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Estimating impacts of warming temperatures on California's electricity system

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ABSTRACT

Despite a clear need, little research has been carried out at the regional-level to quantify potential climate-related impacts to electricity production and delivery systems. This paper introduces a bottom-up study of climate change impacts on California's energy infrastructure, including high temperature effects on power plant capacity, transmission lines, substation capacity, and peak electricity demand. End-of-century impacts were projected using the A2 and B1 Intergovernmental Panel on Climate Change emission scenarios. The study quantifies the effect of high ambient temperatures on electricity generation, the capacity of substations and transmission lines, and the demand for peak power for a set of climate scenarios. Based on these scenarios, atmospheric warming and associated peak demand increases would necessitate up to 38% of additional peak generation capacity and up to 31% additional transmission capacity, assuming current infrastructure. These findings, although based on a limited number of scenarios, suggest that additional funding could be put to good use by supporting R&D into next generation cooling equipment technologies, diversifying the power generation mix without compromising the system's operational flexibility, and designing effective demand side management programs.

1. Introduction

Climate change affects both energy demand and supply through various impacts including: warmer air and water temperatures; changes in snowfall and ice accretion; changes in river flows; coastal inundation; increased wildfire activity; altered soil conditions, cloudiness, and wind speeds. Climate-related impacts to energy systems can affect access, storage, and delivery of fuels as well as the reliability of the electricity system (CCSP, 2007; Lucena et al., 2009, 2010; World Bank, 2011; Karl et al., 2009; Wiser et al., 2011; Schaeffer et al., 2012). Despite a potentially significant impact on energy demand and supply, the literature base on these topics is still limited, but evolving, particularly for the electricity sector. For a comprehensive review of climate change impacts on energy systems, please see World Bank (2011).

IPCC (2011) and Schaeffer et al. (2012) indicated that renewable electricity production may be particularly sensitive to the impacts of climate change. However, performance of thermal power plants also varies according to weather conditions including pressure, air and water temperature, and humidity (e.g., see Kehlhofer et al., 2009). Thermal plant production losses increase when temperatures exceed standard design criteria (e.g., see Erdem and Sevilgen, 2006; Maulbetsch and DiFilippo, 2006). Electricity generation facilities may also be negatively affected by impacts related to extreme weather events, changes in access to cooling water, and inland flooding (Durmayaz and Sogut, 2006; CCSP, 2007; Kopytko and Perkins, 2011). A limited number of studies have discussed the general relationship between temperature and electricity transmission and distribution infrastructure, finding that increased temperatures can accelerate the aging of transformers, lead to efficiency losses, and create power system reliability issues (e.g., Askari et al., 2009; Swift et al., 2001; Li et al., 2005). Despite a clear need, little or no known research has been carried out at the regional-level to quantify potential climate-related impacts to these systems during peak load periods when the system is at its operating limit. This study attempts to fill this gap for the U.S. state of California and proposes a bottom-up methodology that could be applied to other regions.

In California, climate researchers report that average temperatures are expected to warm significantly over the twenty-first

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century, especially in inland areas, and during the summer (Cayan et al., 2009). Researchers also project an increase in the frequency, magnitude, and duration of heat waves (Miller et al., 2007), which can have significant impacts on energy supply and demand.

Changing ambient temperatures affect the output capacity of California natural gas-fired power plants as warmer, less-dense input air decreases the overall efficiency of gas turbines (Maulbetsch and DiFilippo, 2006). In addition to affecting the available capacity of gas-fired power generation, higher ambient temperatures can decrease the carrying capacity of electricity transmission and distribution (T&D) systems and the capacity of the transformers that make up substations. Finally, heat wave conditions often lead to increased consumer demand and, therefore, directly affect the frequency and duration of peak electricity system loads. Climate change may impact other forms of electricity generation in California, including hydropower (e.g. Vicuña et al., 2008 and Hamlet et al., 2009) and wind generation. California has no coal-fired power plants. The vast majority of California's thermal power plants are natural gas-fired (see Sathaye et al., 2012). Accordingly, a major feature of this paper discusses how natural gas-fired generation might be impacted by hotter summer conditions.

The magnitude and timing of these impacts are highly uncertain, vary by region, and depend on the deployment of new technologies (IPCC, 2011; Gellings and Yeager, 2004). Integration of future climate/weather parameters (e.g. high temperature extremes) with spatially-explicit technical information about various energy facilities is important first step to evaluate the overall exposure of energy/electricity infrastructure to climate-related effects. The focus of this analysis is on the possible impacts to California's electricity supply and delivery infrastructure (for the purposes of this study, energy infrastructure includes California's natural gas-fired power generation facilities and electric transmission and distribution system) and consumer demand during peak periods when the system is pushed to its operational limit. It is important to note that this study projects impacts of climate change on the *current* amount and location of energy infrastructure as well as the *current* population of California. Although limited, this type of static analysis is consistent with much of the recent literature on this subject (e.g., see Lehner et al., 2005; Vicuña et al., 2008; Hamlet et al., 2009; Lucena et al., 2009) because it allows researchers to focus on impacts from climate change rather than many other highly uncertain variables (e.g., population growth, technology progress and deployment) that will also change in the future.

The schematic presented in Fig. 1 illustrates analysis stages and procedures for evaluating the entire range of climatic impacts on California's energy infrastructure, where boxes with thicker borders represent analysis components in this study of climate change impacts on California energy infrastructure. Please see Sathaye et al. (2012) for an analysis of additional energy system impacts related to increased incidences of wildfire activity and sea level rise.

The objectives of this study are limited to an: (1) assessment of the possible impacts that increased air temperature may have on the performance of natural gas-fired generation, substations, and major transmission lines and (2) estimate of how higher temperatures might affect peak period electricity demand.

This paper is organized as follows. California's energy infrastructure and peak electricity conditions are discussed in Section 2; Section 3 provides an explanation of the methodological procedures and model assumptions used in this analysis. Section 4

