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Electricity infrastructure vulnerabilities due to long-term growth and extreme heat from climate change in Los Angeles County

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ABSTRACT

Many studies have estimated the effects of rising air temperatures due to climate change on electricity infrastructure systems, but none have quantified impacts in terms of potential outages down to the neighborhood scale. Using high-resolution climate projections, infrastructure maps, and forecasts of peak electricity demand for Los Angeles County (LAC), we estimated vulnerabilities in the electricity infrastructure to 2060. We considered rising air temperatures under IPCC RCP 4.5 and RCP 8.5 at 2 km^2 grid cell resolution, two local government population growth scenarios, different efficiency implementations of new residential and commercial buildings, air conditioners (AC), and higher AC penetration. Results were that generators, substations, and transmission lines could lose up to 20% of safe operating capacities (MW). Moreover, based on recent historical load factors for substations in the Southern California Edison service territory, 848–6724 MW (4–32%) of additional capacity, distributed energy resources, and/or peak load shifting could be needed by 2060 to avoid hardware overloading and outages. If peak load is not mitigated, and/or additional infrastructure capacity not added, then all scenarios result in > 100% substation overloading in Santa Clarita, which would trigger automatic outages, and > 20% substation overloading in at least Lancaster, Palmdale, and Pomona in which protection gear could trip outages within 30 min. Several climate change adaptation options are discussed for electricity infrastructure and building stock with consideration for trade-offs in system stability and other energy and environmental goals.

1. Introduction

Research into the effects of climate change on electric power infrastructure systems has so far largely focused on direct effects at national and regional scales, as opposed to impacts at neighborhood scales (ADB, 2012; DOE, 2016; Forzieri et al., 2018; IPCC, 2013; Panteli and Mancarella, 2015; Ralff-Douglas, 2016). Dozens of studies have considered how power generation capacity could be reduced (Bartos and Chester, 2015; Bonjean Stanton et al., 2016; Burillo et al., 2017; Miara et al., 2017; van Vliet et al., 2016). Likewise, many studies have considered how electricity demand can increase with extreme temperatures via more air conditioning (AC) load during higher highs and heating load during lower lows (Auffhammer et al., 2017; Burillo et al., 2017; Garcia-cerrutti et al., 2011; Reyna et al., 2017; Sailor, 2001; Sailor and Muñoz, 1997; Santamouris et al., 2015; Sathaye et al., 2013). Most of the studies of climate change effects on electricity demand were either based on high-level statistical methods or focused on total annual energy demand. Only a few studies have considered peak demand, which causes the most stress on components and is therefore the most critical factor to consider for the sake of system stability (Dirks et al., 2015). Moreover, while it is generally understood that too much heat stress on materials can cause physical damage, hence circuit breakers and protection relays exist (IEEE, 2013, 2012a, 2012b), only a few studies have attempted to quantify how delivery components could be affected by rising air temperatures (Bartos et al., 2016; Sathaye et al., 2012). We were unable to identify a single study that considered all of these factors together at a sub-city scale inclusive of the hardware dependencies to deliver power from generators to loads. Thus, synthesizing prior research on the effects of climate change on components and processes has enabled us to estimate infrastructure vulnerabilities to the rising air temperature aspect of climate change considering the multiple conditions necessary for service interruptions to occur. In this case, we consider vulnerability a valuable concept for describing states of susceptibility of the system to harm, and for guiding actions to

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enhance well-being through reduction of risk (Adger, 2006). Specifically, we quantified vulnerabilities as shortages in electricity supply and/or delivery capacity that can result in unmet demand, outages, and/or hardware damage.

We defined our system boundary for electricity infrastructure to include generators, lines, and substations. We only considered line and substation components at the transmission level because multiple simultaneous outages during heatwaves have resulted in blackouts affecting millions of people (FERC, 2003; FERC and NERC, 2012). While the majority of service interruptions occur at the distribution level, where there is little or no redundancy, there is also very little potential for cascade and so fewer customers tend to be impacted (Hines et al., 2009). Moreover, we did not have sufficient data at the distribution level as we had at the transmission level. Excessively high temperatures can result in service interruptions in electric power systems via a combination of high demand, and (i) insufficient cumulative generation resources, or (ii) insufficient capacity in delivery components, or (iii) widespread cascading failures due to a combination of multiple instances of either of the former (Bie et al., 2017; Hines et al., 2009; Panteli and Mancarella, 2015). Of the North American power outages and blackouts that have resulted from failures at the transmission level, 25–50% were caused by events impressionable to rising air temperatures, including operation failures, fires, over demand, and supply shortages (Eaton, 2013; NERC, 2015; Vaiman et al., 2012).

Rising air temperatures can affect electricity infrastructure in two ways that are relevant to our methods for quantifying vulnerabilities. First, there can be a direct reduction in the components' (generator, transmission line, or substation) safe operating capacities. Since electric power flow creates heat, and components can only tolerate so much before protection gear trips or internal parts physically break (IEEE, 2012a), their capacity to support power flow generally decreases as ambient air temperatures rise. Second, there can be an increase in the load on those components due to increased AC use as previously cited. Hence, we used the term thermally *de-rated component capacity* to refer specifically to the reduction in wattage that electricity generators can safely supply or that transmission lines and substations can safely deliver to loads. We also used the term *de-rated load factor* to refer to the percent loading of peak hour electricity on components for their thermally de-rated capacity.

Developing a spatially explicit quantitative understanding of electricity infrastructure vulnerabilities to climate change is critical for long-term capital investment planning (Ge et al., 2015; Zhu et al., 2016). Doing so supports identification of potential future hazards, their magnitude and location, and likewise the siting and sizing of future investments including adaptation projects. Because Los Angeles County, California (LAC) has both expansive existing infrastructure in Mediterranean climate zones, as well as significant demand for new infrastructure in the same and developing areas with warmer climate zones, LAC provides an interesting case study which we expect will yield transferrable lessons for other cities around the world. The combination of reliable electricity and affordable AC technologies has resulted in the LAC urban landscape expanding into regions with air temperatures considered uncomfortably hot and often a public health risk (Arsenault, 2016; Taleghani et al., 2013; Yang et al., 2014). These regions include the northern Santa Clarita and Antelope Valley areas, which have historically reached temperatures of up to 52 °C (126 °F) and could reach up to 54 °C (129 °F) by 2060 under worst-case climate change projections (Burillo et al., 2019; Sun et al., 2015). In recent years, LAC had peak demand of 11–18 GW, and imported over 1 GW of electricity during peak hours in the summer (Burillo et al., 2019, 2017; EIA, 2016). While the county may seem to have an ample 13 GW of total import capability from Arizona, Nevada, the Pacific Northwest, and San Diego, if there is insufficient capacity in the delivery network on path to the load locations, then either new generation plants will need to be sited closer to loads, or distribution delivery capacity expanded, or demand somehow shifted from peak to off-peak hours, or demand met via some form of distributed energy resources (DER) such as onsite solar PV and batteries (CPUC, 2016; Willis et al., 2001). With a better understanding of the location and magnitude of electricity infrastructure vulnerabilities in LAC, we can better evaluate the effectiveness of investment and policy options to meet the risks of extreme heat events that could be heightened by climate change.

