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Assessment of projected temperature impacts from climate change on the U.S. electric power sector using the Integrated Planning Model®

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HIGHLIGHTS

- We model the impact of rising temperatures on the U.S. power sector.
- We examine temperature and mitigation impacts on demand, supply, and investment.
- Higher temperatures increase power system costs by about $50 billion by the year 2050.
- Meeting demand from higher temperatures costs slightly more than reducing emissions.
- Mitigation policy cost analyses should account for temperature impacts.

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ABSTRACT

This study analyzes the potential impacts of changes in temperature due to climate change on the U.S. power sector, measuring the energy, environmental, and economic impacts of power system changes due to temperature changes under two emissions trajectories—with and without emissions mitigation. It estimates the impact of temperature change on heating and cooling degree days, electricity demand, and generating unit output and efficiency. These effects are then integrated into a dispatch and capacity planning model to estimate impacts on investment decisions, emissions, system costs, and power prices for 32 U.S. regions. Without mitigation actions, total annual electricity production costs in 2050 are projected to increase 14% ($51 billion) because of greater cooling demand as compared to a control scenario without future temperature changes. For a scenario with global emissions mitigation, including a reduction in U.S. power sector emissions of 36% below 2005 levels in 2050, the increase in total annual electricity production costs is approximately the same as the increase in system costs to satisfy the increased demand associated with unmitigated rising temperatures.

1. Introduction

Changes in both the averages and extremes of climate are projected to impact the electric power sector, including effects on electricity demand, supply, and infrastructure (IPCC, 2007; U.S. Department of Energy (DOE), 2013). Changes in temperature are likely to alter the level, timing, and geographic distribution of electricity demand. In particular, higher temperatures are projected to increase electricity demand for cooling. Changes in both temperature and precipitation are likely to affect the magnitude, efficiency, and reliability of electricity supply. For example, increasing ambient air and water temperatures and increasing water scarcity will likely reduce cooling efficiency and available generation capacity of thermoelectric power plants. Changing precipitation patterns may also affect hydropower. In addition, sea level rise, more intense storms, and higher storm surge and flooding can damage infrastructure located along the coast, potentially disrupting electricity generation and distribution. More intense and frequent storm events or wildfires can also damage electricity transmission and distribution systems. (U.S. Department of Energy (DOE), 2013)

Despite its potential vulnerability to climate impacts, only a few studies have quantified the potential costs of climate change for the electric power industry. Most energy-climate studies have quantified the change in residential and commercial energy expenditures associated with a change in temperature using a historical relationship

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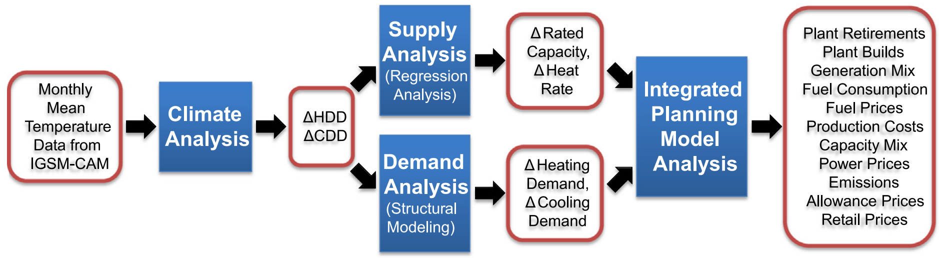

Fig. 1. Study components.

between temperature and energy use. These include studies at the national level (Morrison and Mendelsohn, 1999; Deschenes and Greenstone, 2007; Mansur et al., 2005, 2007; Rosenthal et al., 1995) and studies at the state level (Franco and Sanstad, 2006; Electric Power Research Institute, 2003; Niemi, 2009). A number of different approaches have been used to estimate the impact of rising temperatures on building energy demand[1] and the associated costs. All of these studies have found an increase in electricity demand due to increasing air conditioning needs.

Few studies estimate the impact on electricity production at the national level with sufficient detail to inform effective long-term planning and capital investment. Linder and Inglis (1989) and Hadley et al. (2006) are notable exceptions. Linder and Inglis measured the impacts of temperature change on peak demands and annual energy demand, generating capacity requirements, electricity generation and fuel use, and capital and operating costs at the regional level, using the same utility planning model used in this analysis. Hadley et al. (2006) measured changes in capacity requirements, technologies, and fuel use for nine census regions, as reported by the NEMS model.

The present study analyzes the potential impact of rising temperatures due to climate change on the U.S. electric power sector using similar approaches used in other studies (Rosenthal et al., 1995; Belzer et al., 1996; Amato et al., 2005; Hadley et al., 2006; Zhou et al., 2013, 2014). This analysis translates temperature changes from a climate analysis into changes in heating degree days (HDD) and cooling degree days (CDD) (see Section 3.1.2 for an explanation of HDD and CDD calculations) and uses these to project residential and commercial demand for space heating and cooling. In addition, this study estimates the effects of temperature changes on the efficiency and output of electricity generators (supply), and conducts an integrated analysis of the impact of these factors on the power sector using the Integrated Planning Model (IPM®)[2]. IPM is a well-established dispatch and capacity planning model that is able to systematically quantify the impacts of changes in climate on the operations and long-term planning decisions of the electricity sector. It reflects the unique regional characteristics of the power sector including regional electricity demand and load shapes, and the potential interactions of demand and supply over time. Like the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) used in Hadley et al. (2006), IPM models the construction of new units and retirement of older, less efficient units, thus allowing adaptation of the electricity system in response to climate change.

This study quantifies the impact of changes in air temperature alone; it does not evaluate the impact of other projected, concurrent climate-induced changes such as changes in precipitation, cooling water temperature and availability, and the frequency or duration of extreme weather events. Similar to several studies (e.g., Linder and Inglis, 1989; Hadley et al., 2006), this study measures the energy, emissions, and economic impacts of power system changes due to a change in temperature. It advances the state of knowledge in several respects. First, it incorporates recent projections of temperature change for the United States (an advancement from Linder and Inglis, 1989) to provide detailed power sector impacts such as changes in generation mix and fuel prices. Second, the estimates include impacts of temperature on components of electricity supply, not just demand (unlike Hadley et al., 2006). Third, IPM comprehensively represents the electric power sector, with representations of all electricity production units in the United States that sell into the grid, and provides detailed regional results for 32 model regions. Finally, this study considers a scenario with slower temperature change due to global greenhouse gas (GHG) mitigation, thus allowing comparison between the costs of inaction and the costs of mitigation, which was not addressed in other studies.

