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FINAL PROJECT REPORT

ESTIMATING RISK TO CALIFORNIA ENERGY INFRASTRUCTURE FROM PROJECTED CLIMATE CHANGE

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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

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- Transportation

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For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

This report outlines the results of a study of the impact of climate change on the energy infrastructure of California , including (1) high temperature impacts on power plant capacity, electricity generation, transmission lines, substation capacity, and peak electricity demand; (2) wildfire impacts near transmission lines; and (3) sea level encroachment upon power plants, substations, and natural gas facilities. End-of-century impacts were projected with respect to A2 and B1 Intergovernmental Panel on Climate Change scenarios.

The study quantifies the effect of high ambient temperatures on electricity generation, transmission line capacity, and peak power demand. It shows that atmospheric warming may necessitate up to 38 percent additional peak generation capacity and up to 31 percent additional transmission capacity.

The study demonstrates that key transmission corridors are vulnerable to increased fire frequency. For example it shows a 40 percent increased probability of wildfire exposure for some major transmission lines, including the transmission line bringing hydropower generation from the Pacific Northwest during peak demand periods. Finally, the study identifies energy infrastructure vulnerable to sea level encroachment. Up to 25 current coastal power plants and 86 substations are at risk of flooding or compromised operation due to sea level rise.

Keywords: Electricity, transmission, climate change, generation, sea level, wildfire

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EXECUTIVE SUMMARY

Introduction

This report presents the results of an ongoing research project aimed at quantifying risk to California's energy infrastructure from projected climate change. For this study, *energy infrastructure* includes the state's natural gas-fired power generation facilities, electric transmission and distribution system, and natural gas pipelines in the Sacramento-San Joaquin Delta.

Purpose

This project assessed the vulnerability of California energy infrastructure to three climate-related occurrences:

- Warming temperatures
- Increased incidence of wildfire
- Sea level rise and storm surge

This report outlines the impact of these climate-related occurrences on power plant generation; transmission line and substation capacity during heat spells; wildfires near transmission lines; sea level encroachment upon power plants, substations, and natural gas facilities; and peak electrical demand. Some end-of-century impacts were projected.

Objectives

For the most part, this study projects the impacts of climate change on the current energy infrastructure and the current population of California. This has been the practice in much of the recent literature on the subject because it allows researchers to focus on climate change rather than many other variables (such as population growth and technology advancement) that will also be changing in the future, quite apart from the climate. Although these other variables must be taken into account in making policy decisions, they can be estimated separately, and the research team believes that there is value in gaining knowledge of climate change impacts independent of these variables.

Conclusions and/or Recommendations

The study finds that higher temperatures will decrease the capacity of existing natural gas-fired power plants to generate electricity during particularly hot periods in the future. The estimated decrease in capacity varies by region, emission scenario, climate model, and plant type. During the hot periods of August at the end of the century, under the high emission scenario, the models used for this study estimate a decrease in natural gas power plant generating capacity of 3 percent to 6 percent in California. Under similar conditions, the models suggest diminished transformer and substation capability (between 2 percent and 4 percent across California), a relatively small (1 percent to 3 percent) increase in transmission and distribution losses, and a possible larger (7 percent to 8 percent) decrease in transmission line capacity.

More specifically, California's gas-fired generating plants have a nameplate capacity of 44.1 gigawatts (GW) (out of a total 58.5 GW from all sources). By the end of the century, atmospheric warming at the locations of these plants could reduce their output on hot days by a total of 10.3 GW. This is the *maximum coincident loss*, summed simultaneously over all plants. This should be compared with the 1961–1990 maximum coincident loss of 7.6 GW.

By the end of the century, to deliver the same per-capita power as in 1961–1990, California may need to increase its nameplate peak capacity to 47.6 GW, an 8 percent increase over the current value. (This is above any increase driven by population growth or decrease due to efficiency gains.)

In addition, elevated temperatures will increase electrical demand for cooling. At the 90th percentile (meaning the 1-in-10 temperatures that are above the maximum daily average) level, a 21 percent increase in peak demand is likely. Since this peak demand occurs at the time of maximum temperature, when only part of the nameplate capacity can be delivered, a further nameplate capacity increase of 27 percent will be necessary to drive this air-conditioning load. Decreased substation efficiency will add 2.7 percent to the temperature-induced losses, which at peak temperatures will require 3.5 percent more generation.

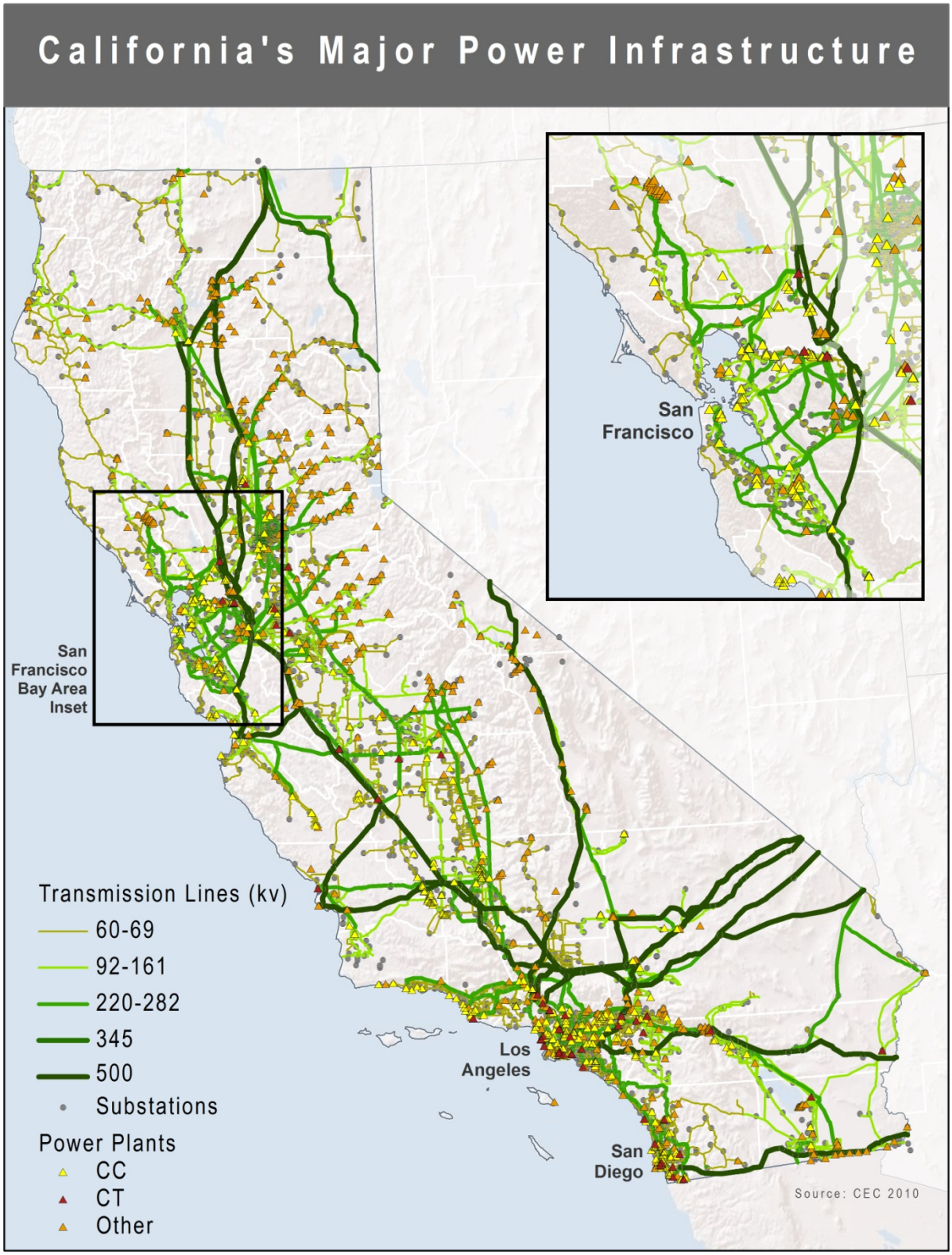
Combining these results, to overcome decreased generator efficiency, decreased substation efficiency, and increased air-conditioning demand, it will be necessary to provide an additional 38.5 percent peak generation capacity. In terms of transmission, a 5º Celsius (9º Fahrenheit) air temperature increase (the average increase predicted for hot days in August according to the Intergovernmental Panel on Climate Change's A2 scenario) diminishes the capacity of a fully loaded transmission line by an average of 7.5 percent.

The heat-induced generation increases mentioned above do not need to be pushed through the transmission lines—they are needed only to bring the generators back to previous power levels. But the 2.7 percent substation handicap and the 21 percent air-conditioning burden do need to be transmitted, so the electrical grid may need to carry 23.7 percent more peak power per-capita than it does today. And it must do this in the face of a 7.5 percent decrease in the capacity of fully loaded transmission lines. This suggests that at least parts of the grid may need up to 31.2 percent more capacity than would be expected from population growth alone.

Climate change and fire risk may pose a more difficult challenge to electric utilities. This work, building on the results of existing fire studies, suggests that climate change and higher temperatures will increase fire risk to transmission lines in California. Under some climate scenarios, the likelihood of fires occurring next to large transmission lines is expected to increase dramatically in parts of California at the end of the century. For example, it shows a 40 percent increased probability of wildfire exposure for some major transmission lines, including the transmission line bringing hydropower generation from the Pacific Northwest during peak demand periods. Fires do not always, or even usually, cause electricity outages—they more often increase electricity maintenance costs and decrease transmission line efficiency.

Similarly, rising sea levels at the end of the century could affect as many as 25 coastal power plants, scores of electricity substations, and numerous natural gas facilities located along California's coast. Properly anticipated however, flooding could be avoided by building dikes, moving plants to higher elevations, and other preventative actions. These preventative actions will ultimately save California ratepayers from paying for more extensive damage in the future. By protecting electrical infrastructure now, Californians can adapt to changes in climate with uninterrupted power usage.

In general, the study concludes that large negative impacts from climate change on California's electricity infrastructure are avoidable, if climate change is anticipated and sufficient excess capacity or ameliorative measures (such as power plant intake chillers or dikes around coastal installations) are installed as needed to deal with diminished generation, transmission, and transformer capacity; increased fire risk; and rising sea levels resulting from climate change. These results are qualified with reference to assumptions described throughout this report.



Electrical Power Infrastructure Examined in this Study

CHAPTER 1: Introduction

This report presents the results of an ongoing research project aimed at quantifying risk to California's energy infrastructure from projected climate change. **For the purposes of this study, *energy infrastructure* includes the state's natural gas-fired power generation facilities, electric transmission and distribution system, and natural gas pipelines in the Delta**. This project is funded by the California Energy Commission's Public Interest Energy Research (PIER) program and builds on earlier work by the California Energy Commission (Energy Commission), including Perez (2009) (which provided the background motivation for this work); Westerling et al. (2009); Bryant and Westerling (2009); and Heberger et al. (2009).

For the most part, this study projects the impacts of climate change on the current energy infrastructure and the current population of California. This has been the practice in much of the recent literature on the subject because it allows researchers to focus on climate change rather than many other variables (such as population growth and technology advancement) that will also be changing in the future, quite apart from the climate. Although these other variables must be taken into account in making policy decisions, they can be estimated separately, and it is believed that there is value in gaining knowledge of climate change impacts independent of these variables.

The general tasks in this research project were to assess the vulnerability of California energy infrastructure to three climate-related occurrences:

1. Warming temperatures
2. Increased incidence of wildfire
3. Sea level rise and storm surge

The relationship between these occurrences and the energy infrastructure is briefly described in this introduction. Published comprehensive studies of the impact of climate change on the energy infrastructure are extremely rare, perhaps because of the complexity of the topic, the diversity of the infrastructure, and the large number of risks posed by climate change (Appendix A). The schematic presented in Figure 1 illustrates analysis stages and procedures for evaluating climatic impacts on California's energy infrastructure.[1]

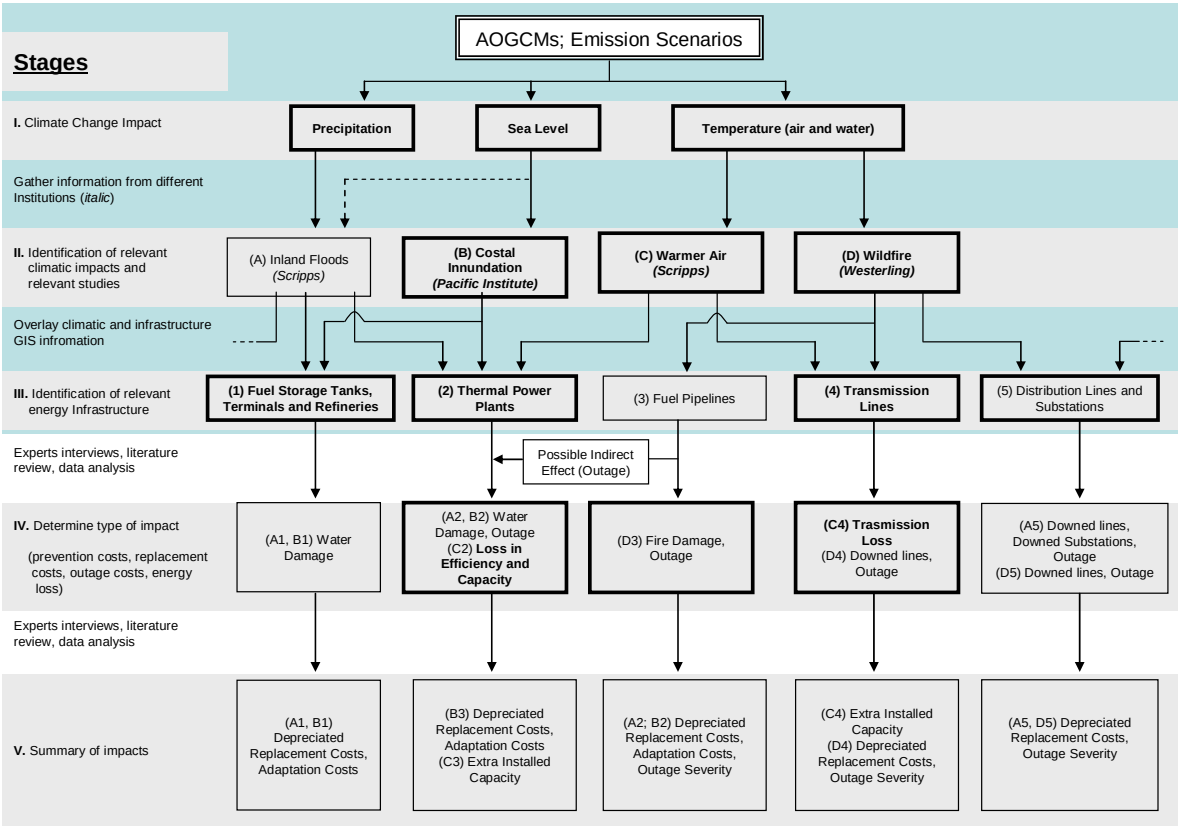
The analysis begins with estimates of climate change provided by Atmospheric-Ocean General Circulation models (AOGCM). These models project changes to a variety of climatic variables—such as precipitation, sea level, and surface air temperature—that are used to project impacts to energy infrastructure throughout the study (Stage I).

[1] The rectangles in bold indicate portions of the schematic covered in this report.

The next analysis (Stage II) identifies a range of climatic impacts affecting energy infrastructure. These climatic impacts include:

- Inland floods
- Coastal inundation
- Warmer air and water
- Wildfire

Figure 1. Stages in the Analysis of Impacts Climate Change on Energy Infrastructure



Preliminary Results: Do not cite or reference.

Given the identified impacts, a geographic information system (GIS) crossing is conducted to link the climatic impacts to the affected energy infrastructure (Stage III). The types of energy infrastructure covered in this stage of the analysis include:

1. Natural gas storage tanks
2. Natural gas pipelines
3. Thermal power plants
4. Transmission lines
5. Substations, distribution lines, and transformers

Once the relevant infrastructure is identified, it is necessary to determine the type of damage imposed by climatic impacts on the energy infrastructure (Stage IV). The stage of the analysis focuses largely on damages to the California electricity infrastructure's capacity during peak periods and the increased electricity demand.

Two additional introductory topics are addressed before turning to an estimate of climate impacts: (1) the climate model projections used in the study, and (2) a description of the California electricity infrastructure during a peak load period.

Climate Model Projections

Before discussing climate impacts, it is necessary to provide a short overview of the climate models and the principle climate projections used in this analysis. As is standard in the literature, the effects of climate change in this study build upon General Circulation Model (GCM) estimates of the future climate. These numerical simulation models generate predictions of future climate under different scenarios of atmospheric greenhouse gas emissions (emission scenarios). The GCMs and emission scenarios used in this study are consistent with those used in other studies funded by the California Energy Commission (e.g., Westerling and Bryant 2008; Westerling et al. 2009; Cayan et al. 2009; Heberger et al. 2009).

The GCM models used in this study include the GFDL (Geophysical Fluid Dynamics Laboratory), PCM1 (Parallel Climate Model), and CNRM (Centre National de Recherches Météorologiques) models. The emission scenarios include the A2 and the B1, as defined by the Intergovernmental Panel on Climate Change (IPCC) (IPCC SRES – IPCC 2000). The A2 scenario describes a world with a large income disparity, slow technological diffusion, and high greenhouse gas emissions. In the A2 scenario, global carbon dioxide (CO_2) emissions reach nearly 30 gigatons of carbon (GtC) annually by 2100. The B1 scenario describes a world moving toward sustainable development and with relatively low greenhouse gas emissions. In the B1 marker scenario, annual emissions reach about 12 GtC in 2040 and decline to about 4 GtC in 2100. The two emission scenarios and three GCM models result in a total of six different future climate projections used in this study. These GCM results must be "downscaled" for the authors' needs (to get temperature projections for specific power plants and transmission lines, for example). GCM data downscaled to a cell size of 1/8º latitude and longitude was provided to us by the Scripps Institution of Oceanography using the Bias Correction and Spatial Downscaling (BCSD) algorithm (Maurer and Hidalgo 2008).

Warming Temperatures

Climate research by Cayan et al. (2009) specific to California for the six AOGCM-IPCC scenarios revealed that in all cases, mean temperatures in California are expected to warm significantly over the twenty-first century, especially in the summer and in inland areas. Results also show an increase in the frequency, magnitude, and duration of heat waves.

One of the goals of this study was to assess the possible impacts that increased air temperature may have on the thermal performance of natural gas-fired generation, substations, and major transmission lines. For example, increased maximum temperatures may decrease peak power generating capacity, because warmer, less-dense input air decreases the power of gas turbines.

Temperature is a key variable in other categories as well, such as wildfire effects on infrastructure. Another goal was to show how higher temperatures will affect peak period electricity demand.

Increased Wildfire Incidence, Severity, and Range

California has an extensive history of wildfire; of the most damaging fires in the United States over the last 170 years, more than half occurred in California, and California leads the nation in economic losses from wildfire (Fried et al. 2004; Torn et al. 1998). Wildfires pose a serious threat to electrical transmission and distribution lines, as they can result in increased maintenance costs and reduced line efficiency. The risk of wildfire is influenced by several variables, including climatic factors, topography, available fuel, and sources of ignition (Westerling et al. 2009). Climate change will only exacerbate the problem, as increased temperatures, a reduced snowpack, and altered precipitation will lead to increased flammability of fuel for longer periods of time, which will affect the size, frequency, and severity of wildfires.

Sea Level Rise/ Coastal Inundation

Over the past century, the sea level along California's coast has risen about 17–20 centimeters (cm), and climate studies assessing the impacts of future sea level rise in California project a substantially greater rise over the coming century (Cayan et al. 2009). According to the results of climate projections under low (B1) to medium-high (A2) emissions scenarios, by 2100 average sea level along the California coast may rise between 1.0 and 1.4 meters (3.3 and 4.6 feet), respectively, in conjunction with an increased rate of extreme high sea level events (Cayan et al. 2008; Cayan et al. 2009). These changing conditions may pose an increasing threat to energy infrastructure along the coast, including power plants, transmission and distribution lines, and gas storage facilities and pipelines.

California's Peak Period Electricity Infrastructure

Electricity use peaks in California on hot summer afternoons when city centers, factories, and suburbs draw in electricity from distant generators via a vast system of transmission lines substations, distribution lines, and transformers (Figure 2).

The path of electricity through the State is highly variable, but generally travels along links connecting cheapest sources to heaviest demand. On a typical day, the cheapest sources include imports (hydropower from the north, thermal coal power from deserts to the east), local hydropower (from the Sierra), and local alternative power (coastal nuclear and geothermal). Electricity from these sources flows through the larger transmission lines and into the two demand locations centered in Northern and Southern California.

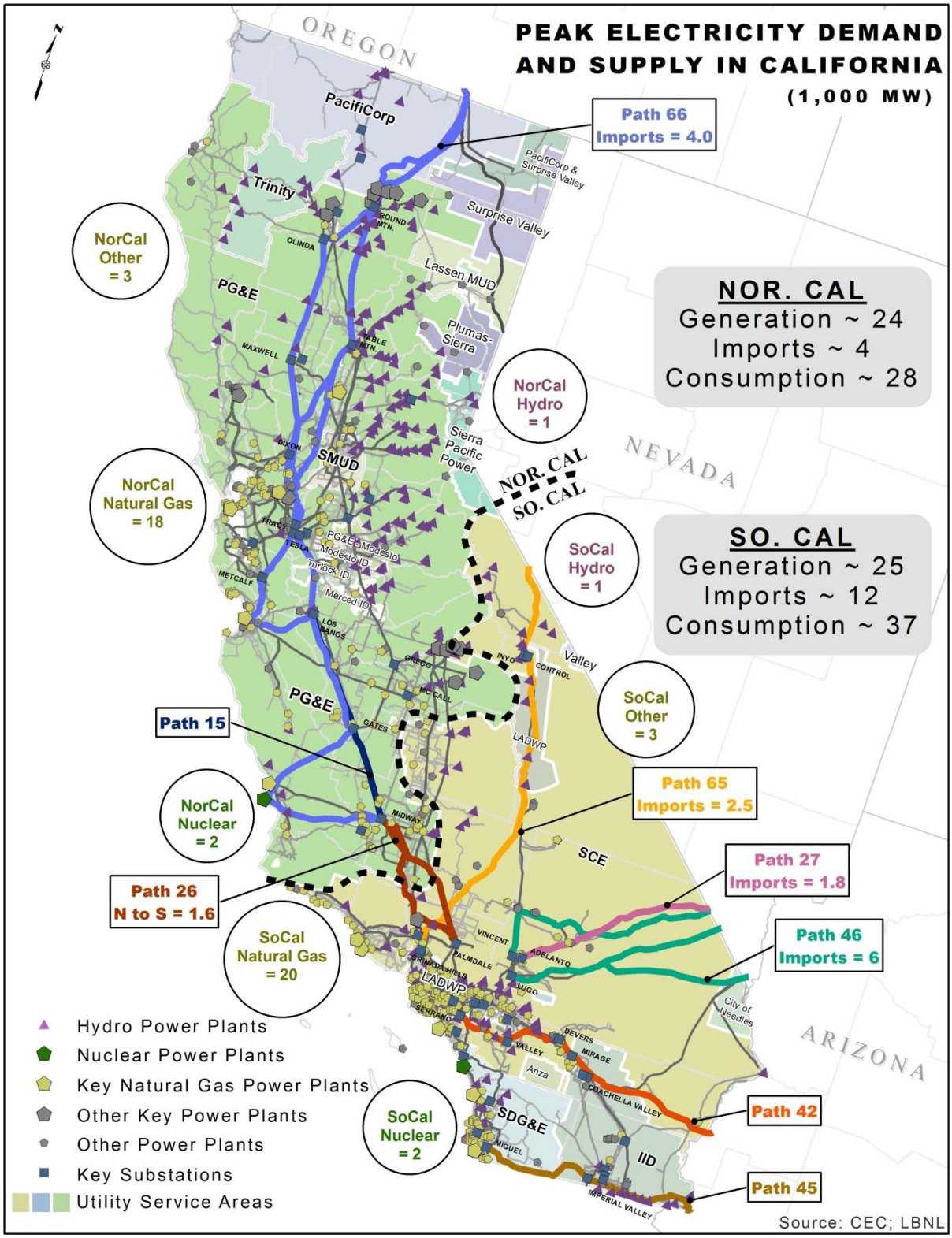
Thus, the larger transmission lines linking imports and hydropower with the urban centers of the State are especially busy on hot summer afternoons. Northern California draws one-third of its peak needs from a mix of relatively inexpensive sources, including imported power and coastal nuclear via path 66 (blue), Sierra hydropower, and geothermal. The other two-thirds of Northern California's needs are drawn from natural gas plants, often located around or close by San Francisco Bay.

