DRAFT STAFF PAPER

EXPECTED PATH 26 POWER FLOWS UNDER HIGH LOAD CONDITIONS

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ABSTRACT

This paper updates a 2008 staff assessment of electricity flows over Path 26 during heat spells in the summers of 2006 – 2008. Path 26 is a major transmission artery connecting the Northern California portion of the California Independent System Operator (California ISO) Balancing Authority with Southern California. With an accepted north-to-south rating of 4,000 megawatts (MW) and a south-to-north rating of 3,000 MW, the path allows significant amounts of generation in one zone to be exported to serve load in the other. The magnitude and direction of actual flows can vary significantly depending on demand, generation availability, and other system conditions in the two zones. The earlier paper concluded that a southward flow of roughly 1,100 MW during the Northern California peak was an appropriate assumption for electric generation resource planning purposes. This paper presents information for 2009 and 2010. It also presents a range of path flows expected at high temperatures, based on regression analysis of path flows, demand, energy imports, and wholesale generation prices. Regression analysis is a statistical method for estimating the association between one variable and one or more other variables. The results of this analysis are generally consistent with the findings of the 2008 study, although high reserve margins (a product of load reductions, low temperatures, and the construction of new generation) indicate 2009 and 2010 flows are likely not representative of expected Path 26 flows during periods of excessively hot weather. In 2009 and 2010, increased reserve margins allowed for the movement of large amounts of energy in response to economic signals rather than need. Staff's estimated model takes into account these effects and presents a distribution of expected path flows corresponding to expected Northern California peak demands under varying temperature conditions.

Keywords: Electricity, demand, imports, transmission flows, Path 26

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TABLE OF CONTENTS

Page

LIST OF FIGURES

Page

LIST OF TABLES

Introduction

Path 26 is a major transmission artery connecting the Northern California portion of the California Independent System Operator (California ISO) Balancing Authority with Southern California. With an accepted north-to-south rating of 4,000 megawatts (MW) and a south-to-north rating of 3,000 MW, the path allows significant amounts of generation in one zone to be exported to serve load in the other. The magnitude and direction of actual flows can vary significantly depending on demand, generation availability, and other system conditions in the two zones. The assumption used for procurement planning is therefore an important consideration for planning and procurement of in-zone electricity generation resources. For Northern California, the question of interest is the range of expected path flows when the north experiences annual peak demand conditions.

In October 2008 the California Energy Commission published *Revisiting Path 26 Power Flow Assumptions*,[1] a staff paper intended to provide information for discussions regarding the appropriate assumptions for the flow of energy over Path 26 under annual peak load conditions in the northern half of the state. It presented information, much of it reprised here, regarding the relationship between daily peak temperatures in Northern and Southern California and flows on Path 26 during the summers of 2006 – 2008 and the flows on Path 26 during heat spells in this period. The paper concluded that roughly 1,100 MW was a reasonable assumption for southward flows over Path 26 at the time of the Northern California peak.

This paper updates the earlier one, providing similar information for the summers of 2009 and 2010. It also presents a range of expected path flows based on regression analysis of path flows, demand, energy imports, and wholesale generation prices. In 2009 and 2010, flows south on the highest-demand days averaged 1,300 MW, but because of high reserve margins (a product of load reductions, mild temperatures, and the construction of new generation), these flows may not be representative of expected Path 26 flows during future extreme temperature events. The increased reserve margins allowed for the movement of large amounts of energy in response to economic signals rather than need, suggesting that 2009 and 2010 path flow relationships are not the most appropriate for planning.

The first section of the paper presents data on the relationship between daily peak temperatures and Path 26 flows during the summers of 2006 – 2010. Next, load diversity between Northern and Southern California and the specifics of heat spells during the summer of 2009 and 2010 are discussed. The next section discusses non-demand variables that affect flows. Finally, staff presents a regression model, which estimates Path 26 flows as a function of demand, prices, and imports. From the estimated models a range of estimated path flows are calculated.

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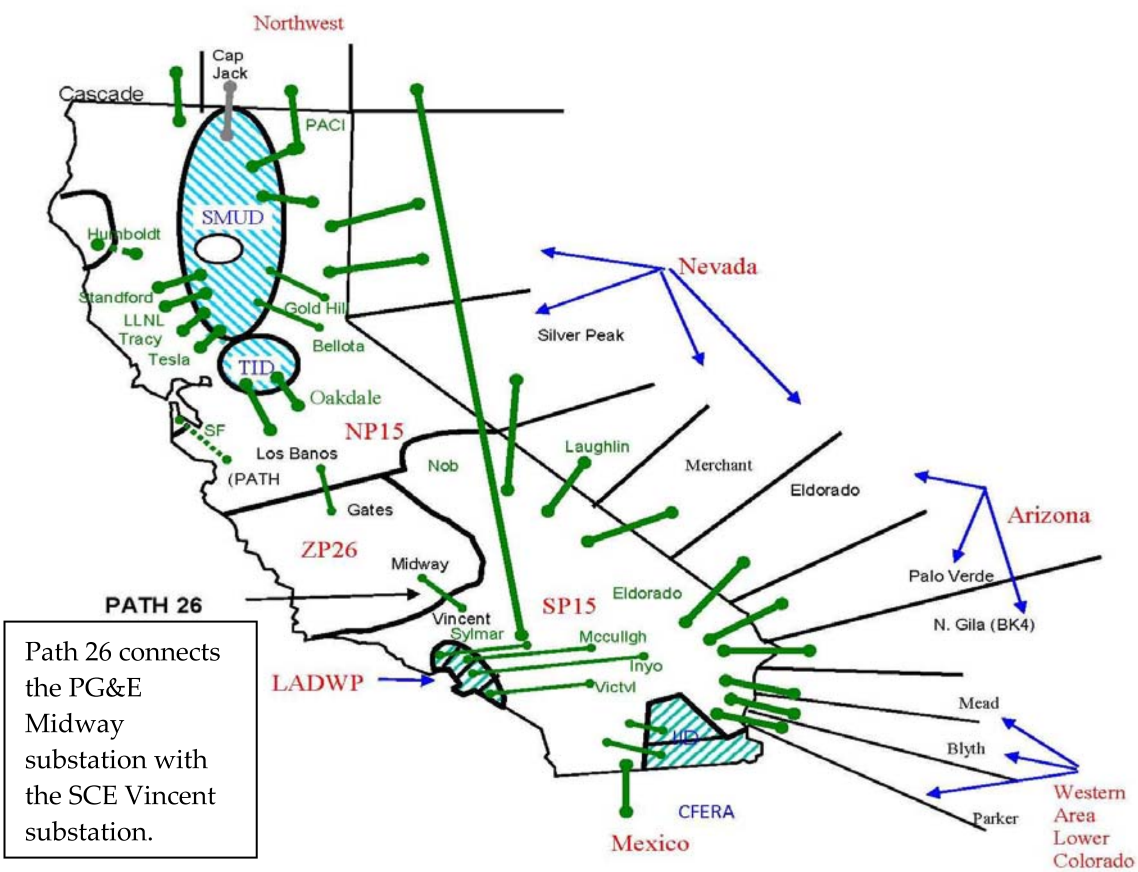
1 California Energy Commission, *Revisiting Path 26 Power Flow Assumption*, 2008, CEC-200-2008-006.

In providing this information, staff acknowledges that a complete investigation of flows over Path 26 during periods of high demand requires additional data. Reserve margins in both halves of the state, the location of efficient gas-fired generation, hydrologic and temperature conditions in neighboring regions, outage conditions, and load forecast errors can all influence the need, ability, and incentive to move energy from north to south throughout the summer in general and during high-load events in particular.

For this analysis, the northern part of California ISO studied is the California ISO's Pacific Gas and Electric (PG&E) Transmission Access Charge (TAC) area, which includes the zones labeled by the California ISO as NP15 and ZP26, shown in **Figure 1**. This includes the PG&E distribution area and load served by the Northern California Power Agency, Silicon Valley Power, and other entities. The area south of Path 26 is composed of the Southern California Edison (SCE) and the San Diego Gas & Electric (SDG&E) TAC areas, which comprise the zone labeled SP15 in **Figure 1**. This paper analyzes data for the SCE TAC area, which includes the Southern California Edison distribution area and load served by the cities of Anaheim, Riverside, Pasadena, and others.

Figure 1: California ISO Zones and Transmission System Topology



Source: California ISO full network model map (http://www.caiso.com/2827/2827798d2ea50.xls).and Energy Commission staff.