2. Material and methods

The analysis consisted of three main steps: the climate analysis (Section 3.1), the electricity demand and supply analysis (Section 3.2), and the integrated power market modeling analysis (Section 3.3). Fig. 1 presents these three main steps, along with the inputs and outputs for each step.

2.1. Overview of IPM

IPM characterizes economic activity in, and linkages between, key components of energy markets (including fuel markets, emission markets, and electricity markets), making it well-suited for developing integrated analyses of impacts on the power sector. IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting total electricity and peak demand requirements over a specified period.

IPM is flexible with respect to data and input assumptions. In general, all inputs to the model are user-defined and case-specific and reflect the specific policy, physical conditions, or market conditions being analyzed. A full list of IPM inputs is illustrated in Fig. A.1. This analysis relies on the data and assumptions used in the U.S. Environmental Protection Agency (EPA) Clean Air Markets Division's Base Case version 4.10_MATS (hereafter referred to as EPA-IPM v4.10).[3] We then

[1] See Scott and Huang (2007) for a summary of numerous studies of climate change impacts on building energy demand.

[2] The IPM modeling platform is a product of ICF Resources, L.L.C., an operating company of ICF International, Inc. and is used in support of its public and private sector clients. IPM® is a registered trademark of ICF Resources, L.L.C.

[3] EPA Base Case v4.10_MATS, the most current available IPM modeling case at the time this work was initiated, was developed by EPA's Clean Air Markets Division with technical support from ICF International. Since that time, EPA has completed its periodic update of the datasets and assumptions supporting its application of the IPM model and used in its regulatory analysis. There are differences between the underlying assumptions in EPA's Base Case version 4.10 and 5.13 and the Base Case results from each—these differences are discussed in Appendix A. For a complete description of the implementation of IPM used in this study, see “Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model” (August 2010) at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html and “Documentation Supplement for EPA Base Case v4.10_MATS—

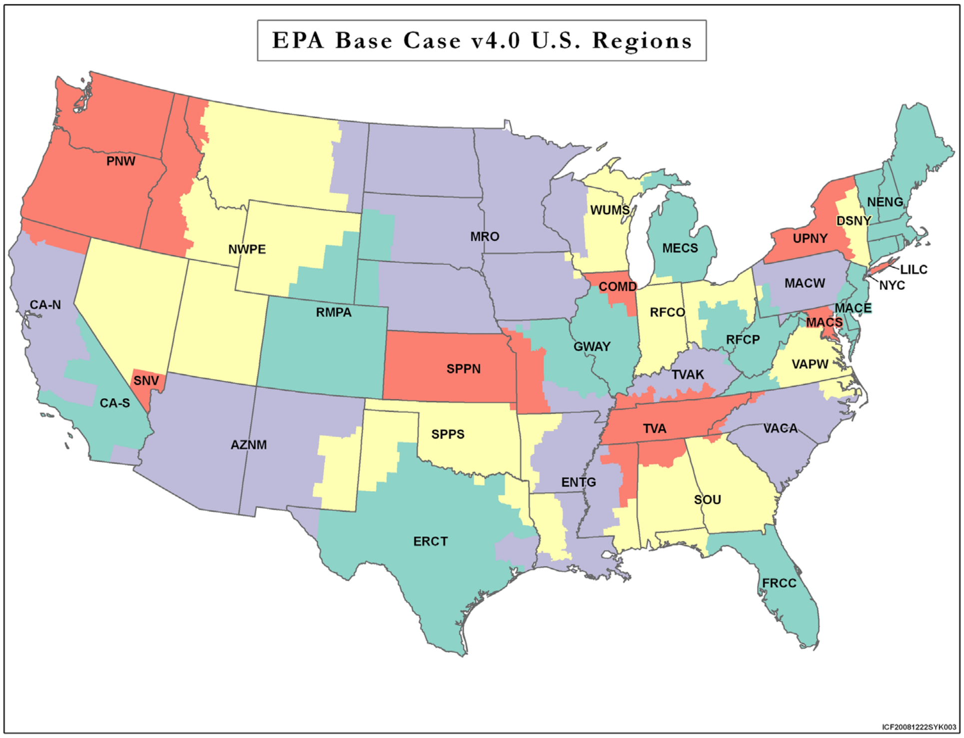

Fig. 2. Model Regions in EPA-IPM v4.10.

adjust demand, heat rate, rated capacity, and emissions constraints inputs for each scenario.

For more information on IPM and EPA-IPM v4.10, see Appendix A and the online documentation for EPA-IPM v4.10. (U.S. Environmental Protection Agency, 2011a,b; U.S. Environmental Protection Agency, 2010)

2.2. Time horizon

IPM is a long-term planning model that provides projections for 30 or 40 years into the future. EPA-IPM v4.10 simulates the planning horizon from 2012 through 2054, represented by six model run years: 2012, 2015, 2020, 2030, 2040, and 2050. Although IPM reports results for model run years only, it takes into account the costs in all years in the planning horizon. In this study, climate data and electricity demand and supply data were aligned with IPM run years.

2.3. IPM regions

Temperature, electricity demand, and electricity supply projections were configured to the same regions used in EPA-IPM v4.10. The regional boundaries of IPM are consistent with the North American Electric Reliability Council regions and the organizational structures of the Regional Transmission Organizations/ Independent System Operators, which administer the transmission grid and system dispatch on a regional basis throughout most of North America. While the total number of regions is flexible, EPA-IPM v4.10 has 32 model regions (see Fig. 2).

This paper aggregates the IPM model results for certain regions. As noted, the IPM supply side analysis presented here is based on a disaggregated model structure with 32 regions. All of the information on the supply side is supported with well-understood information on generating units and local conditions (e.g., transmission constraints). In contrast, the demand side drivers are at a lower resolution (e.g., Census region) and require mapping to the 32 IPM regions using proxies such as population or electricity sales (which are known at the county level and thus are linkable to IPM regions—see Appendix E for more information). As a result, some of the key relationships in the demand models (e.g., square footage per person, persons per household) at the IPM region level may not capture the unique characteristics of each region.