Long-term investments in electricity infrastructure are inherently a matter of public policy because they are critical infrastructure systems (Rinaldi et al., 2001). California, and Los Angeles County specifically, have been leaders in developing energy and environmental policies that affect the electric power sector, including reducing greenhouse gas emissions and conserving limited natural resources via the Zero Net Energy Plan (BluePoint Planning, 2018), comprehensive building energy standards (CEC, 2016), renewable portfolio standards (LARC, 2017), climate action plans (DRP, 2017), and more (Vine, 2012). Furthermore, California has the goal to serve 33% of its load with renewable energy by 2020, and, 50% by 2030 per SB 350 (CEC, 2018). California has made considerable progress on those goals achieving 30% renewable energy as of November 2017, with 57% originating from solar PV (CEC, 2017), and more planned (LADWP, 2016; SCE, 2015). But not all of that energy has the same value. For example, California has produced so much surplus generation from solar PV during mid-day off-peak hours that it has paid Arizona to take some of it (Penn, 2017; Toll, 2016). Because of these time-of-day capacity and usage issues, a mix of solar PV in conjunction with some form of complementary storage (e.g., batteries), fast-ramping central generation (e.g., natural gas), and or power imports will be needed to meet future demand as regulated by California policies.

To better inform long-term capital investment and policy decisions regarding climate change and electricity infrastructure systems, we asked and answered the following three research questions for LAC specifically. First, how much could capacity be reduced at generator plants, transmission lines, and substations by 2060 due to heat waves? Second, considering projections for both increase in peak demand and decrease in infrastructure capacity, what could de-rated load factors be on components throughout the county? Third, what neighborhoods or cities have the highest risk of shortages in delivery infrastructure capacity, and should therefore be prioritized for capital investments and/or demand side management programs?

2. Methods

We estimated the magnitude and location of electricity infrastructure vulnerabilities to rising air temperatures in LAC to 2060 by using several recently released spatial data sets (a.k.a. maps) without which this work would not have been possible. The primary data included our prior projections of air temperature and peak electricity demand (Burillo et al., 2019, 2018), the US Department of Homeland Security's maps of major electricity infrastructure hardware (DHS, 2017a, 2017b), and Southern California Edison's (SCE) distributed energy resource integration map (DERiM) of substation capacities and loads (SCE, 2016a). We first quantified vulnerabilities as component sensitivities to air temperatures in terms of potential de-rating, defined as decreases in percent loadability or reduced MW capacity at generators, MVA capacity at substations, and ampacity in transmission lines. Second, we quantified vulnerability as potential for outages in the form of de-rated load factors by accounting for both decrease in loadability (de-rating) due to higher air temperatures, and increases in peak hour load due to population growth and technology changes per the peak demand forecasts. Due to data constraints, we estimated de-rated load factors for total generation and individual substations, but not transmission lines or any distribution-level components. Estimating load factors at individual generator plants would not be particularly valuable in this analysis, as they work collectively with transmission imports to supply power to the region. Therefore, we evaluated generation capacity in aggregate in terms of local reserve margin, with results indicative of either increased need for additional local generation resources, peak reduction, and/or imports.

We quantified extreme heat and rising air temperatures due to climate change based on 2 km^2 grid cell resolution projections for the daily maximum air temperature (T_{max}), for a base period of 1981–2000, and two future periods, 2021–2040 and 2041–2060 (Sun et al., 2015; Walton et al., 2015). Future projections were based on the standardized climate change scenarios from the Intergovernmental Panel on Climate Change (IPCC) Representative Carbon Pathway (RCP) scenarios: RCP 4.5 and RCP 8.5 for low and high scenarios respectively. We considered rising air temperatures spatially in terms of (i) relative increase throughout the county, equal to approximately 1.5 °C (2.7 °F) by 2040 and 2 °C (3.6 °F) by 2060 on average, and (ii) degrees above 40 °C (104 °F). We quantified degrees above 40 °C (104 °F) because that is the summertime value specified in the ANSI/IEEE standards cited in SCE's Interconnection Handbook (SCE, 2016b), and therefore such temperatures may be problematic if that is the rating that all hardware are designed for. Some locations in LAC reached as high as 52 °C (125 °F) in the base period from 1981 to 2000, and some in the future in RCP 8.5 could reach as high as 54 °C (129 °F) by 2060. Two sets of air temperature projection images were used as previously developed in (Burillo et al., 2019, 2018), *composite* images and *hottest day* images. First, composite images were of the highest projected T_{max} in each 2 km^2 grid cell for each time period and RCP scenario. Second, hottest day images were of the T_{max} in each grid cell on the day that the highest average T_{max} occurs across the county for each period and RCP. These two definitions respectively inform capacity derating factors for individual components and the total resource adequacy requirements for the region. The historical hottest day image is included in Fig. 1 in the next sub-section; see (Burillo et al., 2018, 2019) for all T_{max} projection images and further explanation.

We used two sets of peak demand forecasts, which we previously developed in (Burillo et al., 2019, 2018), based on low and high population growth scenarios, as well as, low and high changes in air temperature, buildings, AC penetration, and efficiencies. The low population growth case was based on the California Department of Finance's (DoF) and USGS projections of an increase in population from 9.7 million in 2010, to 10.3 million in 2040, and 10.9 million in 2060, mostly in the northern Santa Clarita and Antelope Valley region (Sleeter, 2017). The high population growth case was based on projections by the Southern California Association of Government (SCAG), and included significant infill in the already developed basin area for a total of 11.4 million people by 2040 and 12.8 million people by 2060 (SCAG, 2016a, 2016b, 2016c). It is important to note that the electricity demand forecasts were for residential (Reyna et al., 2017) and commercial (Deru et al., 2011) (R&C) buildings only, and did not consider industrial or other sectors. A summary of all of the peak electricity demand forecast scenarios and parameters considered are included in Table 1, and the results used as inputs in this study are summarized in Table 2. See (Burillo et al., 2019, 2018) for the complete geographic projections and detailed analyses.