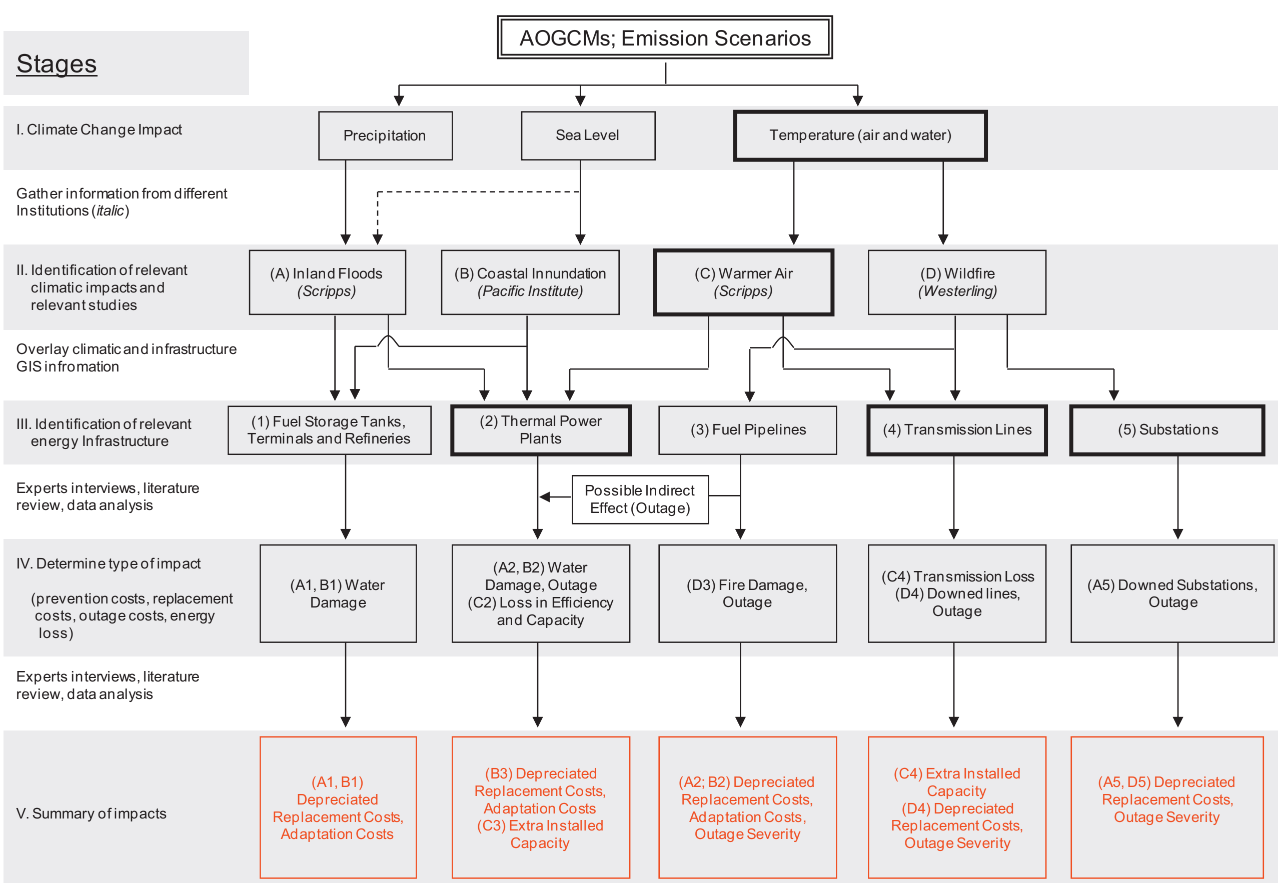

Fig. 1. Stages in the analysis of impacts of climate change on energy infrastructure.

presents our preliminary results. We conclude with a discussion of policy considerations and indentify important future research.

2. California's electricity infrastructure

Fig. 2 is a map depicting the type and location of California electricity infrastructure.

Electricity use typically peaks in California on hot summer afternoons. The routing of electricity throughout California is highly variable and contingent on many factors. The sources of electricity include imports (e.g. hydropower from the Pacific Northwest and fossil fuel-fired thermal power from the Southwest), hydropower (Sierra Nevada mountains), besides coastal nuclear, geothermal, wind, and solar power. Electricity from most power generation facilities is typically carried by larger transmission lines (i.e. 345 kV and 500 kV) to two major regional population centers in Northern and Southern California.

During especially hot periods, the higher capacity, long-distance transmission lines that carry imports and hydropower energy to Northern California population centers can approach their operational capacity limits. Two-thirds of Northern California's needs are drawn from natural gas-fired plants, the rest being obtained by imported power, coastal nuclear plants, Sierra Nevada hydropower, and geothermal (Sathaye et al., 2012).

Southern California transmission lines can also be congested during peak hours, often relying on imports to supply about one-third of regional demand. Hydropower, nuclear, and other generation types make up another 10% of supply. Natural gas-fired power plants, mostly located in the Los Angeles basin, supply much of the remainder of Southern California's power. Southern and Northern California demand centers are surprisingly independent of one another, with little electricity moving north or south. Although we did not evaluate impacts to all of California's electricity system, this analysis evaluated temperature-related impacts at more than 2000 major substations, nearly 400 natural gas-fired power plants, and a hypothetical transmission line.

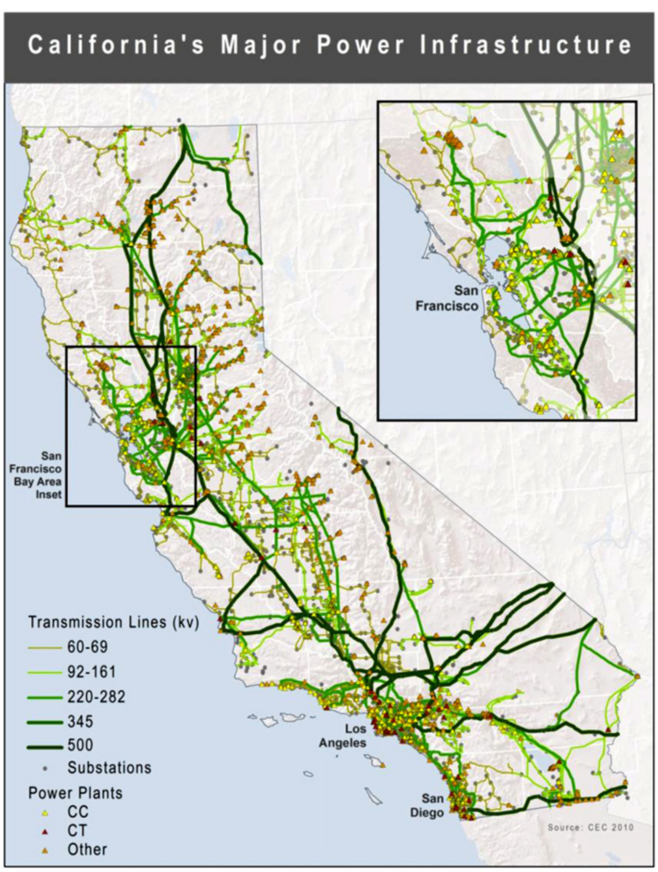

Fig. 2. California's electric power infrastructure. Note: "CC" refers to combined cycle natural gas-fired power plants; "CT" refers to simple cycle combustion turbine natural gas-fired power plants.

3. Methodology

We began our analysis by collecting: (1) projections of future climate change generated by Atmospheric-Ocean General Circulation Models (AOGCMs) and (2) detailed information about California's electricity infrastructure.