Upon review of the IPM results for the climate scenarios, it seemed that some of the impacts were disproportionate to neighboring regions. We were not comfortable that results were true indicators of the impacts as opposed to a reflection of the assumptions driving the underlying demand analysis. Therefore, we aggregated the results for some IPM regions to have greater confidence in the overall impact estimates. Of the 32 regions, eight smaller regions are combined into three aggregated regions, for a total of 27 regions, as follows: NPCC-NY = UPNY + DSNY + NYC + LILC, VA = VAPW + VACA, and TV = TVA + TVAK.

Additionally, although EPA-IPM v4.10 provides results for the contiguous United States, it models both the U.S. and Canadian power markets in an integrated manner, modeling imports and exports on the basis of economic and transmission constraints. As a result, increases in U.S. electricity demand can be satisfied by increases in U.S. generation or by increases in imports from Canada, up to the limits of transfer capabilities.

2.4. Scenarios

Four scenarios from 2012 through 2050 were analyzed using IPM: a control scenario with no change in future temperature, a reference scenario with temperature change associated with an unmitigated trajectory of global GHG emissions, and two scenarios with slower temperature change associated with lower emissions trajectories that assume global GHG mitigation.

The control scenario (CON) serves as a baseline, depicting a system with a constant climate. The rate of growth in annual

(*footnote continued*)
Updates for Final Mercury and Air Toxics Standards (MATS) Rule" (December 2011) at http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html.

electricity demand (kW h) is based on the U.S. Energy Information Administration, 2010a,b Annual Energy Outlook (AEO) Reference Case, the most recent publically available version at the time of the original analysis. Under the CON scenario, the power system is not affected or constrained by temperature change impacts, nor does the model explicitly incorporate any type of temperature change information (e.g., changes to HDD and CDD over time). The regional load duration curves – or the hourly demand pattern over the course of the year – is based on actual load curves derived from reported data.

The three scenarios with changes in future temperatures rely on temperature data from the MIT Integrated Global System Model (IGSM) (Monier et al., 2014), assuming an equilibrium climate sensitivity of 3.0 °C in all cases. IGSM is an established, comprehensive modeling framework used to analyze the interactions between human activities and the earth system. The major model components include an emissions projection model and a climate model with coupled atmosphere, ocean, land, and ecosystem feedbacks. This set of scenarios was selected because the emissions and temperature pathways are consistent with socioeconomic drivers (e.g., population, economic growth, emissions intensity and energy intensity). This consistency allows us to isolate the effects of temperature and policy on the power sector. The reference scenario (REF) temperatures are based on unmitigated projected emissions from the MIT Emissions Predictions and Policy Analysis (EPPA) model (see Paltsev et al., 2013). EPPA, a component of the IGSM, is a multi-sector, multi-region computable general equilibrium model of the world economy that provides projections of world economic development and emissions along with analysis of proposed emissions control measures (Paltsev et al., 2005). Two emissions mitigation scenarios, the RF3.7 and RF3.7+CAP scenarios, were developed using EPPA to represent a future assuming limitations on global GHG emissions such that the radiative forcing (RF) level in 2100 is stabilized at 3.7 W/m^2. The RF3.7 scenario includes temperature change consistent with a radiative forcing of 3.7 W/m^2, but does not include restrictions on U.S. power sector CO_2 emissions. Although restrictions on U.S. power sector CO_2 emissions would likely be required to achieve a radiative forcing of 3.7 W/m^2, the RF3.7 scenario allows the effects of temperature change on the power sector to be isolated from the effects of CO_2 emissions mitigation in the power sector. The RF3.7+CAP scenario uses the same temperature change as the RF3.7 scenario, and represents CO_2 mitigation by imposing a cumulative cap on U.S. power sector emissions of 73.2 Gt of CO_2 from 2015 through 2050—a 21% cumulative reduction compared to the CON scenario. The 21% cumulative reduction translates to annual emission reductions of 3% in 2015, 4% in 2020, 9% in 2030, 25% in 2040, and 56% in 2050. For more information on the emissions-constrained scenario, see Appendix B.

3. Results and discussion

3.1. Climate analysis

3.1.1. Climate data

The first step of the climate analysis was to obtain monthly mean temperature climate data for the REF and RF3.7 scenarios (the climate output from the RF3.7+CAP scenario is identical to the RF3.7 scenario). Climate projections were simulated within the IGSM framework, which is linked with the National Center for Atmospheric Research's Community Atmospheric Model (Version 3; Monier et al., 2013). Monthly mean temperature data were assembled for 1990 to 2064 to provide a 30-year average of monthly mean temperature centered on each IPM run year and a base year of 2005 to calculate changes in temperature. A 30-year period was used to minimize the influence of inter-annual climate variance (e.g., the impact of an El Niño event on temperature anomalies). Fig. 3 shows the annual average surface temperature anomalies for the contiguous United States projected under the REF and RF3.7 scenarios, demonstrating both the general long-term trend and short-term variability of the scenarios used in this study. For the spatial distribution of these U.S. averages, see Monier et al., 2014.

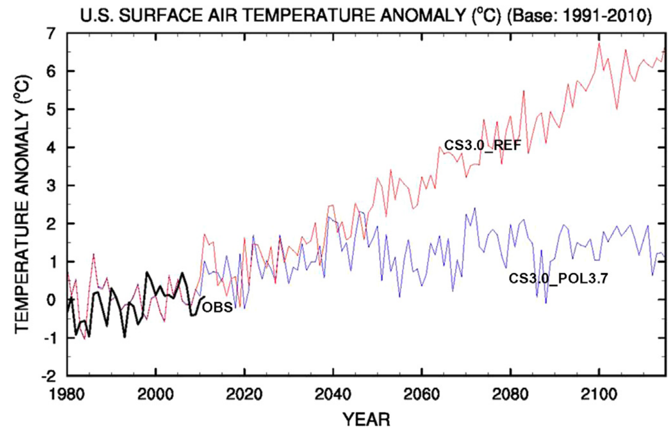

Fig. 3. Projected time series of annual average U.S. surface temperature anomalies through 2115 under REF and RF3.7 scenarios (figure provided by Dr. Erwan Monier, MIT, and adapted from Monier et al., 2014).