2.1. Generation

We assessed vulnerabilities in generation first as potential capacity (MW) losses due to high air temperatures at sensitive generation plants. Generators sensitive to rising air temperatures in LAC are dry-cooled natural gas plants, the dry-cooled portion of combined cycle natural gas plants, and solar PV plants. The locations of these plants are shown in Fig. 1 (EIA, 2017), with values as listed in Table 3 assumed relative to T_{max} = 40 °C (104 °F) (Burillo et al., 2017). Wet-cooled plants were modeled with zero capacity losses for air temperature (Henry and Pratson, 2016). Availability of cooling water, cooling water temperature, potential for mechanical failures, and imports from neighboring regions were categorically out of scope and not considered in this study of air temperature effects on infrastructure within LAC. Vulnerabilities were estimated for individual generators for temperatures in excess of 40 °C (104 °F) using the composite T_{max} projection images developed in Burillo et al. (2019, 2018)). Derating factors were attributable due to chiller performance at the air intake of dry combustion engines for natural gas plants (Brooks, 2000; Henry and Pratson, 2016; Maulbetsch and DiFilippo, 2006; Sathaye et al., 2012), and due to internal carrier recombination rates from thermal excitation of solar PV modules (Dubey et al., 2013). Hydropower plants have been estimated to be vulnerable to climate change between 0.4% and 14% of capacity to 2060 in the US, but primarily due to higher water temperatures and or reduced water availability from drought, as opposed to higher air temperatures (Bartos and Chester, 2015; Henry and Pratson, 2016; van Vliet et al., 2016). Therefore, as those types of plants account for only 2% of the generation in LAC, hydropower derating was considered negligible in this study. Capacity losses were tabulated for the total LAC generation fleet for both average increases in temperatures and for temperatures in excess of 40 °C (104 °F) projected under RCPs 4.5 and 8.5 to 2040 and 2060.

We also quantified vulnerabilities in generation in terms of local reserve margin (LRM), which is the amount of generation capacity more than peak demand for the region. LRM is important to consider for security reasons, because if there is an outage in the long-distance

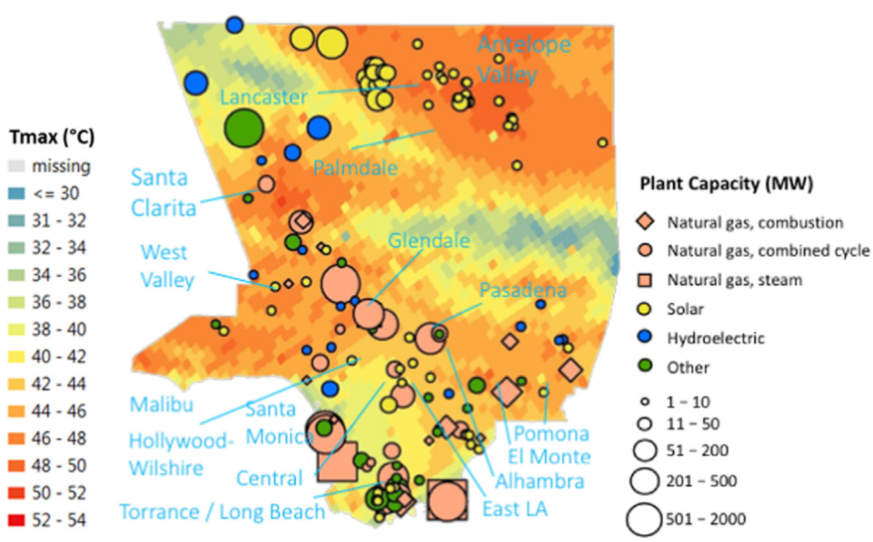

Fig. 1. Map of power plants and historical hottest day air temperatures.

Table 1
Summary of building electricity demand forecast scenarios.

Model parameter	Low demand	High demand
Population	Grows by 1.2 million	Grows by 3.1 million
Residential building turnover	Slow, 0.03% replaced per year	Fast, 3% replaced per year
New housing density	Multifamily units outnumber single-family units by 9 to 1	Single-family units outnumber multifamily units by 11 to 9
Residential AC efficiency	SEER 16	SEER 21
AC penetration	Central AC in all new buildings from both turnover and population growth	

Table 2
Summary of peak electricity demand scenario values.

Time Period	Residential and Commercial Building Peak Demand (GW)			
	DoF - Low	DoF - High	SCAG - Low	SCAG - High
Hottest Day				
2010	9.5	12.7	9.5	12.7
2040	12.3	15.8	13.1	16.7
2060	13.0	17.3	14.7	19.2
Composite				
2010	–	13.5	–	13.5
2040	12.9	17.3	13.8	18.4
2060	13.6	18.8	15.4	20.9

Table 3
Power plant capacities by type and high air temperature derating factors.

Generation type	Power Plants		Derating factor
	Count	Capacity (MW)	(%/1 °C-T_{max})
Hydropower	18	284	–
Natural Gas (steam)	3	3406	–
Natural Gas (combustion)	15	1044	0.6% ± 0.1%
Natural Gas (combined cycle)*	23	5742	0.3% ± 0.1%
Solar PV**	91	890	0.35% ± 0.25%
Other***	24	2137	–
Total	174	13,503	0.20% ± 0.06%

* Includes three "natural gas other" plants with total capacity of 4.4 MW.
** Includes one 3.2 MW solar thermal plant without storage.
*** Includes, by size: pumped storage, biomass, other, and petroleum.

transmission lines, then cities must have enough local power generation for other critical infrastructure systems, as well as basic living provisions in residential buildings, or else catastrophic impacts could occur. We projected LRM to decrease for two separate and distinct reasons. First, plants have reduced generation capacity under the stress of higher ambient air temperatures on the hottest days. Second, there will be higher demand for electric power on the hottest days when ambient air temperatures are highest. Peak demand values used in the LRM calculations were the values listed in Table 2 plus the greater of 5 GW or 50% as an estimate of industrial and other sector processes that could scale with population growth (Burillo et al., 2018).