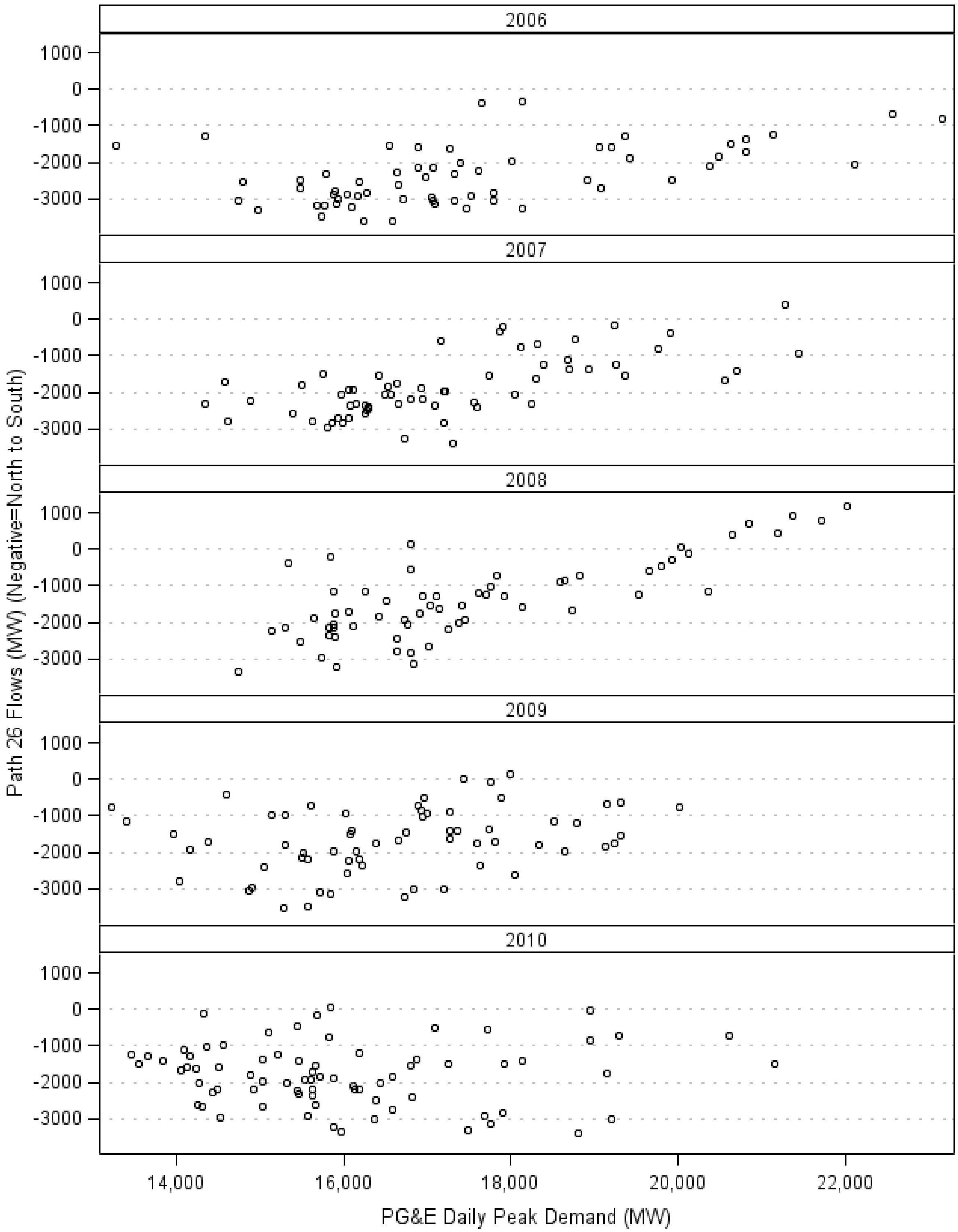
Path 26 Flows and Electricity Demand

Under current resource conditions in California, variation in demand is the primary driver of Path 26 flows during peak periods, in particular demand in the PG&E TAC area. Because the annual peak demand in most of California is driven by high temperatures and a corresponding rise in air conditioning load, this analysis focuses on the period when the annual peak demand is expected to occur, on a summer weekday, with summer generally defined as June 15 to September 15.[2]

Figure 2 shows PG&E summer weekday peak demand and the coincident path flows for 2006 to 2010. When demand is low, there is little or even negative correlation between demand and flows, but at demand levels above 18,000 to 19,000 MW, path flows from north to south begin to decline. While this pattern is clearly visible in the 2006 to 2008 data, it might appear at first glance that in 2009 and 2010 this relationship does not continue. However, note that in 2009 and 2010 there are few days above 19,000 MW. This reflects both lower overall demand and few high temperature events in those years. Three aspects of this lower demand affect path flows: 1) lower temperatures, 2) relative levels of demand in the north versus the south, and 3) lower overall demand after accounting for temperatures. This section discusses each.

2 For 2010 only, data through September 30 were used as this period includes one of the few high temperature periods of that summer.

Figure 2: Summer Weekday Path 26 Flows (MW) and PG&E Daily Peak Demand



Source: California ISO subpoena data and Energy Commission staff.

Temperature and Electricity Demand

Electricity demand in California peaks on hot, summer, weekday afternoons, when high residential and commercial cooling loads are added to the commercial and industrial loads characteristic of the work week. These cooling loads are directly influenced by temperatures: the higher the temperature, the more people rely on air conditioning for comfort, and the more electricity they consume as a result. Electricity demand is lower on weekends as commercial and industrial operations are reduced; many businesses are closed.

Accounting for the effects of temperature on demand is an essential part of demand forecasting and analysis. This paper uses the statistical methods developed by Energy Commission demand analysis staff for peak demand forecasting and weather normalization; a description of the most recent analysis can be found in the *Revised Short-Term (2011-2012) Peak Demand Forecast.*[3] Those methods use two weather variables. The first is a three-day moving average of daily maximum temperatures, which are a weighted average of the temperature of the current day (with a weight of 60 percent), the previous day (30 percent), and two days prior (10 percent). While the current day's peak temperature alone explains a substantial amount of variation in peak electricity demand, a sustained increase in peak temperatures over a three-day period has a greater effect on demand than a sudden, one-day spike. Sustained high temperatures contribute to a "thermal buildup," where heat is absorbed in materials (such as asphalt) and gradually released, increasing discomfort even as surrounding temperatures fall. The second variable is the daily minimum temperature, which captures the effects of lack of nighttime cooling and often higher humidity during high temperature events. For graphical purposes, this paper uses the daily maximum variable. The "Northern California" and "Southern California" temperatures in this paper are the weighted average of daily maximum temperatures at several weather stations, where the weights are based on the saturation of air-conditioning units. The resulting indices are highly correlated with loads in the PG&E and SCE TAC areas.[4]

Demand forecasting staff uses regression models of demand as a function of these temperature statistics to estimate what observed historic demand would have been at varying temperatures, using a database of weather since 1950. The 1-in-2 demand level is defined as the average of the estimated annual peak demand under temperature conditions experienced over the last 60 years. The 1-in-10 estimate is defined as demand at the ninetieth percentile of this distribution.