AOGCMs are numerical simulation models that generate projections of future climate variables under different scenarios of atmospheric greenhouse gas emissions concentrations. For the purpose of this study, we limited our analysis of impacts on electricity infrastructure to one important climate variable: surface air temperature in the warmest month of August. The AOGCMs and emission scenarios used in this study are consistent with those used in other studies for California (e.g., see Cayan et al., 2009; Westerling and Bryant, 2008; Westerling et al., 2009; Heberger et al., 2009) and include the GFDL (Geophysical Fluid Dynamics Laboratory), PCM1 (Parallel Climate Model), and CNRM (Centre National de Recherches Météorologiques) models. The emission scenarios we evaluated include the A2 and the B1, as defined by the Intergovernmental Panel on Climate Change Special Report on Emission Scenarios (SRES) (IPCC, 2000), The A2 SRES scenario generally assumes higher GHG emission levels than the B1 SRES scenario. The two emission scenarios and three AOGCMs allowed us to evaluate a total of six different future climate projections in this study. These AOGCMs results were downscaled to a cell size of 1/8° latitude and longitude by the Scripps Institution of Oceanography using the Bias Correction and Spatial Downscaling (BCSD) algorithm (Maurer and Hidalgo, 2008). Although there are other downscaling techniques (e.g., dynamic downscaling using regional climate models), the data from Scripps was readily available, encompassed a broader range of GCMs and was consistent with other studies conducted for California (Cayan et al., 2009; Westerling and Bryant, 2008; Westerling et al., 2009; Heberger et al., 2009).

The California Energy Commission (CEC) provided us with locations of California's electricity infrastructure. Next, we used a Geographic Information System (i.e., ArcGIS 9.3) to geographically intersect local temperature projections with specific power plants and substations for each day in August between 1960 and 2099. However, computational limitations and other factors hindered our ability to merge high-resolution temperature projections with individual transmission and distribution infrastructure (see Section 3.2).

In this study, we used a base period of 1960–1990 to compare future climate conditions and assess the impacts on energy infrastructure performance. In other words, future infrastructure impacts are estimated by evaluating the incremental variations in August high temperature in relation to a base period (1961–1990).

Like many other regions at this latitude, peak load in California's power system coincides with hotter weather. During times of peak demand the state's electrical grid can be pushed to its operational limit. At the same time, high temperatures can lead to additional impacts on the supply-side of the power system (e.g. wildfires, heat-related performance issues) (Westerling et al., 2009; Franco and Sanstad, 2008). Only one measure of temperature was considered – *daily maximum temperature for the month of August* – – because the climate impacts evaluated in this paper are related to peak load periods. August is, on average, the warmest month in California. Therefore, evaluating maximum temperatures from this month should be a relevant proxy for the time when the state's electrical grid will be most susceptible to warmer temperatures. We acknowledge that increasing temperatures would also affect the power system during other times of the year, especially during the spring when projected climate change may also be significant. However, the focus of this paper is to model possible impacts during peak load conditions, which coincides with the hottest climate month across California—August.

It is documented that climate change may affect both the mean and statistical distribution properties of climatic variables, which may affect the future likelihood of extreme climate events (Mastrandrea et al., 2009). Moreover, changes in extremes may not be proportional to changes in average climate (Mearns et al., 1984; Katz and Brown, 1994; Tebaldi et al., 2006). Therefore, we undertook a probabilistic modeling approach to calculate projected climate-related impacts not only for a single August daily value of maximum temperature ($T_{\max}$), but for a distribution of possible August daily maximum temperatures. The distributions in this integrated assessment model were created by assigning equal statistical weight to each AOGCM's August daily maximum temperature projection and grouping every annual projection into two distinct time periods: (1) the base period (1961–1990) and (2) the future (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. 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. However, we did not have access to such information. Figs. 3 and 4 exemplify the methodology by depicting the likelihood of August daily maximum temperatures at California's major substations for both time periods. For a detailed description of this methodology, please see Sathaye et al. (2012). These figures show that the scenarios project an average increase in maximum temperature at California substations of 2–4 °C by the end of the century. The paper presents end of century estimates, which give a clearer picture of the effects of climate change than mid century estimates. In general, the projected mid century impacts tend to be slightly less than half the projected end of century impacts.

We used these temperature projections to estimate impacts for natural gas-fired power plant capacity, transmission line carrying capacity, substation/transformer capacity, and peak demand. The combination of lower peak output from generation resources and

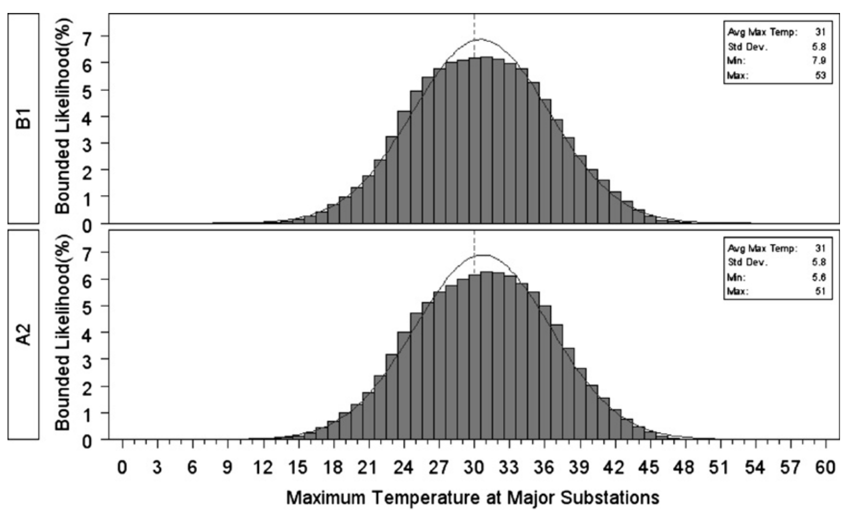

Fig. 3. Range of August daily maximum temperatures at California's major substations (°C): 1961–1990.

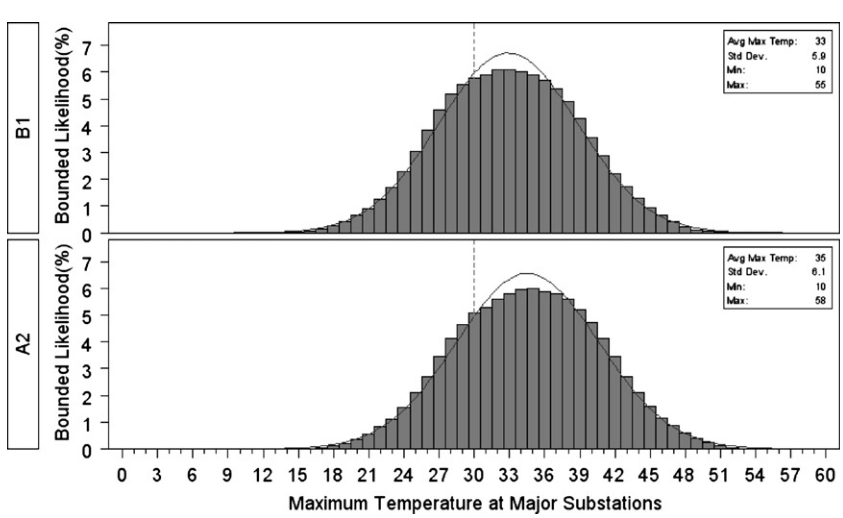

Fig. 4. Range of August daily maximum temperatures at California's major substations (°C): 2070-2099.

increased demand for electricity could be significant for California and may affect the overall reliability of the state's power system. Therefore, the cumulative effects of temperature-induced losses were also examined by combining more than one impact at the same time.

