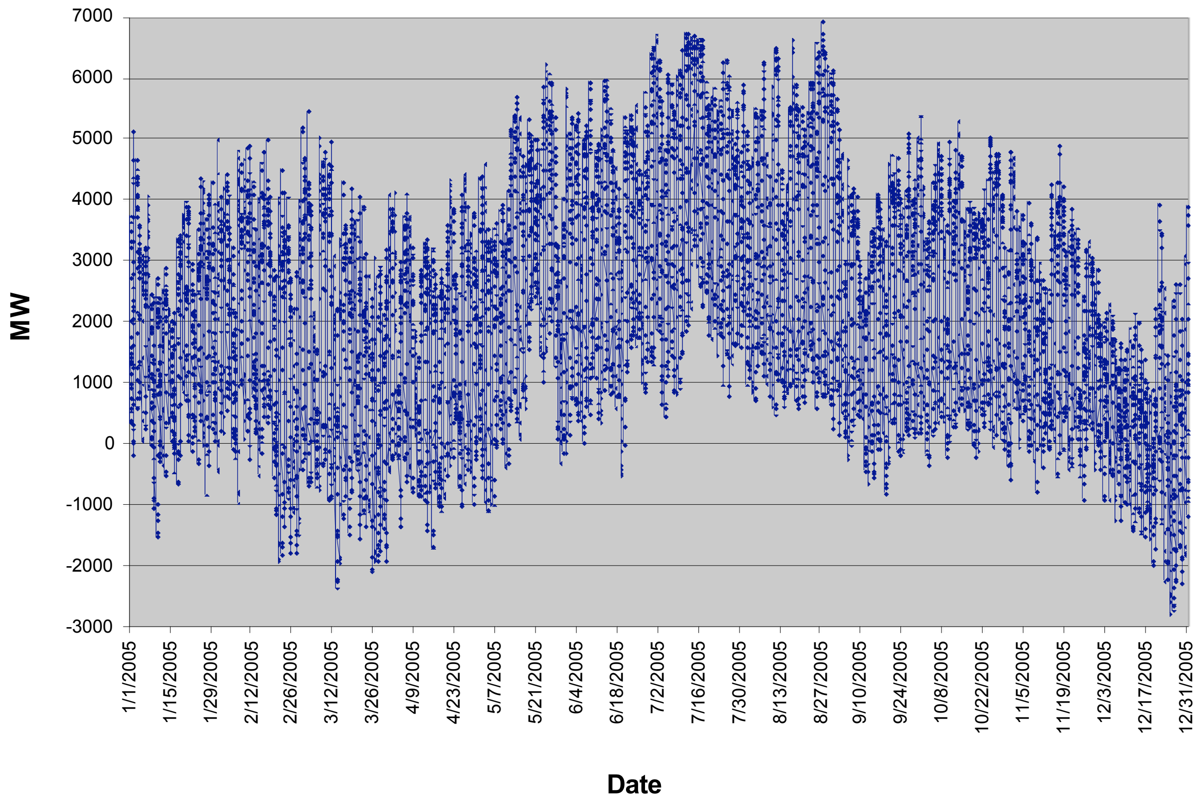
Figure 2: Correlation Between PNW Hydro-Generation and Electricity Imports to California (1993-2005)



Question 11: What is the seasonal and daily pattern of imports, and does that tell us anything about the likely fuel source of imports?

Answer 11: Northwest transmission power-flow data shows that California imports daily peak power throughout the year, imports little power off-peak, and imports more power in the spring during the hydro run-off season and in the summer during periods of high California demand. Figure 3 shows the 2005 Northwest intertie patterns. Data from daily flows shows a diurnal pattern of almost no or even negative imports (in other words, exports) in the off-peak hours.

Figure 3: 2005 CA-PNW Hourly Intertie Flows



Source: BPA OASIS: Operations & Planning Information website
www.transmission.bpa.gov/orgs/opi/internet/index.shtm

These patterns suggest a mix of resources. Some purchases are likely to be daytime six days a week for 16 hours contracts; some are likely to be tied to the surplus hydro available during spring run-off, and some are from resources available during California's summer high demand periods.

<u>Question 12</u>: Since there is a correlation between the amount of surplus hydropower in the Northwest and the amount of Northwest imports, should hydropower have a large share of the imported resource mix?

<u>Answer 12</u>: Staff's sales estimates validate that there is a correlation between hydro surplus and sales to California through the relatively large portion of hydropower in the system sales. Our sales estimates seem to indicate that BPA has reduced its system sales to California over the last decade, but staff has been unable to verify that trend. Staff has asked BPA for overall sales data; so far they have not responded. Using the available data, it appears that independent power producers had a larger share of sales in 2001 through 2005. This period also saw active sales from Northwest utilities to California, perhaps reflecting the development of a larger trading market.

Question 13: Who sells power to California, and what types of generation do they sell in the market?

Answer 13: According to the data staff has been able to amass, there are five types of major Northwest sellers: British Columbia (Powerex), Bonneville Power Administration BPA), investor-owned and publicly owned utilities, independent power producers, and marketers.

The data sources used for compiling the Northwest seller shares and seller resource profiles were: FERC Form 1 – Annual Generating Plant Statistics, EIA Form 412 – Annual Report of Public Electric Utilities (survey terminated December 2003), Rural Utility Services Form 7, annual Net System Power claims reports to the Energy Commission (SB 1305), LSE resource plans filed for the 2005 IEPR, Canadian National Energy Board's annual Electricity Exports and Imports, Washington-Oregon retail sales claims, and interviews and press reports with traders in the Northwest and California.

Staff estimates that, on average, 8 percent of sales are from BPA, 35 percent are from independent power producers and marketers, 37 percent from Northwest investor-owned and publicly owned utilities, and 20 percent from British Columbia. California's publicly-owned utilities purchase between 55 percent and 65 percent of the power imported from the Northwest.

Turning to the fuel sources of the different seller types, British Columbia and BPA staff have assured us that the short-term power they sell to California is surplus power from their hydropower systems. For BPA's firm exports to California, we have used the system fuel mix they report to our SB 1305 retail sales claims. The independent power producers own gas-fired resources. The Northwest utilities report their generation sources to the Washington-Oregon tracking system (see Questions 15 – 21), so we have their total fuel mix. We have some anecdotal information on where the marketers acquire the power they sell. For example, BPA reports in its White Book that much of its export sales were to marketers.

Question 14: Can you demonstrate that Northwest loads don't match the available hydro, so that there is surplus hydro for sale to California?

Answer 14: The staff conducted an additional study to evaluate which generation resources may be on the margin and which may be in surplus after serving Pacific Northwest loads. Staff needed to estimate the hourly electricity demand profile for the Pacific Northwest region and the hourly generation that is likely serving this load. The hourly generation is then stacked according to general operating costs and the hydro-generation operating characteristics.