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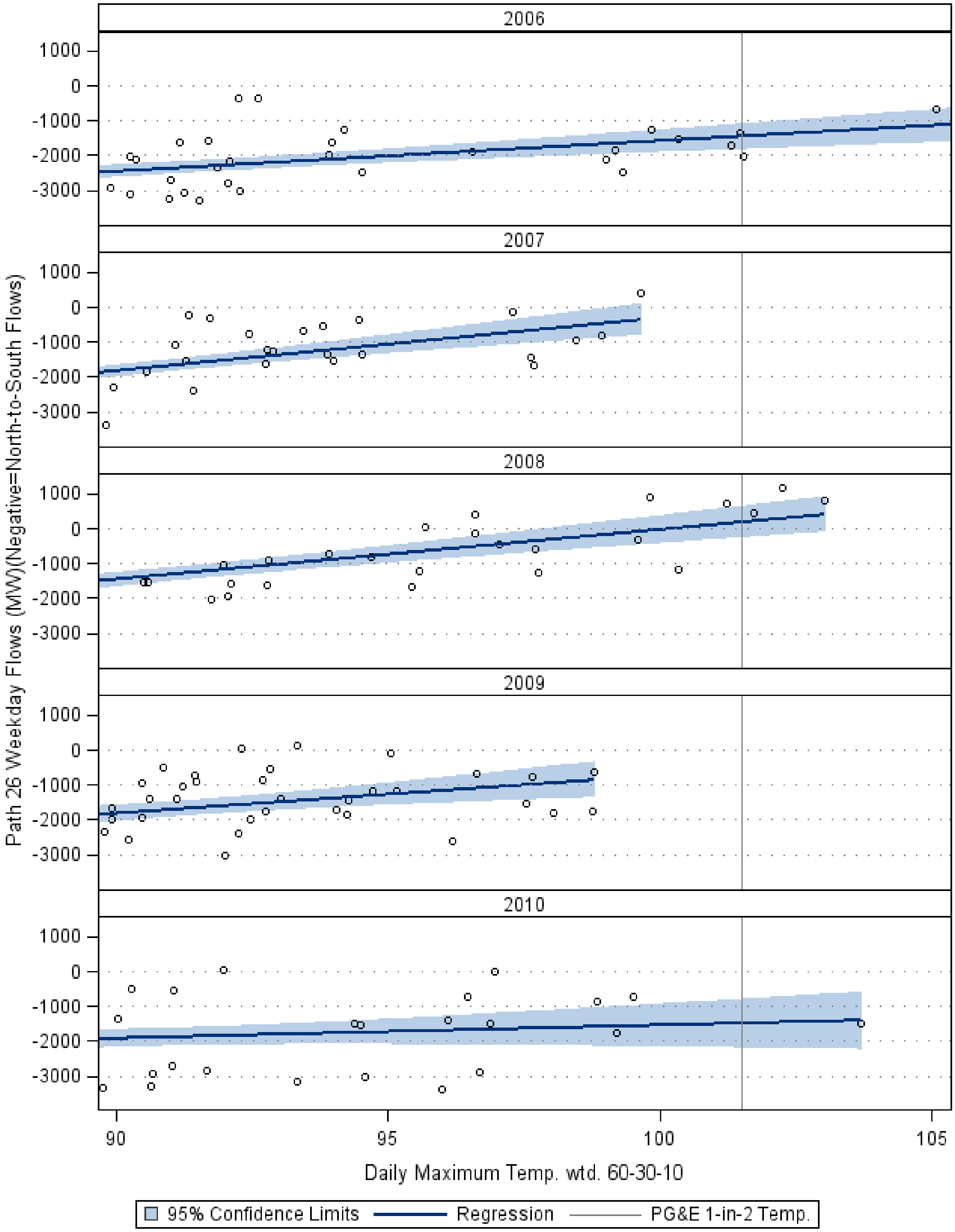
3 California Energy Commission, *Revised Short-Term (2010-2012) Peak Demand Forecast*, 2011, CEC-200-2011-002-CTF.

4 For weather station weights and further discussion of weather variables, see *Final Staff Forecast of 2008 Peak Demand*, CEC-200-2007-006SF, June 2007. The daily minimum variable currently used captures the same effect as the diurnal variation statistic discussed in this reference.

Summer Daily Maximum Temperatures and Path 26 Flows

Figure 3 illustrates that as the Northern California temperature rises, southward flows over Path 26 generally decline. The only year for which this is not clearly the case is 2009 when temperatures never rose above 99 degrees Fahrenheit (°F), below the 1-in-2 temperature of 101.5°F. Based on the observed 2006-2008 flows over Path 26, Energy Commission staff concluded that an appropriate estimate for on-peak flows was approximately 1,100 MW. While average southward flows over Path 26 in summer 2009 and 2010 are higher, the difference is smaller on high temperature days. As the Northern California peak temperature rose above 95°F, flows over Path 26 declined and were, with one exception, below 2,000 MW. The average flows on days with temperatures above 95°F were 1,297 MW southward in 2009 and 1,266 MW in 2010.

Figure 3: Summer Weekday Path 26 Flows (MW) and Northern California Temperatures



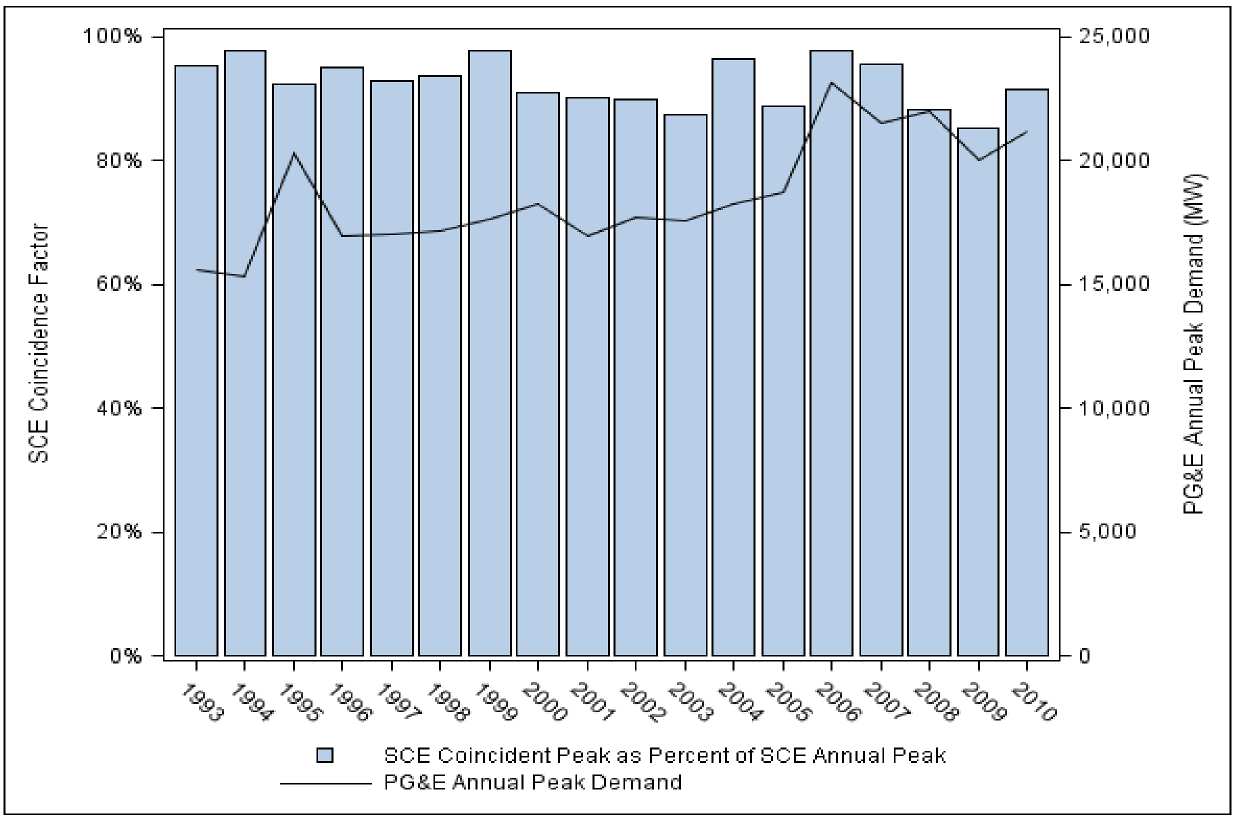
Source: California ISO subpoena data and Energy Commission staff.

Load Diversity and Path 26 Flows

A second aspect of demand that affects path flows is load diversity between Northern and Southern California. Load diversity is the extent to which different loads peak at different times. In this case, it is the difference between the sum of individual TAC area annual peak loads and the coincident peak of the summed hourly loads. Accounting for load diversity in resource planning can allow savings in capacity and spinning reserve requirements.

Primarily due to different temperature patterns, the SCE and PG&E areas typically do not experience their annual peaks at the same time. As discussed in the *Revised Short-Term (2011-2012) Peak Demand* report, the annual California ISO peak tends to be in the late summer when the south usually peaks.[5] Northern California peaks in July, when demand in the south is generally lower. **Figure 4** shows SCE's coincidence with the PG&E annual peak demands since 1993. The SCE coincidence factor shown is SCE's demand at the time of the PG&E peak as a percent of SCE's annual peak in that year. The average coincidence factor for this period was 93 percent, meaning the average coincident peak was 7 percent below SCE's annual peak demand.