3.1.2. HDD/CDD calculations

For each scenario, a 30-year centered average monthly mean temperature was calculated at the center of each 2°-by-2.5° grid cell for each month in each IPM run year, plus the 2005 baseline. Next, the monthly total HDD and monthly total CDD were calculated for each month in each run year (and 2005) for each climate model grid cell using Eqs. (1) and (2) below, where T_{avg} is the 30-year centered average monthly mean temperature (°F) and N is the number of days in the calendar month.

$$\mathrm{HDD} = (65 - T_{avg})N \quad (1)$$

$$\mathrm{CDD} = (T_{avg} - 65)N \quad (2)$$

If the monthly total HDD or CDD value was less than zero, the monthly mean HDD or CDD was set to 0. Next, for each scenario and simulation year, the monthly mean temperature, HDD, and CDD were transformed into averages for each of the 32 IPM regions using an area-weighted averaging method.[4] For each scenario and IPM run year, the changes in the monthly total HDD and monthly total CDD were calculated for each IPM region by taking the difference in their values between the IPM run year (e.g., 2015) and the baseline year (2005).

3.1.3. Climate results

Regardless of the scenario, future temperature increases are generally projected to decrease HDD and increase CDD. Absolute decreases in HDD are greater in magnitude than absolute increases in CDD. However, percent increases in CDD are greater than percent decreases in HDD due to the relatively small CDD baseline in 2005; national average HDD in 2005 (weighted by area) is

[4] A gridded projection cut each IPM region into sections corresponding to each grid cell. As appropriate, a grid cell was split amongst neighboring IPM regions. The area of the grid cells which falls into each IPM region was calculated. Then the average monthly mean temperature, monthly total HDD, and monthly total CDD for each section in each IPM region were multiplied by the corresponding grid area falling within the IPM region. These sectional values were then summed for each IPM region and divided by the area of the entire IPM region.

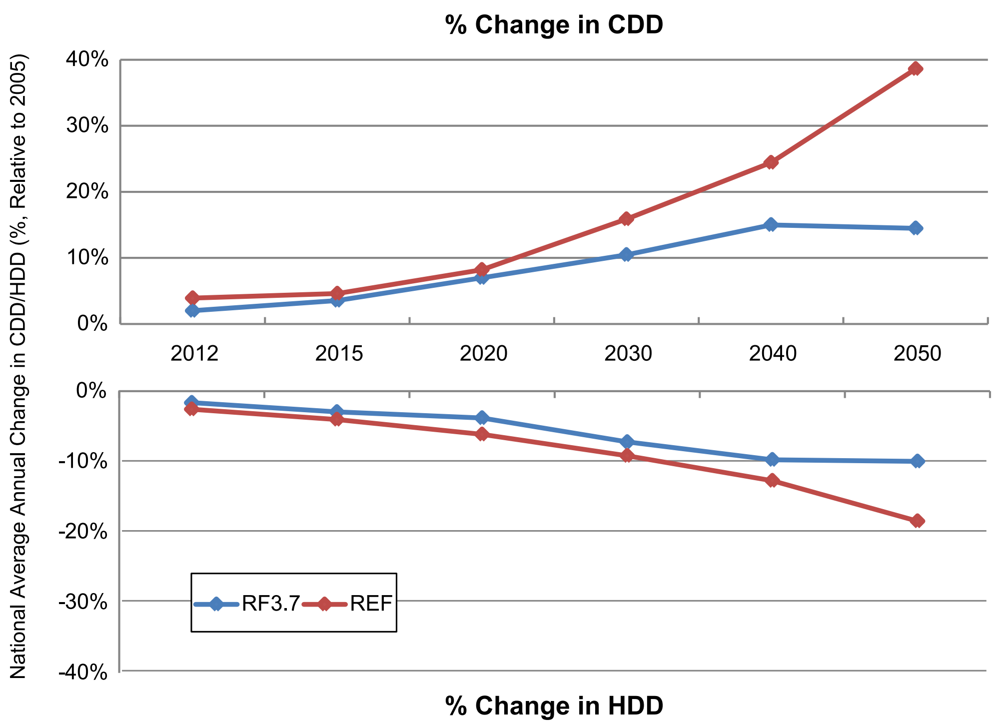

Fig. 4. Percent Change in National (area-weighted) Average Annual CDD and HDD (compared to modeled 2005 values).

nearly 3.5 times greater than national average CDD. Changes in both HDD and CDD are, as expected, greater in magnitude under the REF scenario than under the RF3.7 scenario, due to the larger temperature increase under the REF scenario.

greater percentage decreases in HDD, as shown in Fig. 5. This is due to the higher baseline levels of CDD in the South and the higher baseline levels of HDD in the North in 2005.

$$\begin{array}{llll} \multicolumn{4}{l}{\textbf{\textit{Residential Heating Demand}} =} \\ (\mathit{Population})(\mathit{Residential\ Square\ Footage\ Per\ Capita})(\mathit{HDD})(\mathit{Residential\ Heating\ Intensity\ Factor}) & & & \\ (\text{person}) \quad (\text{sq ft/person}) \quad (\text{degree}-\text{day}) \quad (\text{electricity}/(\text{sq ft} \times \text{degree}-\text{day})) & & & \end{array} \tag{3}$$

$$\begin{array}{l} \textbf{\textit{Commercial Heating Demand}} = \\ (\mathit{Workers})(\mathit{Commercial\ Square\ Footage\ Per\ Capita})(\mathit{HDD})(\mathit{Commercial\ Heating\ Intensity\ Factor}) \\ (\text{person}) \quad (\text{sq ft/person}) \quad (\text{degree}-\text{day}) \quad (\text{electricity}/(\text{sq ft} \times \text{degree}-\text{day})) \end{array} \tag{4}$$

$$\begin{array}{l} \textbf{\textit{Residential Cooling}} = (\mathit{Households})(\mathit{CDD})(\mathit{Residential\ Cooling\ Intensity\ Factor})(\mathit{AC\ Saturation}) \\ \qquad (\text{building})(\text{degree}-\text{day})(\text{electricity}/(\text{building} \times \text{degree}-\text{day})) \quad (\text{unitless}) \end{array} \tag{5}$$

$$\begin{array}{l} \textbf{\textit{Commercial Cooling}} = \\ (\mathit{Commercial\ Buildings})(\mathit{CDD})(\mathit{Commercial\ Cooling\ Intensity\ Factor})(\mathit{AC\ Saturation}) \\ \quad (\text{building}) \quad (\text{degree}-\text{day})(\text{electricity}/(\text{building} \times \text{degree}-\text{day})) \quad (\text{unitless}) \end{array} \tag{6}$$

This study finds that by 2050, national average annual HDD (weighted by area) would decrease by 918 degree-days or 18% under the REF scenario and by 499 degree-days or 10% under the RF3.7 scenario (compared to modeled 2005 values). In the same period, national average annual CDD (weighted by area) would increase by 556 degree-days or 39% under the REF scenario and by 209 degree-days or 14% under the RF3.7 scenario (compared to modeled 2005 values). See Fig. 4 for the percent changes in HDD and CDD over time.