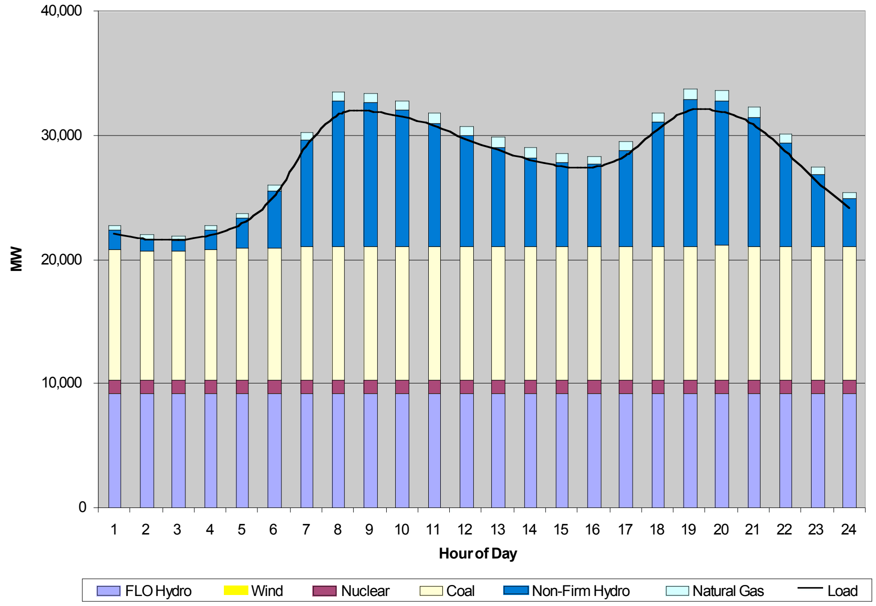
The staff used data from Global Energy's Marketsym model and Velocity Suite energy industry database to estimate average hourly generation of all fuel types in the Pacific Northwest region, as defined by Washington and Oregon. Average hourly load profiles were compared to hourly generation to estimate the resource types that would generate energy above native loads for potential export to other markets, including California. Only the United States portion of the Pacific Northwest was estimated. Load and generation data was aggregated quarterly to emphasize seasonal variations in load and hydro conditions in the region.

Figures 4 to 7 illustrate the results of the hourly generation study. The hourly load data is from a 2007 simulation and includes transmission area loads for Washington, Oregon, Montana, Idaho, Utah, and Northern Nevada.

Hourly generation information is not available for all power plants to conduct this study, so the staff also used the results of an hourly chronological simulation modeling run. The generation information for wind energy and nuclear are actual reported electricity that is averaged for 2003 through 2005. The remaining fuel types (hydro, coal, and natural gas) are results from a Marketsym simulation for 2007. Hourly generation for each fuel type was averaged by quarter and added to the hourly resource stack. Hydro production is divided into two types in the resource stack: hydro energy that is assumed to be sold by the Bonneville Power Administration to meet its average monthly firm load obligations (FLO Hydro) as presented in the *2004 White Book* (page 17), and non-firm hydro energy that is assumed to be sold on the market. Coal and nuclear resources are baseload resources that serve regional loads, while gas-fired resources were the last resources dispatched.

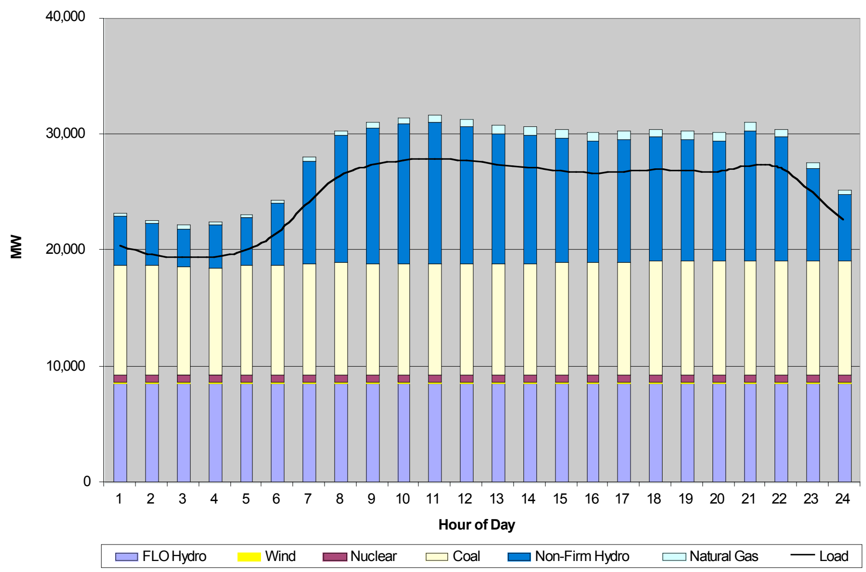
The study results illustrate that the marginal generation from coal-fired facilities ranged from zero percent (Quarters 1, 2 and 4) to 11 percent (Quarter 3), but only during off-peak hours when there is generally no exports to California. Hydro and natural gas generation varied by quarter. Hydro generation was on the margin from zero percent (Quarter 4) to 84 percent (Quarter 2). Gas-fired generation was on the margin from 16 percent (Quarter 2) to 100 percent (Quarter 4).