Figure 4: Historical Coincidence of SCE Loads With PG&E Annual Peak Demand

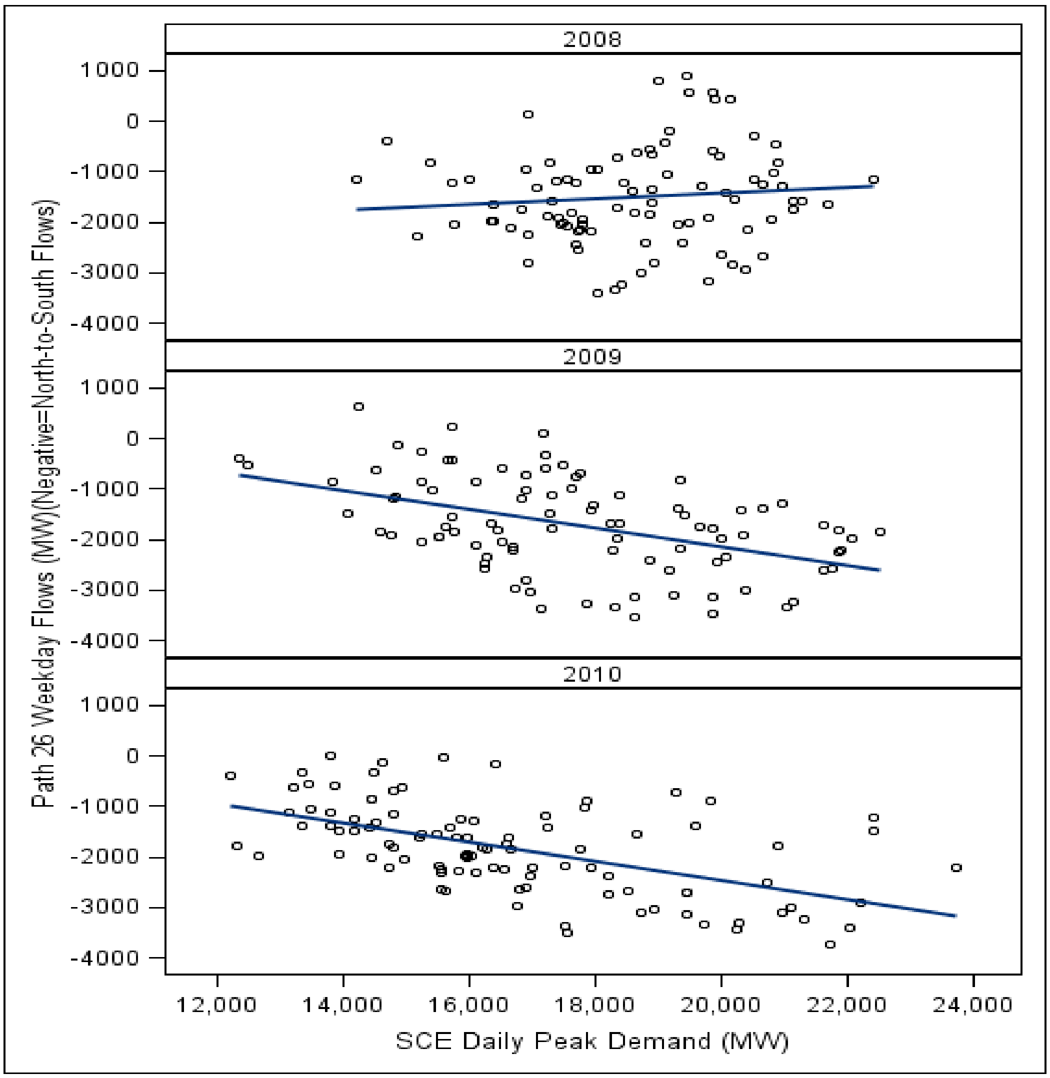


Source: FERC Form 714 (1993-2005), California ISO and Energy Commission staff.

5 See Appendix A.

This diversity between north and south loads allows generation resources to be deployed where they are most valued. **Figure 5** illustrates that the Path 26 flow to the south generally increases as demand in the south increases, although the relationship is weaker than the PG&E demand-path flow correlation. The lack of correlation in 2008 reflects higher temperatures in Northern California that summer, while temperatures in the south were mild; hence the high loads in the north drove path flows. In 2009 and 2010, since temperatures were mild in the north, demand in the south had a somewhat stronger influence on path flows.

Figure 5: Summer 2006-2009 Path 26 Weekday Flows (MW) and SCE Daily Peak Demand (Days on Which SCE Temperature Exceeds 75°F)



Source: California ISO subpoena data and Energy Commission staff.

Detail on temperatures and flows for the periods of highest demand in 2009 and 2010 illustrate the combined influence of north and south loads and temperatures on path flows.

The information provided by the events in summer 2009 is limited by the complete absence of extreme temperature events in Northern California. **Table 1**, **Table 2**, and **Table 3** show temperature and load conditions experienced during peak demand periods of June, July, and August 2009, respectively. These temperatures did not reach the 1-in-2-temperature of 101.5°F at any point during 2009.

Table 1: Peak Loads and Path 26 Flows, June 26 – 30, 2009

	Weighted Max. Temp (°F)		Daily Peak Load (MW)		
Date	**Southern California**	**Northern California**	**SCE**	**PG&E**	**Flow at Peak Hour (MW)**
6/26/2009	84.0	90.6	15,748	16,101	-1,404
6/27/2009	88.3	96.7	15,713	17,902	221
6/28/2009	92.5	100.9	17,159	18,914	126
6/29/2009	**89.2**	**98.8**	**17,314**	**19,392**	**-643**
6/30/2009	87.0	95.0	17,197	17,761	-89

Source: California ISO and Energy Commission staff.

This event featured rapidly increasing maximum temperatures in Northern California over three days and a decline that was almost as rapid. On Monday, June 29, Northern California temperatures peaked slightly less than 3 degrees below their 1-in-2 value; 643 MW flowed southward on Path 26. The corresponding temperature in Southern California (89.2°F) was roughly 6 degrees below its conditionally expected value;[6] had it been higher, a share of the additional energy needed to meet the higher loads would likely have come from Northern California.[7]

6 The expected peak temperature in Southern California, given that Northern California temperatures equal or exceed 99 degrees, is slightly above 95 degrees. The converse is true as well: If the Southern California temperature is 99 degrees, the expected peak in Northern California is 95 degrees, although this value increases slightly as Southern California temperatures increase.

7 A regression of Southern California loads on temperatures for summer 2009 indicates that peak loads rose 333 MW with each degree increase in peak temperature. Had Southern California temperatures peaked at 95 degrees, the expected increase in load would have been roughly 1,900 MW. Only a share of this would have been met by incremental flows over Path 26.

Table 2: Peak Loads and Path 26 Flows, July 13 – 21, 2009

Date	Weighted Max. Temp (°F) Southern California	Weighted Max. Temp (°F) Northern California	Daily Peak Load (MW) SCE	Daily Peak Load (MW) PG&E	Flow at Peak Hour (MW)
7/13/2009	94.7	92.2	19,934	17,631	-2,369
7/14/2009	**92.8**	**97.6**	**19,340**	**20,012**	**-744**
7/15/2009	91.7	97.5	19,416	19,308	-1,534
7/16/2009	93.1	97.0	19,852	19,018	NA
7/17/2009	94.2	98.8	19,854	19,419	-1,767
7/18/2009	95.4	100.1	19,178	18,551	-2,254
7/19/2009	96.6	101.4	20,062	19,116	-2,217
7/20/2009	95.4	96.2	21,627	18,169	-2,611
7/21/2009	95.2	92.0	21,021	17,204	-2,996

Source: California ISO subpoena data and Energy Commission staff.

PG&E experienced its 2009 annual peak on July 14. On that day SCE temperatures were mild, and flows south were 744 MW. On July 18 – 19, 2009, temperatures in the north were close to 1-in-2 levels, but because these temperatures occurred on a weekend, loads were lower than would have been the case had the same temperatures prevailed during the week. Accordingly, the flows over Path 26 less reflect the need for Southern California to import energy from the northern half of the state than the availability of unneeded, economically priced energy from generators in Northern California (and points farther north). The following Monday, as SCE loads rose and PG&E loads declined, flows south increased to 2,611 MW.

Table 3: Peak Loads and Path 26 Flows, August 26–September 4, 2009

Date	Weighted Max. Temp (°F) Southern California	Weighted Max. Temp (°F) Northern California	Daily Peak Load (MW) SCE	Daily Peak Load (MW) PG&E	Flow at Peak Hour (MW)
8/26/2009	98.1	89.9	20,004	16,371	-1,970
8/27/2009	102.9	94.1	21,875	17,818	-1,708
8/28/2009	102.5	98.0	21,845	18,475	-1,798
8/29/2009	101.7	99.9	20,972	18,838	-1,279
8/30/2009	100.8	94.4	20,334	16,008	-1,926
8/31/2009	98.8	89.4	21,909	16,090	-2,214
9/1/2009	96.9	88.7	21,606	17,274	-1,639
9/2/2009	98.1	92.5	22,052	18,724	-1,964
9/3/2009	**99.0**	**94.2**	**22,501**	**19,131**	**-1,859**
9/4/2009	97.9	90.2	21,745	16,037	-2,584

Source: California ISO subpoena data and Energy Commission staff.