2.2. Substations

We assessed substation vulnerabilities first in terms of derated capacity (kVA) of transformers due to rising air temperature only, and second in terms of temperature-adjusted load factors. Substation size and location data were obtained from (DHS, 2017b), and modeled with derating factors of 1.5% and 1% kVA per 1 °C (1.6 °F) for $T_{max} > 40$ °C (104 °F) (IEEE, 2012b) for lower (66–138 kV) and higher (230–500 kV) voltage units respectively. Load factors were estimated for a large sample (50–70%) of the substations owned by SCE where data were available for capacity (kVA) and recent historical peak load (SCE, 2016a). Load factors were defined as peak load divided by capacity, which we assumed was provided in the DERiM data set for 40 °C (104 °F). We used composite temperature images to estimate the highest stress at any substation. Since we did not have precise data as to which buildings are served by which substations, we allocated building peak demand projections, from Burillo et al. (2018) at census block group (CBG) resolution, to substations based on voltage ratings and geographic coverage. We did this to approximate for series and parallel power flows, and verified results for substation load factors in the base period within 15% of SCE DERiM data values as detailed in the technical appendix of Burillo et al. (2018). Briefly, we assumed that higher and lower voltage substations operate in series and divided them into two layers accordingly such that we could allocate peak demand fully to both layers of substations. Next, we assumed substations within a 2 km and 1 km radius in each layer respectively service the same geography in parallel, and we clustered them by summing their capacities into a geographic midpoint. Then, to allocate load to substations, we defined coverage areas based on a Voronoi Tessellation approach for each substation and substation cluster. Voronoi Tessellation is a method to partition a plane with respect to a set of reference points. In this case, the plane was the geography of LAC, the points were substations and clusters, and the optimization method was shortest distance from polygon boundaries to points. Voronoi Tessellation approaches have been used extensively for substation planning for a variety of geographic optimization problems (Ge et al., 2015; Wang et al., 2014; Zhu et al., 2016). Finally, the CBG resolution peak demand projections were uniformly allocated to the Voronoi polygons based on percent geographic overlap. We estimated future scenario load by scaling loads at substations by the corresponding percentage increase in demand projections relative to the base period demand in each polygon. We classified weather-adjusted load factor ratings as described in Table 4 for

Table 4
Substation derated load factor risk metrics.

Load Factor	Risk Level	Reference	Description
n/a	Unknown	n/a	Substation(s) exists in this space according to national database (DHS, 2017b), but not shown in SCE DERiM (SCE, 2016a), so load factor data were unavailable.
0.01–0.5	Very Safe	Assumption	Negligible thermal wear, probably n − 2 reliable if in parallel/redundant configuration.
0.51–0.85	Safe	15% rule	Low thermal wear, probably n − 1 reliable if in parallel/redundant configuration.
0.86–1.00	Caution	15% rule	Some thermal wear, probably not n − 1 reliable.
1.01–1.20	Warning	(IEEE, 2012a; SCE, 2016b)	Moderate thermal wear, component overloaded, automatic switching may occur within 24 h to 30 days if loading continues at this level depending upon switch gear settings.
1.21–2.00	Emergency	(IEEE, 2012a; SCE, 2016b)	Significant thermal wear, component very overloaded, automatic switching may occur within 30 min depending upon switch gear settings.
> 2	Outage	(IEEE, 2012a)	Extreme thermal wear, switchgear will automatically trip to prevent combustion and permanent hardware damage.

the reasons as listed accordingly.

2.3. Transmission lines

We assessed transmission line vulnerabilities as potential decreases in ampacity only. Spatial data were obtained for lines rated from 66 kV to 1000 kV from (DHS, 2017a). Transmission line capacity (MVA) data were unavailable, therefore we were unable to calculate changes in load factors symmetric with the substation and generator analyses. We used the IEEE standard steady state thermal balance equations for calculating the current-temperature relationship of bare overhead conductors (IEEE, 2013) to calculate the effects of air temperature on the maximum safely allowable current. Lines were categorized as above and below 200 kV with derating factors of 0.6 ± 0.3% and 1.5 ± 0.6% Amps per 1 °C respectively per the sensitivity analysis of the IEEE standard equations in Burillo et al. (2018). The basic high-level equation is $q_c + q_r = q_s + I^2RT_c$, where the sum of the convective (q_c) and radiative (q_r) heat loss of the line is equal to the heat gain from the sun (q_s) plus the power flow on the line times the conductor temperature. The power flow on the line is equal to square of the current times the resistance, thus we calculated the ampacity by solving for the current as explained in the IEEE standard. The top five most significant attributes identified in the sensitivity analysis were the conductor resistance at 25 °C (77 °F), the maximum allowable surface temperature, the conductor diameter, air temperature, and emissivity, which were based on parameter ranges taken from the IEEE standard, SCE, Nexant power line performance specifications, and weather data specific to LAC (Burillo et al., 2018; DOA, 2009; IEEE, 2013; Nexans, 2014; SCE, 2016b). Air temperature data used were the same as in other sections, and each line segment was assigned the highest grid cell value that it intersected in scenarios accordingly.

2.4. Overall

With generation, substation, and transmission line capacity sensitivities to air temperatures estimated, and with prior forecasts of changes in peak demand, we considered overall system vulnerability and adaptation options. Because each component class can potentially constrain the system, the highest magnitude of capacity loss in any component class can effectively reduce the capacity of the entire system. For example, if there is insufficient t substation capacity, then transmission and generation capacity may be irrelevant to delivering load, and so on. We also considered adaptation options as the results from the substation analysis are useful to identify locations where distributed energy resources, or some form of demand side management could be implemented to reduce and/or shift peak load and keep substations in safe operating conditions. This would be as an alternative to constructing more and/or larger substations and lines. Analyzing these results across the range of scenarios, also allows us to identify any flexibility, or lack thereof, geographically between the population growth, building, and appliance scenarios to meet California policy goals.

3. Results

3.1. Generation

Of the 13.5 GW of power generation physically located within the County boundary (Fig. 1) up to 240 MW (1.8%) are vulnerable to increases in air temperature. Most of the vulnerable generation are the 23 combined cycle and 15 combustion natural gas plants located in the greater Santa Clarita area (northwest) and on the outer basin areas away from the ocean. By 2060, T_{max} at vulnerable natural gas plants ranged from 40—53 °C (104–127 °F) resulting in 3–9% less capacity than 40 °C (104 °F) summertime rated values. Total capacity of natural gas plants would be 69–104 MW (0.7–1.5%) less than present ratings. The 90 solar PV generation plants are also vulnerable, most significantly in Antelope Valley. Maximum temperatures at solar PV plants ranged from 44 °C to54 °C (111–129 °F), and if such extreme temperatures are realized, individual solar PV output could be 1–8% lower than rated. The total capacity loss of solar PV on the hottest day would be 8–45 MW less than present ratings. The estimated capacity loss of the entire fleet on the hottest day was 110 MW, or approximately half of the total vulnerable capacity identified using the composite T_{max} projection images. Based on the range of temperatures already observed in the historical period, 75 MW of capacity is already vulnerable to temperatures more than 40 °C. Average total plant capacity losses were estimated at 35 MW for average warming by 2060 under RCP 8.5.