Figure 4: Load and Resources PNW-U.S. Portion Only Quarter 1, 2007



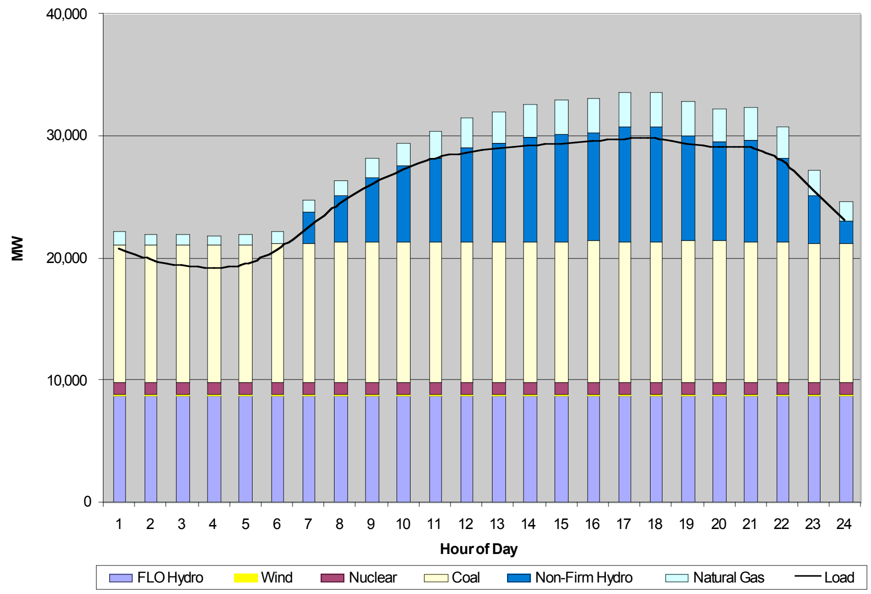
Source: Global Energy Decisions & BPA

Figure 5: Load and Resources PNW-U.S. Portion Only Quarter 2, 2007



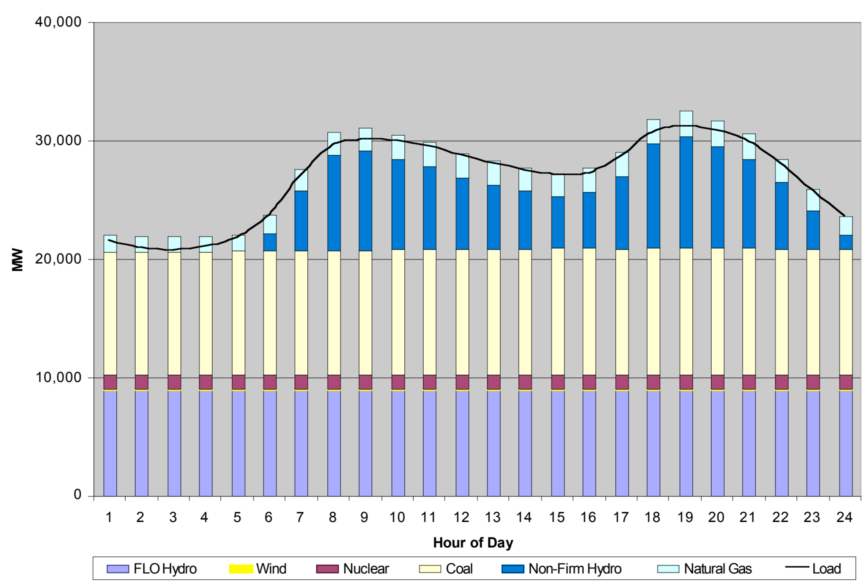
Source: Global Energy Decisions & BPA

Figure 6: Load and Resources PNW-U.S. Portion Only Quarter 3, 2007



Source: Global Energy Decisions & BPA

Figure 7: Load and Resources PNW-U.S. Portion Only Quarter 4, 2007



Source: Global Energy Decisions & BPA

Tracking Activities in Other Western States

Question 15: Are there other Western states which track the resource mix of their native load, imports, and exports? If so, what do they assume for exports to California?

Commissioner Geesman inquired whether there are other states that are attempting to address the electricity imports resource mix issue. The Energy Commission staff may learn from the approaches that others may be using and apply the information to modify the proposed methodology. Furthermore, Energy Commission staff should coordinate with other Western states that may be engaged in similar resource tracking efforts to make sure that double-counting of attributed GHG emissions does not occur.

Answer 15: Washington and Oregon are the only Western states that have implemented a tracking and quantification system for the generation resource mix of power sold to their retail customers. New Mexico prepared a simplified carbon inventory estimate for proposed GHG emission policy on future electricity generation but does not consider other regional power flows or market activities.

Washington manages the tracking system for both Oregon and Washington. Their reports and documentation can be found on the "Fuel Mix Disclosure" page of the Washington State Department of Community, Trade and Economic Development, at www.cted.wa.gov/portal/atlas__CTED. The Energy Commission staff had a number of discussions with the regulatory staff in Washington and Oregon to better understand the methodology used for their power source disclosure program. The discussions were with staff at the Oregon Department of Energy, the Washington Department of Community, Trade and Economic Development, and the Washington State University Energy Program that developed the tracking system. The Washington State team also shared their 2005 data tables with the Energy Commission.

Question 16: What is the Washington and Oregon tracking activity?

Answer 16: The power source disclosure efforts in Washington and Oregon are similar to the Net System Power Report[5] calculations that the Energy Commission prepares each year. A Washington State 2003 Report to the Legislature, *Suggested Fuel Modifications to Fuel Mix Disclosure,* describes the program as follows:

> In an effort to provide retail electricity customers in Washington with reliable and accurate information regarding the fuels that generate their electricity, the state legislature in 2000 passed Engrossed House Bill 2565: An act relating to the disclosure of attributes of electricity

[5] The latest Net System Power report can be found at: [http://www.energy.ca.gov/2006publications/CEC-300-2006-009/CEC-300-2006-009-F.PDF]

> products. RCW 19.29A.010 requires most utilities to disclose their resource fuel mix four times a year to their customers. Washington's disclosure label relies on actual historical data from the prior calendar year.
>
> The U.S portion of the Northwest Power Pool (U.S. NWPP) was chosen as the boundary for fuel mix analysis because of the interconnected nature of the electricity grid system. This includes all or major portions of the states of Washington, Oregon, Idaho, Utah, Nevada, Montana, Wyoming, and a portion of Northern California.
>
> The statute permits any utility to report the default fuel mix, which is the U.S. NWPP net system mix that is calculated annually and is provided by CTED. Each utility can decide to report its resource purchases and owned resources, or the net system mix, or some combination of these. Any power market purchases that are not contractually tied to a specific generating unit are assigned the net system fuel mix of the U.S. NWPP. (page 6)

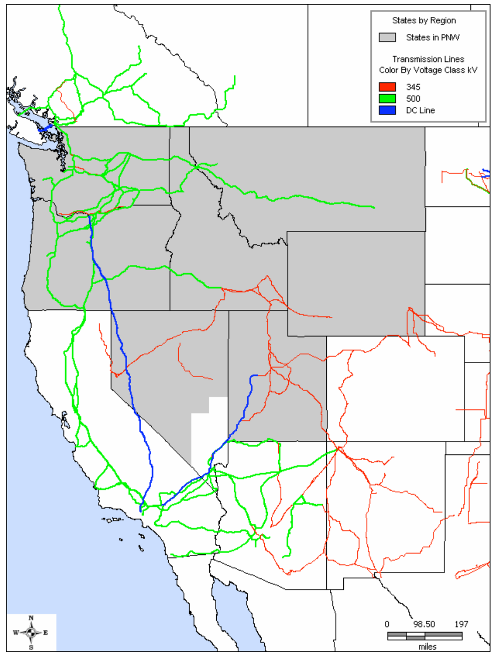
The Washington and Oregon staff uses data from EIA forms 906 and 920 to develop a Northwest Power Pool (NWPP) monthly generation profile by fuel type. The database uses generation information from the Energy Information Administration (EIA) and power source disclosures filings from Oregon and Washington utilities. The monthly electricity totals by fuel type are divided by the total generation to derive the fuel mix percentages for the region. The fuel mix of the reported disclosures and an estimate of the remaining net system generation are reported in electricity bills, similar to California.

The Washington and Oregon utilities then report the annual total generation resources that were claimed to meet retail load obligations. Utility-owned resources (those operated by the utility and facility-specific contracts) and market purchases are counted toward meeting load as a proportion of their retail load, divided by the total of all resources Utilities may also “green” their portfolios by claiming the unbundled environmental attributes that they purchase.

<u>Question 17</u>: How does the geography covered by the Washington and Oregon tracking system compare to that encompassed by California’s definition of the Northwest?

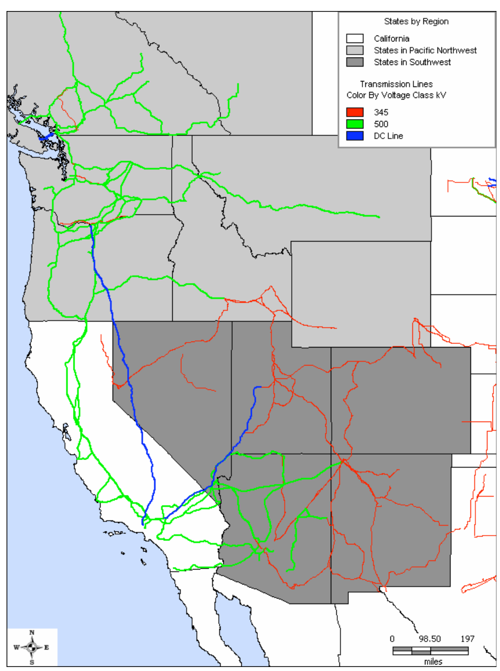
<u>Answer 17</u>: California defines the Northwest as Washington, Oregon, Idaho, Montana and B. C. Hydro. The Washington-Oregon system excludes B. C. Hydro and includes all or major portions of the states of Washington, Oregon, Idaho, Utah, Nevada, Montana, Wyoming, and a portion of Northern California. Figures 8a and 8b show the difference.