Southern California temperatures reached 1-in-2 levels on Friday, August 28, 2009, with Northern California temperatures 2 to 3 degrees above their expected value. When the SCE area peaked on September 3, PG&E temperatures were 7 degrees below 1-in-2 levels and flows south were almost 1,900.

Table 4 and **Table 5** illustrate Path 26 flows during the highest demand events in summer 2010.

Table 4: Peak Loads and Path 26 Flows, August 23 – 27, 2010

	Weighted Max. Temp (°F)		Daily Peak Load (MW)		
Date	**Southern California**	**Northern California**	**SCE**	**PG&E**	**Flow at Peak Hour (MW)**
8/23/2010	97.0	91.7	20,951	17,909	-2,827
8/24/2010	99.9	99.5	22,422	20,611	-720
8/25/2010	**100.7**	**103.7**	**22,426**	**21,180**	**-1,488**
8/26/2010	99.2	96.7	22,200	17,755	-2,902
8/27/2010	91.7	90.7	18,931	15,580	-2,933

Source: California ISO subpoena data and Energy Commission staff.

August 25, 2010, witnessed peak temperatures in Northern California slightly above 1-in-2 values; the corresponding temperatures in Southern California were roughly 5 degrees above their expected conditional values and less than 2 degrees below 1-in-2 values. Despite these higher-than-expected temperatures in the southern half of the state, flows on Path 26 were less than 1,500 MW.

Table 5: Peak Loads and Path 26 Flows, September 24 – 30, 2010

		Weighted Max. Temp (°F)		Daily Peak Load (MW)		
Day	**Date**	**Southern California**	**Northern California**	**SCE**	**PG&E**	**Flow at Peak Hour (MW)**
Fri	9/24/2010	90.8	85.7	17,524	14,999	-2,184
Sat	9/25/2010	99.6	91.6	17,940	15,233	-2,039
Sun	9/26/2010	104.6	93.9	19,462	15,410	-2,706
Mon	**9/27/2010**	**108.8**	**96.9**	**23,714**	**17,915**	**-1,491**
Tue	**9/28/2010**	**101.1**	**99.2**	**20,912**	**19,281**	**-1,775**
Wed	9/29/2010	95.5	98.9	19,839	18,966	-872
Thu	9/30/2010	92.7	94.5	18,666	16,792	-1,546

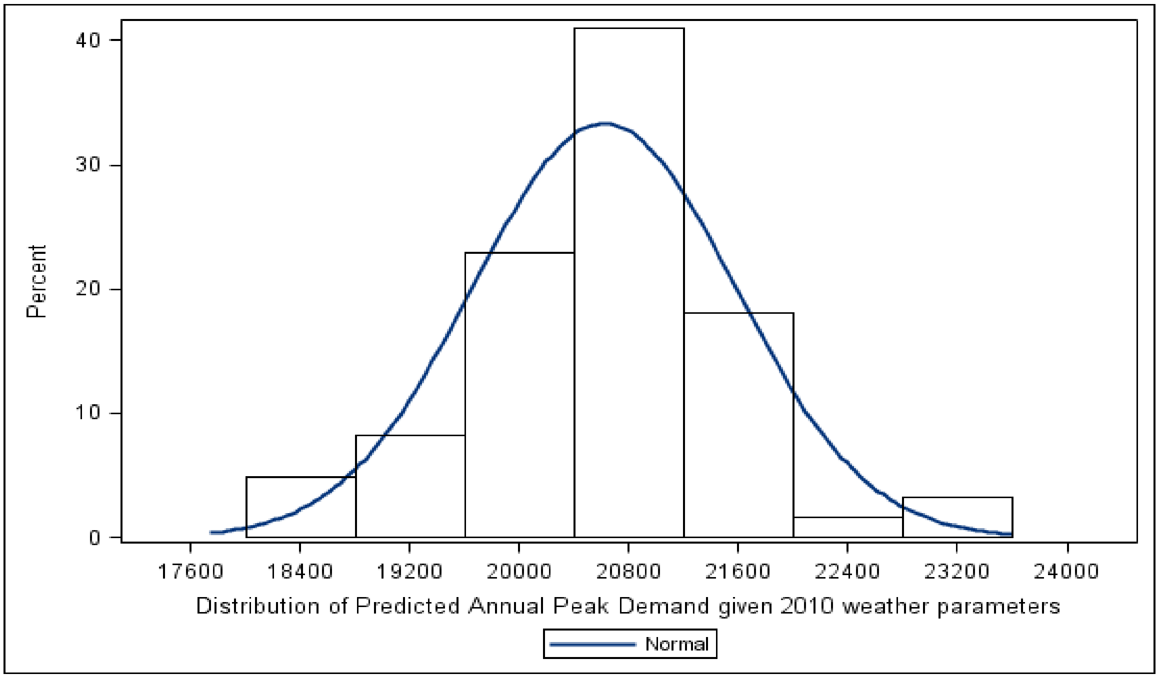
Source: California ISO subpoena data and Energy Commission staff.

On September 27, 2010, Southern California experienced well above 1-in-2 temperatures, while those in Northern California were at their conditional expected values; roughly 3,000 MW flowed south on Path 26. Temperatures rose in Northern California and fell in the southern half of the state the following day, and flows on the path ebbed.

Expected Load Diversity at High Temperatures

The methods used by Energy Commission forecasting staff to normalize historical demand to 1-in-2 temperatures and estimate demand at extreme temperatures can also be used to estimate expected load diversity. Forecasting staff use the estimated relationship between demand and temperature to develop a distribution of expected annual peak demand under historical temperature conditions**. Figure 6** shows the distribution of the PG&E annual peak demands using the 2010 estimated parameters.[8] This represents the range of possible annual peak demand based on historical temperature patterns, normalized to 2010 demand sensitivity to temperature. The mean of the distribution represents the 1-in-2 non-coincident peak demand; demand at the 90th percentile is the 1-in-10 demand.

Figure 6: Northern and Southern California Summer Weekday Demand During Peak Hours