By 2050, southern parts of the country will experience the greater absolute increases in CDD, while northern parts of the country will experience the greater absolute decreases in HDD. Percentage changes follow the opposite pattern: northern parts of the country will experience the greater percentage increases in CDD, while southern parts of the country will experience the

3.2. Electricity demand and supply analysis

Changes in HDD and CDD were used to (1) drive a demand model that estimates changes in electricity demand for heating and cooling services relative to the CON scenario and (2) estimate the effect of warming on electricity supply, specifically the efficiency and net dependable capacity of gas turbine engines and steam turbine generators.

3.2.1. Demand analysis

Electricity demand for heating and cooling are key drivers to overall system electricity demand, a key input to IPM. For this study, changes in residential and commercial demands for cooling and heating relative to the CON scenario were generated for each IPM

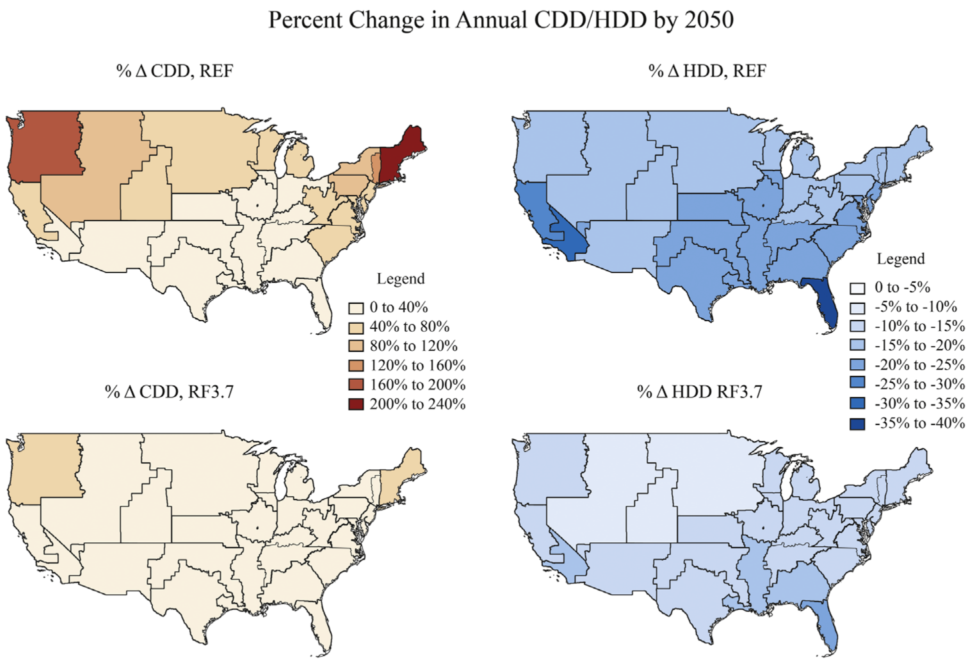

Fig. 5. Percent change in annual HDD and CDD within each IPM region by 2050 from 2005, for REF and RF3.7 scenarios.

region using structural modeling equations. Because the IPM analysis used an existing analytic framework (EPA-IPM v4.10) that relies on an exogenous estimate of system demand based on EIA's Annual Energy Outlook 2010 (U.S. Energy Information Administration, 2010a,b), a methodology was needed to estimate temperature-related changes in sectoral and regional demand consistent with these baseline, system-level electricity demand projections. An implication of using exogenously specified demand is that demand does not respond to power prices (i.e., the price elasticity of demand is zero).

Using the data that underlie the AEO, it was possible to apply a set of structural demand equations (see Eqs. (3)–(6)) that are relatively straightforward and represent the regional, sectoral, and end-use demand structure, as well as end-use saturation impacts. The structural equations were modified from Isaac and van Vuuren (2009) and conceptualize electricity demand as a function of *activity* (e.g., population), *structure* (e.g., square footage, climate), and *intensity* (i.e., electricity used per unit of activity).

These equations were used to calculate changes in residential and commercial heating and cooling for each IPM region and run year, based on changes in HDD and CDD derived from the climate analysis described in the previous section. To calculate changes, new heating and cooling demand was estimated using the equations above, with degree days set equal to the sum of the changes in degree days derived from the climate analysis described in the previous section plus a 10-year average of observed HDD and CDD from 2000 to 2009 from the National Oceanic and Atmospheric Administration (NOAA, 2009a,b). Then, base case heating and cooling demand (from EIA's AER 2010) was subtracted from the estimate of new heating and cooling demand.

Both annual changes in demand and monthly changes in demand were calculated. Annual changes in heating and cooling demand were used to adjust total system demand in IPM. Monthly changes in demand were used to modify load duration curves (see Appendix C). For annual changes, monthly HDD and CDD values for each year and IPM region were totaled to provide annual HDD and CDD.

The Air Conditioning (AC) Saturation term in Eqs. (3)–(6) represents the proportion of households or businesses with air conditioning, and is a function of regional CDD. This proportion varies over time. The saturation values are identical for both Residential and Commercial equations and were estimated using the empirical relationship developed by Sailor and Pavlova (2003) shown in Eq. (7).

$$\boldsymbol{Saturation} = 0.944 - 1.17\,e^{-.00298(\mathrm{CDD})} \quad (7)$$

For more information on the data sources and intensity factors used in these equations, see Appendix D.

Results for the estimates of heating and cooling demand are shown in Figs. 6 and 7. On a percentage basis, the largest increases in cooling demand are in Southern California and the Midwest. The largest declines in heating demand are found in the Pacific Northwest, where relatively mild winter temperatures have led to a high use of electric resistance heating, meaning that increases in heating demand have a greater impact on electricity demand than in other regions (e.g., the Northeast) where other forms of heating (e.g., natural gas heating) are more common. Residential demand and commercial demand have been added together for these plots; since both are driven primarily by changes in temperature (as opposed to changes in the other demand terms in Eqs. (3)–(6)). Despite large absolute changes in HDD nationally, the effects on heating demand are minor compared to the effects on cooling demand since, nationally, electricity's share of cooling demand is much greater than that of heating.