Southern California lines are similarly congested during peak hours. Southern California draws on imports coming east, for about one-third of its needs—via paths 65, 27, 46, 42, and 45. Hydropower, nuclear, and other sources make up another 10 percent of supplies; and natural gas plants, often located in the Los Angeles basin, supply much of the rest. Interestingly, Southern and Northern California demand centers are often surprisingly independent of one another, with little load passing north or south at any one time via path 26 (red).

The rest of this report evaluates the impacts of warming temperatures on the capacity of the infrastructure to generate and supply electricity during peak periods. Chapter 2 evaluates the effect of temperature on the capacity of natural gas plants, transformers, and transmission lines in the State. Chapter 3 addresses the impact of climate change on peak demand and the joint effect of climate change on system supply and demand.

Chapter 4 expands the focus to include the risk posed by wildfires to transmission lines, including several critical transmission paths linking the California grid to imports from other states. Finally, Chapter 5 looks at the possibility that rising sea levels may cause flooding of coastal plants and transmission substations.

Figure 2. Peak Electricity Demand and Supply in California



CHAPTER 2:
Impact of Temperature on Power Plants, Substations, and Transmission Lines

Methodological Overview

Changing ambient temperatures affect the output capacity of natural gas-fired power plants (e.g., Maulbetsch and DiFilippo 2006). In addition to affecting the available capacity of thermal generation, higher ambient temperatures also slightly increase energy losses in electricity transmission and distribution systems, and also decrease the lifespan and capacity of substation transformers. This chapter examines the impacts of warming temperatures on electricity generation, transmission, and substations. This analysis does not consider other climate change-related impact metrics, such as including lost operational efficiency or reductions in the useful lifespan of these types of energy infrastructure.

In the interest of time for this initial evaluation, only one measure of temperature was considered. The analysis examined daily maximum temperature for the month of August, as August is one of the warmest months in California, and taking the maximum temperatures should account for extremes. A power system is often pushed to its operational limit during times of peak load, and the maximum ambient temperature represents the moment when weather-related impacts on the power system (e.g., wildfires, heat-related performance issues) are typically the greatest. These impacts almost always occur during times of peak demand (Franco and Sanstad 2008). The combination of (1) lower peak output from generation resources, and (2) increased demand for electricity could be significant for California and may affect the overall reliability of the State's power system. Chapter 3, Cumulative Effects of Temperature-Induced Losses, will examine the combination of these two effects. The influence of increasing temperature on energy demand have also been examined elsewhere (Aroonruengsawat and Auffhammer 2009; Miller et al. 2007). Additional information about the methodology followed in this report is provided in Appendix B.

Importing Energy Infrastructure Data and Merging Local Maximum Temperature Projections

The first major task in this analysis involved importing a database of California energy infrastructure that contains Energy Commission-compiled technical and location-specific information (e.g., power plant/transmission line/substation location, latitude and longitude, online capacity, type) (personal communication, Jacque Gilbreath, CEC 2009). Next, the location-specific information for California's energy infrastructure was merged with local temperature projections from three AOGCMs for a period ranging from 1960 to 2099 and two IPCC Special Report on Emissions Scenarios (SRES) scenarios (A2 and B1). As described above, the Scripps Institution of Oceanography provided Lawrence Berkeley National Laboratory (LBNL) with downscaled climate information that the research team assigned to each unique piece of energy infrastructure. Finally, the team measured the impact of warming on system capacity during peak energy use periods.

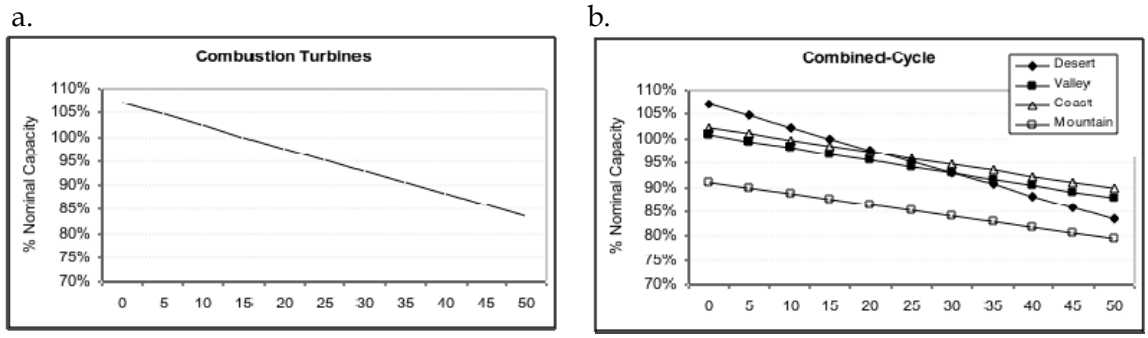
Projected Impacts to Natural Gas-Fired Power Plant Capacity

According to Kehlhofer et al. (2009), there are three reasons why ambient air temperature influences the capacity and efficiency of a natural gas turbine:

1. Hot air is less dense, so the air mass of the turbine at higher temperatures is lower for a given volume intake.
2. Ambient temperature influences the air's specific volume, which in turn influences the compression work and the power consumed by the compressor.
3. The pressure ratio within the turbine is reduced at higher temperatures and consequently reducing mass flow.

Previous studies have quantified relationships between air temperature and gas-fired generation efficiency and capacity (e.g., Tolmasquim et al. 2003; Arrieta and Lora 2005; Maulbetsch and DiFilippo 2006; Kehlhofer et al. 2009). The relationship between temperature and natural gas power plant performance varies across different empirical studies, types of natural gas power plants, and geographic regions. *However, the basic power output-temperature relationship used in most studies is of a linear form with varying inclinations (i.e., slopes).* It is possible that there is a nonlinear relationship between some temperature ranges and plant performance, but these nonlinear relationships would probably occur outside the realistic range of current or future temperatures. Figure 3 depicts one report's relationship between temperature and output for two types of natural gas power plants: (1) simple-cycle combustion turbines (left panel), and (2) combined-cycle combustion (right panel). Both panels use 15ºC (59ºF) as the reference point for 100 percent turbine capacity, which is the most prevalent factory specification for these types of plants.[2]

Figure 3. Change in Turbine Capacity as a Function of Ambient Temperature



Sources: Maulbetsch and DiFilippo 2006; Kehlhofer et al. 2009.

[2] High altitude ("mountain") plants typically have lower nominal capacities, because of low-pressure conditions.

In this study, two basic categories of natural gas power plants were considered: simple-cycle combustion turbines ("CTs") and combined-cycle combustion turbines ("CCs").[3] These plants are typically used to provide electricity in baseload and intermediate load conditions. As discussed in the following section, the capacity-temperature relationship has a different slope for each of these two categories of power plants.

Relating Power Plant Capacity to Ambient Temperature

Maulbetsch and DiFilippo (2006) estimated the relationship between ambient temperature and the capacity potential of combined-cycle natural gas power plants in California, disaggregated by power plant cooling equipment (wet or dry cooling) and region (desert, mountain, coast, and valley; see Figure 3b). On average, these authors found that combined-cycle power plant capacity can change by approximately 0.3–0.5 percent for each degree change above 15ºC. Maulbetsch and DiFilippo report that air-cooled combined-cycle power plants (dry cooling) were typically more sensitive to ambient temperature changes with reductions in capacity of around 0.7 percent per degree change in ambient temperature. LBNL did not obtain information describing the type of cooling equipment currently installed at California power plants. Furthermore, recently proposed regulations targeting once-through-cooling power plants may substantially reduce the number of plants that use wet-cooling technologies in the future, especially along California's coast. Accordingly, this analysis assumed that all natural gas-fired power plants responded to ambient temperature changes as if they were all using air-based cooling technologies in the future (see Table 1).

The research team was unable to find a study similar to Maultbetsch and DeFilippo (2006) for non-combined-cycle gas turbines that specifically focused on California.[4] Kehlhofer et al. (2009) showed that the average simple-cycle combustion turbine was more sensitive to changes in ambient temperature relative to combined-cycle plants (see Figure 3), but aside from a simple graphical depiction, there was no mention of the exact quantitative relationship they calculated for combustion turbines. Accordingly, this study assumed that simple-cycle gas units, which have been shown to be more sensitive to ambient temperature relative to combined-cycle units, decrease by 1.0 percent per degree Celsius above 15ºC. For example, a 500 megawatt (MW) simple-cycle unit located in a place with a projected average daily maximum temperature of

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[3] The Energy Commission power plant database provided to LBNL did not explicitly identify if the plant was a "CT" or a "CC," so LBNL employed a keyword search of the plant description field to determine the plant type. If the database noted that the plant was "reciprocating," "combined cycle," or had "heat recovery," then it was coded as a combined-cycle natural gas-fired power plant. Power plants identified as "cogeneration units" were coded as combined-cycle units for the purposes of this analysis. All other natural gas-fired power plants were coded as simple-cycle combustion turbines.

[4] The results found in Maulbetsch and DiFilippo (2006) were less sensitive to temperature changes when compared to other studies (e.g., Kehlhofer et al. 2009), probably due to the fact that many combined-cycle power plants in California already have chilling equipment that reduces intake air temperature before the combustion process (personal communication, Roy Willis, PG&E 2009)

20ºC (68ºF) would have its nominal capacity reduced by 25 MW during this time period (from 500 MW to 475 MW).

Summary of Key Model Assumptions

Table 1 lists the general assumptions LBNL used in its estimate of the potential losses to natural gas-fired power plant capacity from projected climate change.

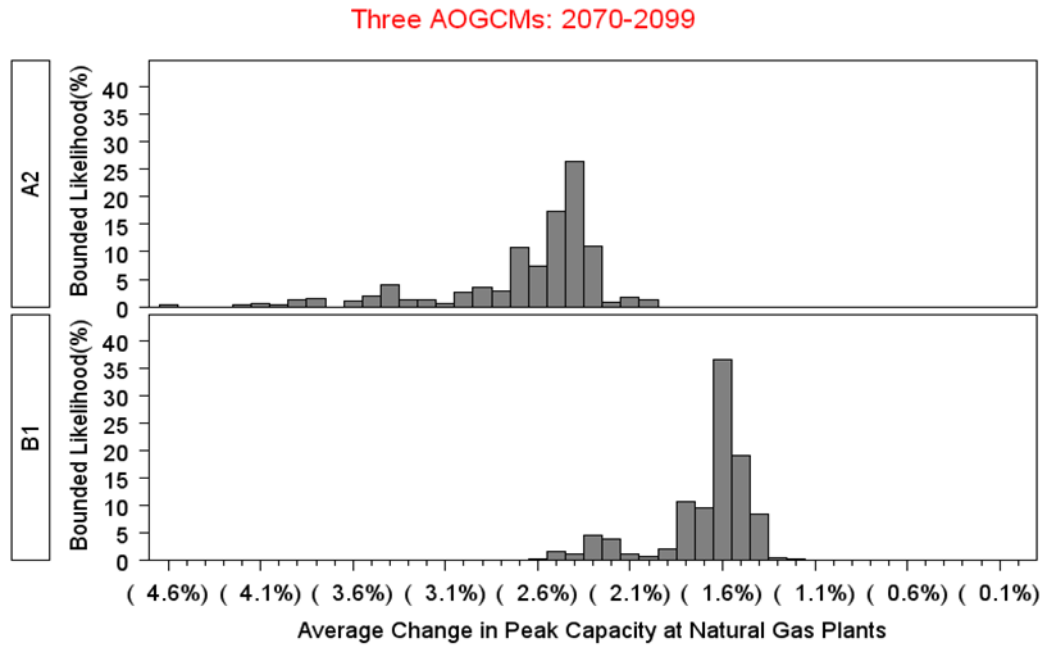
Table 1. Key Assumptions for Natural Gas Power Plant Analysis

Assumption	*Combined Cycle (CC)*	*Simple Cycle (CT)*
Relationship between gas plant nominal capacity and temperature	Linear	Linear
Reference temperature for 100% output	15ºC (59ºF)	15ºC (59ºF)
Change in plant capacity for each degree above 15ºC	-0.7%	-1.0%
Future climate likelihood statistical distribution source	Ensemble of three AOGCMs per IPCC scenario per time period	Ensemble of three AOGCMs per IPCC scenario per time period
Future type of cooling equipment installed at each natural gas plant	Air-cooled	Air-cooled
Aggregate capacity of plants analyzed	26,245 MW (n=340)	17,849 MW (n=51)
Future growth of generation capacity	None	None
Increase capacity when ambient temperatures are less than 15ºC	No increase	No increase

Results

Figure 4 shows a histogram of probable future changes in capacity for all California natural gas units analyzed in this study, taking into account the different loss coefficients for CC and CT power plants. The preliminary estimates show that natural gas-fired power plants across California could lose, **on average**, 1.7–2.7 percent peak capacity by the end of the century under the low emissions scenario (B1) and up to 4.5 percent under the high emissions scenario (A2).

Figure 4. Probability of Changes in Peak Capacity at California Natural Gas Power Plants



NOTES: Distribution based on results from three AOGCMs for 2070-2099 time period.

Source: Authors

As described earlier, reserve margins are low and natural gas power plants are running near their nameplate capacity during peak load periods. Assuming that the maximum temperature occurs at the same time as the peak load, it is plausible that this lost peak capacity may affect the ability of the bulk power system to respond to peak load.

Note that these estimates do not consider any future adaptive measures which may be taken by utility planners, including proactively installing new types of cooling equipment to offset future losses. Of course, additional cooling equipment incurs its own costs in lost capacity, although the overall losses are certainly decreased. In addition, as was pointed out in the assumptions table, no attempt was made to forecast new natural-gas fired capacity growth (or decline) that may occur over the coming decades.

Figures 5 and 6 show the projected capacity loss to natural gas-fired simple-cycle combustion turbine (CT) power plants and combined-cycle (CC) plants in California. These figures are based on an assumed 1 percent capacity loss for each 1°C (1.8°F) increase in ambient air temperature for CT-type plants, and 0.7 percent capacity loss for each 1°C increase in ambient air temperature for CC-type plants.

Notes on Figures 5 and 6: These figures use the 1 percent loss coefficient for CT plants, and the 0.7 percent coefficient for CC plants, as discussed above. Note that the *absolute* capacity losses are shown in the left four maps of each figure, while the *incremental* capacity losses (over and above the temperature-induced losses already experienced during the base period) are shown in the "difference" map in the third column.

Figure 5. Projected Change to Natural Gas-fired CT Power Plant Peak Capacity: Average August loss for each period, taken over three AOGCMs under the A2 scenario

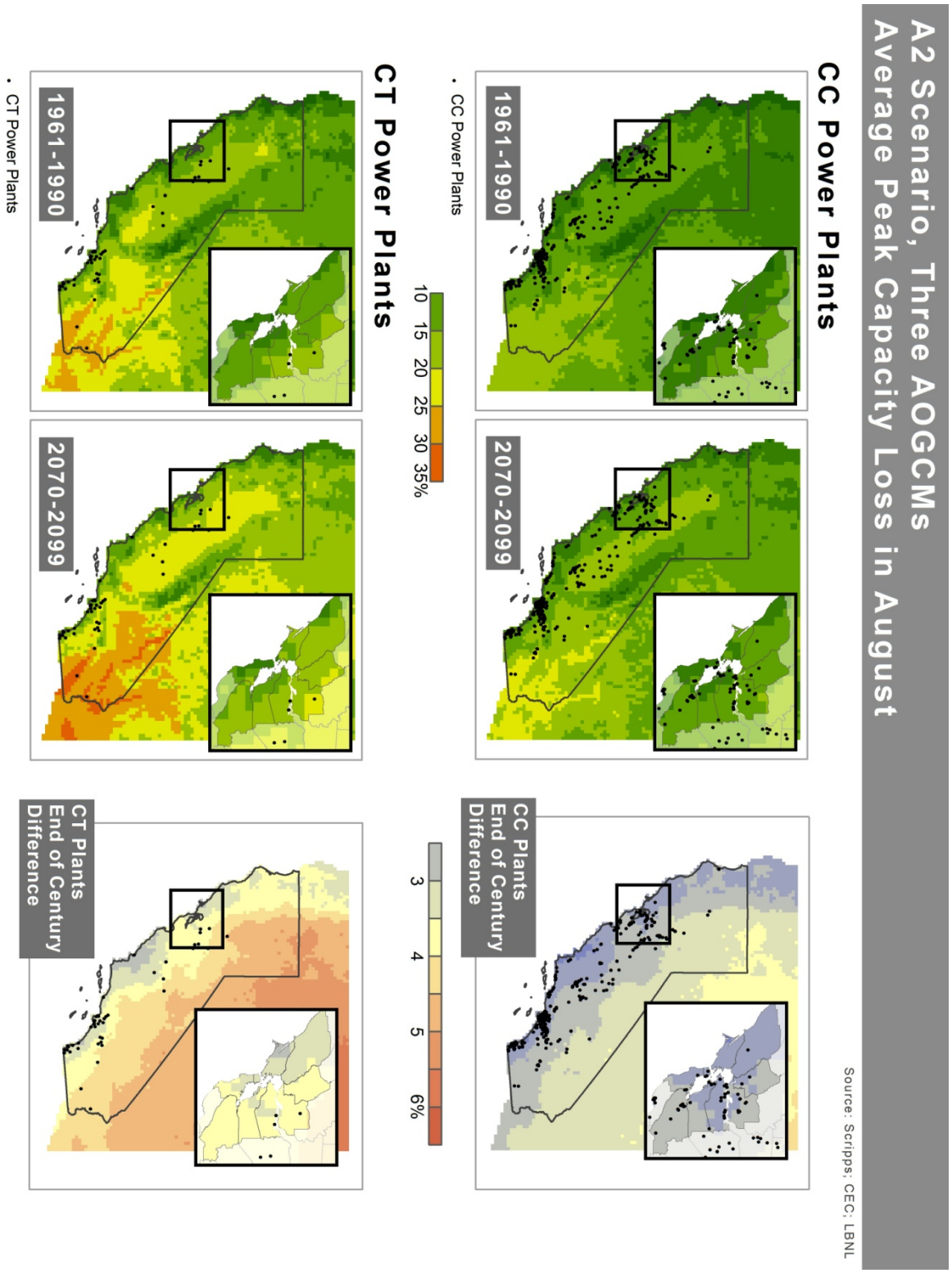
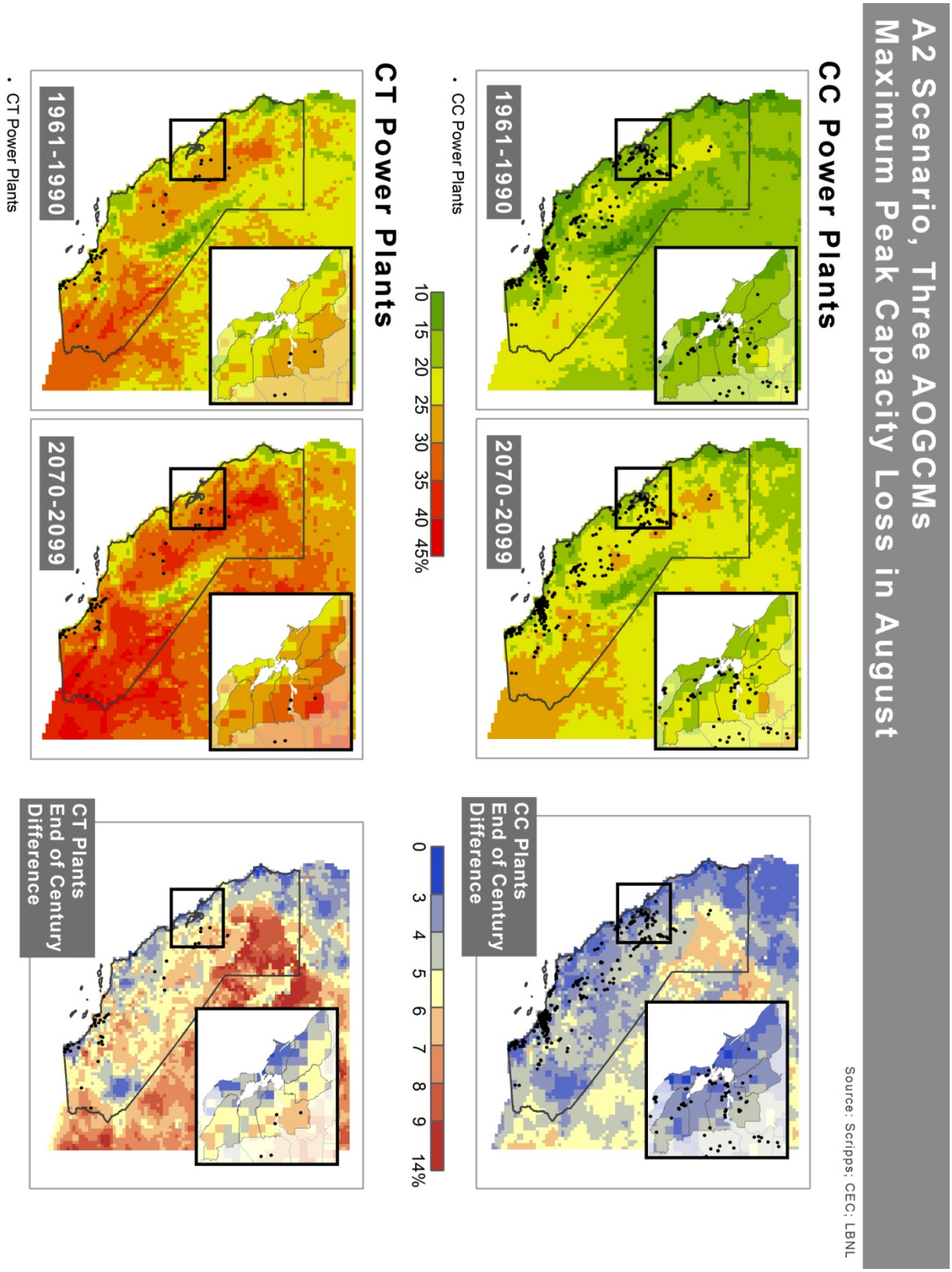


Figure 6. Projected Change to Natural Gas-fired CT Power Plant Peak Capacity: Maximum August loss for each period, taken over three AOGCMs under the A2 scenario



The average loss in capacity shown by these maps results from the forecast rise in the average daily peak August temperature between the base period and the end of the century. The maximum loss in capacity results from the largest forecast rise. A maximum loss projected at the site of any one plant may occur on a different day than the maximum loss projected at another site. Thus system losses across plants in California will be less than the maximum loss at any one site. So these maps present *non-coincident* conditions.