An important caveat should be noted here. We assumed that a majority of the current energy system will still be operating if these climate projections materialize. This is a plausible assumption for long lasting facilities which often operate for decades beyond their designed lifespan. However, for shorter lifespan technologies, we assumed that the facilities would eventually be replaced by similar technologies at the same location, which might not be the case. Assuming the same location for energy infrastructure is a necessary premise, because there is no way to predict where new infrastructure will be sited. Furthermore, it is reasonable to assume that many of these sites will continue to be used for the same purpose, because of existing access to transmission and distribution infrastructure. Clearly, adaptation measures and technical advances could offset some (or all) of the modeled impacts. Also, climate change mitigation policies could also induce changes in the future mix of power generation technologies and customer demand (e.g., higher penetration of renewable sources, increased deployment of electric vehicles).

Although we cannot predict what the mix of California's power system will look like by the end of the century, we can analyze the impacts of climate change based on current demand and existing technologies. This type of analysis allowed us to focus on the possible impacts from climate change rather than on the other highly uncertain variables. We believe the methodology used here can provide important insights into the impacts of climate change on similar power systems operating under similar conditions.

3.1. Projecting impacts to natural gas-fired power plant capacity

Kehlhofer et al. (2009) discusses three reasons that cause ambient air temperature to influence 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, consequently reducing mass flow.

Previous studies have quantified relationships between air temperature and gas-fired generation efficiency and capacity (Maulbetsch and DiFilippo, 2006; Kehlhofer et al., 2009; Tolmasquim et al., 2003; Arrieta and Lora, 2005). The relationship between temperature and natural gas power plant performance varies across different empirical studies, types of natural gas power plants, cooling equipment installed at the plant, and geographic region. 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 range of current or future temperatures. In this study, two basic categories of natural gas power plants were considered: simple-cycle combustion turbines (CT) and combined-cycle combustion turbines (CC). These plants are typically used to provide electricity during intermediate and peak load conditions. Fig. 5 depicts the 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 15 °C as the reference point for 100% turbine capacity, which is the most prevalent factory specification for these types of plants.

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–Fig. 5). On average, the authors found that combined-cycle power plant capacity can change by approximately 0.3–0.5% for each degree change above 15 °C. Maulbetsch and DiFilippo (2006) also 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% per degree change in ambient temperature. In the present study, we did not obtain information describing the type of cooling equipment currently installed at California power plants. Future research into this topic should consider assumptions about current and future configurations of power plant cooling equipment. 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 (SWRCB, 2012). Accordingly, the analysis conducted in this paper assumed that all natural gas-fired power plants responded to ambient temperature changes as if they were all using air-based cooling technologies.

We were unable to find a similar study to Maulbetsch and DiFilippo (2006) for non-combined-cycle gas turbines that specifically focused on California. Kehlhofer et al. (2009) showed that the average simple-cycle combustion turbine is more sensitive to changes in ambient temperature relative to combined-cycle plants (Fig. 5), but aside from a simple graphical depiction, there was no mention of the exact quantitative relationship they calculated for combustion turbines. The results found in Maulbetsch and DiFilippo (2006) were less sensitive to temperature changes when compared to 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.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% per degree Celsius above 15 °C. For example, a 500 megawatt (MW) simple-cycle unit located in a place with a projected average daily maximum temperature of 20 °C would have its nominal capacity reduced by 25 MW during this time

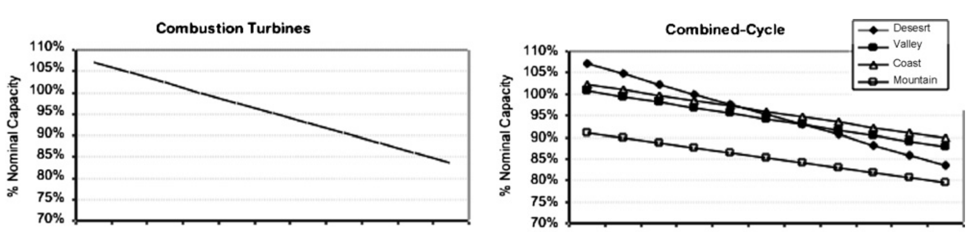

Fig. 5. Change in turbine capacity as a function of ambient temperature (adapted from Kehlhofer et al., 2009 and Maulbetsch and DiFilippo, 2006).

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	15 °C (59 °F)	15 °C (59 °F)
Change in plant capacity for each degree above 15 °C	−0.7%	−1.0%
Future climate likelihood statistical distribution source	Ensemble of three AOGCMs per IPCC emission scenario per time period	Ensemble of three AOGCMs per IPCC emission scenario per time period
Future type of cooling equipment installed at each natural gas plant	Air-cooled	Air-cooled
Aggregate nameplate capacity of plants analyzed	26,245 MW (340 plants)	17,849 MW (51 plants)
Future growth of generation capacity	Not considered	Not considered
Increase capacity when ambient temperatures are less than 15 °C?	No	No

period (from 500 MW to 475 MW). Table 1 lists the general assumptions used in this paper for estimating the potential losses to natural gas-fired power plant capacity from projected climate change.

3.2. Projecting impacts to transmission line carrying capacity

It is documented that transmission conductor temperature is sensitive to ambient air temperature (e.g., IEEE, 2007). Higher air temperatures decrease radiative cooling, which in turn requires current reduction to maintain a safe conductor temperature, thus decreasing the carrying capacity of the line. Additional transmission capacity may be required to overcome this effect.

The IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors (IEEE, 2007) presents a heat balance methodology for modeling transmission line temperature and current under different ambient weather conditions. The basic heat balance is described in equation (1) below (IEEE, 2007):

$$\text{Current heat gain} + \text{Solar heat gain} = \text{Radiative heat loss} + \text{Convective heat loss} \quad (1)$$

The four components of this equation are related to ambient conditions by equations of varying complexity (IEEE, 2007) such that closed-form solutions are generally not possible. But iterative solutions are feasible, so we developed a basic transmission line model that enables us to explore the effects of rising temperatures. Table 2 lists the general assumptions used in our estimate of the potential capacity losses to typical types of transmission lines from projected climate change. We did not attempt to evaluate potential impacts related to changes in future wind speeds.

3.3. Projecting 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 (Lesieutre et al., 1997; Swift et al., 2001; Li and Zielke, 2003; Li et al., 2005; 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 capacity rating is designed for (typically 30 °C). 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. For instance, a 30 °C ambient temperature approximately corresponds to a 120 °C hot spot conductor temperature at a typical transformer (Lesieutre et al., 1997). 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 (Lesieutre et al., 1997). Ambient temperature-induced losses to capacity or an increased rate of failure of substations can lead to power system reliability issues and possibly blackouts.