Los Angeles County's recent historical local reserve margin was estimated to be negative by 1–6 GW, and the highest future scenario modeled was negative 15 GW. The base period value is not disagreeable with the value estimated in Burillo et al. (2017), or presented in CPUC (2016) for SCE territory. This means that the county presently needs to be able to import from neighboring regions 1–6 GW of electric power during heat waves. In practice, imports and exports are not accounted for by county, but this serves as a sufficient approximation. In the worst-case scenario modeled, the need for additional local generation and/or imports increased to 15 GW by 2060. The full range of simulated LRM values are listed in Table 5, where the minimum increase in peak generation capacity needed to meet future peak demand was 3.1 GW by 2040 and 3.8 GW by 2060 for the low growth, high efficiency scenarios under RCP 4.5. Again, details of factor contributions are explained in Burillo et al. (2018, 2019). While it is possible to invest in generation capacity outside of LAC and use long-distance transmission imports to meet future peak demand, doing so exclusively would result in substantially negative LRM, such that at best two thirds of the County's peak electricity demand would be met if imports were unavailable during a heat wave in 2060.

3.2. Substations

Of LAC's 410 substations, 99% are vulnerable to air temperatures over 40 °C (104 °F), including reductions in loadability of up to 20% of their kVA ratings. For worst-case temperature projections, 24 unknown capacity substations (presumably low voltage convective air cooled) and one 138 kV substation, across Antelope Valley, Santa Clarita, El Monte, and Pomona could experience temperatures up to 51–53 °C (123—127 °F) and be safely loadable at 16–20% less than their summertime 40 °C kVA ratings. Substations within 5 km (3.1 mi) of the Santa Monica, Manhattan, and Torrance beaches will not have capacity losses more than 5% as temperatures were not projected to rise above 42 °C (108 °F). As shown in Fig. 4 in the next subsection with transmission lines, 70% of substations were projected to experience average capacity losses of 1.5–3% kVA due to average warming, and 60% of substations were projected to experience capacity losses of 6–12% during heat waves due to temperatures in excess of 40 °C (104 °F). Results for different time periods and RCPs were all within 2% kVA of each other,

Over half of SCE's substations are at risk of overloading in the base-

Table 5
Estimated local reserve margins for time period, population, and demand scenarios.

Time Period	Local Reserve Margin GW (%)			
	DoF–Low	DoF–High	SCAG–Low	SCAG–High
2021–2040	− 3.9 (−29%)	− 10 (−77%)	− 4.7 (−35%)	− 12 (−87%)
2041–2060	− 4.6 (−35%)	− 12 (−93%)	− 6.3 (−47%)	− 15 (−115%)

*Base period LRM estimated between − 0.8 and − 5.7 GW (−6% to −42%).

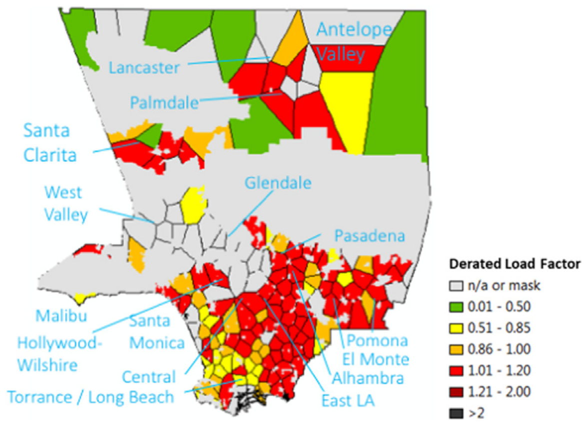

Fig. 2. Map of SCE substation vulnerabilities in base period.

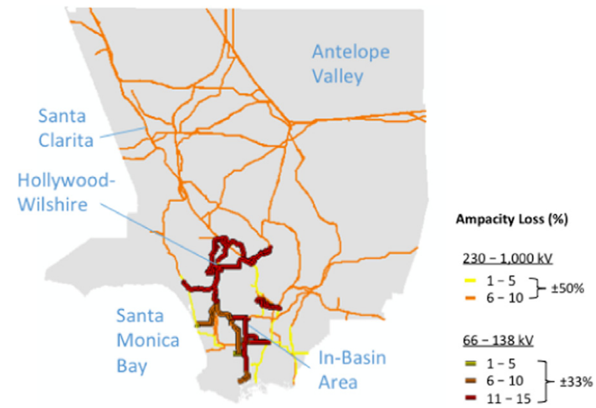

Fig. 3. Map of transmission line vulnerabilities by 2060.

period in the event of an extreme heat wave. The colored Voronoi polygons in Fig. 2 represent the geographic coverage of SCE's lower voltage substations as listed in the DERiM data set. This is a close approximation of SCE's substation vulnerabilities as of the time of this publication, with most operating at a weather-derated load factor of 1–20% over capacity under the highest historical temperatures. The grey polygons represent areas with substations owned by other service operators where we did not have capacity data, which were mostly in the Los Angeles Department of Water and Power service territory. The other grey shaded regions are masked with > 50% area classified as protected lands per the 2017 California Protected Areas Database (GreenInfo Network, 2018). A map of service territories by system operator can be seen in the link in reference (SocalEV, 2015).

In all future scenarios, at least a few substations were projected to exceed tolerance for automatic outage trips with a derated load factor more than two. With implementation of high efficiency measures, and population growth limited to mostly out-of-basin areas, then most substations in the central basin area would realize reduced loading by 2040. But in all other scenarios, either without improved building and AC energy efficiency, or with any form of in-basin densification, most substations will be vulnerable to emergency (> 1.2) or automatic outage (> 2) load factors during the peak hour of an extreme heat wave. Loadings for low and high population growth and demand scenarios are shown in Fig. 5 for 2060 in the Overall results sub-section, which are very similar in pattern as for 2040 but more severe (Burillo et al., 2018).

3.3. Transmission lines

Of LAC's 185 transmission line segments and 3.5 million meters (2200 miles) of conductor length, all segments and 99% of length are vulnerable to air temperatures over 40 °C (104°F). Like substations, reductions in ampacity could be up to 20%. In the highest temperature projections, the higher voltage lines (230–1000 kV) across Antelope and Santa Clarita could experience T_{max} up to 47–54 °C (117–129 °F) and experience 2–13% ampacity reductions from their summertime 40 °C ratings. As shown in Fig. 3, for RCP 8.5, the lower voltage transmission lines (66–138 kV) are generally more vulnerable than the higher voltage due to higher sensitivity of the lines to air temperatures. Lines located in and around the Hollywood-Wilshire regions are most vulnerable, with T_{max} up to 47–50 °C (117–122 °F), and corresponding reductions in ampacity of 6–20%. Also, like substations, shown in Fig. 4, the results only varied by up to 2% of ampacity on any line across time periods and RCPs. The least affected lines were the shorter segments near the Santa Monica Bay and In-Basin areas. Some lines appear to have overlapped colors in Fig. 3. This is due to differences in line segment length and the presence of hotspots. I.e. some lines have higher ampacity loss in the same location on the map because those line segments also cross other areas with higher heat exposure.