3.2.2. *Supply analysis*

Changes in temperature can affect the available capacity and efficiency of electric generating units. These impacts were examined for two generation sources: (1) gas turbine engines and (2) steam turbine generators, for which capacity and efficiency tend to decline as ambient temperature increases. First, impacts of ambient temperature on unit net dependable capacity (net of plant use, measured in MW) were examined.[5] Second, impacts on heat rate (a measure of conversion efficiency, measured in Btu/kWh) were examined. For more information on how temperature impacts on gas turbine engines and steam turbine generators were calculated, see Appendix F.

[5] Net dependable capacity reflects the impact of ambient temperature on unit performance as well as parasitic loads at the plant (i.e., the energy usage for pumps, fans, etc. at the generating station). Net dependable capacity will be lower than a unit's nameplate rating.

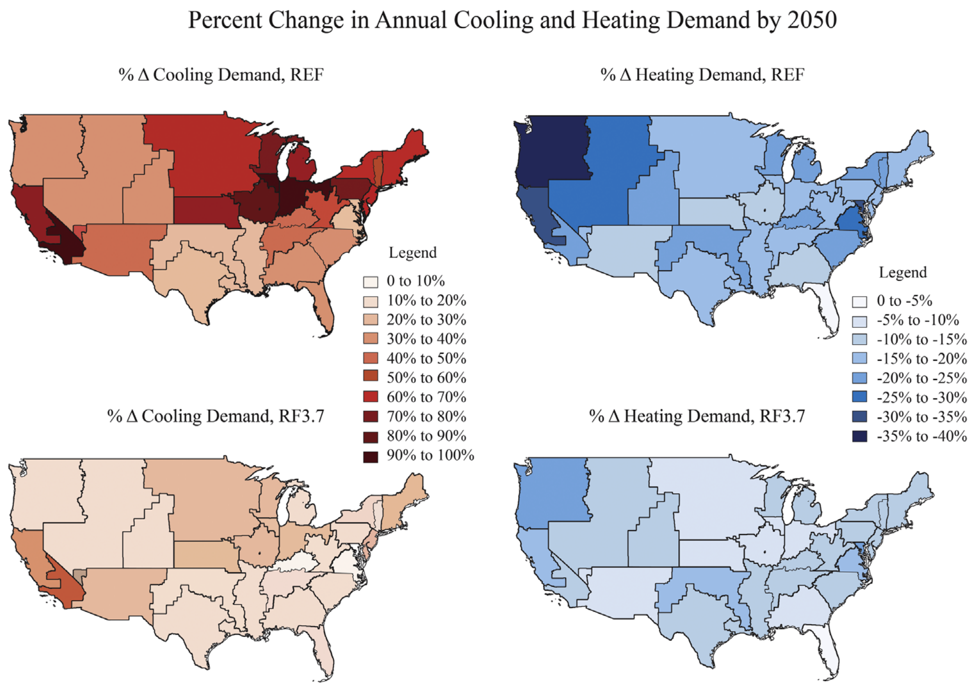

Fig. 6. Percent changes in electricity demand for heating and cooling within each IPM region for 2050 for REF and RF3.7 scenarios.

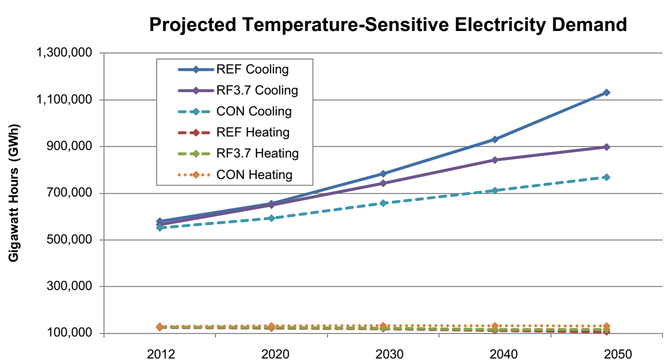

Fig. 7. National heating and cooling electricity demand for CON, REF, and RF3.7 scenarios.

Table 1
Summary of estimated capacity changes caused by loss of efficiency in dry-cooling of turbines.

	Climate-change capacity impact (%)					
	2012 (%)	2015 (%)	2020 (%)	2030 (%)	2040 (%)	2050(%)
RF3.7 gas	−0.3	−0.5	−0.6	−0.9	−1.2	−1.1
RF3.7 steam	−0.1	−0.2	−0.2	−0.3	−0.4	−0.4
REF gas	−0.4	−0.5	−0.8	−1.1	−1.6	−2.0
REF steam	−0.1	−0.2	−0.3	−0.3	−0.5	−0.6

Results indicate that, nationally, net dependable capacity will decrease 2.0% (6.8 GW) for gas turbine engines and 0.6% (3.4 GW) for steam turbine generators by 2050 under the REF scenario. Table 1 shows the percentage change in net dependable capacity due to changes in air temperature for gas turbine engines and steam turbine generators in each model run year.

Nationally, the fleet's average heat rate will increase 0.2% for gas turbine engines and 0.4% for steam turbine generators by 2050 under the REF scenario. A discussion of regional impact on net dependable capacity and heat rate is available in Appendix F.

3.3. Impact of average temperature increases on U.S. electricity generation

Total projected U.S. electricity generation for 2012 through 2050 under the four scenarios diverges more over time as shown in Fig. 8. Rising temperatures under the REF, RF3.7, and RF3.7+CAP scenarios lead to greater electricity demand for cooling compared to the CON scenario. Though the electricity demand is the same under the RF3.7 and RF3.7+CAP scenarios, generation under the RF3.7+CAP scenario is slightly lower because of increased imports of electricity (and leakage of associated emissions) from Canada because there is no emissions limit imposed in Canada. Under the RF3.7+CAP scenario, net imports from Canada in 2050 are 111,490 GW h, compared to 30,061 GW h under the RF3.7 scenario, 31,096 GW h under the REF scenario, and 35,536 GW h under the CON scenario.