Previous studies have quantified the general relationship between air temperature and transformer lifespan and capacity (Swift et al., 2001; Li et al., 2005). As was the case with natural gas-fired power plants, the relationship between ambient temperature and transformer (substation) performance varies across different empirical studies, size of substation, geographic region, and other factors. 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), for example, report decreased transformer capacity of approximately 0.7% 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 Fig. 6).

Unfortunately, information for 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 was not available. Therefore, this

Table 2
Key assumptions for transmission analysis.

Assumption	Transmission Line
Current–temperature relationship	See IEEE (2007)
Typical line design temperature (maximum normal operating temperature)	80 °C
Typical emergency operating temperature	100 °C
Typical operating wind speed perpendicular to conductor	0.61 m/s
Future August maximum temperature	Ensemble of three AOGCMs per IPCC Scenario per time period
Future growth of new transmission capacity	Not considered
Increase carrying capacity when ambient temperatures are less than 80 °C?	No

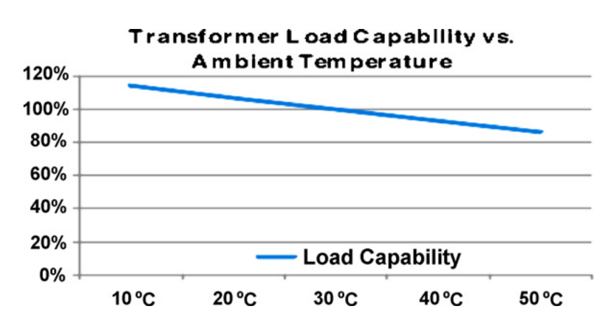

Fig. 6. Change in transformer capacity as a function of ambient temperature (adapted from Li et al., 2005).

Table 3
General substation capacity model assumptions.

Assumption	Major substations
Relationship between substation capacity and temperature	Linear
Temperature beyond which substations begin to lose potential capacity	30 °C
Change in substation capacity for each degree above 30 °C	−0.7%
Future climate likelihood statistical distribution source	Ensemble of three AOGCMs per IPCC emission scenario per time period
Current or future type of cooling equipment installed at each substation	Unknown
Number of substations analyzed	2530
Actual substation rating (kVA or kV) and typical historical loading	Unknown
Increase capacity when ambient temperatures are less than 30 °C?	No
Future growth of new substation capacity	Not considered

preliminary impact analysis was limited to changes in the percentage of substation capacity and assumed that all substations had equal sensitivity to changing ambient temperatures. Table 3 lists the general assumptions used in the estimate of the potential changes to substation capacity from projected climate change.

3.4. Projecting impacts to peak demand

Franco and Sanstad (2008) provide an overview and a methodology for forecasting demand applied to four urban areas in California (San Jose, Sacramento, Fresno, and Los Angeles). This study used a similar methodology, but applied it across the entire state. Other studies have also analyzed the influence of increasing temperature on energy demand in California (see Miller et al., 2007; Aroonruengsawat and Auffhamer, 2009).

The first step in estimating future demand involved collecting actual statewide hourly load data for the years 2003–2009, for which historical load data was uniformly available (Ventyx, 2010). Next, we normalized the hourly load data to per-capita by using population information from the California Department of Finance (CDF, 2010). The daily maximum loads, divided by the population, were used to derive the daily per-capita peak demand. This information was spatially intersected with temperature information for major population centers chosen from the California Irrigation Management Information System (CIMIS) database (CIMIS, 2010). We used this relationship – along with the downscaled AOGCM temperature data at each weather station – to project the statewide per-capita peak demand for every day from 2070–2099.

A simple regression correlating temperatures above 25 °C against statewide peak load produced a good fit (i.e. r-squared of 0.82). Temperature data specific to major population centers were weighted to estimate average statewide temperatures. These weights were determined by a multiple regression on the 2003–2009 actual data. Fig. 7 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.

4. Results

All results presented in this section are dependent on the climate scenarios used and other important assumptions described in this paper. Climate change impact assessments lie at the end of a chain of cumulative and compounding uncertainties. The uncertainties in our estimates are initially based on uncertain pathways of greenhouse gas emissions and any corresponding temperature response at the local level many decades in the future. In addition, there is uncertainty embedded in our modeling assumptions about energy infrastructure. Schneider (1983) describes this process as the “cascading pyramid of uncertainties”. For these reasons, it is important that the results presented here are viewed as a one scenario of the future rather than explicit predictions.

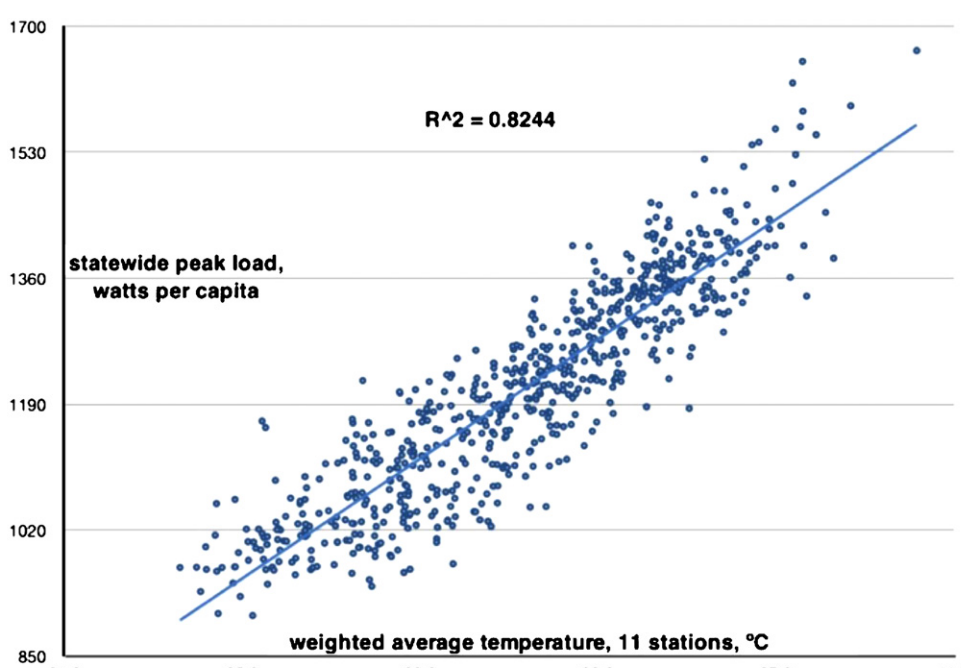

Fig. 7. Weighted average temperatures from the 11 CIMIS stations versus actual statewide per-capita peak load: 2003–2009.