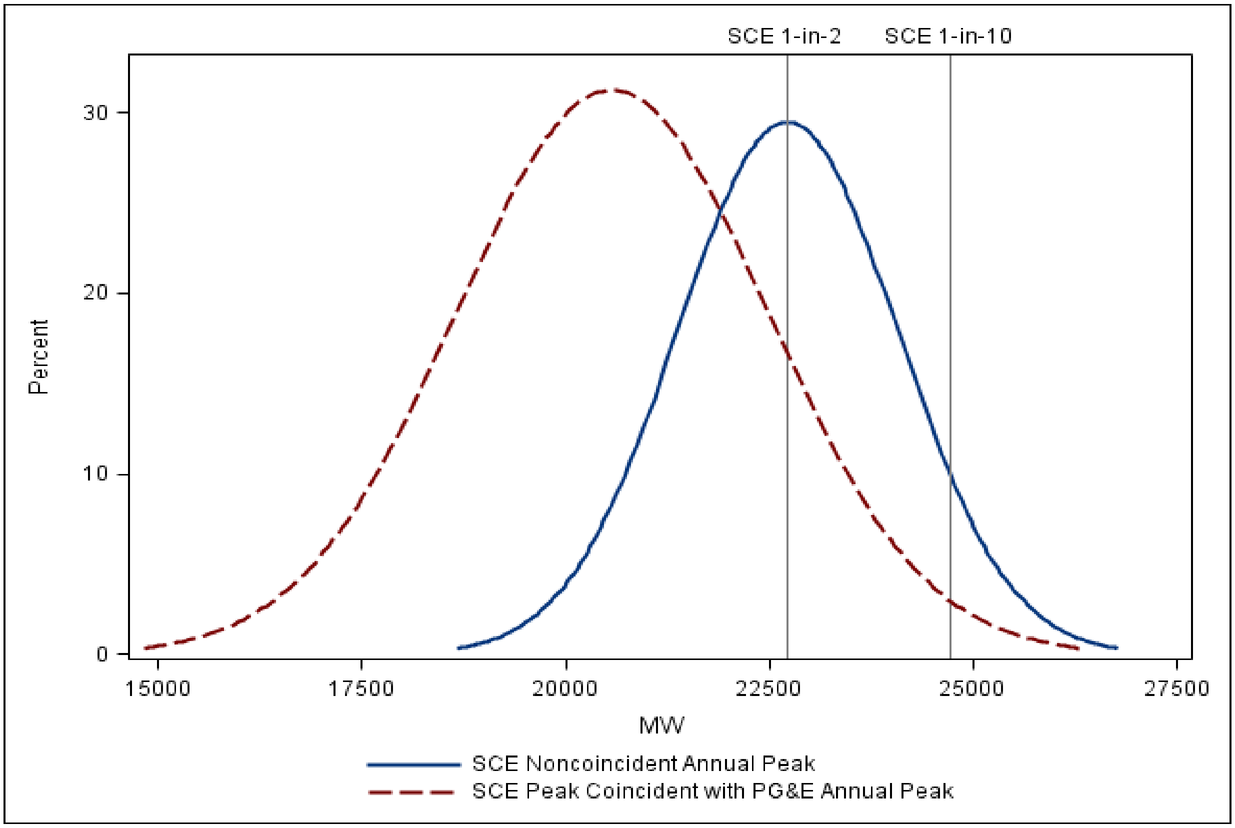


Source: Energy Commission staff.

To assess expected SCE peak demand at the time of the PG&E peak, staff used the temperature model estimated for SCE to calculate the SCE peak demand on the date of the predicted PG&E annual peak for each year from 1950 to 2010. **Figure 7** shows the distribution of annual non-coincident peak demand used as the basis for the 1-in-2 forecast, and the distribution of SCE peak demand coincident with the annual PG&E peaks. The difference between the two represents temperature-driven load diversity. The average coincident peak is 91 percent of the non-coincident peak. By comparison, for 1993-2010, the average of the actual coincidence factors was 93 percent. The distribution of estimated PG&E peaks and SCE peaks coincident with the PG&E peak provide a basis for estimating path flows at the time of a 1-in-2 PG&E peak, to be discussed in the section on expected path flows under high temperature conditions.

[8] See Appendix B of the *Revised Short-Term (2011-2012) Peak Demand Forecast.*

Figure 7: Distribution of SCE Annual Peak Demand and SCE Peak Coincident With PG&E Predicted by Historic Annual Maximum Temperatures

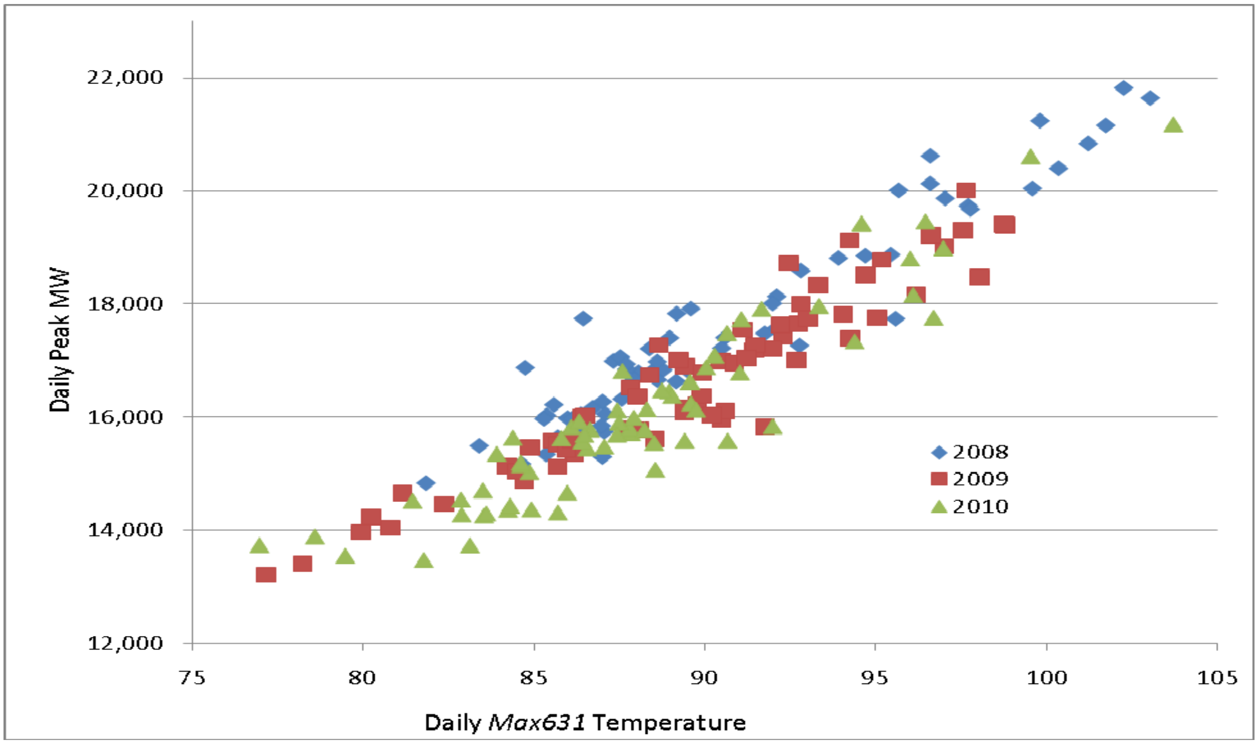


Source: Energy Commission staff.

Demand Levels

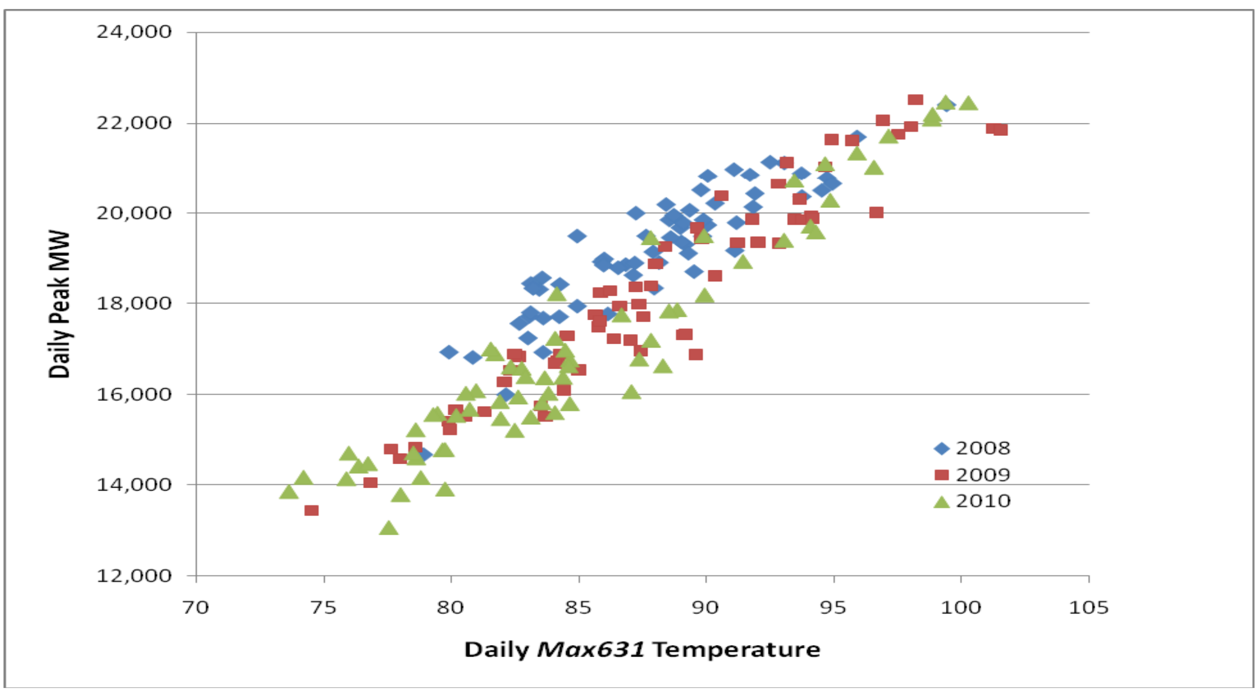
Aside from temperature effects and load diversity, a third aspect of demand significant for path flows is the absolute level of demand relative to available resources. Daily weekday peak demand and temperatures for Northern and Southern California for 2008 – 2010 are graphed in **Figure 8** and **Figure 9**. After accounting for the effects of lower temperatures, PG&E demand in summer 2009 was about 3 percent lower than 2008, with a further slight decline in 2010 demand. In SCE, weather-adjusted peak demand was 5 percent lower in 2009 and dropped slightly more in 2010. As discussed in the *Revised Short-Term (2011-2012) Peak Demand Forecast* report, this can be attributed to the downturn in the economy. These lower demand levels contribute to improved reserve margins and allow resource owners more flexibility to respond to market conditions rather than operational needs.