Figure 8a: Northwest Geographic Boundaries: as Defined by the Washington-Oregon Tracking System



Source: Energy Commission staff, Global Energy Velocity Suite

Figure 8b: Northwest Geographic Boundaries: as Defined by Energy Commission Staff



Source: Energy Commission staff, Global Energy Velocity Suite

Question 18: Does the Washington-Oregon system individually track the resource mix of retail sales in the rest of the Northwest or to California?

Answer 18: No, all retail sales outside of Washington and Oregon are assigned a uniform, residual power mix.[6]

Specific California power purchase claims filed with Washington are removed from the NWPP gross system mix. In 2005, this consisted of three wind power contracts and three small coal purchases. These specific claims were verified by the Energy Commission's own net power source tracking program.

The remaining "adjusted" fuel mix (net system power) is then assumed to be used by all other LSEs in the NWPP and by California exports. Washington and Oregon do not attempt to estimate what generation resources are used in the other power pool states to meet their native electricity demand versus what is sold into the short-term market.

Question 19: How does the Washington-Oregon residual system mix and the staff's estimates of California purchases from the Northwest compare?

Answer 19: Table 4 compares the results of the Washington-Oregon method and staff's proposed method for estimating the unspecified portion of the fuel mix for Pacific Northwest electricity exports. Annual averages differ significantly, in particular for coal and natural gas generated exports.

Table 4: The Results of Different Accounting Conventions for Northwest Imports

Methodology	Hydro	Natural Gas	Coal	Uranium	Renewable
OR/WA residual regional mix	43%	13%	39%	3%	1%
CA estimate	65%	19%	11%	2%	2%

Question 20: How can these differences be explained?

Answer 20: The Energy Commission staff worked with Washington and Oregon staff to reconcile the differences in the accounting results. The following differences were identified:

[6] In the Washington-Oregon tracking system, annual utility retail claims capture between 90 and 95 percent of Washington electricity consumption and 70 percent of Oregon loads.

1. California counts fewer states as being in the Northwest. It does not include generation from Wyoming. For California, electricity imports from Utah, Nevada and Colorado are generally delivered through the southwest transmission links to California, and so generation from these three states are considered to be in the Southwest.

   The Washington and Oregon methodology assumes that generation from Utah and Northern Nevada are in the Northwest. (Like California, the southern tip of Nevada is allocated to the southwest region). Utah and Nevada account for 63 percent of all the electricity generated by coal in the six states of the NWPP.

   This difference is important because the Washington-Oregon method uses the regional mix of all of its version of the Northwest in the average regional mix assigned to California. From the point of view of California's tracking system, generation from Utah and northern Nevada is being double-counted. Both the NWPP and California account separately for the coal-fired generation from the Utah Intermountain Power Plant, which is owned by California public utilities, so it is not double-counted.

2. In the Washington-Oregon system, they do not try to subtract out from the NWPP gross system mix, the generation that is used to serve native load in other states. Much of the baseload generation that is owned by investor-owned utilities in these states likely serves ratepayer loads instead of exports and would change the net system mix calculation that is assumed to serve exports.

3. Imports from the British Columbia Hydro Authority are not included in the Washington-Oregon system. We know that California LSEs purchase power from B.C., and the California accounting method does include the Canadian generation when evaluating the resource mix from the Pacific Northwest.

   About 10 percent to 20 percent of California's Northwest imports come from Canada. Annual imports and sources are reported in the *Electricity Exports and Imports* report from Canada's National Energy Board. Table 3 reports 2005 B.C. exports of 4,135 GWh (page 13), and Table 5 reports that B.C. exports are from hydraulic power. The report is available at: www.neb.gc.ca/Statistics. Checking reports for other years, we find:

2002 BC Exports to California	1,923 GWh
2003 BC exports to California	3,177 GWh
2004 BC exports to California	2,484 GWh
2005 BC exports to California	4,135 GWh
2006 BC exports to California	1,838 GWh

4. Currently, all counting conventions are voluntary. One way that California and Northwest utilities differ is that Northwest utilities are allowed to purchase unbundled environmental attributes to "green" their portfolios. Thus, a Northwest

utility that sells hydropower to California and receives gas-fired generation in exchange is allowed to count the environmental attributes of its total hydro and to exclude the environmental attributes of its gas-fired purchases. Some California POUs may do the same thing, and other LSEs do not. Until there are standard counting conventions and environmental tracking, the potential for double-counting exists.

Given the different purposes and focus of the Washington and Oregon tracking system that treats all non-claimed retail sales as an undifferentiated leftover, Energy Commission staff recommends using the resource mix proposal that was presented in this paper. Energy Commission staff will continue to work with the Pacific Northwest staff on how to best reconcile differences in the tracking methods.

Question 21: What concerns have the Washington and Oregon staffs raised regarding the Energy Commission staff's proposed method?

Answer 21: The Washington and Oregon staff had concerns about the proposed Energy Commission staff's prior method to estimate the resource mix of electricity imports. They were most concerned that California LSEs not claim resources that were being claimed by other LSEs. In general, all tracking systems need to be careful about how to compute unspecified resources. In the Northwest, it is probably not a good idea to put firm hydro (BPA, WAPA, Idaho Power, and so forth) in the net mix. Energy Commission staff should work with the hydropower sources to more closely account for their sales.

They questioned the validity of using the marginal generation analysis to apply to the complex mechanics of the Northwest system. They were not comfortable with the export fuel mix containing only 4 percent coal generation and no nuclear resources, but did not provide an alternative estimate that would also address the limits of their own accounting method. They were still more comfortable with California using an average regional system mix to characterize unspecified purchases.

Both staffs agree that tracking systems ought to be able to expand as new state electricity systems are added. This will require accounting for exports as well as imports, intra-state trades, claiming of environmental credits, common geographic boundaries, and so forth.

The Washington-Oregon staff has not yet had an opportunity to review staff's revised methodology.

Conclusions for Imports from the Northwest

Question 22: What is staff's recommended approach for estimating Northwest imports, and what is the result of applying it for the test year 2005?

<u>Answer 22 :</u> Based on the analysis which shows that California's purchases track available hydropower, that California purchases vary greatly over the course of the day and season, that Northwest marginal generation is rarely coal, and staff's estimate of the seller shares and fuel mix of their sales, Staff recommends the following Northwest imports method:

- Use the net imports measured at California control area borders as a control total.
- Subtract the generation produced by resources owned by or under specified contracts to California LSEs and attribute that, coal, and wind generation directly to the LSE. Specified resources accounted for 2 percent of Northwest imports in 2005.
- For the remaining unspecified imports, identify the types of sellers and attribute generation type to either the type of product they report to be selling or to their claimed overall resource mix.