The effect of restrictions on power sector CO_2 emissions is clearly visible in Fig. 9. The complete divergence of the CO_2 emissions trajectory under the RF3.7+CAP scenario away from the emissions trajectories under the other three scenarios is a result of the cap on cumulative power sector emissions of 73 $GtCO_2$ from 2015 through 2050. During this 35-year period, the cumulative emissions under the CON scenario are 93 $GtCO_2$. Emissions under the REF and RF3.7 scenarios are 95 and 94 $GtCO_2$, respectively. In 2050, annual power sector emissions under the RF3.7+CAP scenario are 1444 million metric tonnes CO_2 ($MMtCO_2$), 53 percent lower than emissions under the CON scenario, or 36% below 2005 emission levels (2215 $MMtCO_2$). While U.S. emissions in 2050 are significantly lower under the RF3.7+CAP scenario compared with the CON scenario, Canadian emissions in 2050 under this scenario increase from 133.3 $MMtCO_2$ under CON to 163.3 $MMtCO_2$ under RF3.7+CAP.

The gap between the cap and actual emissions from roughly the mid-2030s to the mid-2040s represents banked emissions that are then used from the mid-2040s to 2050 when actual emissions exceed the cap. The CO_2 price representing the marginal cost of abatement under the RF3.7+CAP scenario is plotted on the right-hand axis of this graph.

Fig. 10 shows the change in U.S. generating capacity mix in 2050, relative to the CON scenario, under all three climate change scenarios. In response to higher demands under the REF scenario, there is a 97 GW increase in combined cycle and combustion turbine capacity. In addition, 16 GW of new coal capacity comes on-line in 2050. Under the RF3.7+CAP scenario, there is a marked increase in capacity from nuclear (177 GW), renewable resources (71 GW), and coal with carbon capture and sequestration (CCS) (39 GW). Under emission constraints, these lower emitting types of capacity are less expensive to build and operate than higher emitting coal and gas units. To produce the 39 GW of CCS capacity, 52 GW of coal steam capacity is retrofitted (a CCS retrofit results in a capacity penalty of 25%); new-build CCS is not cost-effective under this scenario. Nonetheless, new nuclear is the predominant compliance strategy of choice, with renewables and CCS retrofits also playing a substantial role. These changes reflect economic and technology expansion limits in EPA-IPM v4.10, which represent assumptions regarding constraints for technologies that require specialized engineering and construction resources.

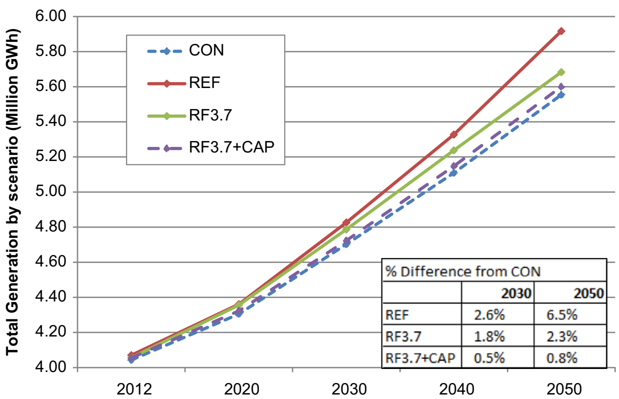

Fig. 8. Total generation under the four scenarios with percent change from CON scenario in 2030 and 2050 shown.

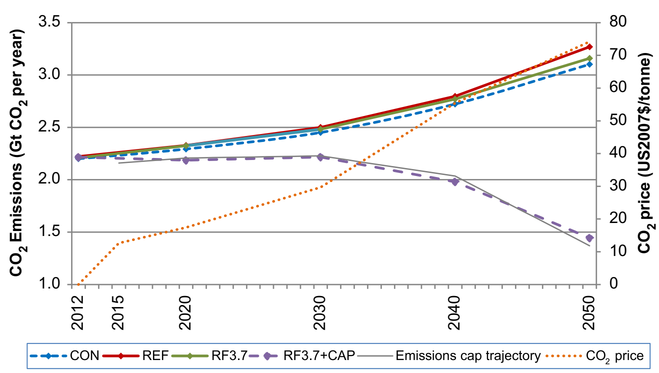

Fig. 9. CO_2 Emissions under each scenario. CO_2 price for the RF3.7+CAP scenario is plotted on the secondary axis on the right.

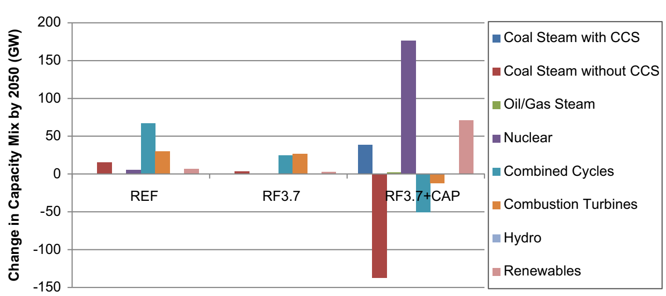

Fig. 10. Change in capacity mix relative to CON scenario, by 2050.

Changes in capacity mix and operations have corresponding effects on system costs, fuel consumption, and power prices. The effect of changes in capacity mix and operations on production costs is illustrated in Fig. 11. In IPM, power production costs encompass 'going forward costs' only (and exclude embedded costs such as the carrying costs of existing generation, costs associated with transmission and distribution, and overhead or administrative costs). Power production costs are a function of fixed operation and maintenance (FOM) costs, variable operation and maintenance (VOM) costs, fuel costs, the annualized capital cost for new investments, and under the RF3.7+CAP scenario, the costs to transport and store CO_2. The cost of CO_2 emissions allowances is not included in these estimates.

The analysis compares the system costs of increasing temperature with the system costs of emissions mitigation. Under the RF3.7+CAP scenario, emissions reduction policies trigger increased investment in nuclear and renewable power production, carbon capture and sequestration retrofits of coal plants, and a shift away from coal steam and combined cycle technologies. Although the technologies are quite different, the change in total system costs by 2050 is similar to the change under the REF scenario. While annual costs in 2050 are $51 bn, or 14% greater than the CON scenario under the REF scenario, they are $48 bn, or 13% greater than the CON scenario under the RF3.7+CAP scenario. Thus, by 2050, production costs under the RF3.7+CAP scenario are similar to production costs under the REF scenario, though the capital costs associated with new investment in nuclear and renewable energy make up a far greater proportion of the increase under the RF3.7+CAP scenario, while fuel costs decline substantially.