Figure 8: Summer Weekday Peak (MW) Versus Daily Maximum Temperatures, PG&E 2008-2010



Source: Energy Commission, *Revised Short-Term (2011-2012) Peak Demand Forecast.*

Figure 9: Summer Weekday Peak (MW) Versus Daily Maximum Temperatures, SCE 2008-2010



Source: Energy Commission, *Revised Short-Term (2011-2012) Peak Demand Forecast.*

Other Variables Affecting Path 26 Flows

The marked decline in daily peak loads over 2008 – 2010 has been accompanied by an increase in available supply. **Table 6** presents the major resource additions in the California ISO balancing authority area between September 30, 2008 and June 15, 2010.

Table 6: Major Additions, California ISO Control Area, September 30, 2008 – June 15, 2010

Resource	Region	MW
Inland Empire	So Cal	670
Gateway	Nor Cal	530
Starwood - Midway	Nor Cal	111
Panoche Energy Center	Nor Cal	381
Otay Mesa	So Cal	604
Orange Grove	So Cal	96
Humboldt Bay (net)	Nor Cal	58
Total		**2,450**

Source: Energy Commission staff; 2010 NQC values are used where available.

The sole major retirement during this period was South Bay (Units 3 and 4,397 MW); more than 2,000 MW of additional efficient, dispatchable generation was available in the California ISO control area during summer 2010.

The effective reserve margin in California also increased over 2009 – 2010 as a result of higher imports from the Pacific Northwest. **Table 7** illustrates the average increase in imports from the Pacific Northwest on the Alternating Current (AC) and Direct Current (DC) Interties during peak hours (hours ending 13 – 18) on weekdays during June –through September.

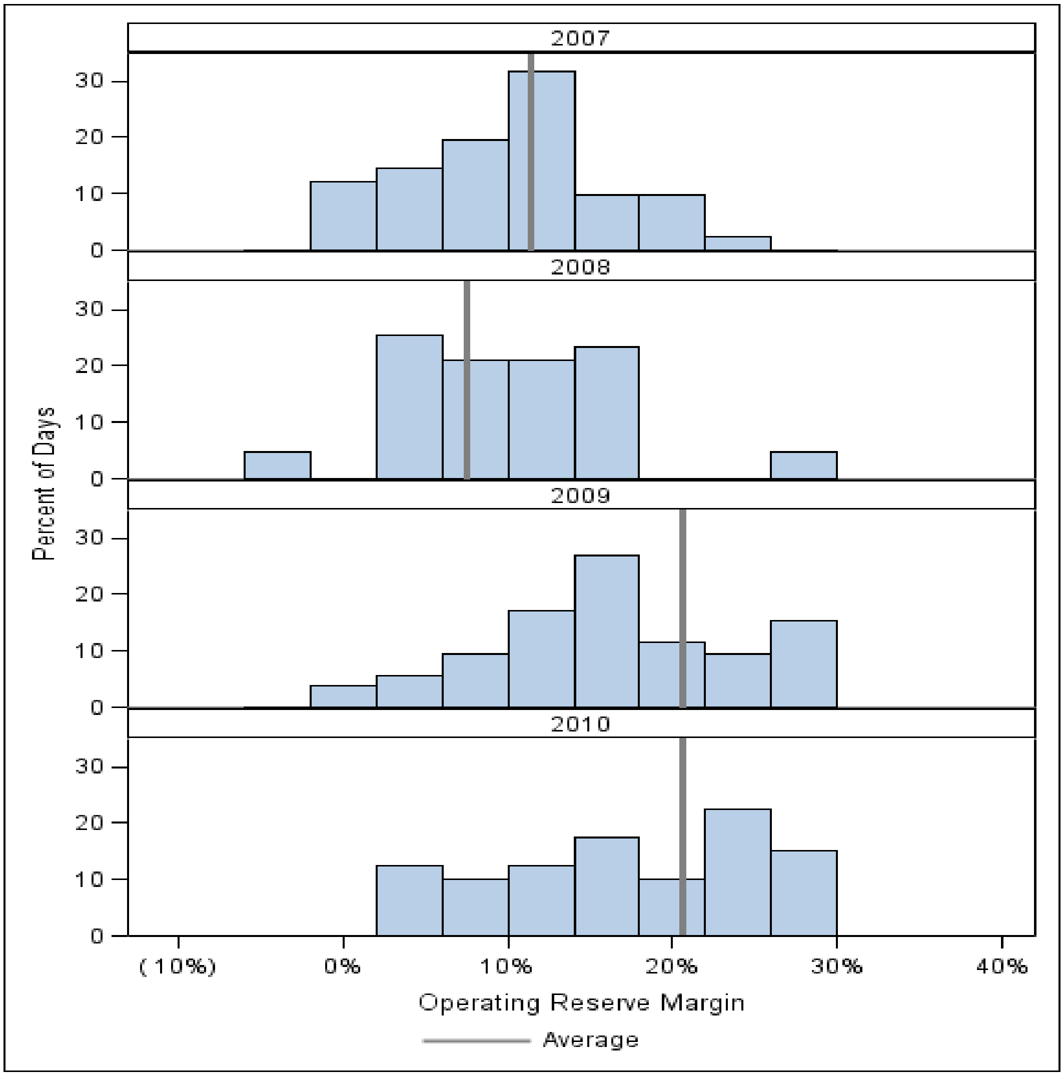
Table 7: Change in Average Imports From the Pacific Northwest, 2009 – 2010, Weekdays, Hours Ending 13 - 18

Month	AC Intertie	AC and DC Interties
June	500	1,344
July	283	522
August	563	1,013
September	158	153

Source: Bonneville Power Administration Transmission, compiled by Energy Commission staff.

The combined effects of these demand and supply trends can be seen in the higher operating reserves experienced in the California ISO in 2009 and 2010, shown in **Figure 10**. Average operating reserve margins on high temperatures days were 20 percent in 2009 and 2010, compared to 12 and 8 percent in 2007 and 2008, respectively.

Figure 10: Distribution of California ISO Peak-Hour Operating Reserve Margins (Summer Weekdays over 90 °F)



Source: California ISO and Energy Commission staff.

Expected Path Flows Under High Temperature Conditions

To estimate Path 26 flows during peak demand conditions, staff first used regression analysis to estimate path flows at the time of the PG&E peak as a function of PG&E demand, SCE peak, on-peak wholesale prices, and energy imports, for 2008 through 2010. Imports are characterized by flows from the northwest on the Pacific AC and DC Intertie Lines and imports into Southern California via the Intermountain DC Line (Path 27), the California ISO-Mexico tie (Path 45), and from west of the Colorado River (Path 46). Because there are numerous other variables that affect relative supply balances and therefore could affect flows, indicator variables are used for 2009 and 2010 to allow for variation between years. Since the relationship of interest is path flows during high demand conditions, only days where the temperature exceeded 93F° in either the north or south were used. As seen in **Figure 3**, demand appears to have little effect on flows below that level. The same pattern is observed with SCE loads and temperatures.

Table 8 shows the estimated model. While the overall fit (an adjusted R^2 of 86 percent) suggests that additional factors affect path flows, the estimated parameters for demand and imports are significant and are consistent with staff's assessment of PG&E demand as the primary driver of path flows. A 100 MW increase in PG&E demand decreases path flows south by about 50 MW, while a 100 MW increase in SCE demand increases flows by a smaller amount (30 MW). Imports from the northwest allow for increased flows southward, while Southwest imports decrease flows south, as would be expected. In regression estimates of effects by year, the influence of price varied. In 2008, prices did not contribute to flow patterns, so only a price variable was used only for 2009 and 2010. In regression of the data by year, the price variable was the only one to show significantly different patterns across years. This differential suggests that in years with high reserve margins, path flows were more affected by market incentives than operational need.