3.4. Overall

The overall vulnerability of components in LAC's electricity infrastructure to rising air temperatures is a 2–20% loss of capacity by 2060. The only infrastructure in the region that are not at risk of experiencing air temperatures above 40 °C (104 °F) are the components within a few miles of the western-facing coast of Santa Monica Bay. As shown in Fig. 5, by considering all the major potential changes in population, building stock, and subsequent peak demand along with climate change we were able to project future operational constraints for future weather and demand at the same time. In all future scenarios, by 2040 and 2060, at least a few substations exceed tolerance for automatic outage trips with a derated load factor more than two. By implementing high efficiency measures, most substation in the central basin area should be able to operate with load factors below one, even during the worst heat wave conditions. Substations in the Santa Clarita area exceed automatic outage tolerances in all scenarios. Even with significant energy efficiency improvements, the Palmdale and Lancaster areas are vulnerable to automatic outages by 2060 under the DoF population projections. The basin area has central and near costal spots more vulnerable to automatic outages in the SCAG population projections. Both population projection scenarios, even with high efficiency measures, result in emergency conditions (load factor > 1.2) during the peak hour of a heat wave in northern locations and Pomona.

Additional substation capacity, distributed energy resources, or some form of demand side management will be necessary to reduce and/or shift peak load to keep substations in safe operating conditions in any future scenario. Table 6 lists the amount by which SCE's high and low voltage substations could be overloaded at 40 °C (104 °F) and for the composite image temperatures in all scenarios. No high voltage substations were identified as overloaded during the base period, but several low voltage substations were, which is consistent with the preliminary analysis of substation loading using SCE DERiM data in the Appendix of Burillo et al. (2018). The low voltage substations with a load factor greater than one were estimated to be overloaded by a total of 31 MVA at 40 °C (104 °F) in the base period and overloaded by 389 MVA cumulatively for the worst-case historical heat wave conditions in the composite images. The values listed in that table do not include any substations or substation clusters with a load factor less than one. The difference between substation capacity with and without considerations for spatial differences in air temperature and extreme heat waves is 911 MW in the highest case. The total nameplate capacity of SCE's high and low voltage transmission substations in LAC is 10,883 MVA and 10,155 MVA respectively in the base period, or 21 GVA total (SCE, 2016a). Therefore, the total additional capacity requirement by 2060 using the 40 °C (104 °F) rating approach is 557–5260 MVA (3–25%).

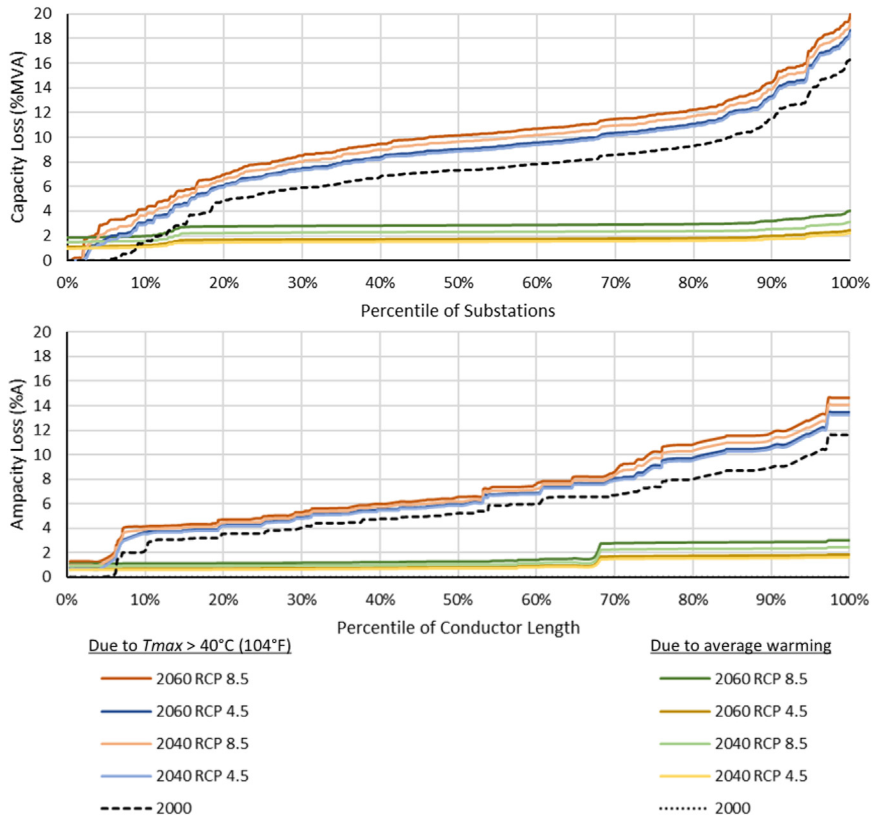

Fig. 4. Loadability reductions in substations and transmission lines.

Using the composite image approach with consideration for extreme heat waves and warming due to climate change, it is 848–6724 MVA (4–32%).

4. Discussion

A better understanding of electricity infrastructure vulnerabilities to heat waves heightened by climate change enables stakeholders to evaluate policy and investment options more effectively which facilitate population growth in a safe, reliable, cost-effective, and environmentally responsible manner. With that in mind, we listed several climate change adaptation options in Fig. 6 to mitigate risks of outages during heat waves, along with their effects on system stability and other factors important for consideration in California as well. The following sub-sections categorically discuss effects and trade-offs of those options in terms of supply, demand, and building stock. Our list and discussion are not intended to be exhaustive nor advocate for any particular option as a one-size fits all solution, especially in regions that have unique geographic constraints. Our goal in this discussion is to inform researchers, LAC, California, and readers in general of pragmatic approaches for incorporating new knowledge of climate change into pre-existing decision-making processes with complex competing stakeholder objectives.