The resulting resource mix for test year 2005 is shown in Table 5.

Table 5: 2005 Northwest Import Resource Mix Net Imports (GWh)

Resource Type	Specified	Unspecified	Unspecified Percent	Total	Percent mix
Coal	565	1,572	8.8%	2,137	10.5%
Nuclear	161	305	1.7%	466	2.3%
Hydropower	1,432	11,811	66.0%	13,243	65.3%
Natural Gas	0	3,945	22.1%	3,945	19.4%
Renewables	237	249	1.4%	486	2.4%
Other	9	0	0%	9	0%
Total Imports	2,404	17,882	100%	20,286	100%
Percent Specified and Unspecified	12%	88%		100%	

Other Issues

Competitive Gas-Fired Generation Costs

Question 23: Is it really cheaper to build a new natural gas-fired unit in the Southwest?

Steven Kelly, with the Independent Energy Producers Association, commented regarding generation costs between California and the Southwest. He suggested that gas plants that have been built in California and in the Southwest are relatively the same kinds of units with similar heat rates, and so the only difference is probably the transmission costs from Arizona to California. This suggests that the Southwest natural gas-fired generation would not be competitive and would displace California generation. So, in theory the Southwest generators would use the gas locally and instead export the cheaper coal-fired generation to catch the higher market clearing price in California. If this is the case, this would lead to the conclusion that more coal-fired generation is imported to California.

Answer 23: Recent studies by the California ISO and other parties for the Palo Verde 2 transmission line certificate of public convenience and need (CPCN) looked at the costs of natural gas generation in California and the Southwest. These studies found that generation was cheaper in the Southwest, both because there is cheaper natural gas due to lower transportation costs and construction costs such as land costs are somewhat lower in the Southwest.

Emission Rights

Question 24: Does this generation tracking indicate whether it would be possible to assign emission rights to imports?

Ash Lashgari, with the California Air Resources Board, inquired whether it is possible to require entities delivering electrical energy across a transmission line to purchase the right to emit carbon dioxide and black carbon associated with that energy.

Answer 24: This specific question goes beyond the analytic boundaries of this project. The investigation shows that it would be relatively straightforward to assign emission responsibility to specific purchases. Unspecified purchases would have to be estimated, using this or some other approach.

Fuel Mix of Energy Service Providers

Question 25: Does staff have more information on the fuel mix of energy service providers?

Commissioner Geesman directed staff to further study the fuel mix of the energy service providers (ESP). The staff presented the fuel mix of only one ESP that provided information in the Public Source Disclosure filings to the Energy Commission.

Answer 25: Staff reviewed the ESP resource plan filings for the 2005 IEPR and the 2005 Net System Power claims to see if additional information is available on their fuel mix. Sempra is the only ESP to file a specific claim. In the IEPR resource plans, ESPs generally procure capacity and energy under contracts ranging from 3- to 24-months, with most of the contracts in the 3- to 6- month range. All of these contracts are, almost without exception, including those of APS with APS the utility, liquidated damages contracts for system power.

The contracts are with power marketers or the marketing arms of utilities or, rarely, with marketing arms of generation companies such as Calpine and Coral. The only exception was APS, which purchased a majority of its power from its regulated utility and the remainder from the unregulated trading arm of the utility. The remaining ESPs that have a wholesale marketing counterpart contract with that entity for their power.

Since almost all of the contracts were short-term and for liquidated damages, it is reasonable to treat ESP fuel shares as from resources that were on the margin.

Import Counting Conventions

Question 26: Are imports measured on a gross or net basis?

Answer 26: Historically, California has reported its imports on a net basis. This is how they are reported in the Department of Finance's California Statistical Abstracts (Table J-11), and that document is the most widely used source of import numbers. The Energy Commission is responsible for developing that table. In the May, 2006 paper, staff presented gross imports based on the theory that staff was trying to account for all generation out-of-state. But that introduced its own error. Overall staff was counting too much generation, both all the generation that occurred in California and all the generation imported into California. Exports were being double-counted.

In this paper, staff has returned to the convention of accounting for net imports. This reduces the amount of imports we are counting by less than 10 percent and retains all the in-state generation with its associated emissions. Appendix C shows the conversion of gross to net imports.

Staff expects that this accounting convention will be replaced in the next few years as more accurate in-state and out-of-state tracking conventions are developed.

Question 27: Are the state's geographic borders or its control area borders used as the definition of out-of-state?

Answer 27: In this paper, staff has shifted from using control areas as the boundaries to using a geographic basis. A geographic boundary approach is consistent with the way other states and the federal government track fuel shares and GHG emissions. In practice, this has no impact on total emissions; it just shifts three power plants with dedicated output from one category to another. The three plants are Mohave (shut in December 2005), Intermountain Generating Station and Caithness Dixie Valley. These facilities are located in other states but within California control areas. Since the output, fuel mix, and emissions of these units are known and directly assigned to California LSEs, no change in attribution occurs when shifting them from one category to another. They now all appear in the gross Southwest numbers but then are subtracted out as firm imports before estimating Southwest fuel shares is done.

Conclusions, Caveats, and Next Steps

The Energy Commission staff believes that quantifying the sources of specified power imports and estimating the resource mix of short-term electricity purchases is a more accurate approach than the averaging method that has been used for previous Commission reports. Given the historical observations and modeling simulations, staff believes that it is reasonable to assume that natural gas-fired generation is the primary resource serving the short-term electricity market in the Southwest. Hydro-generation is the largest resource providing Pacific Northwest system exports to California with natural gas, coal, nuclear, and renewables providing the balance.

Table 6 compares the resulting resource mix from applying the averaging method and the market methods to the 2005 statewide imports. The main change is the shift between coal, a baseload resource, and natural gas, an intermediate resource. This is consistent with the analytic change between assuming that imports are from the same total system which serves to an approach which accounts for both firm, specific resources and market-based, marginal purchases.

Table 6: Comparison of the 2005 Total Statewide Imports Resource Mix Using the Revised and Average Estimation Methods

Resource Type	Revised Method	Average Method
Coal	45.9%	59.4%
Large Hydro	18.6%	18.2%
Natural Gas	25.8%	15.5%
Nuclear	9.1%	6.8%
Renewables	0.6%	0.0%
Total	**100.0%**	**100.0%**

Source: sum of Tables 3 and 5, and Table A-4.

Each year's resource mix will be different, as hydro conditions, prices, transmission constraints, and the incremental generation needed by an LSE to fill its portfolio will vary.

The share of imports which needs to be estimated could be reduced by LSEs providing more specific data on their historic imports for 2001 – 2006. Disaggregating purchases into northwest and southwest sources and into known versus unspecified sources would be immensely helpful. For unspecified purchases, the type of seller would also be useful. This could also more closely link the statewide control total with the individual LSE import estimates which will be needed to implement AB 32.