Table 2 summarizes the results for *coincident* end-of-century power plant capacity loss. Under the A2 scenario (over the three AOGCMs), limited to weekdays, it is expected that the *maximum* loss would grow up to 6.2 percent. The maximum expected heat-induced loss, 10.305 gigawatts (GW), amounts to 23 percent of the total current gas-fired capacity, and this is the loss that would be imposed on the current infrastructure by temperatures projected for the end of the century.

Table 2a & 2b. Maximum and average A2 and B1 coincident statewide peak capacity loss (weekdays) at gas-fired power plants. (Percentage total is the fraction of the total state gas-fired generating capacity of 44.1 GW.)

2a.

	Maximum daily MW lost				
A2	**1961–1990**	**%total**	**2070–2099**	**%total**	**Δ loss**
All GCMs	**7577**	**17.2**	**10305**	**23.4**	**6.2%**
GFDL	**6600**	**15.0**	**8630**	**19.6**	**4.6%**
CNRM	**7577**	**17.2**	**10305**	**23.4**	**6.2%**
PCM1	**6819**	**15.5**	**7479**	**17.0**	**1.5%**
B1	**1961–1990**	**%total**	**2070–2099**	**%total**	**Δ loss**
All GCMs	**5975**	**13.6**	**8096**	**18.4**	**4.8%**
GFDL	**6289**	**14.3**	**8096**	**18.4**	**4.1%**
CNRM	**6030**	**13.7**	**7811**	**17.7**	**4.0%**
PCM1	**5605**	**12.7**	**7859**	**17.8**	**5.1%**

2b.

	Average daily MW lost				
A2	**1961–1990**	**%total**	**2070–2099**	**%total**	**Δ loss**
All GCMs	**5207**	**11.8**	**6486**	**14.7**	**2.9%**
GFDL	**5146**	**11.7**	**6742**	**15.3**	**3.6%**
CNRM	**5216**	**11.8**	**6773**	**15.4**	**3.5%**
PCM1	**5259**	**11.9**	**5942**	**13.5**	**1.5%**
B1	**1961–1990**	**%total**	**2070–2099**	**%total**	**Δ loss**
All GCMs	**5157**	**11.7**	**5975**	**13.5**	**1.9%**
GFDL	**5131**	**11.6**	**6289**	**14.3**	**2.6%**
CNRM	**5161**	**11.7**	**6030**	**13.7**	**2.0%**
PCM1	**5181**	**11.7**	**5605**	**12.7**	**1.0%**

Table 2 presents the total projected megawatt losses due to heat at California gas-fired power plants, using daily modeled temperature data at the location of each plant. Both simple-cycle CT and CC plants are covered, assuming that the former lose 1 percent of peak capacity per °C rise, and the latter lose 0.7 percent of peak capacity per °C rise (each over 15°C). For each time period, the research team took the day with the largest statewide loss, showing the worst possible case according to each climate model. Thus "Δ loss" is the additional peak capacity that generation would need to supply to maintain the same level of service throughout 2070–2099 as in 1961–1990 (with no growth in demand).

The significance of this is that at the time of the peak historical loss, the system was able to deliver 36.5 GW. With no capacity increase, this could fall to 33.8 GW by the end of the century—a 2.7 GW shortfall. In order to match historic service levels at the end-of-century loss rate, there may need to be a peak capacity of 47.7 GW (since 47.7 * (1 - .234) = 36.5). This is an 8 percent increase over the current nameplate capacity, just to bring the generators back to their historic output levels.

Projected Impacts to Substation/Transformer Capacity

Major substations contain clusters (or banks) of transformers which allow alternating current (AC) voltage to be "stepped up" or "stepped down" between various components of the power system (e.g., higher voltage transmission lines are typically stepped down to lower voltage local power distribution lines). A number of studies have been conducted on the performance and monitoring of transformers under different operating conditions, including changing ambient temperatures (e.g., Lesieutre et al. 1997; Li et al. 2005; Li and Zielke 2003; Swift et al. 2001; Askari et al. 2009).

A transformer's peak load capacity, which depends on the ambient temperature observed at the site, is very different from the ambient temperature that the nameplate rating is designed for (typically 30°C, [86°F]). Li et al. (2005) point out that a critical piece of planning information is the ambient temperature at the time of peak system load. Higher ambient temperatures affect the hot spot conductor temperature (HST) within the transformer, which in turn reduces the peak load capacity of the bank of transformers.[5] In some extreme cases, excessive HST can lead to catastrophic failure of the transformer, so improved methods to monitor these internal temperatures are occasionally proposed (e.g., Lesieutre et al. 1997). Ambient temperature-induced lost capacity or an increased rate of failure of substations can lead to widespread power system failures and subsequent blackouts.

Relating Substation/Transformer Capacity to Ambient Temperature

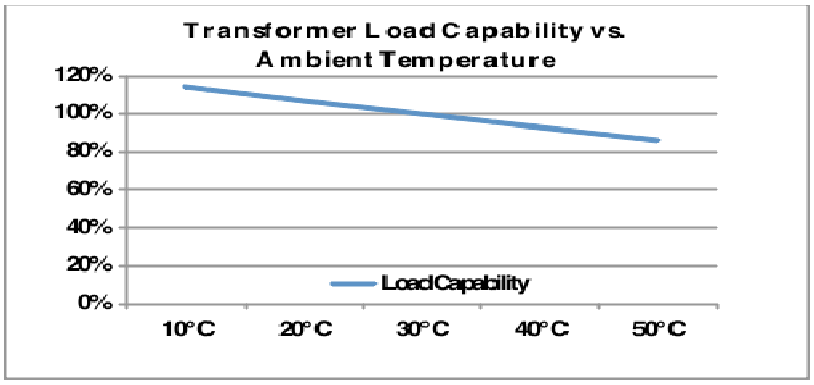
A number of studies have quantified the general relationship between air temperature and transformer lifespan and capacity (e.g., Li et al. 2005 and Swift et al. 2001). As was the case with natural gas-fired power plants, the relationship between ambient temperature and transformer

[5] A 30°C ambient temperature approximately corresponds to a 120°C (248°F) hot spot conductor temperature at a typical transformer (Swift et al. 2001).

(substation) performance varies across different empirical studies, size of substation, geographic regions, and other factors. This preliminary analysis limits the potential impacts research to the possible change in substation capacity from increased ambient temperatures.

Again, the basic power capacity-temperature relationship used in most studies is of a linear form with varying inclinations (i.e., slopes). Li et al. (2005) report transformer load capacity as a function of ambient temperature. The authors report decreased transformer capacity of approximately 0.7 percent for each 1°C of higher ambient temperature, with slight variations dependent on the HST limit allowed (e.g., 120°C) and type of cooling equipment installed (see Figure 7, which is adapted from the authors' original article).

Figure 7. Change in Transformer Capacity as a Function of Ambient Temperature



Source: (adapted from Li et al. 2005)

Unfortunately, the research team did not have the exact rating in kilovolts (kV) or kilovolt-amperes (kVA) of each major substation in California, the type of cooling equipment currently installed, or typical historical (or future) loadings. Therefore, the impact analysis was limited to changes in the percentage of substation capacity and assumed that all substations had equal sensitivity to changing ambient temperatures. As noted in the section on power plant performance, future changes in capacity were estimated by evaluating the *incremental* losses above the lost capacity that was estimated for the base period: 1961–1990. In other words, lost capacity for the time period 2070–2099 represents additional ambient temperature-related losses that may not have been accounted for in the original substation cooling equipment performance specifications.

Summary of Key Model Assumptions

Table 3 is a list of the general assumptions that LBNL used in its estimate of the potential changes to substation capacity from projected climate change.

Table 3. General Substation Capacity Model Assumptions

Assumption	*Major Substation (SS)*
Relationship between substation capacity and temperature	Linear
Temperature beyond which substations begin to lose potential capacity	30ºC
Change in substation capacity for each degree above 30ºC (β)	-0.7%
Future climate likelihood statistical distribution source	Ensemble of three AOGCMs per IPCC Scenario per time period
Current or future type of cooling equipment installed at each substation	Unknown
Number of substations analyzed by LBNL	2,530
Actual substation rating (kVA or kV) and typical historical loading	Unknown
Increase capacity when ambient temperatures are less than 30ºC?	No
Future growth of new substation capacity	None

Results

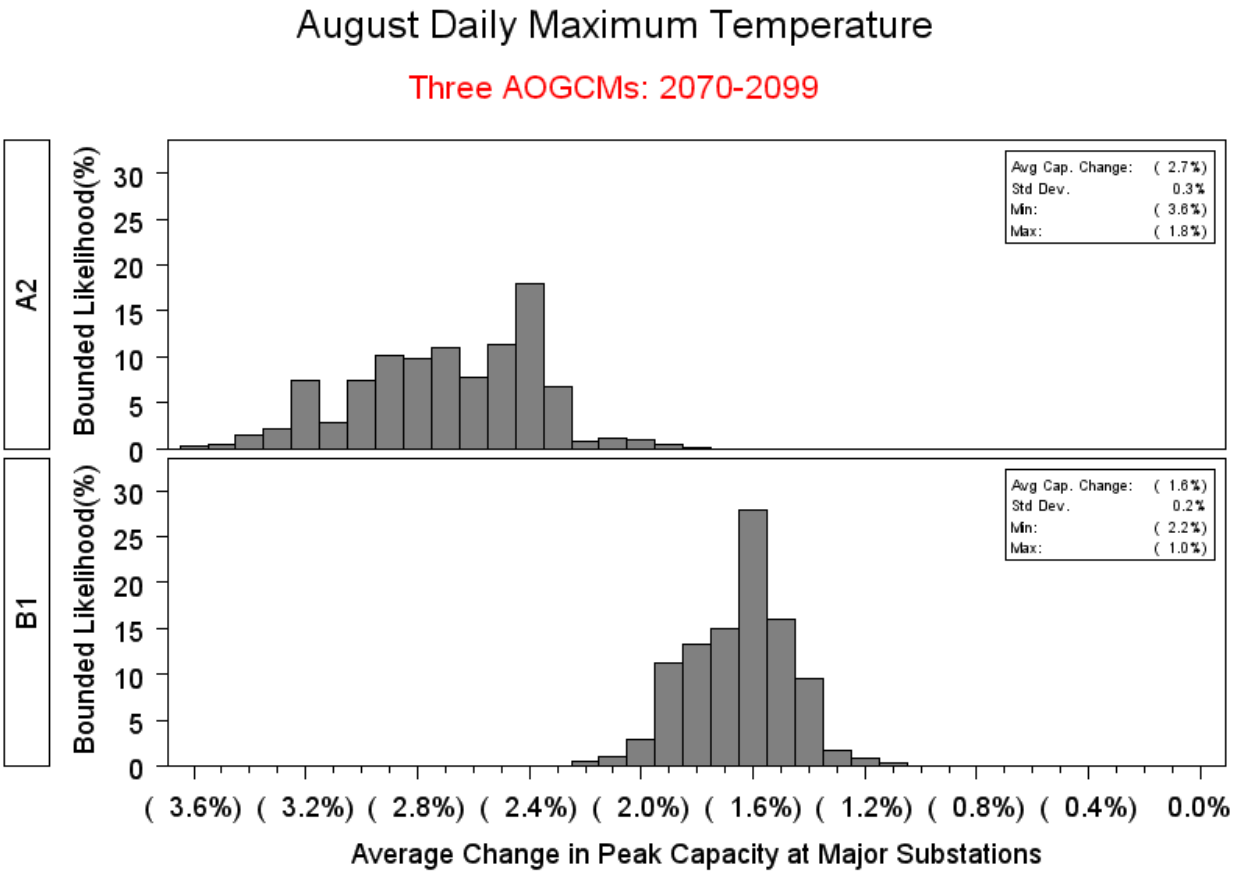
The results of this integrated assessment model are presented in two ways. First, by using a histogram that depicts the range of average substation lost capacity across California by future time period and IPCC scenario. Maps are also used to report average substation lost capacity results by California region, scenario, and future time period.

As seen above there is expectation to see only 76.6 percent of the nameplate peak electrical output at the maximum A2-projected end-of-century temperatures. Thus, to overcome an additional substation loss of 2.7 percent (the median projected A2 loss below), 2.7/.776 = 3.5 percent would need to be added to the nameplate generation capacity. This is summed with other losses in Chapter 3 below.

Figure 8 is a probability density function (histogram) of additional future changes in capacity for all California substations that were analyzed in this study. Preliminary estimates show that substations across the State of California could lose, on average, an additional 0.7–0.8 percent of capacity in the 2005–2034 time period, 1.2–1.4 percent in 2035–2064, and 1.6–2.7 percent by the end of the century. It is important to note that these estimates do not consider any future adaptive measures which may be taken by utility planners, including proactively installing new types of cooling equipment to offset future losses. In addition, as was pointed out in the assumptions table, no attempt was made to forecast new substation capacity growth (or decline) that may occur over the coming decades. The study also assumed that changes in substation capacity due to ambient temperature change correspond equally to changes in transformer

capacity, and that all types and sizes of transformers have equal sensitivity to ambient temperature.

Figure 8. Average Changes in Peak Capacity at California Substations (2070–2099)

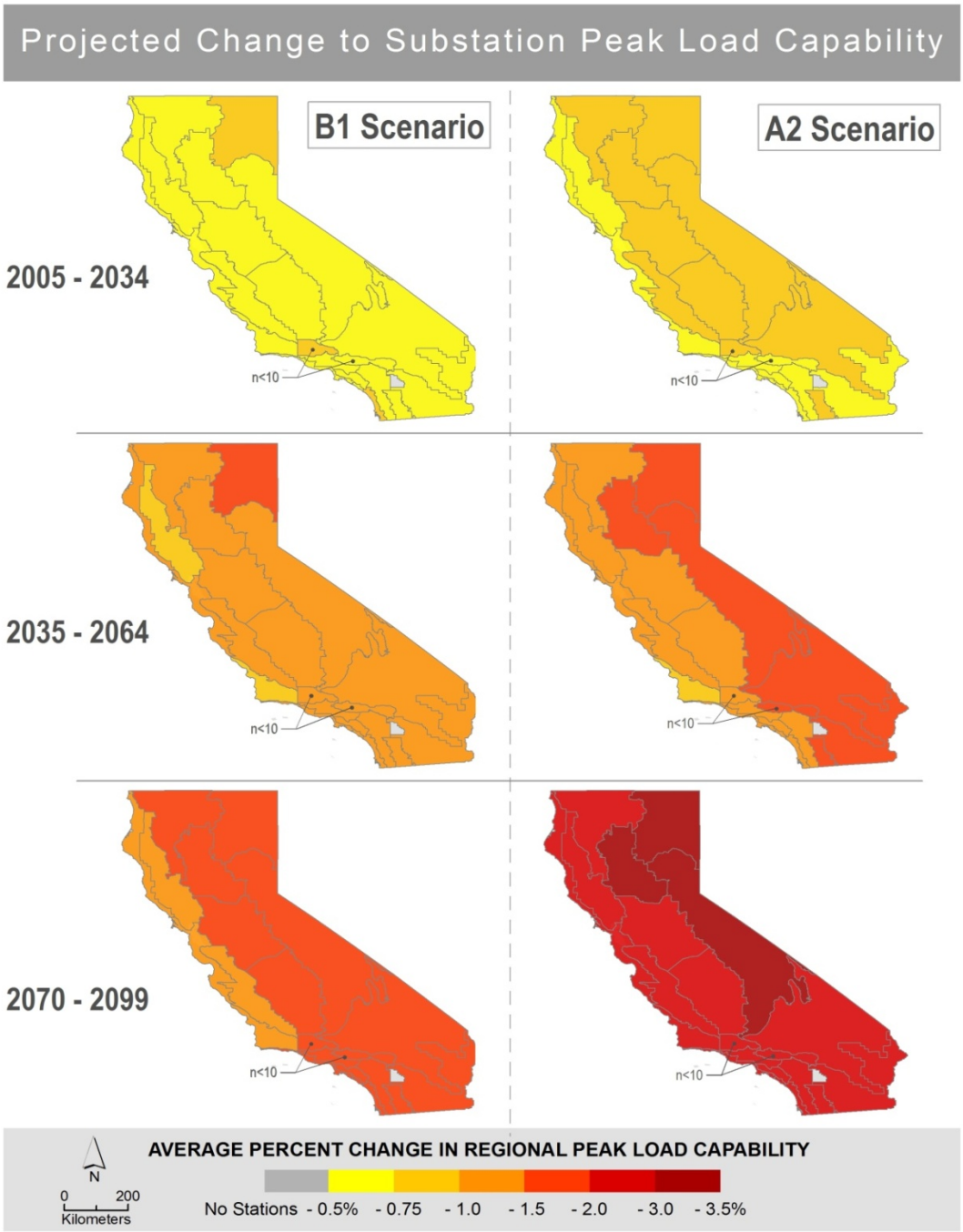


NOTES: Distribution based on results from three AOGCMs for 2070-2099 time period.

Source: Authors

Figure 9 depicts projected changes to substation peak capacity by region for three future time periods and each IPCC scenario, using projected daily maximum temperatures for August. The map shows that regions in the Sierra Nevada Mountains/Foothills and Eastern part of California, in general, might be more at risk to lost substation peak capacity than regions in the Western part of the State.

Figure 9. Projected Average Change to Regional Substation Capacity



Source: Authors

These maps suggest that peak load capacity of substations along the coast and in the San Francisco region will decline somewhat less than peak load capacity of substations in California's inland areas. Capacity will decline between 1 percent and 1.5 percent under the B1 scenario, and between 2 percent and 3 percent under the A2 scenario.

Projected Impacts to Transmission Line Carrying Capacity

It is well documented that transmission lines incur incremental power losses at elevated conductor temperatures (IEEE 738-2006). In general, higher temperatures increase the resistance of a conductor and this effect decreases the carrying capacity of the line and requires additional generation to offset the increased resistance over the lines. But as seen below, the effect of ambient temperature on heat transfer will probably be stronger than the slight increase in resistance on the power capacity of the line.

Relating Transmission Carrying Capacity to Ambient Temperature

The *IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors* (IEEE 738-2006) presents a heat balance methodology for modeling transmission line temperature and current under different ambient conditions. The basic heat balance equation is

Current heat gain + Solar heat gain = Radiative heat loss + Convective heat loss

The four components of this equation are related to ambient conditions by equations of varying complexity (see IEEE 738-2006 for the details), such that closed-form solutions are generally not possible. But iterative solutions are feasible, and LBNL has coded a basic transmission line model that enables us to explore the effects of both rising temperatures and increased wildfire soot deposition.

Summary of Key Model Assumptions

Table 4 lists the general assumptions LBNL used in the authors' estimate of the potential losses to transmission from projected climate change.

Table 4. Key Assumptions for Transmission Analysis

Assumption	*Transmission Line*
Current-temperature relationship	Complicated, see IEEE 738-2006
Typical line design temperature (maximum normal operating temperature)	80°C (176°F)
Typical emergency operating temperature	100°C (212°F)
Typical operating wind speed perpendicular to conductor	2 ft/sec
Future climate likelihood statistical distribution source	Ensemble of three AOGCMs per IPCC Scenario per time period
Future growth of new transmission capacity	None
Increase carrying capacity when ambient temperatures are less than 20°C?	No increase

Results

Tables 5 and 6 below give the parameters of a sample 230 KV transmission line operating near its rated capacity under hot conditions.

Table 5. Sample Transmission Line Parameters

Parameter	Value	Units
Conductor type	"Cardinal" ASCR #954	
Voltage	230	kV
Phase current	950	Amps
Rated ampacity	996	Amps
Conductor design temperature	80	°C
Line capacity	360	Megawatts
Number of conductors / phase	1	Number
Conductor emissivity	0.5	
Conductor absorptivity	0.5	
Wind perpendicular to conductor	0.61	Meters/second
Solar flux	1030	Watts/square meter
Latitude	34	Degrees
Resistance at 20°C	5.87E-05	Ohms/meter
Resistance at 75°C	7.48E-05	Ohms/meter

Table 6. Conductor Temperature and Line Loss under Hot Ambient Conditions

Ambient conditions	Conductor temperature (°C/°F)	Full line loss per mile (kW)	Percent loss in capacity for a 75-mile line	Change (%)
38°C, wind=0.61 meters/sec	84.8/184.6	338.4	7.05	□Δ=.14
43°C, wind=0.61 meters/sec	90.0/194	345.1	7.19	
38°C, wind=0.00 meters/sec	112.5/234.5	373.8	7.79	□Δ=.14
43°C, wind=0.00 meters/sec	117.8/244	380.5	7.93	

Note that current-driven resistive heating can drive conductor temperature far higher than the surrounding air temperature, and even under extreme ambient conditions, the energy lost to resistive heating grows very slowly as the air temperature increases. The research team has not yet characterized all California transmission lines with similar results, but it seems that increased resistive losses in transmission lines due to increased temperatures are not expected to become significant during the next century.

However, another way to look at the problem is to note that transmission line operators will want to avoid damage to their lines and that the California ISO will reduce current as necessary to keep the steady-state conductor temperature at the design limit of 80°C (176°F). In this case, the *capacity loss* (as opposed to the resistive loss) can be significant (Table 7).

Table 7. Ambient Temperature and Conductor Capacity Loss. (Conductor temperature held constant at 80°C by reducing line current.)

Conductor Type and Voltage	Air Temperature (wind = 2 ft/sec) (°C)	Conductor Capacity (MW)	Percent Capacity Loss (%)
Falcon (ACSR #1590) @ 765 kV	38	1534	Δ=7.5
	43	1419	
Falcon (ACSR #1590) @ 500 kV	38	1003	Δ=7.6
	43	927	
Condor (ACSR #795) @ 345 kV	38	455	Δ=7.5
	43	421	
Bittern (ACSR #1272) @ 345 kV	38	605	Δ=7.6
	43	559	
Bittern (ACSR #1272) @ 230 kV	38	403	Δ=7.4
	43	373	
Cardinal (ACSR #954) @ 230 kV	38	339	Δ=7.7
	43	313	

Note: 38°C and 43°C were the typical maximum air temperatures for the beginning and end, respectively, of the twentieth century.

These calculations were made using the *IEEE 738-2006 Standard For Calculating the Current-Temperature of Bare Overhead Conductors.* (Assumptions: wind speed = 2 ft/sec perpendicular to the conductor, emissivity = 0.5, absorptivity = 0.5, solar flux = 1030 watts/square meter, latitude = 34°, conductor resistance as quoted by the manufacturer.) Once it was determined that the current that would produce an 80°C conductor temperature, and the resulting conductor capacity was calculated as √3 • current • voltage • 0.95 power factor.

The consequences of this are that, under this operating scenario, capacity losses could be dramatic, amounting to an additional 7–8 percent of peak capacity when air temperature increases by 5°C (9°F). (Of course, the California independent system operator [ISO] will attempt to reroute power around saturated lines, and if this becomes impossible, to impose brownouts rather than allow damage to transmission lines from overheating or excess sag.

Table 7 above shows what the ISO might face if any grid segments become saturated.) This potential for high capacity losses calls for further research into transmission line operating practices and design parameters.

Also worth noting in Table 6 above are the increases in conductor temperature under zero-wind conditions. Utilities generally count on the presence of at least 2 ft/sec of wind on hot days and meteorological studies [still unavailable at the time of this publication] show that still air at transmission line sites on very hot days is expected to be exceedingly rare. Nevertheless, if this should happen, conductor temperatures can rise into the "emergency" range (above 100°C [212°F]), where continued operation may result in permanent damage and may cause excessive conductor sag and even wildfire ignition. This necessitates further investigation into the effects of climate change on the probability and duration of no-wind conditions on hot days.