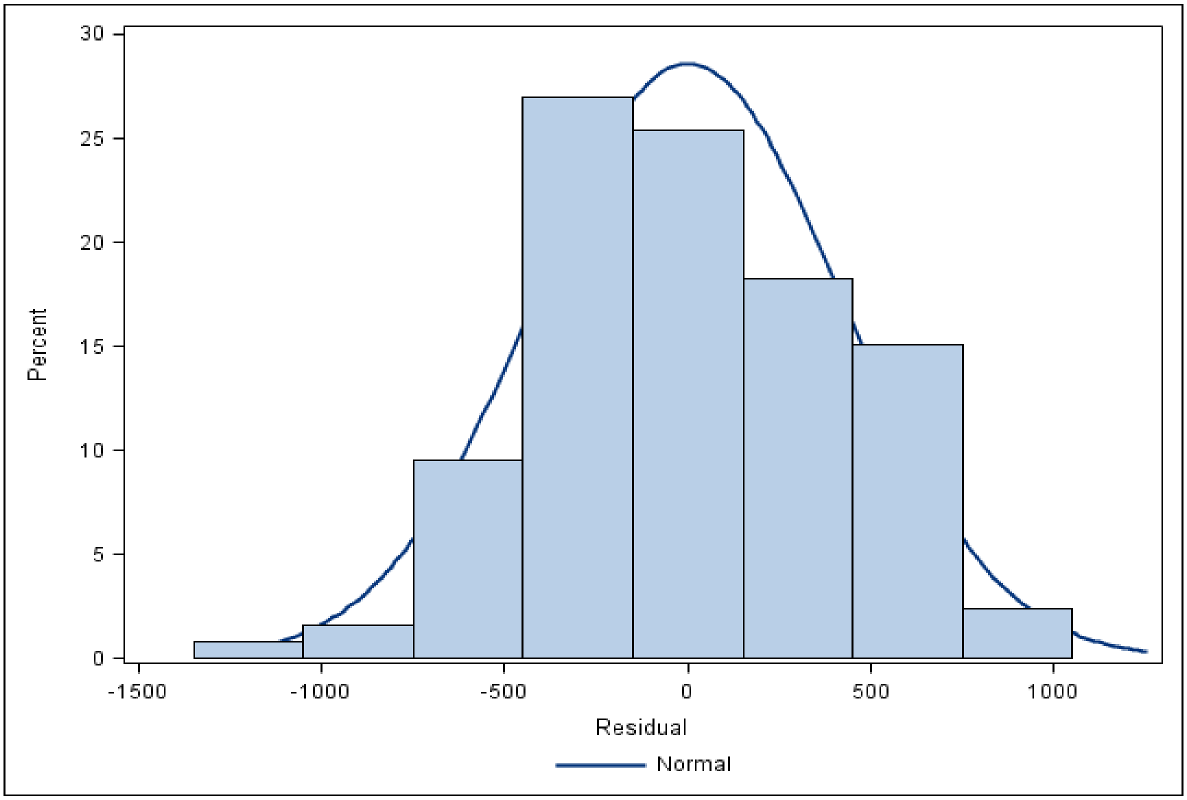
Table 8: Regression Estimates of Summer Weekday Path Flows on High Temperature Days (2008-2010)

Variable	Parameter Estimate	Standard Error	t-Statistic
Intercept	-5,813	791	-7.35
Year2008	854	776	1.1
Year2009	2,949	1,000	2.95
PG&E Demand (MW)	0.52	0.03	15.55
SCE Demand (MW)	(0.29)	0.03	-11.48
AC and DC Intertie Flow (MW)	(0.17)	0.05	-3.24
Southwest Imports (mw)	0.15	0.06	2.46
Wholesale Price 2009	(67.49)	16.84	-4.01
Wholesale Price 2010	(13.55)	14.08	-0.96
Southwest Imports 2010	0.21	0.09	2.36
Adjusted R^2=0.86			

Source: Energy Commission staff.

Figure 11 shows the distribution of the model residuals: the difference between predicted and actual flows. While the error in a few cases is as large as 1,000 MW, the errors are approximately normally distributed around zero, indicating the model specification is a good fit for the data.

Figure 11: Distribution of Regression Model Residuals

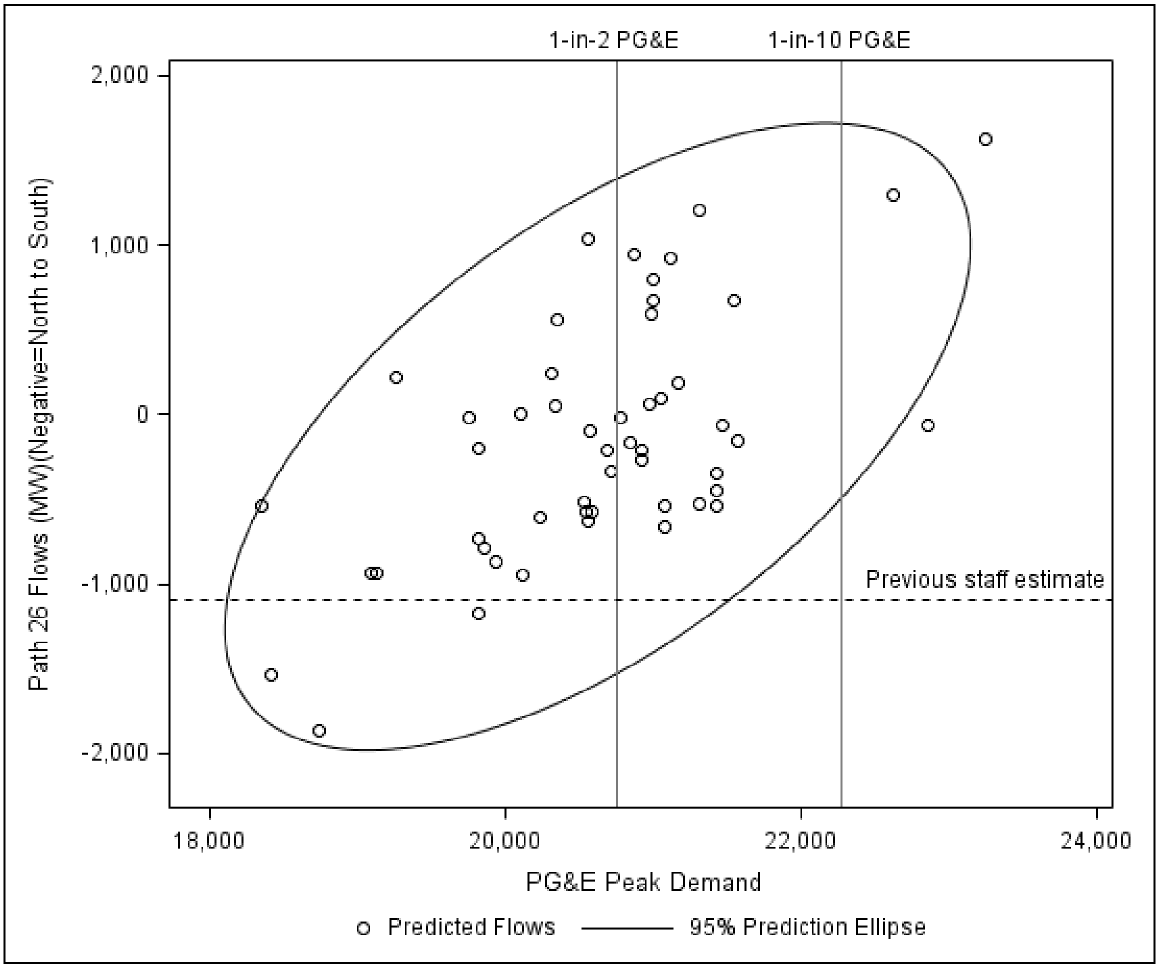


Source: Energy Commission staff.

Staff used the estimated model and the predicted demand from the demand forecasting load-temperature models (shown in **Figure 6** and **Figure 7**) to construct a series of path flows predicted as a function of demand, imports, and wholesale power prices. For this initial analysis, imports were held constant at the average value observed on days with temperatures above 93°F.

Figure 12 shows predicted path flows for the range of annual PG&E peak demands and coincident SCE demands predicted to occur under historic temperature conditions. At 1-in-2 demand levels, flows are in the range of 1,000 MW southward or less. As demand increases to 1-in-10 levels, predicted flows south decline. At 1-in-2 temperatures and above, the lower bound of the prediction interval is about 1,800 MW southward. While the variation in path flows suggests numerous other factors can affect flows, this analysis indicates a reasonable assumption for path flows at the time of a PG&E peak lies in the range of 1,000 MW to 1,500 MW southward, consistent with staff's earlier estimate of 1,100 MW.

Figure 12: Simulated Path Flows Coincident With Annual PG&E Peak Demands



Source: Energy Commission staff.