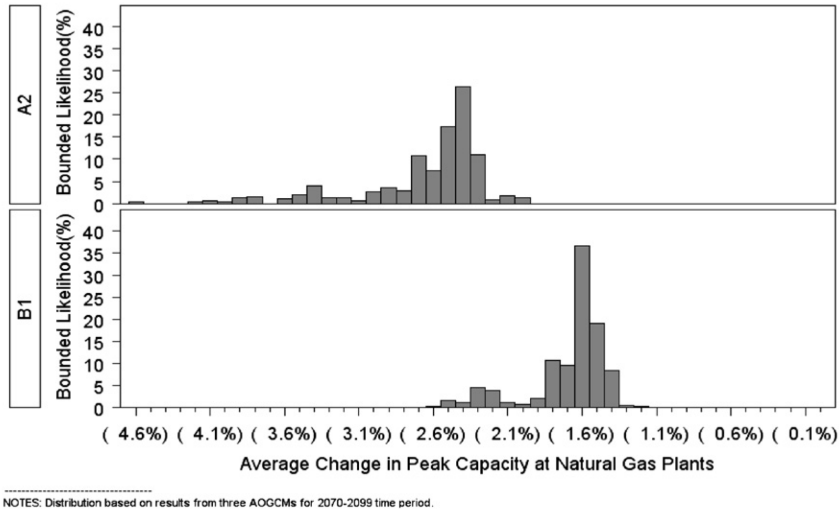

Fig. 8. Losses in peak nameplate capacity at california natural gas-fired power plants: 2070–2099.

4.1. Impacts to natural gas-fired power plant capacity

Fig. 8 shows a histogram of possible future changes in capacity for all California natural gas-fired units analyzed in this study, taking into account (A) different loss coefficients for combined-cycle and simple cycle natural gas-fired power plants and (B) temperature projections at each plant. Our modeling results suggest that natural gas-fired power plants across California could lose between 1.1–2.7% peak capacity by the end of the century under the B1 emissions scenario and 2.0%–4.6% under the A2 emissions scenario.

Table 4 presents the total modeled capacity losses (in MW) due to higher temperatures at California gas-fired power plants using daily modeled temperature data at the location of each plant based on the A2 and B1 scenarios. Both CT and CC plants are evaluated, assuming that the former lose 1% of peak capacity per °C rise and the latter lose 0.7% of peak capacity per °C rise over 15 °C, assuming the technical characteristics of existing natural gas-fired power plants. The average change in peak capacity results from the scenario projections for rise in the average daily maximum August temperature between the base period and the end of the century. The maximum change in peak capacity was modeled using the maximum temperature scenario projection for August. Table 4 summarizes the modeling results for coincident end-of-century power plant capacity loss, showing the maximum loss summed over all the state's power plants at the same time.

For each day of time period, we summed the losses across all the state's power plants, referring to this as the coincident statewide peak capacity loss. In Table 4, "Δ loss" is the additional peak capacity that California natural gas-fired power plants would need to supply in order to maintain the same level of service throughout 2070–2099 when compared to the base period (1961–1990) assuming no growth in demand. Using the A2 and B1 scenarios, the three AOGCMs, and limiting our analysis to weekdays, it is modeled that the maximum coincident loss would increase up to 2.7 GW in the warmest scenarios. For perspective, this increased loss is equivalent to ~6% of California's total current natural gas-fired nameplate capacity.

During peak load periods reserve margins are low and natural gas power plants are running near full capacity. 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 reliably respond to peak consumer demand.

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 in anticipation of future losses. Furthermore, as was pointed out in the previous section, we did not attempt to forecast new natural-gas fired capacity (or any other generation source) that may occur over the coming decades.

4.2. Impacts to transmission line carrying capacity

The transmission line modeling results indicate that a 5 °C increase in ambient air temperature (the average increase projected by the 3 AOGCMs used in this study for hot days in August by the end of the century) has a very slight effect on

Table 4
Maximum and average coincident statewide peak capacity loss (weekdays) at natural gas-fired power plants.

A2 scenario	1961–1990	2070–2099	Maximum Δ loss
Maximum coincident daily loss (Gigawatts)			
All AOGCMs A2	7.577	10.305	2.728
GFDL A2	6.6	8.63	2.030
CNRM A2	7.577	10.305	2.728
PCM1 A2	6.819	7.479	0.660
B1 scenario	**1961–1990**	**2070–2099**	**Maximum Δ loss**
Maximum coincident daily loss (Gigawatts)			
All AOGCMs B1	6.289	8.096	1.807
GFDL B1	6.289	8.096	1.807
CNRM B1	6.03	7.811	1.781
PCM1 B1	5.605	7.859	2.254
A2 scenario	**1961–1990**	**2070–2099**	**Average Δ loss**
Average daily loss (Gigawatts) (σ = standard deviation)			
All AOGCMs A2	5.207 (σ = 0.636)	6.486 (σ = 0.784)	1.279
GFDL A2	5.146 (σ = 0.546)	6.742 (σ = 0.634)	1.596
CNRM A2	5.216 (σ = 0.759)	6.773 (σ = 0.848)	1.557
PCM1 A2	5.259 (σ = 0.578)	5.942 (σ = 0.527)	0.683
B1 scenario	**1961–1990**	**2070–2099**	**Average Δ loss**
Average daily loss (Gigawatts) (ó = standard deviation)			
All AOGCMs B1	5.157 (σ = 0.571)	5.975 (σ = 0.677)	0.818
GFDL B1	5.131 (σ = 0.562)	6.289 (σ = 0.639)	1.158
CNRM B1	5.161 (σ = 0.543)	6.030 (σ = 0.616)	0.869
PCM1 B1	5.181 (σ = 0.607)	5.605 (σ = 0.593)	0.424

Note: GFDL – Geophysical Fluid Dynamics Laboratory; PCM1 – Parallel Climate Model; CNRM – Centre National de Recherches Météorologiques

Table 5
Conductor temperature and line loss under high temperature conditions.

Ambient conditions	Conductor temperature (°C/°F)	Full line loss per mile (kW)	Percent loss in capacity for a 75-mile line	Change (%)
Temp. = 38 °C; wind speed = 0.61 m/s	84.8/184.6	338.4	7.05	Δ = 0.14
Temp. = 43 °C; wind speed = 0.61 m/s	90.0/194	345.1	7.19	
Temp. = 38 °C; wind speed = 0.00 m/s	112.5/234.5	373.8	7.79	Δ = 0.14
Temp. = 43 °C; wind speed = 0.00 m/s	117.8/244	380.5	7.93	

Note: the technical parameters of the sample line are described in IEEE (2007).

resistive losses for a typical 230 kV transmission line operating near its rated capacity (see Table 5). Although these results apply to a sample 230 kV transmission line, we can extrapolate our results to different lines. Increased *resistive losses* in transmission lines – due to increased temperatures – is not expected to become a significant issue over the remainder of the 21st century.

However, it is important to assume that transmission line operators will continue to avoid damaging their lines by reducing the current necessary to keep the steady-state conductor temperature at the design limit of approximately 80 °C. In this case, the *capacity loss* (as opposed to the resistive loss) could be more significant. Table 6 presents capacity loss estimates for a number of transmission lines. After we determined the current that would produce an 80 °C conductor temperature, the resulting conductor capacity was calculated using equation (2) (see IEEE, 2007):

$$\text{Conductor capacity} = (\sqrt{3}) \times (\text{current}) \times (\text{voltage}) \times (0.95\,\text{power factor}) \quad (2)$$

The modeling results presented in Table 6 indicate that, under the operating scenario, operative capacity losses could be significant, amounting to an additional 7–8% of peak capacity when air temperature increases by 5 °C.