Projected Impacts to Transmission and Distribution Efficiency

Transmission and distribution losses are greatest during periods of peak electricity demand. As global warming increases demand for electricity in California, such losses will increase and additional generation will be required to match system supply and demand. In this section, system load and loss data from the Sacramento region is used to estimate climate related transmission and distribution losses in the rest of California.

The electricity load-loss factor represents the average percentage losses that occur in both the transmission and distribution stages of the electricity grid system. Data from the Sacramento area electricity system illustrate the relationship between system load and transmission and distribution system loss factors (Table 8).

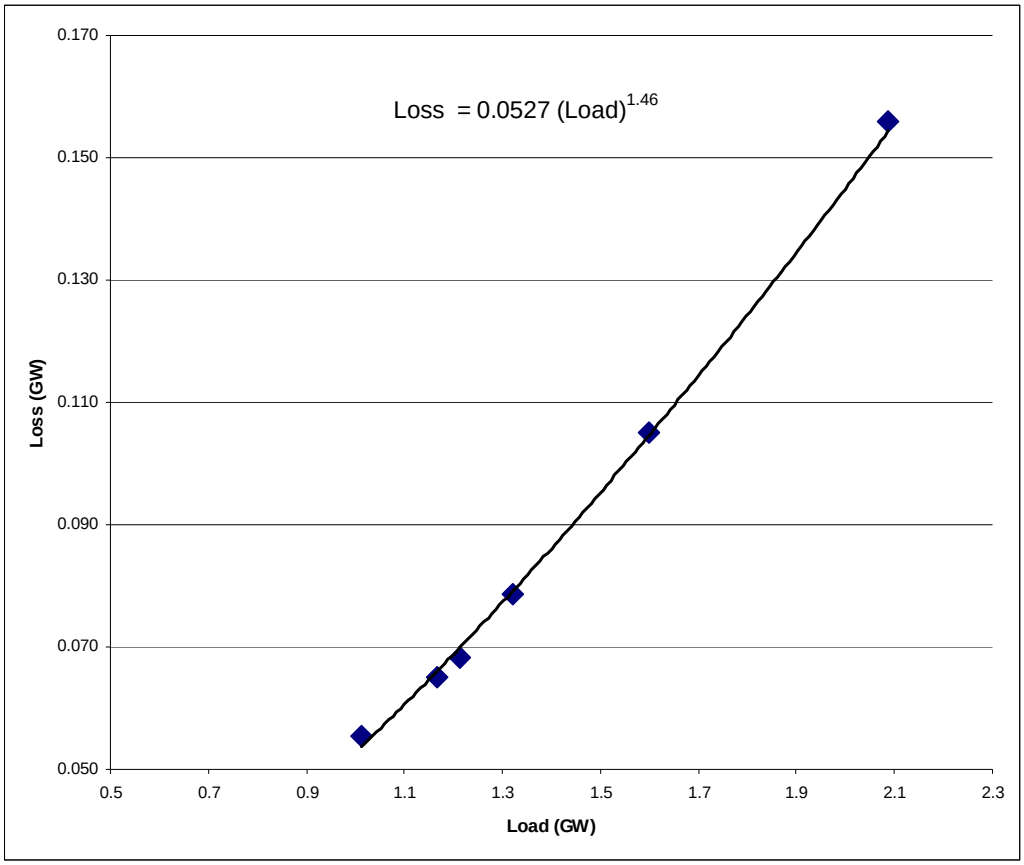
Table 8. System Average Loss Factors in 2000

Period	Average Temperature	Load	Transmission loss factors	Distribution loss factors	Total loss factors
	(Fahrenheit)	(MW)	(%)	(%)	(%)
Summer Super Peak	85.5	2088.4	2.0	5.5	7.5
Summer On-Peak	79.0	1600.3	1.7	4.9	6.6
Summer Off-Peak	66.9	1213.6	1.5	4.2	5.6
Spring	60.9	1167.9	1.4	4.1	5.6
Winter On-Peak	53.8	1319.9	1.5	4.4	6.0
Winter Off-Peak	45.9	1011.3	1.4	4.1	5.5

Source: Sacramento Municipal Utility District

It is apparent that loss factors increase as system load and temperature increase. For example, during summer super-peak, when load is highest, system losses average 7.5 percent; while during the winter off-peak, when load is lowest, losses average 5.5 percent. The loss-to-load relationship is roughly linear in percentage terms, with average system losses increasing about 1.5 percent for every 1 percent increase in the load (Figure 10).

Figure 10. System Load and System Losses



Source: Authors

This relationship describes a single time period and region, and as such provides only a general sense of the scale of end-of-century transmission and distribution losses. Nevertheless, peak loads are expected to increase in California 10–20 percent due to climate change, and increased peak period losses appear unavoidable (Miller et al. 2007). Loss factors across California currently average some 8.5 percent according to the California Energy Commission, and these system losses will likely increase as a result of climate change (CEC 2009). Assuming the above increase in system load, and applying the load loss relationship illustrated in Figure 10 suggests that global warming will increase transmission and distribution losses in California between 1.5 and 2.5 percent.

Implications for Utilities and Potential Future Research

Although this analysis of California natural gas power plants, substations, and transmission lines is preliminary, it is evident that there is significant potential for constraints on electricity production and delivery capacity resulting from changes to high temperatures in August. If these projected changes actually materialize, then system planners will want to consider building extra transmission capacity, substations, and power plants; not only to accommodate increased customer loads from warmer temperatures, but also to address potential reliability shortfalls.

However, before major conclusions can be drawn from this research, it is important to improve some of the modeling assumptions, including gathering information on the (1) type of cooling equipment already installed at natural gas plants and substations (and how much this technology costs to install), and (2) appropriate statistical distributions to use when projecting a range of future climate scenarios.

In addition to the basic improvements listed above, there are a number of additional research questions that could be studied using this type of integrated modeling framework. For example, Swift et al. (2001) present an interesting table that relates increases in HST to increased acceleration of transformer aging. Smith et al. cites an IEEE guide that details that the average lifetime of a typical transformer is about 20.6 years. Given the typical age of a current transformer in California and a typical capital replacement cost, future research could be undertaken to estimate the additional cost to utilities from having to replace transformers more frequently due to more intense heat waves, as projected by the AOGCMs. Larsen et al. (2008) employed a similar analysis for Alaska by altering the lifespan of infrastructure due to accelerated changes in climate and then discounting the future costs back to the present.

Also worth noting is that one other effect of temperature not analyzed here is that energy infrastructure operation and maintenance activities may be jeopardized by very hot temperatures, not only through technical aspects, but through labor restrictions, including worker safety and pauses due to very hot conditions present in the outside environment (personal communication, Roy Willis, PG&E 2009).

CHAPTER 3:
Cumulative Effects of Temperature-Induced Losses

As seen, increasing summer temperature will

- Increase peak electricity demand.
- Decrease peak generating capacity.
- Decrease substation efficiency.
- Limit transmission capacity.
- Increase wildfire exposure.

So far this report has looked at these effects separately. But for the most part they are concurrent, and their effects are cumulative. To gauge their total impact, the non-coincident peaks of each of these effects could simply be added , but the actual coincident impacts are what California will experience as summer heat degrades specific generators and raises demand in specific population centers. As Coughlin and Goldman (2008) note, "a preliminary analysis of historical data for extreme temperatures within the existing WECC [Western Electricity Coordinating Council] control areas suggests that there are definite correlations between different areas, or equivalently, that heat waves tend to occur in particular spatial patterns."

This section will look at the coincident additive impact of the first two effects: an increase in peak demand, coupled with a simultaneous decrease in peak generating capacity. The most important conclusion is this: California's peak supply capacity will need to grow faster than the population as the climate warms. This has implications for utility rates, since steady per-capita rates may not be able to finance per-capita capacity growth.

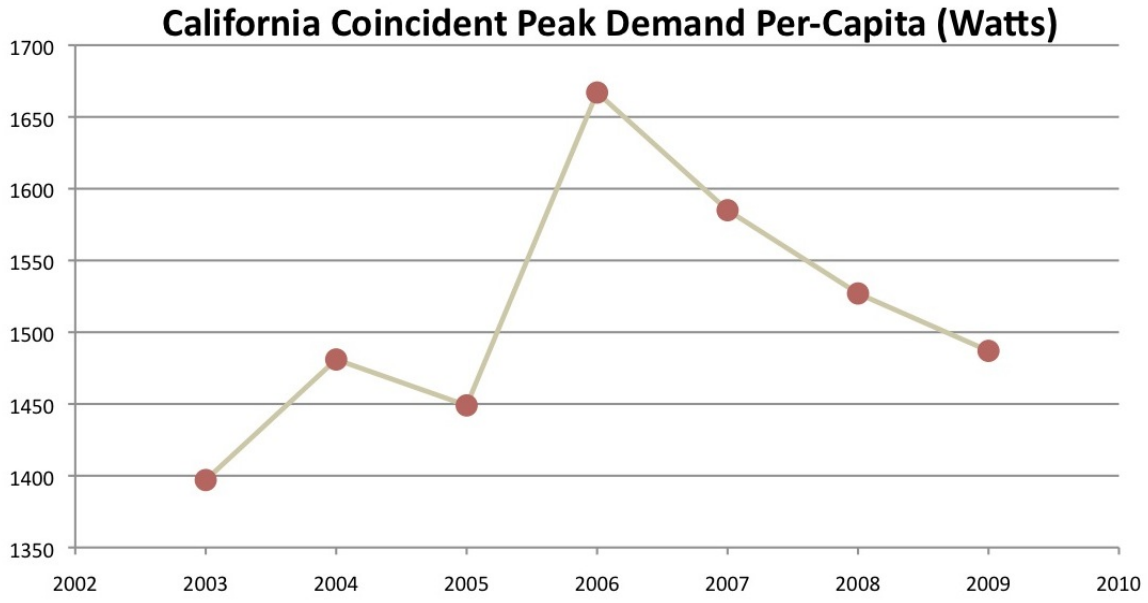
Demand

The authors have not yet looked at demand projections, but as discussed later, **temperature-induced demand overshadows other climate-change impacts in taxing California's energy infrastructure**. Franco and Sanstad (2008) provide an overview and a methodology for demand forecasts applied to four urban areas (San Jose, Sacramento, Fresno, and Los Angeles). This study used a similar methodology, but applied it statewide.

First, actual statewide hourly load data was obtained from the Ventyx Corporation for the years 2003–2009. (These were the only years for which historical load data were uniformly available.) Next, these figures were normalized to per-capita load using population data from the California Department of Finance (2010). (Over the period 2003–2009, California population increased linearly at 419,838 people/year, to an accuracy of $R^2 = .99$.) The daily maximum loads, divided by the population, were used to derive the daily per-capita peaks.

For reference, Figure 11 shows the largest of the daily peak loads for each of the years 2003–2009. Clearly the economy is a factor in per-capita energy consumption (the falloff from 2006–2009 was 11 percent), yet, this is a second-order effect; the correlation between peak per-capita energy demand and air temperature is still quite good.

Figure 11. Maximum Yearly Peak Demand, Statewide Per-Capita



Source: Authors

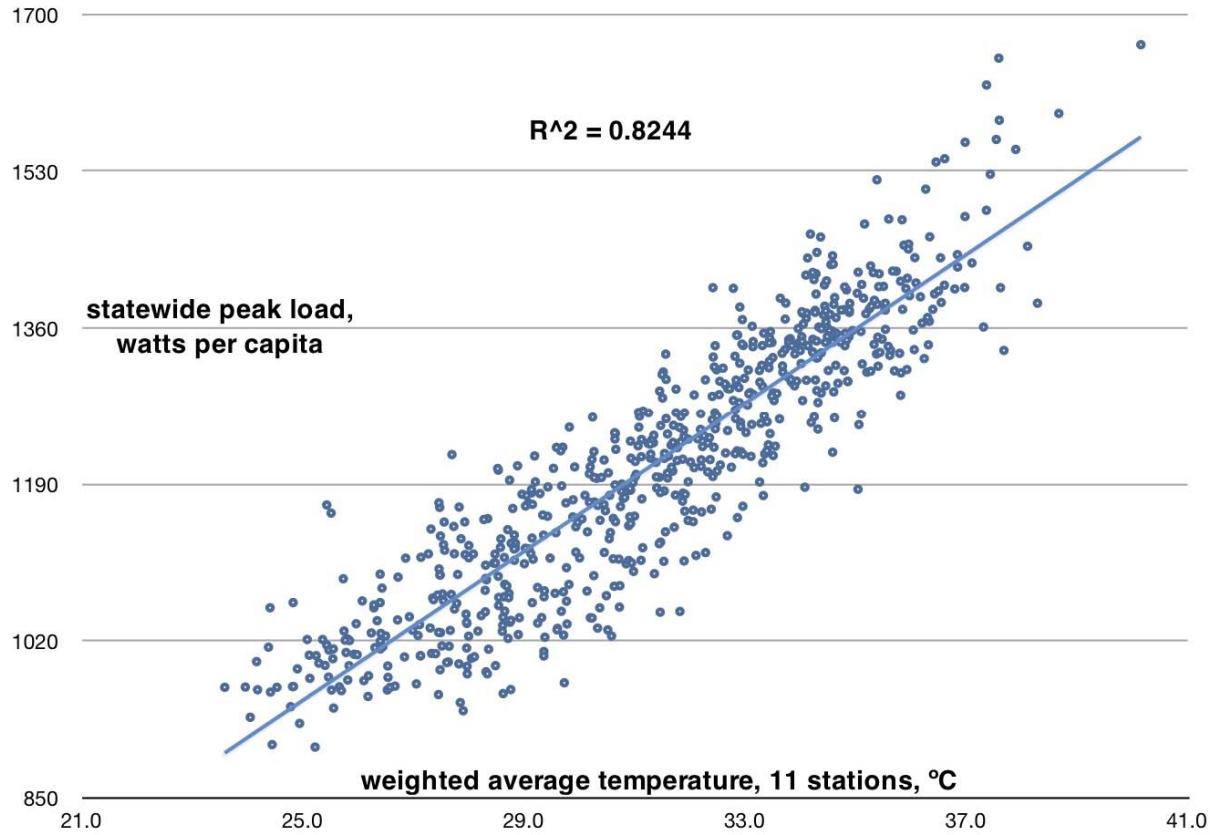
Next, weather stations grouped near the major population centers were chosen from the California Irrigation Management Information System (CIMIS) database. Then researchers took daily maximum temperatures from these stations for the period 2003–2009. Figure 12 shows a map of the stations that were used to project statewide load.

Figure 12. CIMIS Weather Stations Used to Project Statewide Peak Load. The numbers in the figure identify the weather stations.

Source: Authors

A regression on these temperatures (above 25ºC [77ºF]) versus the statewide peak load produces a good fit. The research team used a weighted average of the temperatures from these stations, with weights determined by a multiple regression on the 2003–2009 actual data. The weights thus obtained were: W_6= -1.09, W_{47}= 1.7, W_{75}= 1.21, W_{84}= 15.42, W_{131}= 11.16, W_{133}= 3.25, W_{139}= 6.04, W_{140}= -8.87, W_{150}= 1.67, W_{153}= 4.84, and W_{159}= 5.0. Figure 13 shows a scatter plot of the weighted average temperature for each weekday of 2003–2009 versus the actual statewide peak load in watts per capita.

Figure 13. Weighted Average Temperatures from the 11 CIMIS Stations versus Actual Statewide Per-Capita Peak Load, 2003–2009



Source: Authors

Using this relationship along with the downscaled AOGCM temperature data at the site of each weather station, the team was able to project the statewide per-capita demand for each peak day of 2070–2099, as shown in Table 9. This study also investigated the effect of longer and more frequent heat spells on peak load—another likely impact of climate change—but in this case peak loads were not found to be much affected by heat spells. A discussion of this finding is provided in Appendix C.

Table 9. Statewide August Peak Load Per-Capita

	Statewide August Peak Load Per Capita (watts)							
	Mean	**Δ (%)**	**Days > 1,254 (%)**	**90th percentile**	**Δ (%)**	**Days > 1,387 (%)**	**Max**	**Δ (%)**
Actual 2003–2009	**1,254**		50	**1,387**		10	**1585**	
CNRM/A2 2070–2099	1,532	22	98	1,661	20	94	1,930	22
GFDL/A2 2070–2099	1,552	24	100	1,683	21	88	1,851	17
PCM1/A2 2070–2099	1,490	19	93	1,585	14	67	1,778	12
CNRM/B1 2070–2099	1,449	16	96	1,571	13	82	1,720	9
GFDL/B1 2070–2099	1,490	19	97	1,613	16	73	1,795	13
PCM1/B1 2070–2099	1,405	12	89	1,529	10	55	1,678	6

During 2003–2009, the median ("1-in-2") load was 1254 watts per capita, while the 90th percentile ("1-in-10") load was 1387 watts per capita. As is shown in Table 9 and the charts below, most summer days are expected to exceed these values by the end of the century (Figures 14 and 15).

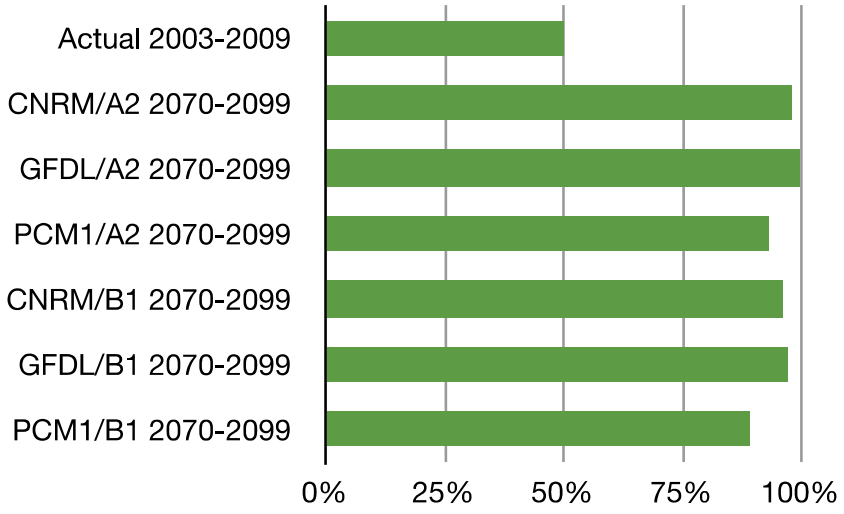
Note: As far as the researchers know, there is no single "reliability standard" to which California utilities adhere, but informally, most utilities seem to plan to cover the "1-in-10" (90th percentile) forecast within their own supply capacity, leaving the top 10 percent of peak loads to be covered by reserve margins or imported power or by demand-response policies or rolling blackouts as necessary. In its annual outlook reports, the California Energy Commission presents 1-in-2 and 1-in-10 forecasts. Note that these are per-capita peak load increases.

In short, 90th percentile per-capita peak loads are projected to increase between 10 percent and 20 percent at the end of the century due to the effects of climate change on summer weekday afternoon temperatures (Table 9).[6]

[6] These projections are similar to estimates presented in another resent study of California peak loads and climate change (Miller et al. 2007), which projects 90th percentile peak demand increases of 6.2–19.2 percent under the A2 scenario.

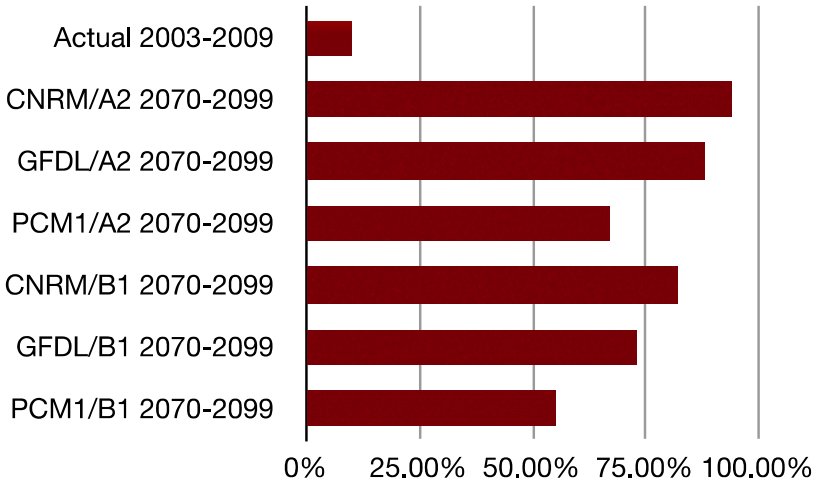
The significance of this is that at the 90th percentile (1-in-10) level, there is a projected increase in peak demand of up to 21 percent. Since this demand occurs at the time of maximum temperature when only 77 percent of the nameplate capacity is delivered, there will need to be a nameplate capacity increase of 27 percent to drive this air conditioning load.

Figure 14. August Days with Peak Loads > Average August Peak 2003–2009



Source: Authors

Figure 15. August Days with Peak Loads > 1-in-10 August Peak 2003–2009



Source: Authors

Cumulative Effect of Demand and Generation on Peak Load

In combining these demand figures with the peak capacity loss results, researchers can consider the temperature-induced generation loss to be a kind of "parasitic demand"—that is, utilities must supply that amount of electricity in addition to the demands of their paying customers. Thus the per-capita demand (as determined above) can be added to the per-capita generation loss (determined using the earlier generation loss results). This provides a better picture of the total energy that California must supply or import than either the revenue-generating demand or the generation losses alone does.

These quantities were computed using the per-capita results above, applied to California's current population and power plant distribution. (That is, the excess temperature-induced capacity loss at the site of each gas-fired power plant in California were combined with the coincident temperature-induced demand, over all August days 2070–2099.)

The demand values in Table 10 include an average of 10 percent temperature-induced generation loss and 90 percent paying-customer demand (and this 10/90 split is very nearly uniform across all the days of each 30-year period). Thus it can be concluded that 90 percent of the expected growth in per-capita peak demand will come from temperature-induced cooling demand, and 10 percent will come from temperature-induced generation loss. These calculations do not include the transmission and distribution losses resulting from climate change. These losses could increase anticipated shortfalls 1.5 percent to 2.5 percent, as described above.

Table 10. Total Statewide Peak Demand Plus Temperature-Induced Generation Losses, in Watts Per Capita[7]

Watts per capita	1961–1990 1-in-10 total demand	2070–2099 1-in-10 total demand	Δ (%)	2070–2099 days > 1961–1990 1-in-10 (%)
GFDL/A2	1541	1875	22	93
CNRM /A2	1490	1857	25	93
PCM1 /A2	1534	1748	14	68
GFDL /B1	1497	1696	13	59
CNRM /B1	1494	1654	11	48
PCM1 /B1	1500	1593	6	25

These projections are what would occur *if end-of-century temperatures were imposed on California's current population and current power plant distribution*. Not included is any acceleration of demand

[7] Represents the 1-in-10 = 90th percentile demand and generation. Current California gas-fired generating capacity = 1,146 watts per-capita (2010).

from increased penetration of air conditioners into unsaturated markets, which would increase the 2070–2099 demand figures above.

Of course, by the end of the century, population growth will increase these values. But if temperature projections hold true, the per-capita peak capacity will need to increase disproportionately to the population.