This paper will be discussed at an April12 public workshop held by the Energy Commission and the California Public Utilities Commission. After that workshop, decisions will be made on next steps. The proceeding will need resource mix totals for Northwest and Southwest imports for 2001 through 2006. Future statewide control totals for imports could be computed annually. These can serve as control totals for assuring that all GHG emissions from California-caused generation have been accounted for

This is an interim method, to be replaced during the implementation of AB 32. Future tracking will need to be coordinated with other western states. On February 26, 2007, the Governors of California, Oregon, Washington, Arizona, and New Mexico signed the Western Regional Climate Action Initiative. It says that the states will:

- "Developing, within eighteen months of the effective date of this agreement, a design for a regional, market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve the regional GHG reduction goal, and
- Participating in a multi-sector GHG registry to enable tracking, management and crediting for emissions that reduce GHG emissions, consistent with state GHG reporting mechanisms and requirements."

This multistate initiative may facilitate establishing an electricity generation tracking system for the West that will use common counting conventions to assign GHG emissions responsibilities. It is important that all regulators use a consistent method for tracking or estimating the generation serving regional electricity markets. A consistent western methodology will avoid the possibility of double-counting or the use of inconsistent accounting practices to shift the attribution of GHG emissions when implementing global climate change programs in one state or the other.

APPENDIX A: MAY 2006 PROPOSED METHOD TO ESTIMATE THE RESOURCE MIX OF ELECTRICITY IMPORTS

This attachment summarizes the May 2006 proposed method to estimate the resource mix of electricity imports. The Staff Paper provides a more detailed description of the assumptions supporting the proposed methodology.

The proposed method for estimating the fuel mix of electricity imports first identifies all known out-of-state generation ownership shares and contracts. The ownership shares and contracted imports are subtracted from the total imports to the California control areas. Remaining imports are treated as unspecified system purchases.

Table A-1 shows that in 2005, half of all imports were from known resources. These resources are located primarily in the Southwest. Most purchases from the Pacific Northwest were from undisclosed sources.

Table A-1: 2005 Firm and System Electricity Imports (GWh)

Imports Type	PNW	SW	Total
Known, firm Imports	1,123	44,159	45,282
System Imports	21,224	21,706	42,930
Total Imports	22,347	65,865	88,212

The staff identified which generation resources in the Western Electricity Coordinating Council (WECC) regions are on the margin and typically set market-clearing prices. After generation located in California was separated out, the electricity system simulation results showed that natural gas-fired generation is the generation resource that sets the market clearing price 96 percent of the time throughout the rest of the Western region. Coal-fired generation sets the market-clearing price 4 percent of the time — almost always during off-peak periods when California has surpluses and does not need to purchase electricity.

Since the Pacific Northwest electricity system operates differently than the Southwest system, the staff used a different method to identify the marginal generation resources The WECC electricity system model that was used to simulate the Western electricity system treats hydroelectric generation as a must-run and must-take resource. If this modeling convention were applied, hydroelectric generation would never be the marginal resource in the Pacific Northwest. Hydro-generation from the Columbia and Snake River systems, however, can be the marginal resource when surplus quantities are available in spring and early summer. California utilities, marketers, and generators typically buy this surplus electricity to serve their customer obligations or to reduce costs.

Given that there is a high correlation between Pacific Northwest water conditions and imports, the staff assumes that 50 percent of the reported imports are from hydroelectric generation. This assumption is lower than the estimated contributions using generation averages, where hydro-generation represented 64 percent of the total electricity produced in the region in 2005. The staff believes that the 50 percent hydro-generation estimate is reasonable, given the PNW planning criteria that is used for meeting regional electricity demands. The balance of Pacific Northwest electricity imports is assumed to be 46 percent from natural gas-fired generation and 4 percent from coal-fired facilities, applying the marginal generation modeling results.

Table A-2 provides the resource mix estimates of the Pacific Northwest and Southwest system imports for 2005, reported in gigawatt-hours and percentages.

Table A-2: 2005 Resource Mix Estimates of Total System Imports (GWh and Percent)

	PNW	Share	SW	Share	Total	Share
Total System Imports	21,447	100.0%	21,707	100.0%	43,154	100.0%
Coal	858	4.0%	868	4.0%	1,726	4.0%
Hydro	10,723	50.0%	0	0.0%	10,723	24.8%
Natural Gas	9,866	46.0%	20,839	96.0%	30,705	71.2%

Table A-3 provides the resource mix estimates for total electricity imports (firm and system imports) from the Pacific Northwest and Southwest. For comparison, Table A-4 shows the resource mix using the average generation mix approach that was applied to past Net System Power Reports. The total amount of imports and the resource mix is slightly higher than the *2005 Net System Power Report* since total electricity imports are used instead of net imports. The amount of estimated coal generation imports will likely decline in 2006 since the Mohave Generation Station is now shut down.

Table A-5 provides a comparison of the estimated resource mix for in-state generation and the applied methodologies for electricity imports. The proposed methodology shows that coal generation is less than the approach used for past *Net System Power Reports*. The estimated generation from natural gas-fired facilities increases accordingly.

Table A-3: 2005 Resource Mix Estimates of Total Imports (Firm and System) Using the Proposed Methodology (GWh and Percent)

	PNW	Share	SW	Share	Total	Share*
Total Imports (firm and system)	22,347	100.0%	65,866	100.0%	88,212	100.0%
Coal	1,758	7.9%	35,860	54.4%	37,617	42.6%
Hydro	10,723	48.0%	2,093	3.2%	12,816	14.5%
Natural Gas	9,866	44.1%	20,839	31.6%	30,705	34.8%
Nuclear	0	0.0%	7,074	10.7%	7,074	8.0%

*Numbers do not add to 100% due to rounding.

Table A- 4: 2005 Resource Mix Estimates of Total Imports Using the Average Generation Mix Methodology (GWh and Percent)

	PNW	Share	SW	Share	Total	Share*
Total Imports (firm and system)	22,347	100.0%	65,866	100.0%	88,212	100.0%
Coal	5,426	24.3%	47,028	71.4%	52,454	59.4%
Hydro	14,192	63.5%	1,844	2.8%	16,036	18.2%
Natural Gas	1,967	8.8%	11,724	17.8%	13,691	15.5%
Nuclear	761	3.4%	5,269	8.0%	6,030	6.8%

*Numbers do not add to 100% due to rounding.

Table A- 5: Comparison of the 2005 Total Statewide Generation and Imports Resource Mix Using the Proposed and Average Estimation Methodologies

Resource Type	Proposed Methodology	Average Methodology
Coal	14.3%	20.1%
Large Hydro	16.3%	17.0%
Natural Gas	43.8%	37.7%
Nuclear	14.9%	14.5%
Renewables	10.7%	10.7%
Total	**100.0%**	**100.0%**

Background for Question and Answer 2: Figures 7 and 8 from the May 2006 staff paper