4.1. Electrical systems – supply

Additional supply can meet increases in peak demand in the form of transmission imports, central generation, or DER. The most prominent fast-ramping central generation technology is combined cycle natural gas plants, which both consume water and emit various gasses into the atmosphere. Combustion-only natural gas plants do not use water, but are more sensitive to rising air temperatures, as well as less fuel-efficient, and therefore costlier and more emissions intensive per MWh. Major tradeoffs between centralized systems and distributed solar PV (with storage and power quality controls) in meeting demand are: land space requirements, delivery congestion relief, water usage, air emissions, and marginal capital costs. Solar PV can be installed on building roofs, whereas central generation systems require their own dedicated land space (Bridge et al., 2013; Carrasco et al., 2006; Fthenakis and Chul, 2009; Ochoa and Harrison, 2011). When implemented at the distribution level, solar PV can meet load directly without burdening delivery components that are necessary for central systems. The net effect is a relative decrease in load from the perspective of the grid; however, the solar production profile throughout the day is not the same as the demand profile which begs questions of storage. Monitoring the differences in demand and load will be important in the future as those two values have historically been one and the same. While levelized costs of solar PV are now at or below parity with bulk generation plants on a per kWh basis, the combined costs of solar PV with storage to provide 24/7 dispatchable energy and regulation services are still significantly higher than traditional central generation plants (Zakeri and Syri, 2015).

Implementing DER with new buildings may be the most cost-effective way to meet demand associated with growth in areas where delivery infrastructure is already over capacity during heat waves. In such areas, some substations may also be able to be adapted with improved heat sinks, forced air, or water-cooling systems to increase capacity, but some may not. Regardless, convective cooling to ambient air will still be a limiting factor for overhead power lines. The cost of increasing delivery infrastructure capacity necessary to meet demand through central generation or long-distance imported power could be quite significant at $10–130 million USD per substation and $1–3 million USD per mile of line length (Mason et al., 2012; PG&E, 2012). For the 848–6724 MVA of projected substation overloading, if we assume an average size of 80 MVA per new substation, then an additional 11–84 substations would be needed, which would cost $110 million to $11 billion USD. With 100–300 miles distance between LAC and neighboring regions (CEC, 1999), the cost of increasing the

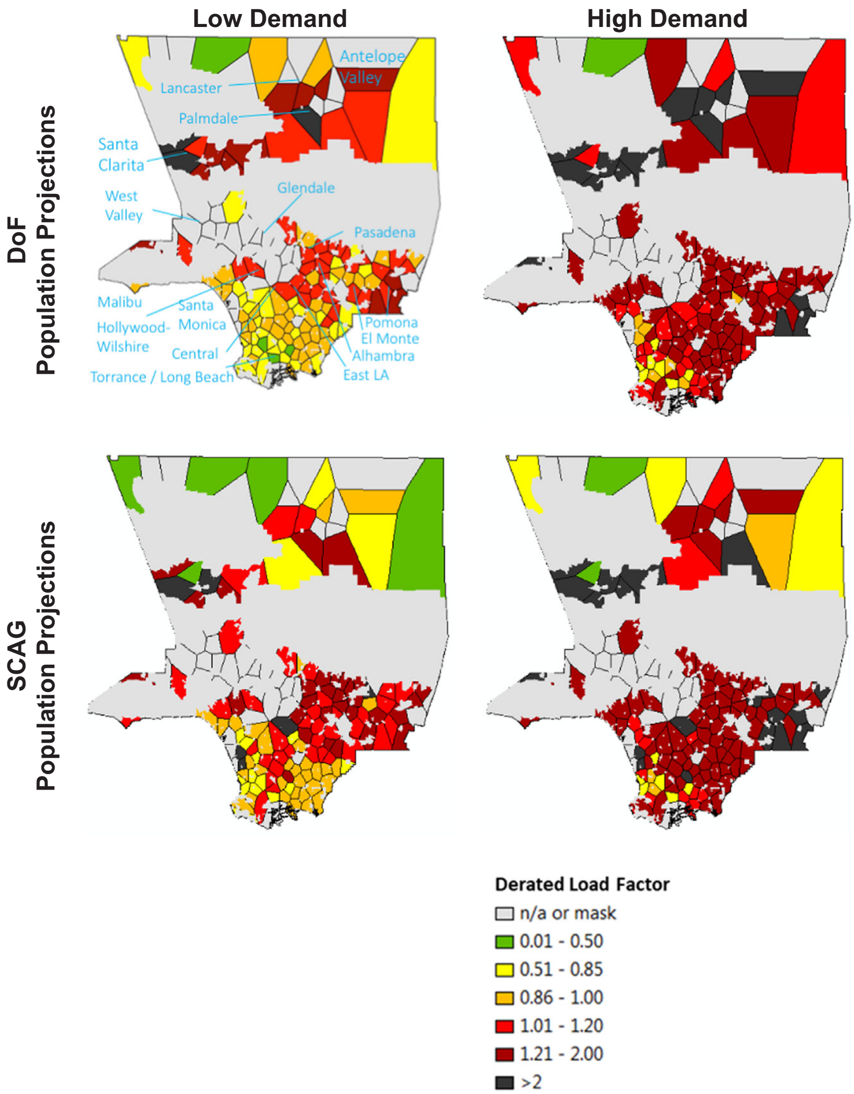

Fig. 5. Maps of substation vulnerabilities by 2060.

transmission import capabilities could be another $100–$900 million USD. There would probably be additional costs associated with upgrading distribution-level transformers and power lines as well.

Distribution-level components will generally be more sensitive to changes in air temperature because they are designed for less thermal stress from electrical power flow. Logically following, if contingency capacities are the same at the distribution level as at the transmission level, then outages will be more probable at the distribution level and more likely to result in service interruptions as there are far more components and fewer redundancies (Willis et al., 2001). Also, distribution-level components cooled by convective means are more likely to exceed evening temperature limits because of heightened lows. Given the recent widespread transformer outages, and tens of thousands of customers left without power for days in LAC during a record-breaking heat wave in July of 2018, this appears to be the case (Bravo and Wynter, 2018; Rand and Miracle, 2018).

Future work for understanding vulnerabilities and making adaptation plans should consider 24-h load profiles on distribution-level

Table 6
Peak hour substation overloading (MVA).