Summary and Implications for Utilities

- By the end of the century, the daily per-capita peak demand is expected to exceed current 90th percentile peak demand on almost every summer day. The maximum per-capita peak loads could increase up to 24 percent over those of 2003–2009 (with an average increase of 18.5 percent across all scenarios), and the 90th percentile peak loads could increase up to 21 percent (with an average increase of 16 percent across all scenarios).
- At the 90th percentile, people can expect up to 25 percent growth in total per-capita total peak demand. And it is worth noting that "recent data show that actual emissions growth since 2000 exceeds the highest-growth scenario..." (Coughlin and Goldman 2008).
- Combining results, it can be seen that in order to overcome the decreased efficiency of the generators, the decreased efficiency of the substations, and the increased demand for air conditioning, people may need an additional 38.5 percent peak generation capacity.
- The heat-induced generation increases mentioned above do not need to be pushed through the transmission lines—they are only needed to bring the generators back to previous power output. But the 2.7 percent substation handicap and the 21 percent air conditioning burden do need to be transmitted, so the electrical grid may need to carry 23.7 percent more peak power per-capita than it does today. And it must do this in the face of a 7.5 percent decrease in the capacity of fully-loaded transmission lines. This suggests that at least parts of the grid may need up to 31.2 percent more capacity than would be expected from population growth alone.
- Thus, as additional generating capacity is added to serve California's steadily increasing population, the state will need to add proportionately more peak capacity (in generation or efficiency offsets) to cover the combined effects of increased cooling demand and decreased generator efficiency on the hottest summer days.
- Electric utilities can deal with projected increased total peak demand by investing in new generation and cooling technology. The potential need for increased system capacity and higher electricity rates suggests the need for long-range capacity and financial planning.

Caveats

Note that this analysis does not include the "heat wave effect"—the theory that concurrent hot days increase the air conditioning demand disproportionately as stored heat builds up in building mass (Appendix C). This study's analysis shows that (possibly due to demand-response policies), no heat wave effect appears in the historical load/temperature data for the Sacramento Municipal Utility District (Fitts 2010).

Also, this study's temperature data were taken from agricultural weather stations, so it may not accurately reflect any urban heat island effects, which might change the temperature/demand relationship over time.

Of course, the efficiency/generation supply ratio may be altered by deliberate policy or societal change. This analysis only quantifies the total supply increases (efficiency gains plus generation increases) that may be needed.

CHAPTER 4:
Projected Wildfire Risk to Electricity Transmission

Several studies have shown that climate change will increase the size and frequency of wildfires in California, which is problematic for a state that already leads the nation in wildfire-related economic losses (Flannigan et al. 2000; Lutz et al. 2009; Westerling et al. 2009). Of the 10 largest wildfires in California's history, 8 have occurred since 2001. Weather-related effects on fire include behavior (wind conditions), fuels (combustible material), and ignitions (lightning). Wildfires are also greatly affected by moisture availability, as influenced by temperature, precipitation, snowpack, and other meteorological factors, all of which may be affected by climate change.
In regard to energy infrastructure, increases in the size and frequency of wildfires in California will increasingly affect electricity transmission lines. What's more, transmission line-related impacts from wildfires are not restricted to the actual destruction of the structures (Aspen Environmental Group 2008; (personal communication, Fishman and Hawkins, CAISO 2009). In fact, only smaller lines may be directly destroyed in a wildfire event, because these types of power lines are typically built with wooden poles. Instead, the transmission capacity of a line can be affected by the heat, smoke, and particulate matter from a fire, even if there is no actual damage to the physical structure. For one, the insulators that attach the lines to the towers can accumulate soot, creating a conductive path and causing leakage currents that may force the line to be shut down. Ionized air in smoke can act as a conductor, causing arcing; either between lines, or between lines and the ground, that results in a line outage. Finally, even if the lines are protected from fire, the effects of firefighting can also negatively affect transmission operation either by aircraft dumping loads of fire retardant that can foul the lines, or through preventive shutdowns for safety measures.

While the physical effects of fire on transmission lines is widely noted, it is more difficult to estimate the length of time that a line would be down in these cases, as these impacts can interrupt the line's service either momentarily or for an extended time period (personal communication, Fishman and Hawkins, 2009). It is even more difficult to relate these events to an actual outage, since the transmission system can often cope because of the redundancy intentionally built into the power system. In the future, however, this redundancy may become less reliable, as electricity demand is expected to increase as a result of both climate change and population growth, and research suggests that wildfires will increasingly affect transmission lines.

This section examines transmission lines 220 kV and greater in the context of projections to wildfire acreage burned, as modeled under several climate scenarios.

Projected Wildfire Risk and Transmission Lines (Westerling Dataset)

For this analysis, the research team used wildfire s provided by Westerling et al. (2009), who have estimated the future probability of wildfire in California for three 30-year time periods relative to a historical 30-year base period centered on 1975. The risk projections available to us

included projections with and without assumed climate-induced vegetation migration (vegetation pattern alterations caused by climate changes) and projections based on two different values for household density.[8] The authors used the set of projections that reached the most conservative results for increased fire risk, including vegetation migration and a household density threshold of 1,000 houses per square kilometer (km^2). However, these projections do not incorporate changes in lightning strikes, an additional source of wildfire ignition, or the affect climate change may have on wind patterns, which can greatly influence wildfire spread and severity. As stressed in Bryant and Westerling (2009), the projections of fire risk rely on some uncertain predicted variables, like precipitation. To avoid biases, Westerling purposefully compared future projections to the 1975 base period, to arrive at a relative risk change.[9]

Methods

Westerling's wildfire projection grids were first overlaid on top of the electricity transmission infrastructure to measure the length of lines in regions experiencing a modeled increase or decrease in area burned in the future. The California Energy Commission provided a transmission line database that had been recently updated for improved spatial accuracy. For the purposes of this study, to examine the effect of wildfires on electrical transmission of regional and statewide importance, the authors only looked at lines 220 kV and greater. Lines were divided by the boundaries of the 1/8° grid cells and assigned the associated fire attributes of the cell they intersected. The result is a measure of exposure to wildfire rather than a direct impact, since a line may be located near a burned area but not necessarily be affected by the fire. The actual impacts will depend on how the lines are individually affected by the temperature changes, soot accumulation and, in the worst case, destruction of lines.

After line segments were assigned the projected fire attributes of the cell they intersected, segments for individual lines were merged back together, and the attributes for each used to calculate the probability of a line being exposed to wildfire at some point during the 30-year study period. This probability was approximated by first estimating the weighted probability of no fire across all cells along the line. For this the authors took the probability of fire in a cell to be the projected area burned divided by the total area of the cell (e.g., if 5 percent of the cell is projected to burn, the cell was assigned a 5 percent fire probability). Weights were determined from the relative length of the line within each cell, where 1 is the longest possible length, and 0 is the shortest. Thus, the probability of a fire at any point along a particular transmission line was calculated as: $PF = 1 - \sum(1 - p_i \bullet w_i)$, where p_i is the probability of a fire in cell i and w_i is the relative length of the line in cell i. In this way, with the entire length of a transmission line taken into account, the authors estimated the probability that each particular line will be exposed to fire somewhere along its path over each 30-year period.

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[8] The *urban density* is defined as the fraction of a gridcell that has a household density greater than an assumed threshold of houses/square kilometer.

[9] In fact, the fire risk for different AOGCM forcings for the base period is not necessarily the same, since the climate simulations differ according to AOGCM.

Results

Figures 16 and 17 display the results for each of the AOGCMs and each of the three 30-year time periods, for the A2 and B1 SRES scenarios, respectively. Lines displayed in dark to light green, which represent the majority of lines in the State, were projected to have a 0.1 to 30 percent probability of being affected by wildfire over a 30-year period. Lines displayed in orange to dark red were modeled to have a 50 to 80 percent chance of being affected by wildfire.

As the projections move forward in time, in all climate scenarios there is a clear increase in the number and length of transmission lines exposed to wildfires. Not surprisingly, across all AOGCMs, the results for the A2 scenario are more severe than those for the B1 scenario. The GFDL climate model, which projects higher temperatures relative to the other models, shows a distinct increase in lengths of transmission lines exposed to burned areas by the end of the century. Because the fire impacts have been aggregated along entire lines, however, these effects appear more muted than for individual line segments. Generally speaking, the forested regions of northern California, the Sierra Nevada foothills, and the greater Los Angeles and San Diego areas appear to experience a significant relative increase in the area burned, as compared to the 1975 base period.

Figure 18 summarizes change by the end of the century in the length of lines exposed to areas of either increasing or decreasing area burned, the later being more common. Lines shown in green to red are expected to experience an increase in exposure to wildfires; whereas, lines in light or dark blue are expected to experience a decrease in exposure to burned areas. While most of the lines across the State are modeled to be increasingly exposed to wildfire risks, certain areas around the State stick out as being less at risk in the future.

In the San Francisco Bay Area, notably the South Bay, there actually appears in places to be a decrease in expected area burned. There are also small areas around the foothills of the greater Los Angeles area where modeling shows a decrease in exposure to wildfire. Both of these cases are probably a result of vegetation migration or increasing urbanization as accounted for in the Westerling fire model.

Transmission lines passing through the desert areas in southeastern California are also projected to experience a decrease in the length of lines exposed to wildfires in the future. This too is a probable result of vegetation migration, as assumed in the Westerling model. Certain areas that are currently inhabited with more wildfire-prone vegetation under a new climate regime are likely to be inhabited by different species in the future; thereby reducing the number of areas vulnerable to wildfire, which will in turn reduce the fire risk of transmission lines running through the area.

Figure 16. Projected Fire Risk to Transmission Lines for the A2 Scenario

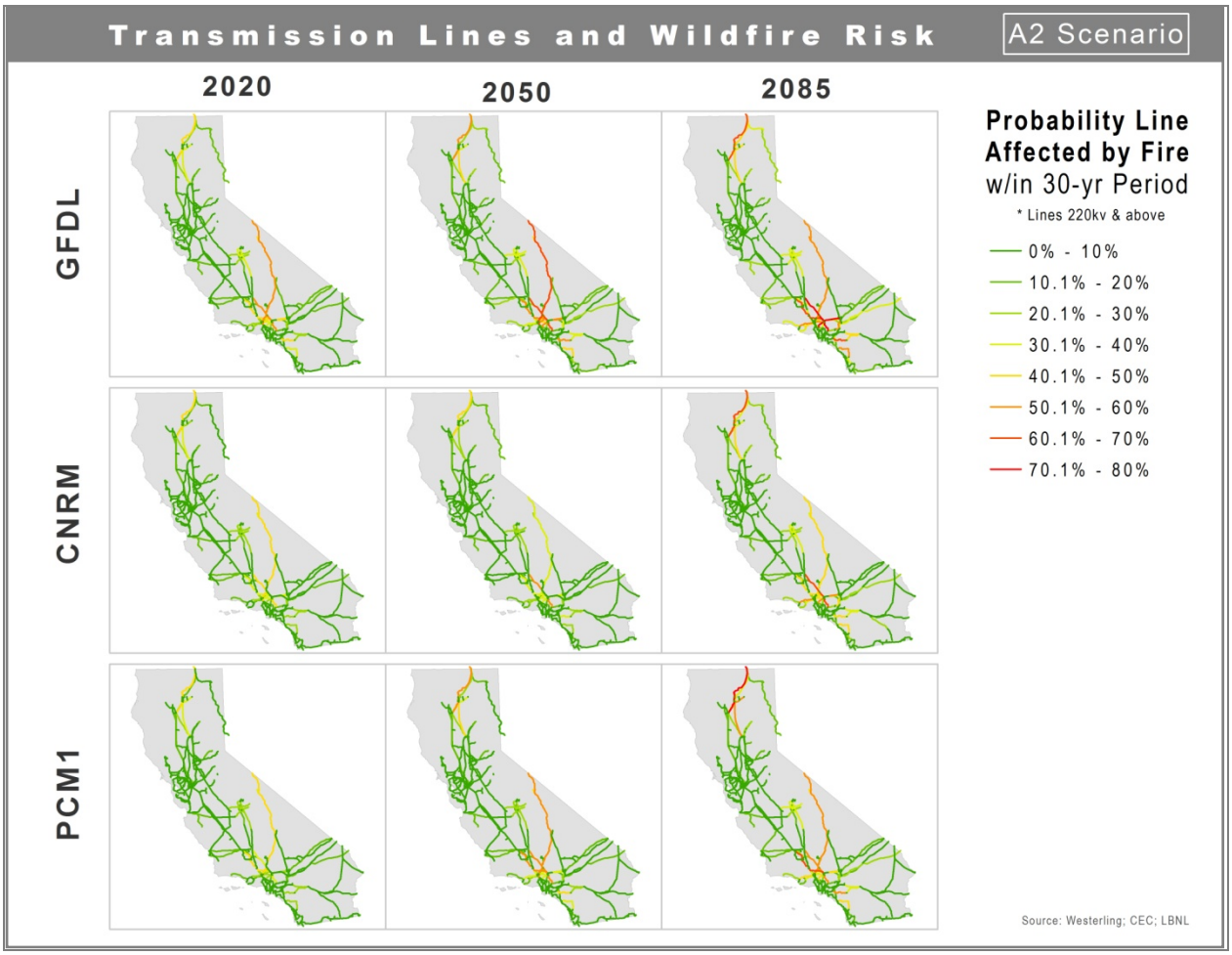


Figure 17. Projected Fire Risk to Transmission Lines for the B1 Scenario

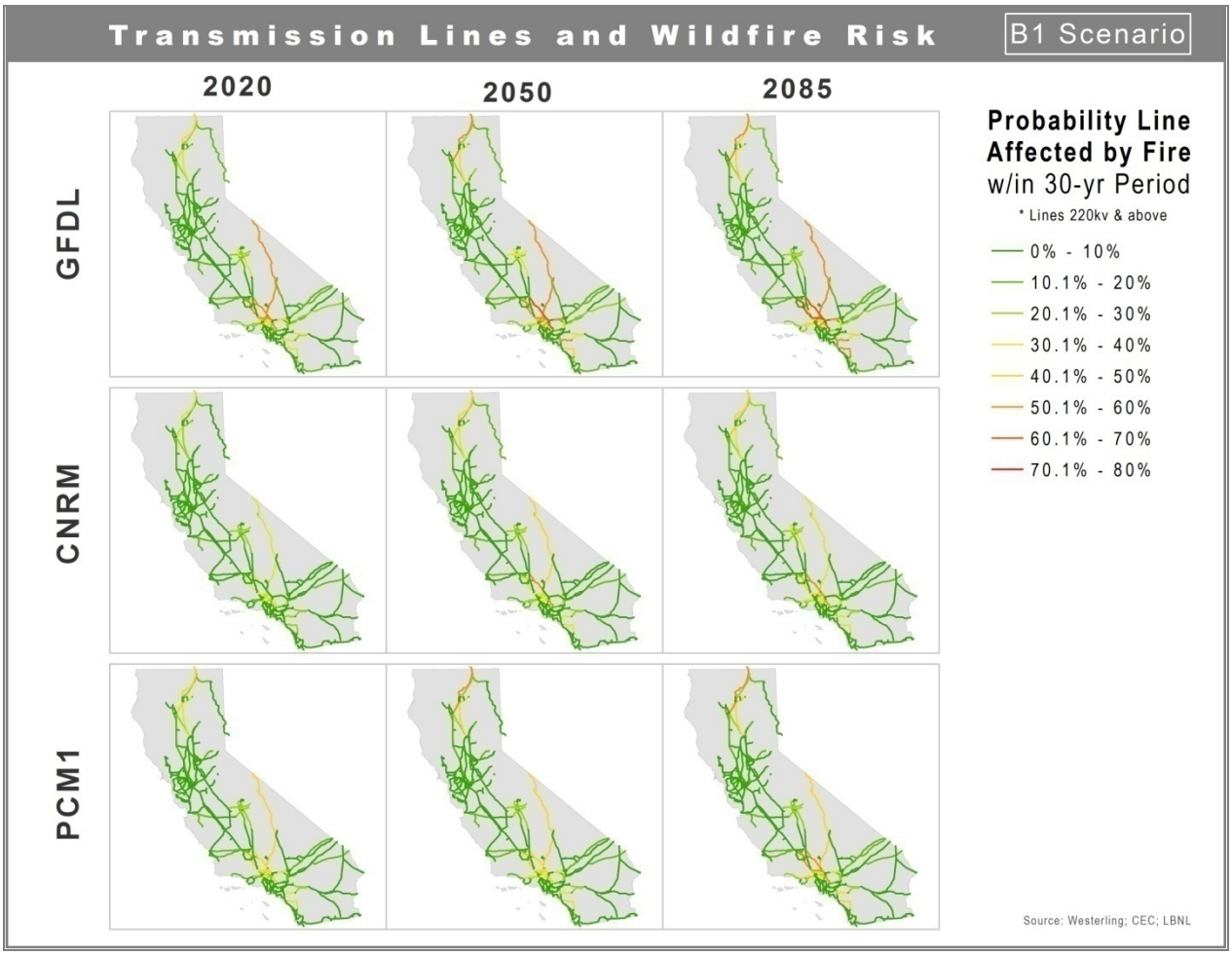
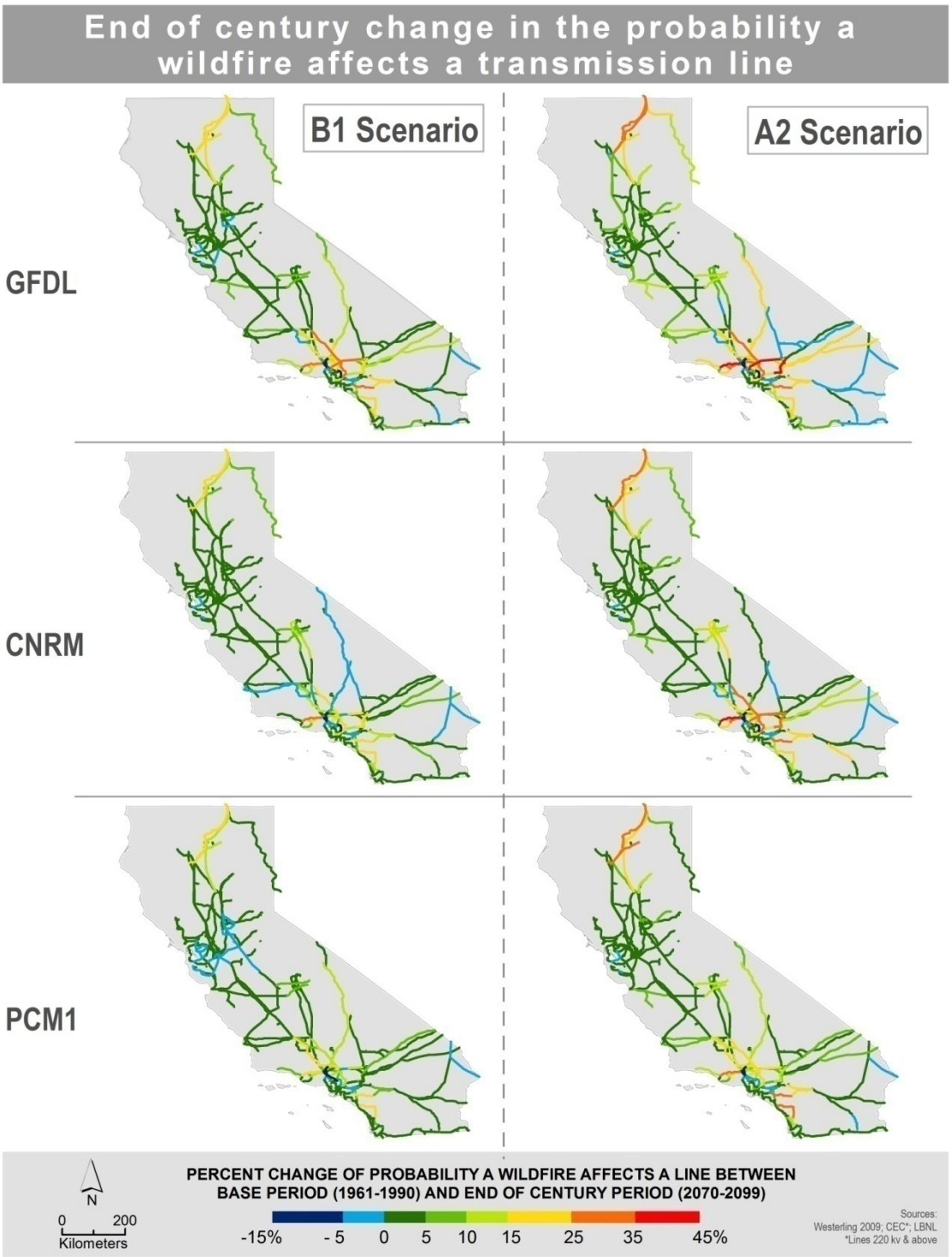


Figure 18. Whole-line Exposure to Wildfire Risk



Implications for Utilities and Next Steps

The electric utilities that own the majority of the exposed transmission lines are Pacific Gas and Electric (PG&E) and Southern California Edison (SCE), because of their service regions and because they own the greatest length of lines. Other utilities with significant exposure to fire risk include San Diego Gas and Electric (SDG&E) and PacifiCorp. These utilities may want to consider planning for additional long-run transmission capacity to offset some of the risks posed by fires to their infrastructure. Undergrounding and improved design and materials should also be considered.

The projected wildfire data used in this study do not account for the effect of climate change on wind patterns, which can greatly influence the severity of wildfires. Where possible, future studies on the influence of climate change on wildfires should include the effects of wind. In addition, the impact of wildfires on energy generation, notably hydroelectric power, also requires further research. In California, most sediment enters waterways after a wildfire event, increasing silt accumulation in dams, reducing their effectiveness and longevity in generating hydropower (Fried et al. 2004). Yet another unexplored effect is soot deposition by fires onto transmission lines, which may increase their solar absorptivity and lower their radiative emissivity, thereby increasing conductor temperature and lowering electrical capacity. These topics and others need to be further explored in future studies.

CHAPTER 5:
Impact of Sea Level Rise/ Coastal Inundation

Mean sea level along California's coast has risen at a rate of 17–20 cm per century for several decades—a rate that may increase (Cayan et al. 2009). Mean high water, which poses an even more significant threat, is increasing at an even faster rate (Flick et al. 2003). Extreme surge events at high tides, often provoked by winter storms, are also expected to increase (Cayan et al. 2008). The conjunction of these three trends puts increasing amounts of the coastal energy infrastructure at risk.