However, these results assume that all grid segments are affected equally by the increased temperature. The California Independent System Operator (ISO) may attempt to reroute power around fully loaded lines, and if this becomes impossible, they may choose to impose brownouts rather than allow damage to transmission lines and conductors. This potential for climate-change induced line capacity losses should be further researched, including identification of loss minimizing operating practices and new design parameters (e.g. underground transmission lines).

Table 6
Ambient temperature and conductor capacity loss.

Conductor type and voltage	Air temperature (wind speed = 0.61 m/s) (°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: we held the conductor temperature constant at 80 °C by reducing the line's current. These calculations were based on information from the IEEE (2007), with the following assumptions: wind speed = 0.61 m/s perpendicular to the conductor; emissivity = 0.5; absorbtivity = 0.5; solar flux = 1030 W/m^2; latitude = 34°; and with a conductor resistance as quoted by the manufacturer.

It is important to note that the increases in conductor temperature reported in Table 6 assume 0.61 m/s wind conditions. Utilities generally count on the presence of at least 0.61 m/s of wind on hot days. If a zero-wind condition should happen during extremely high temperatures, conductor temperatures may rise into the "emergency" range (i.e. above 100 °C), where continued operation may cause excessive conductor sag, permanent damage, and even lead to fires. Further investigation into the effects of climate change on the probability and duration of no-wind conditions on hot days is necessary to evaluate the impacts on transmission capacity.

4.3. Impacts to substation/transformer capacity

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 were modeled 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 for a given climate scenario.

Fig. 9 shows a probability density function (histogram) of additional future changes in capacity for all California substations that we analyzed in this study. Our model results indicate that substations across the State of California could lose an additional 1.0–3.6% by the end of the century – depending on the climate scenario. It is important to note that these results 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, 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 high ambient temperatures.

An analysis of California regions found that 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. This results from the fact that the AOGCMs project the largest temperature changes for Eastern California and foothills of the Sierra Nevada. Peak load capacity of substations along the coast and in the San Francisco region may decline somewhat less than peak load capacity of substations in California's inland areas (Sathaye et al., 2012).

4.4. Temperature-induced peak demand impacts

To the best of our knowledge, there is no single reliability standard to which California utilities adhere, but most utilities appear to plan for a "1-in-10" (90th percentile) forecast within their own supply capacity, leaving the most extreme peak load scenarios to be addressed by imported power, reserve margins, demand-response, or in rare cases – rolling blackouts. In its revised

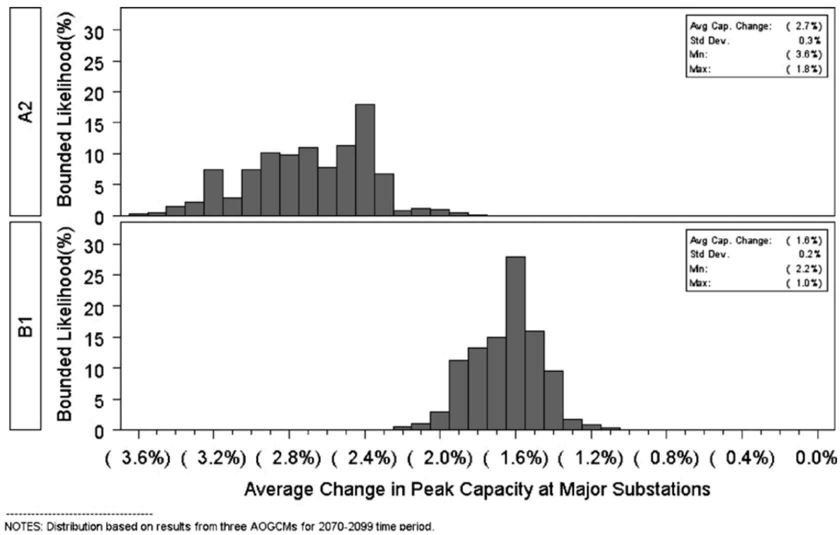

Fig. 9. Average change in peak capacity at California substations (2070–2099).

short-term peak load forecast document, the California Energy Commission presents 1-in-2 and 1-in-10 forecasts (CEC, 2010). In summary, the CEC projects 90th percentile per-capita peak loads to increase 10–20% by the end of the century due to the effects of climate change on summer weekday afternoon temperatures. These projections are similar to projections 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% under the A2 scenario.

We used the linear relationships described in Section 3.4 to model statewide per-capita demand for each peak day of 2070–2099 (see Table 7). 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 7, most summer peak days would exceed these values by the end of the century, according to the climate scenarios used.

4.5. Cumulative impacts of demand and generation peak-load

We combined temperature-induced generation losses with increased customer demand to estimate the additional peak capacity requirement that utilities would need to provide through demand or supply-side resources (or a combination of both). In other words, we added the per-capita peak demand to the per-capita peak generation loss – as described in the previous sections. This cumulative estimate provides a better picture of the total capacity that California may need to build, address with conservation strategies, or import – again, assuming that the temperature projections materialize and the existing mix of infrastructure remains the same in the future.

Table 8 presents the 90th percentile of the additional capacity modeled for the six scenarios we evaluated. The results indicate that statewide peak load capacity requirements would increase 6–25% across the six scenarios we evaluated by the end-of-the-century. It is important to note these calculations do not include substation and T&D losses resulting from climate change, which could increase anticipated shortfalls.

It is important to note that these are model projections of what could occur if end-of-century temperatures were imposed on California's current population and distribution of power plants. We have not accounted for the increased capacity requirement from a higher penetration of air conditioners into unsaturated markets, which could significantly increase the 2070–2099 demand figures discussed above. In addition, it is obvious that population growth will also increase these estimates. However, if these temperature projections materialize, then California's per-capita peak capacity will need to increase disproportionately to the population. Also, we have not considered the possibility of changes in the mix of power generation sources that would be used to meet peak demand by the end of the century. Natural gas is regarded as a viable option for meeting peak demand given its operational flexibility. However, breakthrough technologies will come online

Table 7
Statewide August peak load (watts per-capita).