Period & Scenario	High voltage		Low voltage	
	@40 °C (104 °F)	w/Composite temperatures	@40 °C (104 °F)	w/Composite temperatures
Base	–	–	31	389
2040 DoF - Low	–	–	278	474
2040 DoF - High	312	623	1834	2634
2040 SCAG - Low	–	–	410	761
2040 SCAG - High	597	1003	2517	3357
2060 DoF - Low	–	–	557	848
2060 DoF - High	513	1002	2733	3669
2060 SCAG - Low	37	241	1035	1570
2060 SCAG - High	1209	1762	4051	4962

Options / Effects		Stability factors					Other factors			
		Peak load, normal	Peak load, heatwave	Load variance	Delivery congestion	Power quality	Total energy consumption	Water use	Air emission	Land use
Electrical systems										
Supply	Distributed - solar PV without VAR control or storage	↓	↓	↓	↓	⇩	-	-	-	-
	Distributed - solar PV with smart-inverter & storage	↓	↓	↓	↓	↑	-	-	-	-
	Central - CCNG, nuclear, or other	-	-	-	⇧	↑	-	⇧	⇧	⇧
	Imports, long distance transmission	-	-	-	⇧	↑	-	-	-	⇧
Demand	Appliances: higher energy efficiency	↓	↓	↓	↓	-	↓	-	↓	-
	ACs: peak performance metric	-	↓	↓	↓	-	-	-	-	-
	ACs: dual-systems with ice thermal storage	-	↓	↓	↓	-	-	⇧	-	-
	ACs: water-based evaporative systems	-	↓	↓	↓	↑	↓	⇧	↓	-
Building stock										
	Growth on fringe (single-family or multi-family)	⇧	⇧	⇧	⇧	-	⇧	⇧	-	⇧
	Growth in-basin (densification with multi-family units)	⇧	⇧	⇧	⇧	-	⇧	⇧	-	-
	Lighter color exteriors and additional shading	↓	↓	↓	↓	-	↓	-	↓	-
	Improved building thermal insulation	↓	↓	↓	↓	-	↓	-	↓	-

Fig. 6. Climate change adaptation options and effects. Arrows indicate an increase or decrease in the factor. Solid green indicates higher efficiencies and or conservation of limited natural resources. Hollow red indicates the opposite (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article).

circuits, the total Watt-hours of necessary storage capacity to complement solar PV capacity, and opportunities for network aggregation to supply ancillary grid services. Circuits with higher portions of commercial and industrial loads may be preferable for the installation of DERs, as their load profiles may more closely match the PV generation profile peaking at mid-day, and be more storage efficient. Effective implementation of energy storage would reduce load variance by charging during off-peak hours and discharging during peak hours, resulting in a more consistent load, which is more readily manageable by system operators, and therefore has lower operations and maintenance costs (Willis et al., 2001). This could occur through some kind of automated and networked market incentives for storage, which are now available for wholesale markets as of February 2018 (St. John, 2018).

Implementation of new bulk generation systems and delivery infrastructure may be more cost-effective in Santa Clarita and Antelope Valley. Those areas are relatively less developed and so land should be more readily available for construction. Future studies should consider the stability and security benefits of redundant central and distributed energy systems, and determine what amount of each, including storage, is optimal for different outage risk tolerances.

4.2. Electrical systems – demand

More energy efficient appliances can reduce total energy consumption, peak load, and load variance. To mitigate risks from heat waves, AC units should be the primary focus of attention. While differences in lighting and other appliance efficiencies are significant for total annual energy consumption, they accounted for less than a 2% difference in peak demand in the models. By contrast, AC units generally accounted for 60–70% of summertime peak demand within residential buildings, and higher air temperatures resulted in a 3–7% increase in demand per 1 °C (1.8 °F). LAC currently has only 45% AC penetration in its residential buildings, meaning that peak demand in just over half of the current building stock does not increase with air temperature. By 2060 almost all buildings could have AC.

Policies that would guide AC manufacturing based on different performance constraints or technologies could be beneficial for reducing the risk of excessive peak demand during extreme heat events. It is possible to design AC units that are more efficient under the hottest conditions or that utilize thermal storage to achieve 'flat' efficiency curves that do not degrade at the hottest temperatures (Bush and Ruddell, 2015; Ruddell et al., 2014). For example, developing a new 'peak performance rating' for ACs at 50 °C (122°F) could be useful to mitigate peak load during extreme heat waves. Doing so could provide incentive for ACs to be designed for more efficient performance at or near such extreme temperatures. Current standards, SEER and EER, are primarily for air temperatures at or below 35 °C (95 °F) (SCE, 2003). The current SEER standard, SEER 13, is optimized to the point that improvements in SEER ratings in the model up to SEER 21 only affected peak demand by a few percent and were slightly counter-effective in some instances where temperatures exceeded 45 °C (113 °F). Water-based evaporative cooling systems are another option that uses much less electric power, but requires water to operate, and are often not accepted by users as the sole-source of air conditioning due to insufficient comfort levels when the weather is both hot and humid (Kumar et al., 2016; Parsons, 2003). Further research may be useful to identify the practicality of hybrid designs.

4.3. Building stock

Population growth will increase peak demand, but where and by how much can be significantly influenced through implementation of policies and practices that affect building energy consumption. For example, current LAC development and proposals favor single-family housing (Stein, 2018), which can readily be built in the less developed northern areas of Santa Clarita, Lancaster, and Palmdale as projected by the DoF. However, building more single-family housing in those areas would increase peak demand and energy consumption per capita by almost twice as much as building multifamily housing in cooler southern areas (Burillo et al., 2019, 2018). While supplying new housing for growth in the in-basin area via densification is generally more energy efficient, it has historically been limited due to complex siting politics around the land that is predominantly zoned for single-family detached housing only (Cooper et al., 2016; Decker et al., 2017). Future research should study the synergistic benefits of densification for other policy goals, as well as, the appeal of different urban designs for different demographics. Much of western Europe, Japan, and Singapore should serve as useful case studies where high density residential and commercial building integration is quite common in the form of walkable “villages.” Such places also have narrow streets, ample transit, parks, shade, and significantly less private auto use per capita. Since the transportation sector has recently overtaken the electricity sector as the top greenhouse gas emitter in the USA (EPA, 2019), further research and development there should be higher priority in achieving greenhouse gas reduction goals. Regardless of building type or urban form, reducing the amount of sunlight absorbed through landscaping, lighter roofs, rooftop solar PV, and rooftop vegetation can significantly reduce electricity demand for cooling and thus peak demand (Hirano, 2005; Levinson et al., 2010; Shashua-Bar et al., 2009; Wang et al., 2006). Likewise, improvements in building thermal insulation would generally improve efficiency, and further research should investigate options for retrofitting older buildings as well as developing advanced materials for new buildings.

4.4. Conclusions

This study is directly useful for California governments and utilities to assess their electricity infrastructure vulnerabilities to climate change and develop long-term adaptation plans and policies. Geographically quantifying vulnerabilities is also valuable for identifying locations where capital-intensive infrastructure projects can meet various stakeholder objectives across service reliability, economics, environment, and security. Our approach can be used to consider vulnerabilities to other forms of climate change (e.g. wildfire, draught, and storms), from other technology change (e.g. intermittent generation and vehicle electrification), and in other infrastructure systems (e.g. gas, transportation, water, and telecom). Entities in other regions can likewise develop similar studies through interdisciplinary collaboration across multiple stakeholder organizations as was critical to produce this work.

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