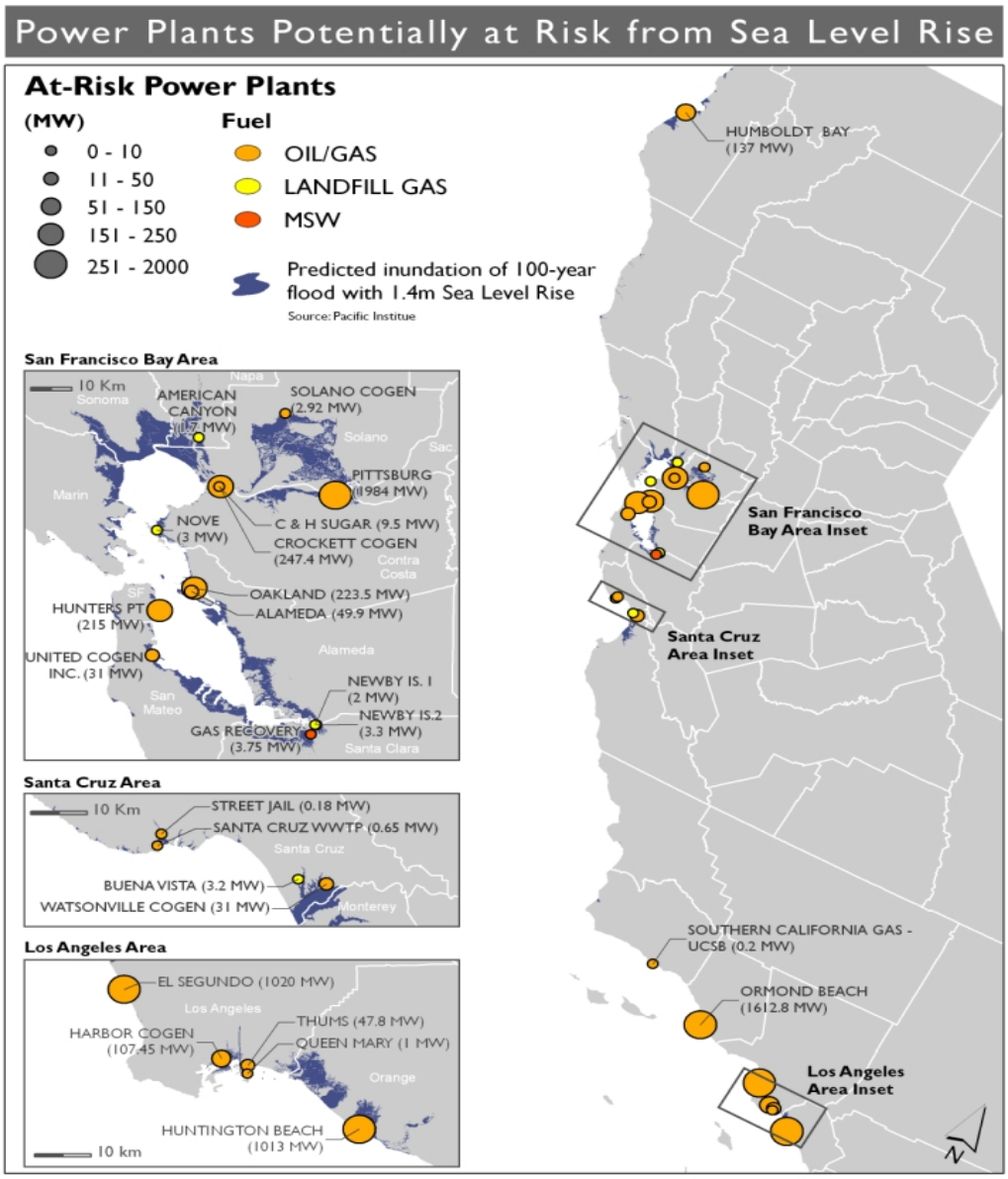
Projected Power Plant Impacts

A 2009 Pacific Institute study assessing infrastructure at risk from a projected 1.4 meter (m) sea level rise determined that 30 California coastal power plants with a combined generating capacity of 10,000 MW were at risk of inundation from a 100-year flood event[10] (Heberger et al. 2009). What is more, several of the power plants identified by Heberger et al. (2009) are already at risk from a 100-year flood, without even considering a rise in sea level (e.g., Huntington Beach and Long Beach Peaker). This is especially alarming given that Noah Knowles's hydrology model of the San Francisco Bay shows that a 1.4 m sea level rise on an area presently vulnerable to a 100-year event will put it at risk of annual flood events by 2100.

In the time since the Pacific Institute study was first published, the California Energy Commission has improved the accuracy of their power plant spatial dataset. Using these new data, intersected with the same sea level rise data used by the Pacific Institute, the authors' analysis shows a noticeable difference in the number of power plants potentially at risk from sea level rise-related impacts. While the Pacific Institute study found 30 plants at risk of a 100-year flood with a 1.4 m sea level rise, the authors' analysis, using updated power plant data, shows only 25 plants at risk, 13 of which are in the San Francisco Bay Area (See Figure 19). That being said, the data used are still not entirely accurate, and site-specific analyses will still be necessary to determine actual risks, as will be discussed in more detail below. In addition, many of the plants shown to be at risk in this study are likely to be retired over the next few decades.

[10] A 100-year flood is an extreme flood that has a 1 percent chance of happening every year (Heberger et al. 2009).

Figure 19. Power Plants Potentially at Risk to a 100-year Flood with a 1.4 m Sea Level Rise

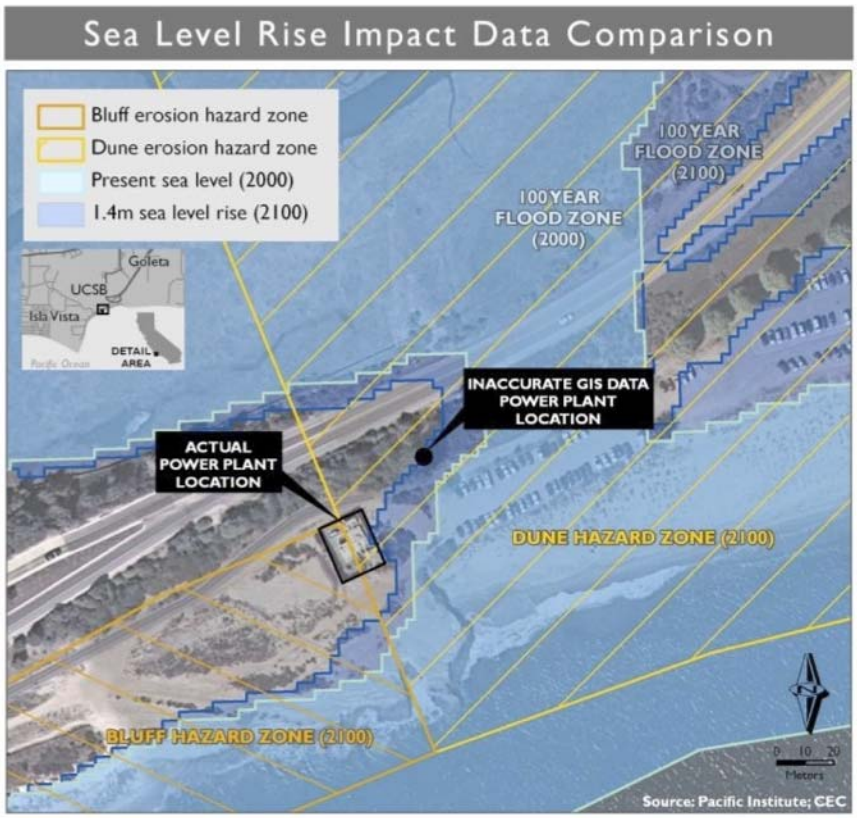


Source: Pacific Institute

For example, power plant location data are currently provided in x,y format and are input into a GIS as point data. For a spatial data analysis such as this one, this is problematic because a data point representing a power plant may have been digitized at a 1:24,000 scale or collected by a standard global positioning system (GPS) unit with a ±40 foot accuracy, and a power plant is a three-dimensional object that involves many structures that cannot be represented by a single point. (The plant may be a large rectangular with linear intake pipes, round holding tanks, and many other three-dimensional features).

Figure 20 illustrates a situation where spatial data accuracy of even the newer, more exact data affects analysis results and highlights the need for more accurate data and site visits in studies such as this. In this case, the inaccurate point data locate the power plant within the 100-year flood zone (given a 1.4 m sea level rise); however, when the data was overlaid on aerial imagery, the actual plant location is not. Closer analysis shows the plant is more likely to be affected by bluff erosion, which may be accelerated by the effects of sea level rise (Pacific Institute data). Thus, this plant may still be affected by sea level rise, but not by direct inundation as the analysis may imply. Ideally, complete polygons of the extent of each plant would be available to determine which elements would be most at risk of harm if a flooding event were to take place.

Figure 20. Sea Level Rise Impact Data Comparison



It is also important to note that while this study is illustrating a 1.4 m rise scenario, Cayan and colleagues present a range of sea level rise estimates for 2100 between 0.6 and 1.4 m, for optimistic (B1) and pessimistic scenarios (A2), respectively; and even this range did not consider the most pessimistic scenario acknowledged by the IPCC (Cayan et al. 2009). In this way, sea level rise predictions are not exact, but rather, offer a wide range of possibilities. When assessing the effects of sea level rise it is important to acknowledge the inherent variability in the input data, and that not all variables influencing sea level have necessarily been included in the model. Although global sea level rise is estimated using state-of-the-art modeling, local projections for changes in sea-level vary widely, and the effect will depend on conditions including tectonic upheaval, atmospheric pressure, and the topography of the coastline (e.g., Douglas and Peltier 2002). And of course, even if sea level does rise to 1.4 meters by 2100, this rise will not halt in 2101.

Finally, yet another source of error or uncertainty in such analyses is the vertical and horizontal accuracy of the elevation data used for such analyses. In some cases the vertical error may exceed the projected sea level rise, thereby leading to incorrect impacts. Sources of such errors may be minimized in later studies with the use of more accurate elevation data.

Future studies should note that at the time of this writing there is an extensive mapping effort underway to capture seamless high-accuracy Light Detection and Ranging (LiDAR) data along the entire West Coast, from Oregon to Mexico and extending from the present shoreline up to the 10 m topographic contour. Organized by the California Ocean Protection Council, the California Coastal LiDAR Project (CCLP) is a joint effort between U.S. Army Corps of Engineers (USACE), the National Oceanic and Atmospheric Administration (NOAA), and the U.S. Geological Survey (USGS). The CCLP dataset should undoubtedly be used in future studies involving sea level rise analyses.

Another limitation of the power plant risk analysis is that it does not consider the existence of levees. As Knowles (2009) points out, many areas at risk of inundation are presently behind levees and would only be flooded if there is a breach or if the flood elevation overtops the levees. For all of these reasons, and as noted in the Pacific Institute study, the vulnerability of power plants to flooding is very site specific; therefore, more information should be gathered on a site-by-site basis.

Impacts on Natural Gas Facilities in the Delta

In the San Francisco Bay Area, the results of Heberger et al. (2009) for coastal flood risk were based on those estimated by Knowles (2008) using a hydrodynamic model for the San Francisco Estuary. The study area extends from the entrance to the Bay to Pittsburg in the east and San Jose in the south. Sea level rise information for the Sacramento-San Joaquin River Delta was not available at the time of the Pacific Institute study, and therefore was not included in their analysis.

Special attention should be given to the Sacramento-San Joaquin River Delta (herein referred to as the Delta), where much of the land harboring vital energy infrastructure presently resides below sea level. Given its connectivity to San Francisco Bay and the Pacific Ocean, as well as to

runoff from the Sierra Nevada snowpack, the Delta will increasingly be affected by sea level rise and climate change effects. Mean Delta water levels are expected to rise along with mean sea level, although owing to the gradient in mean water level across the Delta, the effect of the rise will be smaller upstream. Roughly speaking, the landward reaches of the Delta may see around 50 cm (19 in) less rise in mean water level than the seaward reaches. In addition, in terms of higher-frequency variability, the landward reaches will be more dominated by river flow effects (which are expected to change with increasing temperatures, with higher peaks as snowpack disappears), and the seaward reaches will continue to be dominated by impacts such as tides and storm surges (Knowles, personal communication. July 6, 2010).

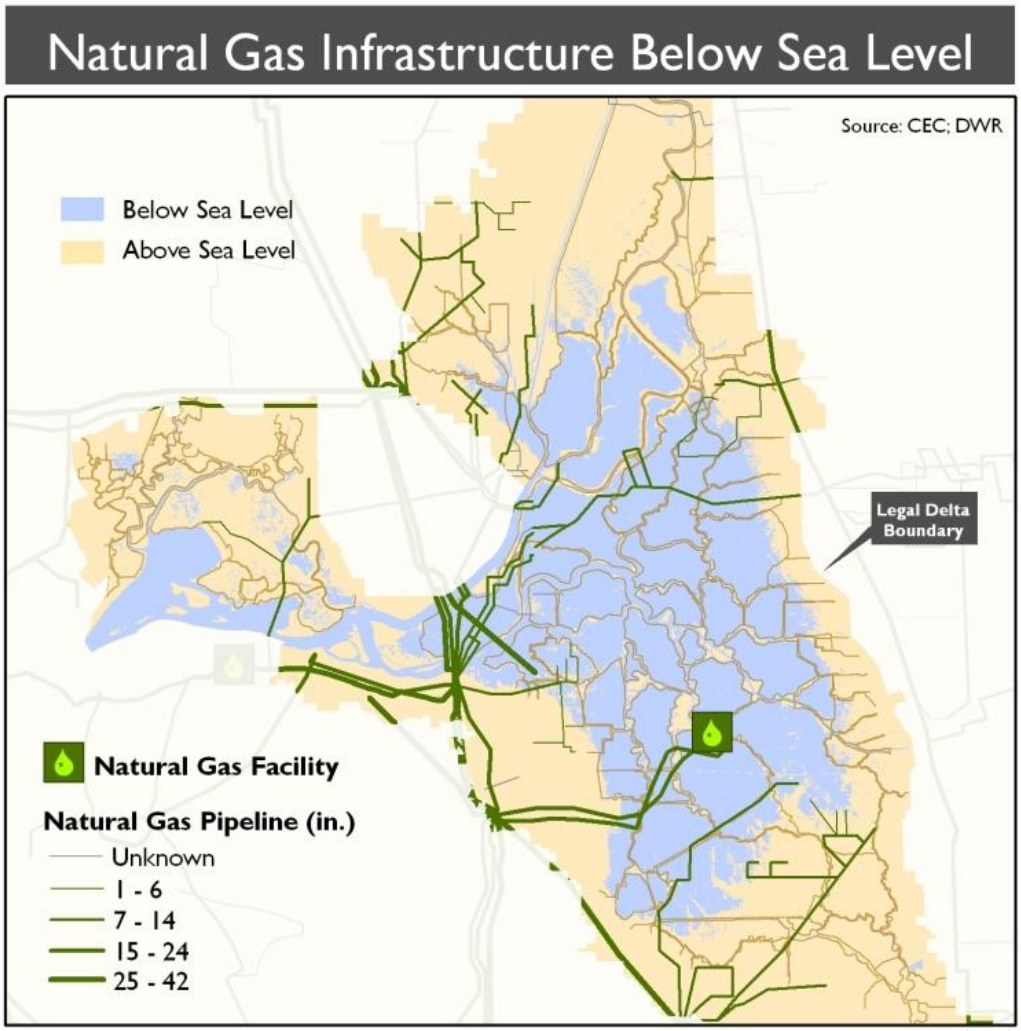
The Delta is also affected by storm surge propagating from the open ocean and is most vulnerable during winter months when extremes in river discharge and storm surge occur simultaneously with extreme high tides, all of which are expected to intensify with climate change (Bromirski and Flick 2008; Cayan et al. 2008). Furthermore, when levees protecting islands subsided well below sea level experience increased hydrostatic pressure during storms, the likelihood of failure increases—an effect to be enhanced by sea level rise (DWR 2011). The western Delta islands, which are closest to the San Francisco Bay, deserve the greatest concern, as they have some of the highest risks of levee failure, and are also the nexus of energy infrastructure in the Delta (Mount and Twiss 2005).

This is clearly an issue of potentially great concern to the State, since the risk of levee failure is high even without climate change and the potential cost of losing sensitive energy infrastructure in the region may be very large. However, in terms of this study it is difficult for us to estimate the added risk posed by climate change to an already vulnerable infrastructure within the Delta. Studies to estimate the distribution of high-water stages throughout the Delta under climate change are planned, but not yet under way (Knowles, personal communication. July 6, 2010). When those studies are completed it may be possible to evaluate the incremental risk of climate change to the energy infrastructure.

Natural Gas Facilities in the Delta

There is one natural gas storage facility currently operating below sea level—the PG&E facility on McDonald Island—which collects, stores, and withdraws natural gas in the California Delta. The facility is primarily used to supply gas to the Bay Area and Sacramento/Stockton urban centers at times of peak demand, when supplies from Canada and the Southwestern United States are inadequate (Stoutamore, cited in CALFED Delta Wetlands EIR/EIS 2000). Although the ground elevation in the field averages 10 feet below sea level and is subsiding at a rate of 4.5 inches per year, the water is currently held back by levees 16 ft high. In addition, in the event of a levee break or island flooding, the compressor and the well-head controls are designed to operate under a 20 ft head of water (Figure 21).

Figure 21. Natural Gas Facilities Near Sea Level in the Sacramento-San Joaquin River Delta

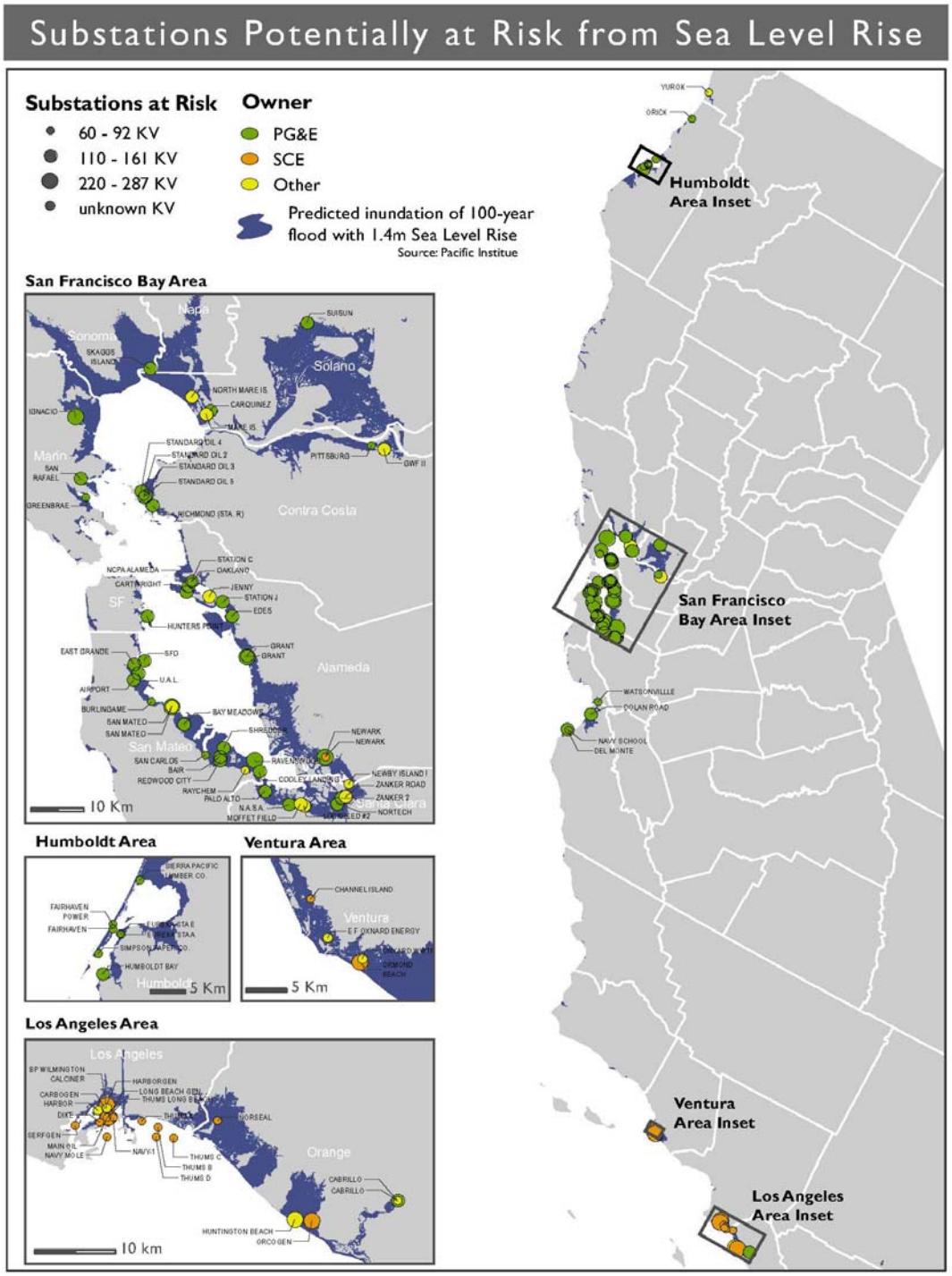


Source: Lee 1968

Impact of Sea Level Rise on Substations

Using the same methods and data as the sea level rise analysis on power plants above, Figure 22 shows the results of this study's examination of substations at risk from a 100-year flood event given a 1.4 m sea level rise. Like the power plant data, the substation database was also recently updated by the Energy Commission, which resulted in a significant improvement in spatial accuracy. Based on these newer infrastructure data, this study reveals that out of a database of 2,690 substations statewide, 86 substations are at risk of inundation; 49 of which are in the Bay Area. Of the 86 substations at risk, PG&E owns 51, SCE owns 18, and 17 are owned by other utility companies. Given that modeling shows only 3.2 percent of California's major substations to be affected as a result of sea level rise and climate change, this is not by any means the largest threat to California's electrical infrastructure. However, it will be an added impact for utility companies to anticipate and manage as the end of the century approaches. Most of these substations are built to serve local load so any climate-related risk to the substations will pose a risk to the associated load as well.

Figure 22. Substations at Risk to a 100-year Flood with a 1.4m Sea Level Rise



CHAPTER 6: Conclusion

This report outlines the results of a study on the impact of climate change on California's energy infrastructure, including impacts on power plant energy generation; transmission line and substation capacity during heat spells; wildfires near transmission lines; and sea level encroachment upon power plants, substations, and natural gas facilities.
The study finds that higher temperatures will decrease the capability of existing natural gas-fired power plants to generate electricity and increase the future demand for electricity. The estimated decrease in capacity varies by region, emission scenario, climate model, and plant type. During exceptionally hot periods in August at the end of the century, under the highest emission scenario, the models used in this study estimate a decrease in simple-cycle natural gas power plant generating capacity between 3 and 6 percent in California overall, and between 3 and 4 percent in the San Francisco region. Under similar conditions, the models suggest diminished transformers and substation capability between 2 and 4 percent across California overall, and between 2 and 3 percent in the San Francisco region, as well as a very small increase in transmission line losses. Coupled with increased peak period demand, the summary effect of climate change will be to require substantial new investment in generation, transmission, and distribution. These impacts would occur during the hottest hours of the day, when electricity demand is at a maximum. The projected increase in electricity demand varies between 6 percent and 22 percent, depending upon the emission scenario and time period.

However, although climate change might decrease the capacity of the electricity infrastructure and increase peak period demands on that infrastructure, utility companies have time to anticipate this change and build the additional system capacity needed to offset this impact. For example, utilities may increase the number of existing power plants and introduce new plants with chillers to offset high temperature impacts. Therefore, while it is predicted that climate change will increase the cost of providing electricity, if properly anticipated, the frequency of electricity outages should not increase.

Fire risk as affected by climate change, however, may pose a more difficult challenge to electric utility companies. Building on the results of existing fire studies, this study suggests that climate change will increase transmission line exposure to wildfires. For example, in parts of California, the likelihood that fires will occur next to large important transmission lines at the end of the century is expected to increase over 300 percent. It should be noted that while fires do not necessarily cause electricity outages, they more often increase electricity maintenance costs and decrease transmission line efficiency.

Similarly, rising sea levels at the end of the century are likely to affect electricity production costs. This study shows that given 1.4 m (4.6 ft) sea level rise scenario, a 100-year flood event could inundate as many as 25 power plants, scores of electricity substations, and at least one natural gas storage facility located along California's coast. Properly anticipated however,

flooding could be avoided by building additional or more robust levees, moving plants to higher elevations, and other preventative actions.

In brief, protective measures, including proper planning and excess capacity, are possible options to help utilities avoid electricity outages and prevent major economic damages from the effects of climate change. In some cases these measures may be expensive and involve a need for "excess" or redundant system capacity, but they do not pose insurmountable economic obstacles to reliable electricity infrastructure.