Figure 7: Arizona 1993 LDC Loads and Supply

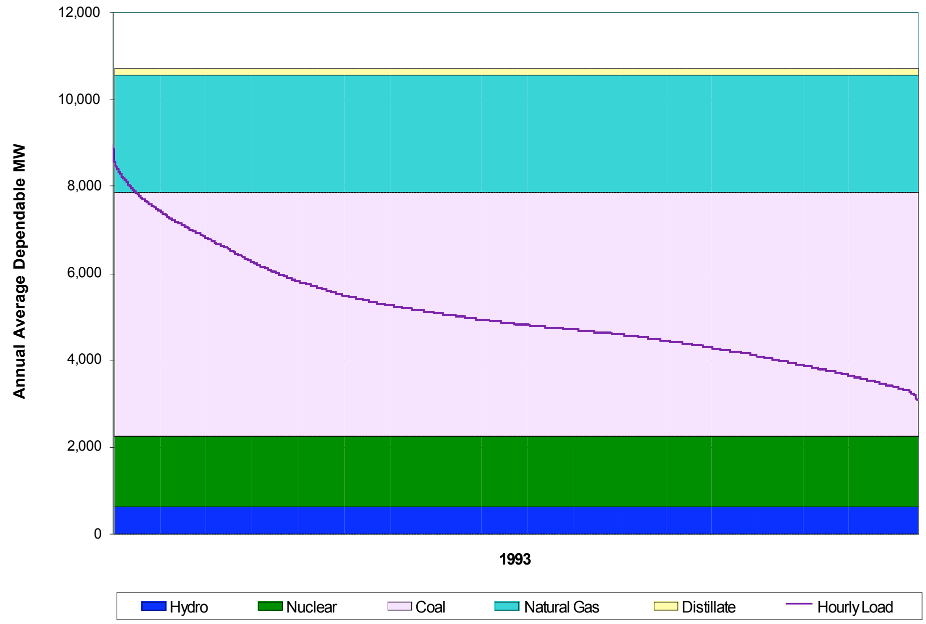
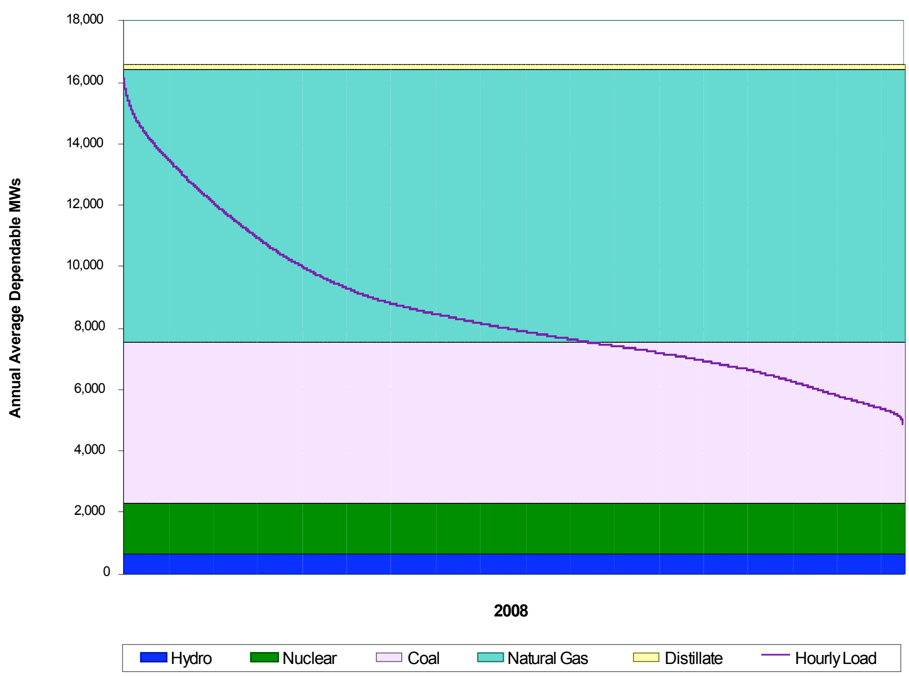


Figure 8: Arizona 2008 LDC Loads and Supply



APPENDIX B: HYBRID METHODOLOGY USED TO ESTIMATE THE DECEMBER 2006 GREENHOUSE GAS EMISSIONS INVENTORY REPORT

Citation: California Energy Commission, December *2006, INVENTORY OF CALIFORNIA GREENHOUSE GAS EMISSIONS AND SINKS: 1990 TO 2004*, CEC-600-2006-013, Sacramento, California, page 40-42.

Documentation for Line 45-Imported Electricity

During the 1990 to 2004 period, California imported 22 to 32 percent of its electric energy from nearby states. The method of generating this imported electric energy ranges from coal-fired power plants to nuclear and hydroelectric power plants. The generation of electricity from burning coal releases relatively large amounts of GHG emissions while the generation of electricity from nuclear and hydroelectric power plants do not emit GHGs.

Electricity imported from the Pacific Northwest has a large hydroelectric component compared to the Southwest, which is largely coal based. Thus, energy imported from the Southwest is much higher in carbon content than is energy imported from the Pacific Northwest.

Due to the nature of imported electrical energy transactions, it is often not possible to determine the type of facility and associated carbon-based fuel used to generate the imported electricity. However, to estimate carbon emissions from imported electricity, it is necessary to estimate the source(s) of electricity and associated rates of carbon emissions per gigawatt-hour of imported electricity. Thus, an estimate must be made of the fuel used to generate this portion of the imported electricity.

The EPA GHG emissions inventory guidance document recommends that states estimate emissions from net imports of electricity. California occasionally exports a small amount of electricity, but nearly all of the transactions are imports. The GHG inventory of in-state emissions could be reduced to account for the electricity exported from California, but the amount is small enough to ignore this factor. However, 2000 experienced greater than average electricity exports due to the turbulent market conditions that existed at that time.

To estimate the CO_2 emissions from Pacific Northwest electricity imports, we assume 20 percent was generated by coal and 80 percent from hydroelectricity. Correspondingly, for electricity from the Southwest, we assume 74 percent coal and 26 percent hydroelectricity. These values were adopted for use in the 1994 Electricity Report for the 1994 to 1999 period.

This paper assumes that these percentages apply for the entire 1990 to 2000 period. Additional electrical energy is also generated from two out-of-state coal-fired power plants owned by California electric utilities. The fuel used to generate this energy is known to be coal, and there is no need to estimate its fuel source. These emissions are calculated separately and the results added to the values estimated for the Pacific Northwest and Southwest to obtain overall carbon emissions from imported electricity.

To estimate CO_2 emissions from out-of-state electricity generation for 2001 and later years, data from the Energy Commission's Electricity Office was used. This data is based upon reported electrical energy transactions to estimate the percentage of energy from coal, natural gas, oil, nuclear, and other sources. These percentages were used for 2001 through 2004, after removing the two known coal-fired electricity generating facilities.

The State of California's Department of Finance publishes a table (J11) of electrical energy generation from utility-owned and non-utility owned power plants with gigawatt-hours (GWh) of electrical energy production intended for use in California shown by fuel type. The table also shows overall gigawatt imports from the Pacific Northwest and Southwest.

This table is used, along with the percentage data above, to derive annual values for total GWhs of imported electrical energy by fuel type. To convert electrical energy into its British Thermal Unit (BTU) equivalent, staff assumed a thermal conversion rate of 10,000 BTUs per kilowatt-hour (BTU/kWh). This is an approximate value that could be refined, but this step is deemed not necessary due to the uncertainty of other assumptions needed to estimate imported energy levels by type of fuel.

After obtaining annual BTU estimates for each fuel type using the method described above, CO_2 emissions are calculated in the same manner as other sources of fossil fuel emissions for Lines 2 through 8. Appendix C of the GHG emission inventory report discusses two other approaches for estimating CO_2 emissions from electricity imported to California.