	Statewide August peak load (watts per-capita)							
	Median ("1 in 2")	Δ (%)	# of Days > 1254 (%)	90th Percentile ("1 in 10")	Δ (%)	# of Days > 1387 (%)	Max	Δ (%)
Actual Peak Loads: 2003–2009	1254	N/A	50	1387	N/A	10	1585	N/A
AOGCM/IPCC Emissions Scenario	2070–2099 Projections (watts per-capita)							
CNRM/A2	1532	+22	98	1661	+20	94	1930	+22
GFDL/A2	1552	+24	100	1683	+21	88	1851	+17
PCM1/A2	1490	+19	93	1585	+14	67	1778	+12
CNRM/B1	1449	+16	96	1571	+13	82	1720	+9
GFDL/B1	1490	+19	97	1613	+16	73	1795	+13
PCM1/B1	1405	+12	89	1529	+10	55	1678	+6

Note: GFDL – Geophysical Fluid Dynamics Laboratory; PCM1 – Parallel Climate Model; CNRM – Centre National de Recherches Météorologiques

Table 8
Total statewide peak capacity requirement including temperature-induced generation losses (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 (%)
A2				
GFDL	1541	1875	+22	93
CNRM	1490	1857	+25	93
PCM1	1534	1748	+14	68
B1				
GFDL	1497	1696	+13	59
CNRM	1494	1654	+11	48
PCM1	1500	1593	+6	25

Note: "1-in-10" represents the 90th percentile value for demand and natural gas-fired generation. Note that current California natural gas-fired generating capacity is 1146 watts per-capita.

by the end of the century and we cannot anticipate their risk to climate change. As we discussed earlier, projecting the future power generation mix does not fall within the scope of this paper.

4.6. Key results

Table 9 contains a summary of the range of modeled impacts for the assumptions adopted, across the impact categories reported in this paper.

California's gas-fired generating plants have a nameplate capacity of 44.1 GW (out of a total 58.5 GW from all sources). For the climate scenarios we considered, end-of-century model results indicate that atmospheric warming at the locations of these plants could reduce their output on hot days by an aggregate of 10.3 GW (Table 4). This is the maximum coincident loss, summed simultaneously over all plants. This should be compared with the maximum 1961–1990 coincident loss of 7.6 GW (Table 4).

By the end of the century, the models suggest that in order to deliver the same per-capita power as in 1961–1990, California would need to increase its nameplate peak capacity to 47.6 GW, an 8% increase over the current value. This is in addition to increase driven by population growth. In addition, elevated temperatures would increase electrical demand for cooling. At the 90th percentile (1-in-10) level, we modeled a 21% increase in peak demand (Table 7). Since this peak demand occurs at the time of maximum temperature when only part of our nameplate capacity is able to deliver, a further nameplate capacity increase of 27% would be needed to drive this load.

Modeled decreased substation efficiency suggests an addition of 2.7% to temperature-induced losses, which at peak temperatures would require 3.5% more generation. Combining these model results indicates that in order to overcome the decreased efficiency of generators, the decreased efficiency of substations and increased demand for air conditioning an additional 38.5% peak generation capacity would be needed.

A similar set of calculations may be used to derive the amount of new transmission capacity needed to provide the baseline level of service at the end of the century. A 5 °C air temperature increase (the average increase for hot days in August for the climate scenarios) diminishes the capacity of a fully loaded transmission line by an average of 7.5% (Table 6).

The heat-induced generation increases mentioned above do not need to be pushed through transmission lines–they would only be needed to bring generators back to previous power levels. It follows that the 2.7% substation shortfall and the 21% air conditioning effect would still need to be transmitted. Accordingly, the electrical grid may need to carry 23.7% more peak power per-capita than it does today. And it would have to do this in the face of a 7.5% decrease in the capacity of fully-loaded transmission lines. These model results suggest that at least parts of the grid may need up to 31.2% more capacity than would be expected from population growth alone.

Table 9
Summary of modeled impacts.

Impact Category	Modeled Impacts (2070–2099)
Natural gas-fired power plant capacity losses	+2% to 5%
Substation capacity losses	+2% to 4%
Transmission and distribution resistivity losses	+<1%
Transmission line capacity losses	+7% to 8%
Peak load increase (above 2003–2009 levels)	+6 to 22% (maximum) or +10 to 21% (90th percentile)

Total estimated additional peak generation capacity: ~38%.
Total estimated additional transmission and distribution capacity: ~31%

4.7. Policy considerations and future research

This study found that higher temperature scenarios could significantly decrease the capacity of existing energy infrastructure in California to attend peak demand over the course of this century. The projections vary by region, emission scenario, and climate model. It follows that as incremental generating capacity is added to serve California's increasing population, the state may need to add proportionately more peaking capacity (new generation and/or demand-responsive resources) to cover the combined effects of increased cooling demand, decreased generator efficiency, and other system losses on the hottest summer days.

It has been noted that electric utility planners and grid operators can adapt to projected increases in total peak demand and supply-side capacity losses (Gellings and Yeager, 2004). These findings, although based on large uncertainties, suggest that additional funding could be put to good use by (A) learning from power system operational experiences in hot and dry regions; (B) supporting R&D into next generation cooling equipment technologies; (C) designing effective demand side management programs; and (D) diversifying the power generation mix, including importing power into California, while maintain operational flexibility. Peak load shifting measures (see, for example, Qureshi et al., 2011) is a particularly important demand side management strategy that could help reduce future vulnerability to climate change.

Utility resource planners, electric system operators, and government regulators should also consider increasing system capacity reserve margin requirements and incorporating long-term climate projections into infrastructure siting decisions – to account for the potential of more frequent and severe heat waves in the future.

We believe it is important to carry out additional research that could affect the results of this analysis. Important additional research could include gathering information on the: (1) type and cost of cooling equipment already installed at natural gas-fired plants and substations; (2) future location of new power plants and demand-side resources (see footnote in Section 1); (3) a wider range of climate scenarios and climate variables; and (4) most appropriate statistical distributions to use when projecting a range of future climate scenarios. For example, conducting a Monte-Carlo simulation – using alternative statistical distributions (e.g., Cauchy, Gumbell) – would more accurately capture the statistical uncertainty inherent in predicting local meteorological measures many decades into the future (e.g., see discussion in Larsen et al., 2008).

A number of other research questions could be studied using the type of integrated modeling framework discussed in this paper. We did not consider other climate change-related impact metrics, including reductions in the useful lifespan of these types of infrastructure, which could be an interesting future development to this work. For example, Swift et al. (2001) relate increases in transformer hot spot temperature to increased acceleration of transformer aging. 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. Additionally, the issues raised in this study and the methodology employed could be applied at a more local level or to regions outside California where power system peak load coincides with hotter weather.

It is also worth noting that there are additional effects of climate change not analyzed here. Electricity production operation and maintenance (O&M) activities may be jeopardized by very hot temperatures, not only through infrastructure-based impacts, but through labor restrictions that address worker safety during very hot conditions. Also, there are other climate-related impact categories, like wildfires and sea level rise, the effects of which were not analyzed here. As noted earlier, we recommend an investigation into the effects of climate change on the probability and duration of no-wind conditions on hot days – to more accurately evaluate impacts on transmission line capacity.

Despite the need for additional research, it is shown that increasing temperatures (during the hottest months of the year) could constrain load serving entities in their efforts to reliably produce and deliver electricity to their customers. If these projected changes in California's climate actually materialize, then system planners will want to consider adapting existing and future energy infrastructure to these anticipated conditions. Adaptive strategies should be based on coincidental and cumulative impacts from warmer temperatures including increased customer loads and reliability shortfalls to the supply-side of the power system.

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