Perhaps the largest challenge posed by climate change is the risk posed by a broad mix of coincident climate impacts, including frequent heat spells, winds, drought, fires, and flooding; thereby resulting in diminished generating and transmission capacity. The broad range of temperature forecasts across climate models suggests much uncertainty about the predictions of any single risk factor; the combined uncertainly across many factors is much higher. Electricity infrastructure, like most engineered systems, is designed to achieve a high degree of reliability in the face of uncertainty involving climate-related events (e.g., unexpectedly high load during heat spells). However, climate change seems likely to increase uncertainty and risk beyond current experience, and engineering practices sufficient for dealing with existing climate variability may need to be changed. Safety margins that may have been sufficient under historical conditions may need to be increased to deal with future event frequencies. For example, standards for withstanding an historical 100-year flood are likely to be insufficient for dealing with future floods.

While this report concludes that electric utilities can maintain system reliability in the future, it is important to note that the level of system capacity needed to do so may be difficult to determine and finance. Engineering standards used to set current system capacity levels may need to be revised. Utility commission rate-setting practices for financing new and higher capacity levels may also need to be changed. Thus, adapting to climate change may raise institutional issues related to how researchers measure (a) climate uncertainty and its implications, (b) accepted engineering practices for setting system capacity levels needed to cope with climate change, and (c) utility commission practices for financing infrastructure, given climate uncertainty.

In short, if properly anticipated, climate change-related impacts do not appear to pose a significant risk to the reliability of the electricity infrastructure in California and the San Francisco region. Anticipated impacts of climate change can be addressed with increases in generating, transmission, and distribution capacity, as well as through improvements to equipment design.

In some cases, however, the impacts of climate change may not be so easy to anticipate. It will be difficult for utilities to determine with any precision the level of "excess" capacity" needed to avoid outages given rising climate uncertainty. Similarly, it may be difficult for utility commissions to permit rate hikes needed to finance the required "excess" capacity. Thus, it is not necessarily the impacts themselves, but rather the uncertainty about climate change impacts that may pose the largest challenge to the electricity system. In future work on this topic the

authors strongly recommend that the institutional challenges of climate change be examined along with the scientific and engineering challenges described in this report.

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APPENDIX A:
Literature Review

Climate change affects both energy demand and energy supply through various parameters. These parameters include warmer air and water caused by higher temperatures, changes in flow of rivers, snowfall and ice accretion, coastal inundation, wildfires, soil conditions, cloudiness, and wind speeds. Increases in energy demand and supply loss create a combined problem for ensuring an adequate supply of fuels and electricity. Projections of these parameters, combined with those of energy demand and supply over the next century, are needed to improve understanding of the increased vulnerability of the energy sector. In addition, a detailed physical layout of the various facilities is necessary to understand the exposure of energy infrastructure to the climate-related challenges. Despite a potentially significant impact on energy demand and supply, the international literature base on these topics is very limited, particularly in the developing countries and on the supply component. As a result, this presentation reports on selected international quantitative evaluations of energy demand, qualitative evaluations of energy supply impacts, and related policy implications. Given the limited amount of literature on this subject, the authors discuss an approach that they have used for evaluating the impact of climate change on the California energy demand and supply systems. This method could provide insights and form the basis for "bottom-up" evaluations in other countries.

Table A-1 shows the hydro-meteorological and climate parameters for selected energy uses. This table indicates the various connections between the sets of parameters. For example, changes in air temperature would affect electricity generation efficiency, including that of solar photovoltaic (PV) panels and the demand for cooling and heating. Robust evaluation of energy supply and demand impacts should examine each of the listed parameters while also taking into consideration the interconnections between them. Warmer temperatures may affect generation, transmission, and transformer substations leading to a compounded impact.

Table A-1: Hydro-meteorological and Climate Parameters for Select Energy Uses

Hydro-meteorological and/or climate parameter	Select energy uses
Air temperature	Turbine production efficiency, air source generation potential and output, demand (cooling/heating), demand simulation/modeling, solar PV panel efficiency
Rainfall	Hydro-generation potential and efficiency, biomass production, demand, demand simulation/modeling
Wind speed and/or direction	Wind generation potential and efficiency, demand, demand simulation/modeling
Cloudiness	Solar generation potential, demand, demand simulation/modeling
Snowfall and ice accretion	Power line maintenance, demand, demand simulation/modeling
Humidity	Demand, demand simulation/modeling
Short-wave radiation	Solar generation potential and output, output modeling, demand, demand simulation/modeling
River flow	Hydro-generation and potential, hydro-generation modeling (including dam control), power station cooling water demands
Coastal wave height and frequency, and statistics	Wave generation potential and output, generation modeling, off-shore infrastructure protection and design
Sub-surface soil temperatures	Ground source generation potential and output
Flood statistics	Raw material production and delivery, infrastructure protection and design, cooling water demands
Drought statistics	Hydro-generation output, demand
Storm statistics (includes strong winds, heavy rain, hail, lightning)	Infrastructure protection and design, demand surges
Sea level	Offshore operations, coastal energy infrastructure

Formal analysis of impacts of climate change on energy supply infrastructure is extremely limited. Studies exist for the United Kingdom, Brazil, and the U.S. state of Alaska, and there may be other studies currently being conducted elsewhere. Warmer temperatures may affect generation, transmission, and transformer substations, leading to a compounded impact. Larson et al. (2008) estimated the risk to Alaska public infrastructure and energy systems from climate warming. The model used in this study projected the additional costs of climate change with and without adaptation scenarios within a probabilistic framework.

Lucena et al. (2010) applied an integrated resource planning approach to calculate least-cost adaptation measures to a set of projected climate impacts in 2100 on the Brazilian power sector. The focus of this study was on electricity demand, hydropower capacity factor, and natural gas efficiency. The authors project climate change impacts including increased electricity demand in residential and service sectors (by 6 percent and 5 percent, respectively), and decreased hydropower firm capacity (about 30 percent) and natural gas generation (about 2 percent).

A number of papers discuss how cooling and heating energy use will be affected by projected changes in temperature. Previous analyses of climate impacts on demand has shown that the overall impact of higher temperatures is likely to reduce demand for heating more than the effect of increased cooling load. For example, a recent publication (Petrick et al. 2010) evaluates residential data for 157 countries over three decades and shows that energy use declines due to rising temperatures, indicating that reduction in heating has played a more important role than the increase in air conditioning load. An analysis using the POLES Model for Europe (EU27)

also notes that only a limited literature develops the discussion of these issues, and no definitive conclusions exist about quantified evaluations of these impacts and their respective costs (Mima et al. 2010). This paper estimates that European energy expenditures on supply-side resources will be $65 billion higher in 2100—or 0.08 percent of gross domestic product—in one climate change scenario. Conversely, energy expenditures on the demand side are projected to decrease by $480 billion for heating and increase by $10 billion for cooling. Another paper by Isaac and Van Vuuren (2009) estimates that global heating energy demand decreases by 800–1000 Mtoe while cooling demand increases by 80–100 Mtoe by 2100.

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APPENDIX B:
Methodological Overview

Changing ambient temperatures affect the output capacity of California natural gas-fired power plants (e.g., see Maulbetsch and DiFilippo 2006). In addition to affecting the available capacity of thermal generation, higher ambient temperatures also increase energy losses in electricity transmission and distribution systems (e.g., extreme temperatures affect the electric resistance of transmission line conductors and also decrease the lifespan and capability of substation transformers). This section describes an analysis methodology of the Lawrence Berkeley National Laboratory (LBNL) integrated assessment of the impacts of warming temperatures on electricity generation, transmission, and substations. The methodology is used to estimate capacity reductions for natural gas-fired power plants, transmission lines, and major substations from projected maximum daily ambient temperatures.

In this analysis, one measure of temperature was considered: maximum daily temperature (T_{max}) for the month of August. Daily maximum temperature, T_{max}, was used in this analysis because a power system is often pushed to its operational limit during times of peak load. The maximum ambient temperature represents the moment when weather-related impacts on the power system are typically the greatest (e.g., wildfires, heat-related performance issues) and these impacts almost always occur during times of peak demand (Franco and Sanstad 2008). The combination of the two effects, including: (1) lower peak output from power supply resources, and (2) increased demand for electricity, could be significant for California. This effort involved a number of specific tasks, including: importing infrastructure data from the California Energy Commission, mapping future climate conditions to each location where infrastructure is present, relating projected changes in California's climate to changes in infrastructure performance, interpreting results, and identifying new research opportunities.

Importing Energy Infrastructure Data and Merging Local Maximum Temperature Projections

The first major task in this analysis involved importing a database of California energy infrastructure that contains Energy Commission-compiled technical and location-specific information (e.g., power plant/transmission line/substation location, latitude and longitude, online capacity, type) (personal communication, Jacque Gilbreath, CEC 2009). Next, the location-specific information for California's energy infrastructure with local temperature projections from three Atmosphere-Ocean General Circulation Models (AOGCMs) was merged for a period ranging from 1960 to 2099 and two IPCC SRES scenarios (i.e., A2 and B1). As described earlier in this report, the Scripps Institution of Oceanography provided LBNL with downscaled climate information that was assigned to each unique piece of energy infrastructure.

Quantifying Likelihood of Temperature Projections

Next, a probabilistic modeling approach was undertook that calculated projected climate-related impacts not for a single August daily value of maximum temperature (Tmax), but for a

distribution of possible August daily maximum temperatures. The distributions in this integrated assessment model were created by assigning equal statistical weight[11] to each AOGCM's August daily maximum temperature projection and grouping every annual projection into four distinct time periods: (1) 1961–1990 (base period), (2) 2005–2034, (3) 2035–2064, and (4) 2070–2099. Accordingly, the statistical distributions produced for each time period and scenario combination represent the results of a three AOGCM ensemble of climate simulations at a particular infrastructure location. Figure B-1 depicts the probability density functions—disaggregated by IPCC scenario and time period—for August *maximum* daily temperatures at *all* of the natural gas-fired units analyzed in this study. Figure B-2 depicts the probability density functions—disaggregated by IPCC scenario and time period—for August *maximum* daily temperatures at *all* of the major substations analyzed in this study.

It is well documented that climate change may affect both the mean and statistical distribution properties of climatic variables (e.g., increases in the standard deviation of maximum temperature), which may affect the future likelihood of extreme climate events (Mastrandrea et al. 2009). Furthermore, changes in extremes may not be proportional to changes in average climate (Mearns et al. 1984; Katz and Brown 1994; Tebaldi et al. 2006). The simulated average August daily maximum temperature at all natural gas power plants over the 1961–1990 time period was 31°C (88°F), and the standard deviation was 5.6°C (10°F) for the A2 scenario. For the 2070–2099 time period and A2 scenario, the projected average daily maximum temperature in August increased to 35°C (95°F), and so has the standard deviation (5.9°C, or 10.4°F). Accordingly, there is evidence from this ensemble of climate model simulations that extreme temperature deviations at energy infrastructure locations may become more frequent over the coming decades.[12]

Additional research should be undertaken to improve the temperature likelihood estimation process, including conducting a Monte-Carlo simulation with alternative statistical distributions that are better able to capture the statistical uncertainty inherent in predicting local meteorological measures many decades into the future. Larsen et al. (2008) assume a normal distribution of future temperatures in their integrated assessment model for Alaska infrastructure at risk, but the authors also stress the importance of using alternative uncertainty quantification methods. For example, fat-tailed statistical distributions, including the Weibull, Cauchy, or Gumbel distributions may be more representative of the possible range of future temperature outcomes. In addition, alternative statistical distributions of future temperature (or other climate variables) could be used to estimate the accelerated reduction of useful lifespan (and additional replacement costs) if the likelihood and intensity of extreme events is increased at a given infrastructure location.

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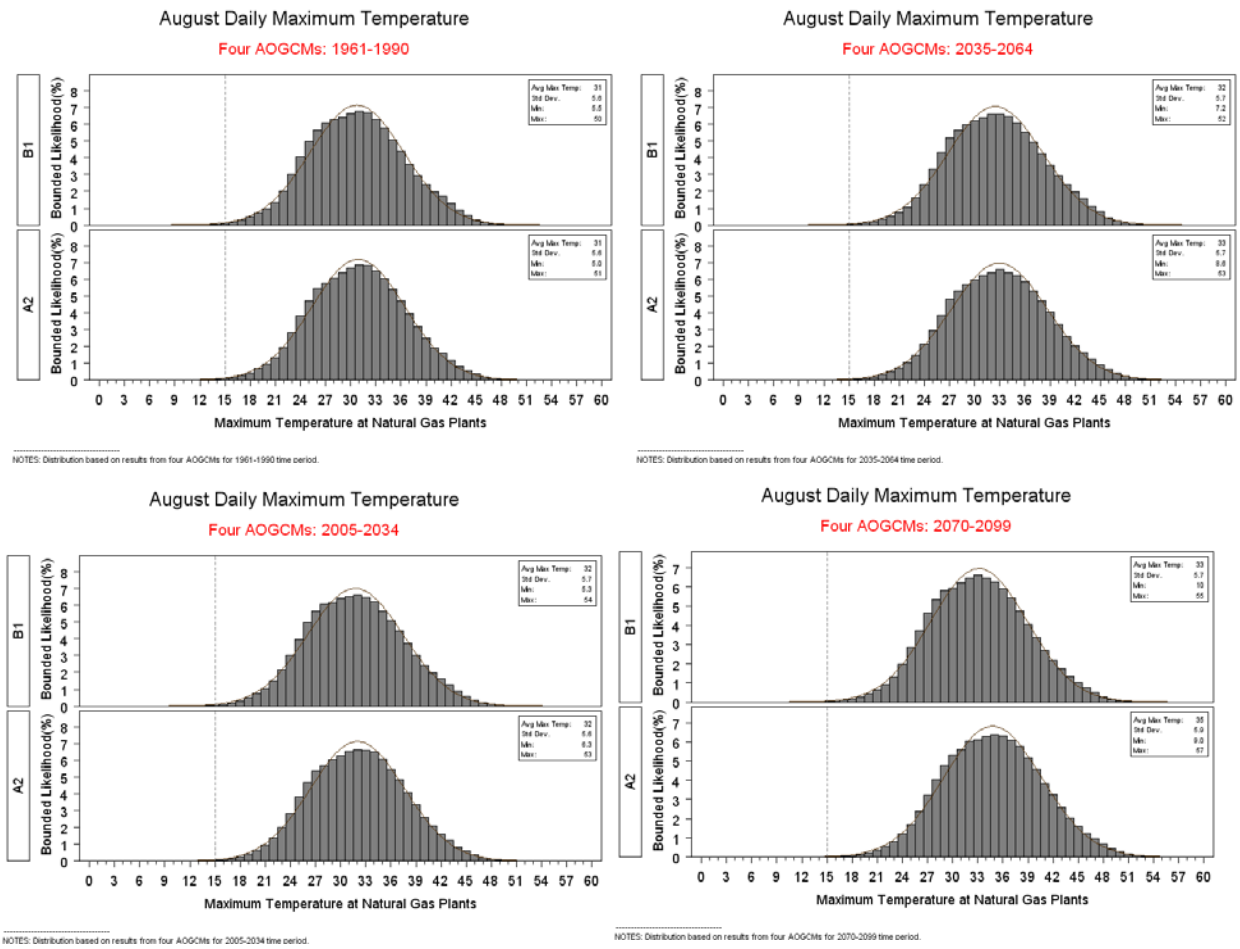
[11] Tebaldi et al. (2005) discuss a Bayesian statistical method to quantify uncertainty from an ensemble of climate models by assigning more statistical weight to those AOGCMs that are relatively more accurate at simulating observed climate conditions for a particular region.

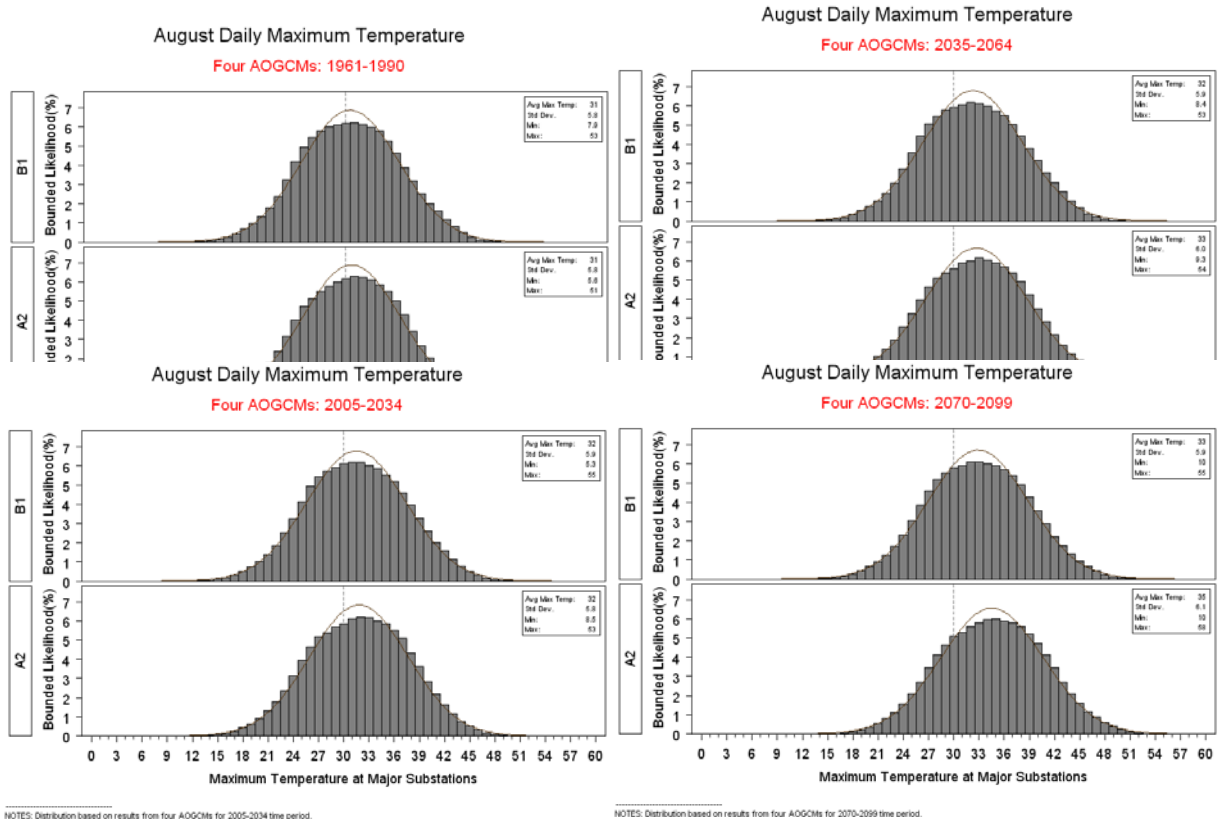
[12] LBNL carried out a Kolmogorov-Smirnov test for normality on the aggregated ensemble of maximum temperature simulations. The null hypothesis of statistical normality was rejected for all time periods analyzed at the 5 percent significance level.

Figure B-1. Projected Range of August Daily Maximum Temperatures at California's Natural Gas-fired Power Plants



Source: Authors

Figure B-2. Projected Range of August Daily Maximum Temperatures at California's Major Substations



Source: Authors

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APPENDIX C:
The Effect of Heat Storms on Electricity Demand

As the climate warms, will more-frequent heat waves cause a disproportionate increase in peak electricity demand? Historical data seem to say no.

With climbing temperatures, peak electricity demand will grow (Auffhammer and Aroonruengsawat 2010; Franco and Sanstad 2008), and the frequency of these peaks will increase as well, following the increased frequency of hot days. But will the increased *juxtaposition* of hot days (i.e., more frequent heat waves) drive the demand peaks even higher? This question does not seem to have been addressed in the literature, although there appears to be a widespread belief that this is true, as suggested by the California Energy Commission definition of "heat storm":

> "Heat storms occur when temperatures exceed 100 degrees Fahrenheit over a large area for three days in a row. Normal hot temperatures cause electricity demand to increase during the peak summertime hours of 4 to 7 p.m. when air conditioners are straining to overcome the heat. If a hot spell extends to three days or more, however, nighttime temperatures do not cool down, and the thermal mass in homes and buildings retains the heat from previous days. This heat build-up causes air conditioners to turn on earlier and to stay on later in the day. As a result, available electricity supplies are challenged during a higher, wider peak electricity consumption period." (CEC 2008)

To study this "heat storm effect," the authors looked at historical data provided by the Sacramento Municipal Utility District—hourly loads and temperatures for the years 1998 through 2009. Surprisingly, the data do not seem to show this effect. There were 17 Energy Commission-defined heat storms during this period, and these are charted below. One would expect to see peak loads increase over the course of these heat spells as the environment and the infrastructure heat up, or increased total energy consumption day-to-day. But this seldom happens. When it does, it is often mingled with one of two other effects: the "Monday effect" and the "Day Two" effect. Commercial and industrial buildings often shut down or decrease their air conditioning over the weekend, and start it up again on Monday, leading to a Monday spike in power consumption. Also, the data seem to show a large growth in power consumption on the second day of a heat storm (4.6 percent average peak load gain), with much smaller growth (little change in peak load and 2.25 percent average daily growth in total generation) after that. Discounting backward causality, it can be assumed that this Day Two effect is characteristic of most temperature spikes, and is not due to the heat storm itself. (A lagged-temperature analysis of the entire dataset should be done to check this.)

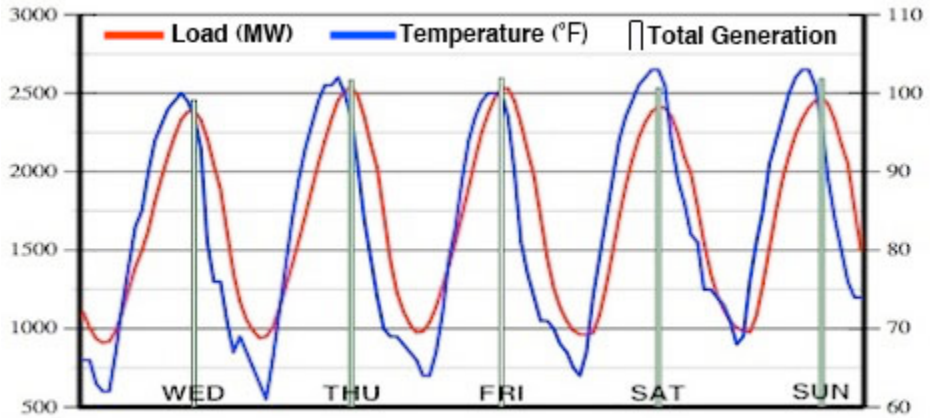
A Heat Storm effect per se—continued significant growth in peak load or total generation as high temperatures persist—is not apparent in the data. It may be worth trying out other definitions of "heat storm" than the Energy Commission definition quoted above to see if these produce a more noticeable effect. (Researchers should also check whether or not load-limiting

policies were in effect during these heat storms, although in that case one would expect to see truncation at the tops of the load curves, and this is not apparent.)

Figures C-1 through C-17, Sacramento Heat Storms 1998–2009

Hourly electrical load is charted in megawatts, along with the temperature in degrees Fahrenheit. The electrical loads have been population-normalized to January 2000 using data provided by the Sacramento Municipal Utility District (SMUD) on the number of connected meters. Total energy generation for each day is shown as a vertical bar with no axis scale, but these are zero-based so they can be compared visually.