APPENDIX C: 2005 SOUTHWEST RESOURCE MIX DETAILS

Table C-1: 2005 Southwest Fuel Mix for Net Electricity Imports (GWh and Percent)

	Specified	Unspecified	Total	Percent Mix of Total Imports
Coal				
Four Corners	5,403		5,403	8.7%
Navajo	3,611		3,611	5.8%
San Juan	3,016		3,016	4.8%
Inter-mountain	13,118		13,118	21.1%
Mohave	6,954		6,954	11.2%
Reid Gardner	1,176		1,176	1.9%
Sempra ESP	1,714		1,714	2.8%
Subtotal	**34,992**	**723**	**35,715**	**57.4%**
Nuclear				
Palo Verde	7,074		7,074	
Subtotal	**7,074**	**0**	**7,074**	**11.4%**
Hydro				
Hoover Entitlements	2,093		2,093	
Subtotal	**2,093**	**0**	**2,093**	**3.4%**
Natural Gas	**0**	**17,360**	**17,360**	**27.9%**
Total Net Imports	**44,159**	**18,083**	**62,242**	**100.0%**

Source: California Energy Commission, Electricity Analysis Office

Net imports = Gross imports - exports
Firm imports = California LSE ownership shares times total generation
Non-firm imports = Net imports minus firm imports times marginal resource mix shares

APPENDIX D: CONVERTING FROM GROSS TO NET ACCOUNTING

Table D-1: California Import/Export Data Summary (MWh)

Gross Imports						
Region	**Year**	**Q1**	**Q2**	**Q3**	**Q4**	**Annual total**
PNW	2001	2,686,806	2,925,793	3,164,629	3,895,215	12,672,443
	2002	4,902,982	9,340,960	8,894,501	5,068,055	28,206,498
	2003	4,900,088	7,717,723	6,382,322	4,774,696	23,774,829
	2004	4,231,046	6,284,849	5,599,096	6,247,893	22,362,884
	2005	4,592,016	6,062,609	7,593,342	4,098,955	22,346,922
SW	2001	15,844,233	17,742,303	13,518,944	15,506,376	62,611,855
	2002	15,070,524	13,856,353	14,593,322	17,931,461	61,451,660
	2003	16,077,212	13,978,154	16,227,149	17,127,827	63,410,341
	2004	16,861,103	16,373,226	17,838,203	18,170,234	69,242,767
	2005	16,444,886	14,187,936	16,860,354	18,314,777	65,807,954
Export (MWh)						
Region	**Year**	**Q1**	**Q2**	**Q3**	**Q4**	**Annual total**
PNW	2001	3,050,938	1,450,178	922,009	423,084	5,846,209
	2002	283,492	132,236	342,790	261,888	1,020,406
	2003	417,812	183,635	389,592	480,346	1,471,385
	2004	377,742	292,647	563,791	297,969	1,532,149
	2005	594,995	330,898	528,497	606,848	2,061,238
SW	2001	494,698	4,999,585	2,394,086	1,119,003	9,007,372
	2002	816,964	1,471,143	2,455,830	769,629	5,513,566
	2003	827,810	1,401,653	1,462,198	863,046	4,554,707
	2004	975,464	813,515	934,717	568,728	3,292,424
	2005	593,309	1,371,982	1,277,594	380,408	3,623,293
Net Import						
Region	**Year**	**Q1**	**Q2**	**Q3**	**Q4**	**Annual total**
PNW	2001	-364,132	1,475,615	2,242,620	3,472,131	6,826,234
	2002	4,619,490	9,208,724	8,551,711	4,806,167	27,186,092
	2003	4,482,276	7,534,088	5,992,730	4,294,350	22,303,444
	2004	3,853,304	5,992,202	5,035,305	5,949,924	20,830,735
	2005	3,997,021	5,731,711	7,064,845	3,492,107	20,285,684
SW	2001	15,349,535	12,742,718	11,124,858	14,387,373	53,604,483
	2002	14,253,560	12,385,210	12,137,492	17,161,832	55,938,094
	2003	15,249,402	12,576,501	14,764,951	16,264,781	58,855,634
	2004	15,885,639	15,559,711	16,903,486	17,601,506	65,950,343
	2005	15,851,577	12,815,954	15,582,760	17,934,369	62,184,661

Source: California Energy Commission, QFER filings

Updated: February 2007

APPENDIX E: NORTHWEST RESOURCE MIX DETAILS

The Northwest resource mix calculations include information on California utility wholesale energy purchases by sellers that are located in the Northwest Power Pool Region. The electricity sales information is compiled into the major types of sellers: Canada, Bonneville Power Administration, independent power producers and marketers, and utilities. The utility sellers include investor-owned and publicly owned utilities and cooperatives.

The reported electricity imports by California LSEs represents approximately 80 percent of the recorded Northwest net power flows to the State. The balance of the net imports is assumed to be delivered to energy service providers, other marketers that may be selling to California LSEs and/or California merchant generators that are purchasing economy energy to meet contract obligations.

The EIA-412 reporting requirements were terminated on December 31, 2003. Considering that California's publicly owned utilities purchase between 55 percent and 65 percent of the power imported from the Northwest, it is important to derive an estimate of the amount of electricity purchases in 2005. The staff used the average California LSE purchases between 2001 and 2003 to estimate the amount of electricity that likely occurred in 2005 for the resource mix calculation.

Table E-1 provides the information on electricity sales information to California LSEs and calculated imports by energy service providers and marketers. The Canadian imports are served by hydro resources. SMUD has a facility specific contract with the Snohomish biogas facility; SDG&E and Turlock Irrigation District have a contract with Portland General Electric that is served by the Boardman coal facility; and several other California LSEs have contracts with the Bonneville Power Administration that provides a disclosure filing on the resources serving these imports. The imports from Northwest independent power producers and marketers are assumed to be served by surplus hydropower (50 percent), merchant natural gas-fired generation (46 percent) and some coal that may be available during off-peak periods (4 percent).

The calculated resource mixes of the Northwest electricity imports by seller type are shown on Table E-2.

Table E-1: 2005 Net Northwest Electricity Imports (GWh)

CA LSE Imports	
Canada – hydro	886
Snohomish Biogas - renewable	223
BPA Contracts	
Hydro	1,432
Renewable	14
Nuclear	161
IPP and Marketer sales	
Hydro	3179
Gas	2925
Coal	254
IOU, Muni & Other sales	
Hydro	4,153
Gas	677
Coal	1,883
Nuclear	305
Renewables	249
Other	9
CA LSE Total	16,350
Other Imports - Sales to ESPs And Marketers Serving CA Load	
Canada – hydro	3,249
IPP and Marketer sales	687
Hydro	344
Gas	316
Coal	27
Other Imports Total	3,936
Total Net Imports	**20,286**

Table E-2: 2005 Net Northwest Electricity Imports Seller and Resource Mix (Gwh)

Seller to California	Hydro	Coal	Natural Gas	Nuclear	Renewables	Other	Total	Percent
Canada	4,135	0	0	0	0	0	4,135	20%
BPA	1,432	0	0	161	14	0	1,607	8%
IPP and Marketers	3,523	282	3,241	0	0	0	7,045	35%
IOU, Muni & Other sales	4,153	1,883	677	305	472	9	7,499	37%
Total	13,243	2,165	3,918	466	486	9	20,286	100%