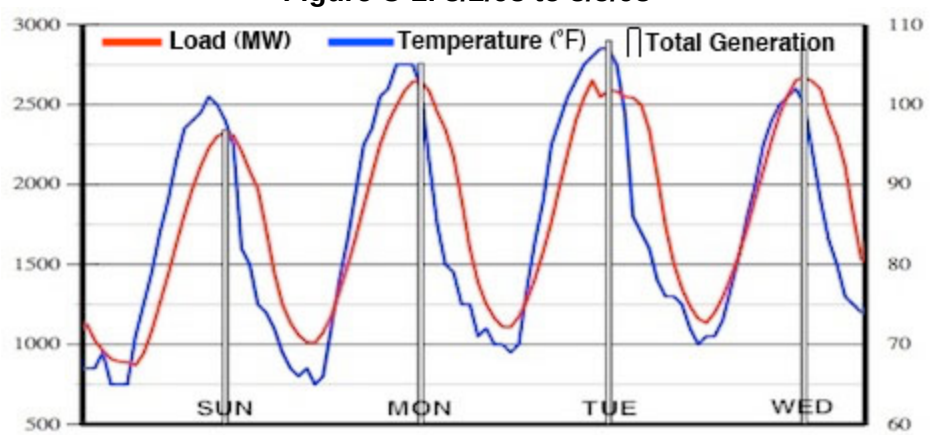
Figure C-1. 7/15/98 to 7/19/98



Source: Authors

6 percent peak load gain and 5 percent total generation gain on Day Two, dropping on Saturday.

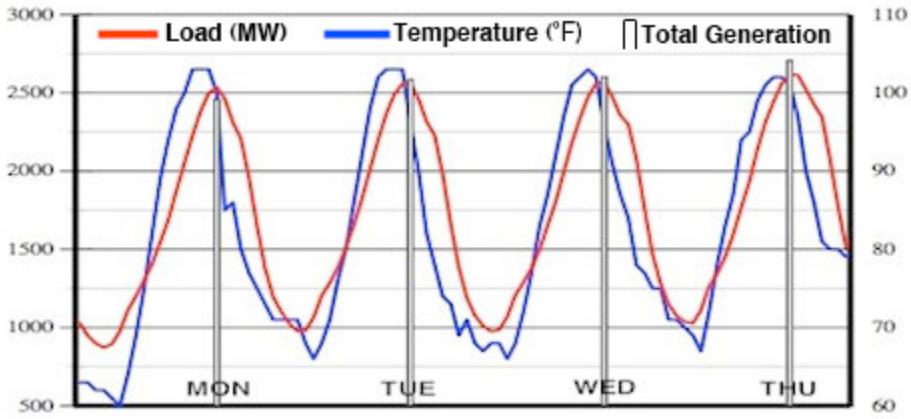
Figure C-2. 8/2/98 to 8/5/98



Source: Authors

14 percent peak gain from Day One to Day Two (but this was a Monday), and no subsequent peak gain. Total generation gain follows the temperature.

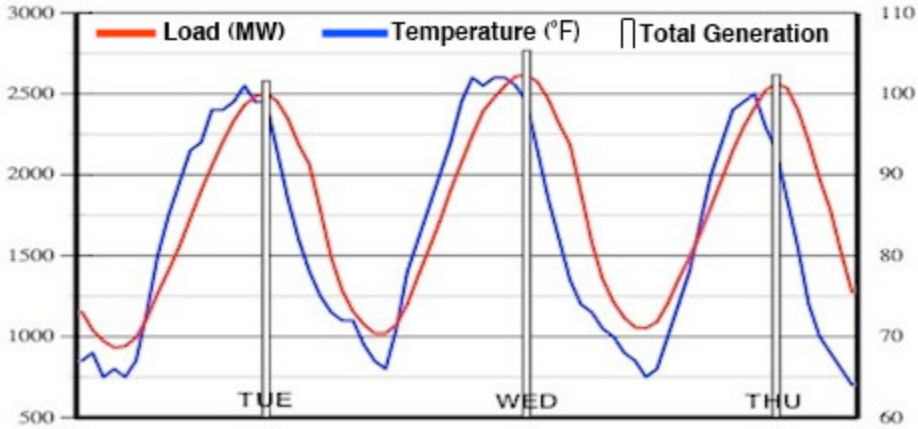
Figure C-3. 8/31/98 to 9/3/98



Source: Authors

Approximately 1.5 percent gains in peak load per day, with an average 3 percent total generation gain.

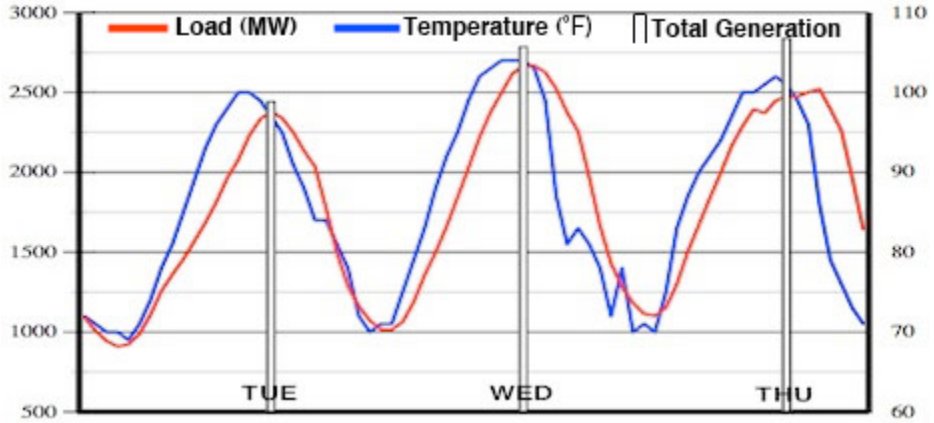
Figure C-4. 6/29/99 to 7/1/99



Source: Authors

4 percent peak load gain on Day Two, but a decrease on Day Three

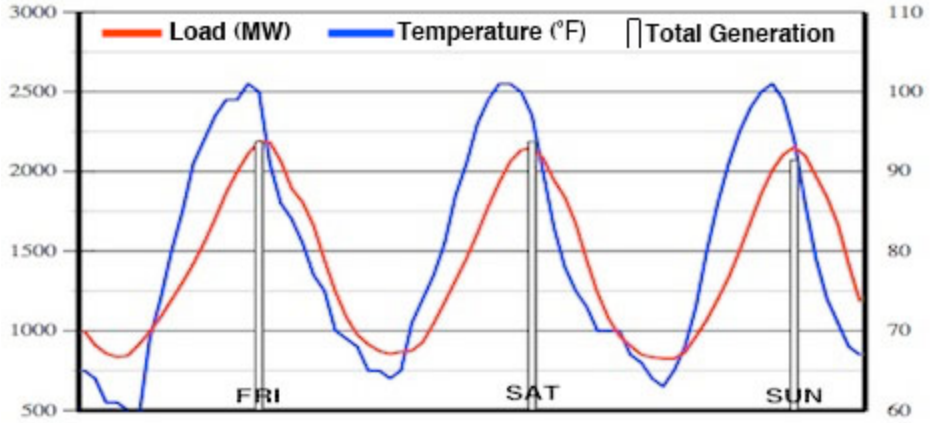
Figure C-5. 6/13/00 to 6/15/00



Source: Authors

12 percent peak load gain on Day Two (coincident with a higher peak temperature), but a decreased peak load after that. Average 8 percent total generation gain.

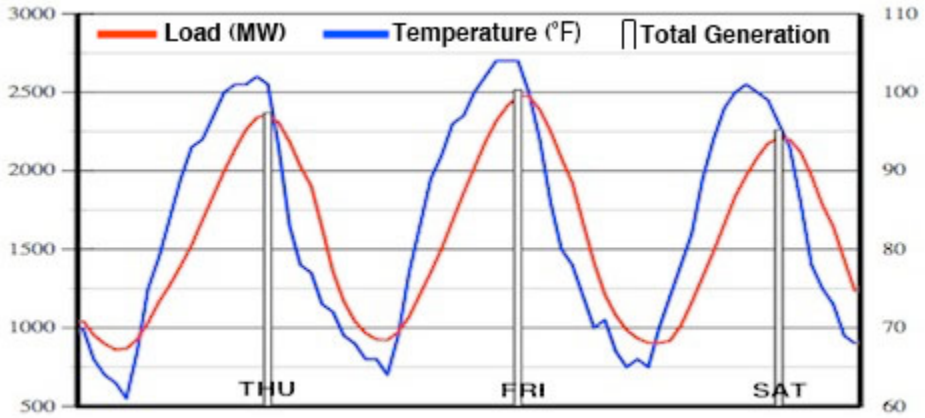
Figure C-6. 8/9/02 to 8/11/02



Source: Authors

The weekend, with no peak load gain or total generation gain during the heat storm.

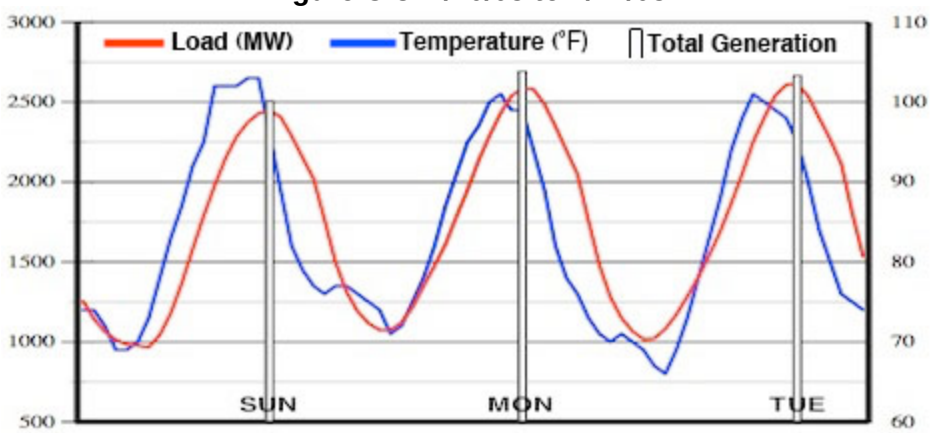
Figure C-7. 6/26/03 to 6/28/03



Source: Authors

5 percent peak load gain and 6 percent total generation gain on Day Two, along with a higher peak temperature, then a substantial decrease on Saturday.

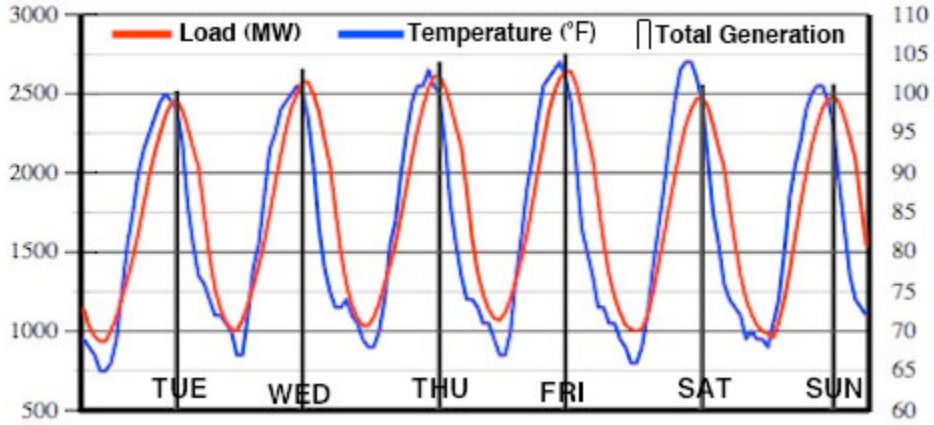
Figure C-8. 7/20/03 to 7/22/03



Source: Authors

5 percent peak load increase on Day Two (but this was a Monday); nothing after that

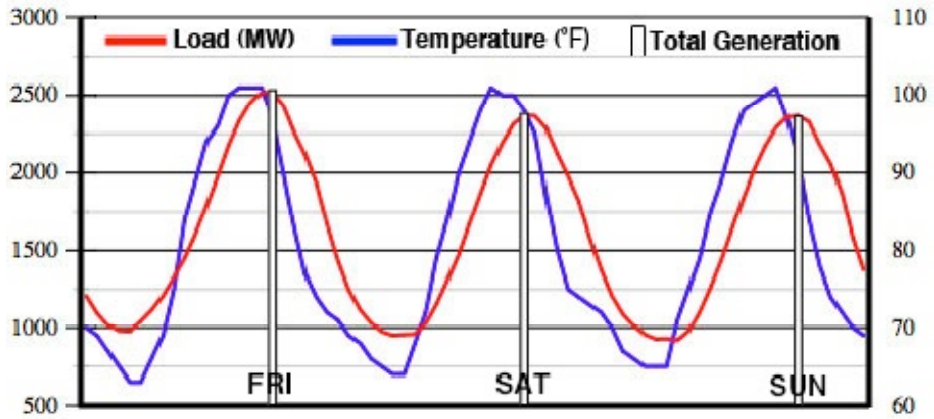
Figure C-9. 7/12/05 to 7/17/05



Source: Authors

3.5 percent peak load gains from Day One to Day Four (coincident with increasing temperatures), along with an average 2 percent gain in total generation, followed by a decreased peak load with no decrease in temperature over the weekend.

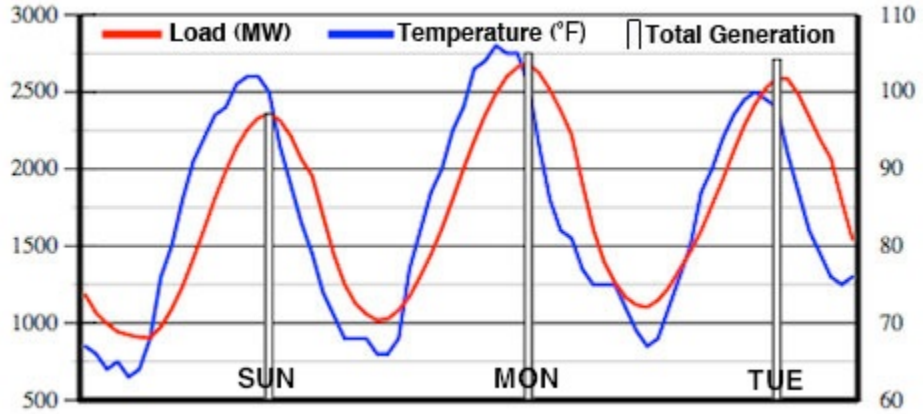
Figure C-10. 8/5/05 to 8/7/05



Source: Authors

Decreasing peak loads and total generation into the weekend

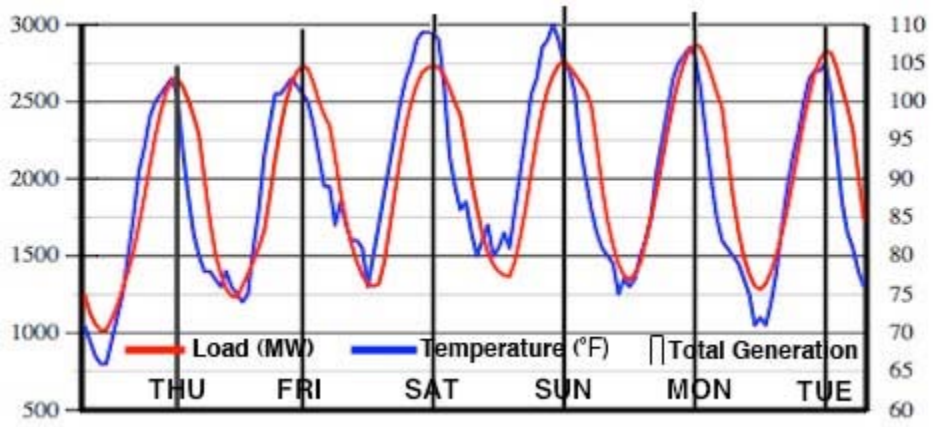
Figure C-11. 7/16/06 to 7/18/06



Source: Authors

14 percent peak load gain on Day Two, but day this was a Monday

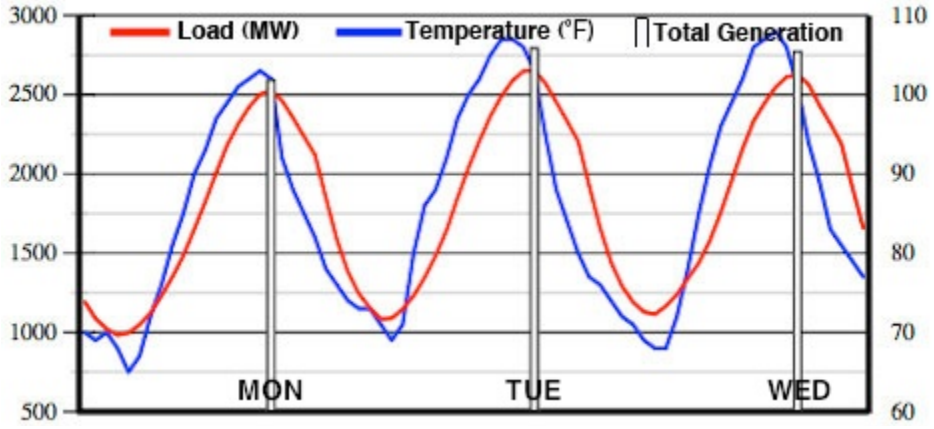
Figure C-12. 7/20/06 to 7/25/06



Source: Authors

3 percent peak load gain on Day Two, and an 8 percent total generation gain. Monday shows a 3.6 percent peak load gain, but a drop in total generation along with a drop in temperature.

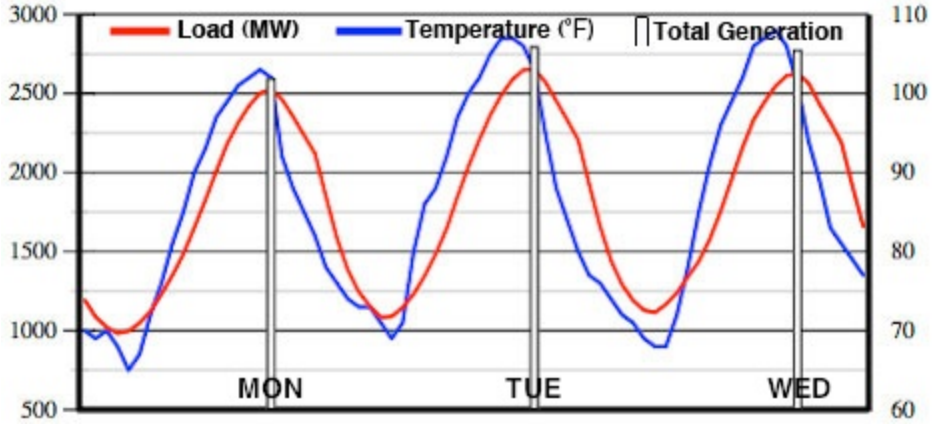
Figure C-13. 7/7/08 to 7/9/08



Source: Authors

2 percent peak load gain and an 8 percent total generation gain on Day Two, coincident with a gain in temperature, but a peak load decrease on Day Three

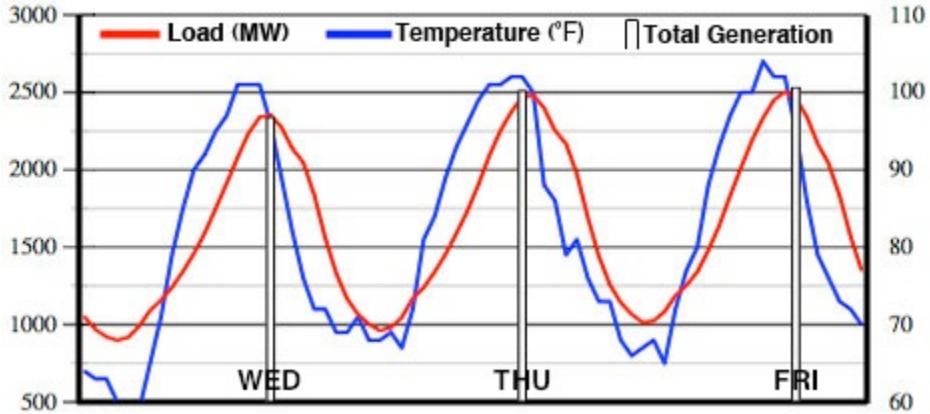
Figure C-14. 8/13/08 to 8/15/08



Source: Authors

1 percent peak load gain and total generation gain on Day Two; a decrease in both on Day Three

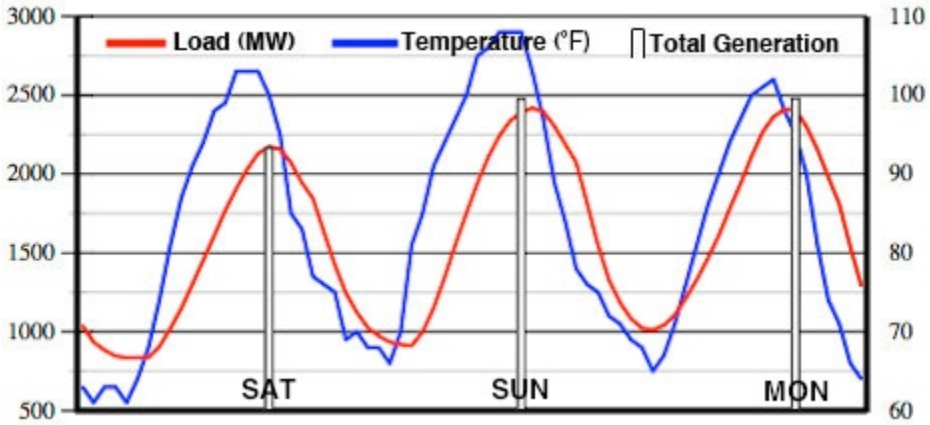
Figure C-15. 8/27/08 to 8/29/08



Source: Authors

5 percent peak load gain and 7 percent total generation gain on Day Two, then steady

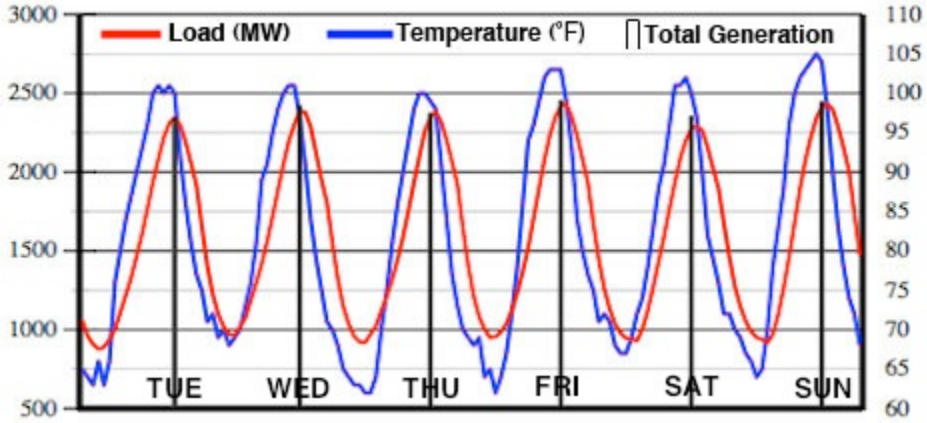
Figure C-16. 6/27/09 to 6/29/09



Source: Authors

11 percent peak load gain and 14 percent total generation gain on Day Two (coincident with a temperature increase). No "Monday effect," although there was a temperature decrease.

Figure C-17. 7/14/09 to 7/19/09



Source: Authors

3.6 percent overall peak load gain, and 4.6 percent total generation gain, through Day Four, decreasing on Saturday

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