Fig. 12 shows the regional breakdown of the projected change in total system costs for 2050 (reflecting costs of U.S. generation), in percentage terms. Under the REF scenario (top panel), demand for electricity increases in response to higher temperatures, necessitating capacity additions and therefore higher system costs across the United States in 2050. This increase in demand also results in a change in the direction, extent, and pattern of imports and exports of power between regions. For example, although the region that primarily consists of Kansas (SPPN) has a low generation baseline under the CON scenario, capacity and generation in

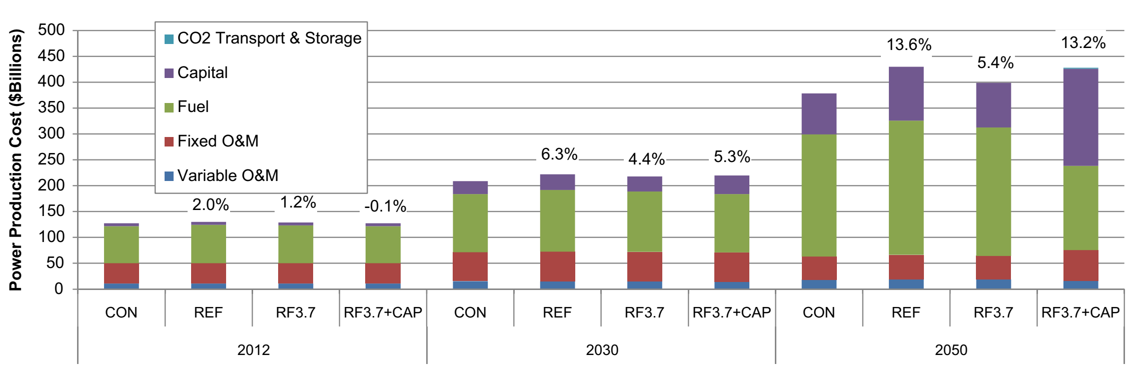

Fig. 11. Power production cost. Percentages indicate change from CON scenario.

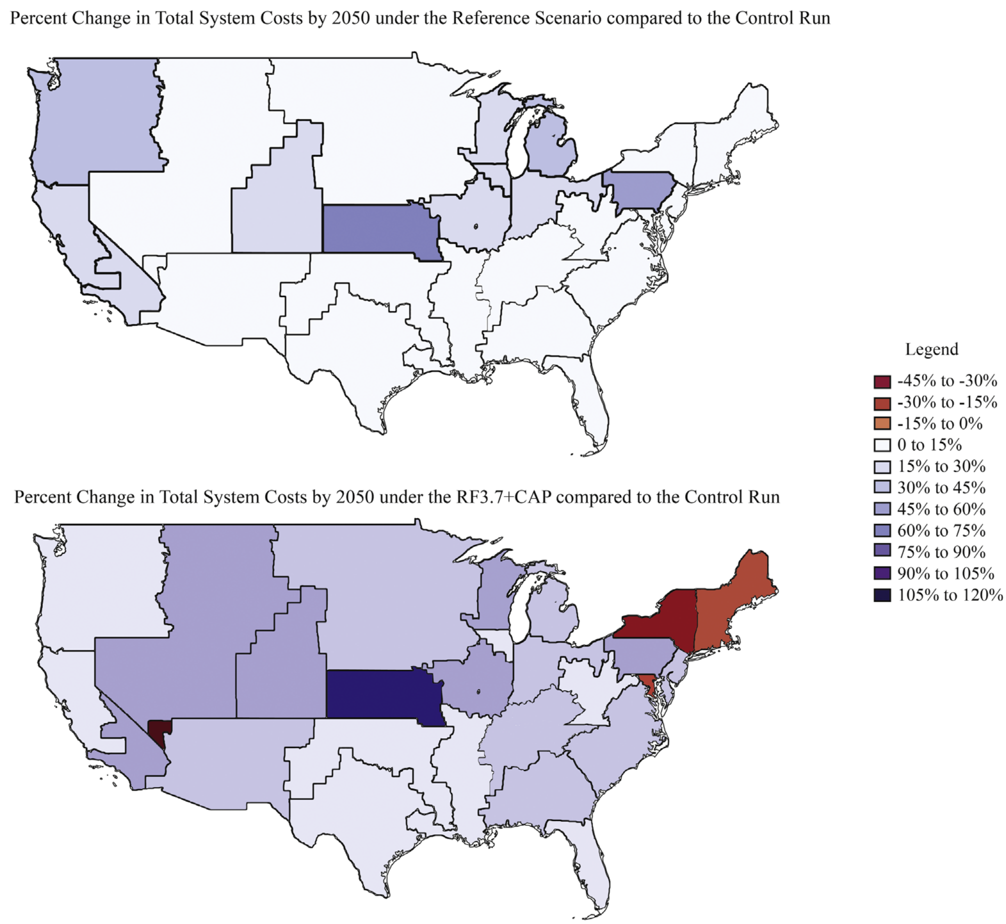

Fig. 12. Regional change in total system costs by 2050 (in percentage terms).

this region increase by 2050 under the REF scenario to meet both internal and export demand, resulting in a substantial percentage increase in system costs. The Pacific Northwest follows a similar storyline. An importer of power under the CON scenario, capacity in this region increases under the REF scenario, resulting in higher system costs in 2050. Though not shown in Fig. 12, regional changes under the RF3.7 scenario follow the same pattern as the changes under the REF scenario, though the magnitude of the changes is smaller due to the smaller temperature change.

Under the RF3.7+CAP scenario (bottom panel), the cap on power sector emissions changes the relative power pricing between regions, which affects power imports and exports between regions, resulting in different impacts on system cost by region. The extent of changes in cost will be a function of the new build capacity and retirement of existing units. As an example, southern Nevada exports power (mainly coal-based) to California under the CON scenario—exports to California account for a large proportion of this small market. Because California is building nuclear capacity by 2050 under the RF3.7+CAP scenario, it reduces imports from Nevada, and Nevada's system costs drop substantially. New England also shows a decrease in system generation costs, as the region increases the percentage of electricity imported from Canada.

The increase in power imports from Canada is substantial under the RF3.7+CAP scenario because Canadian emissions are not capped in this scenario, while U.S. emissions are capped. While the national net cost of power purchases from Canada in 2050 is $2.65 bn under the CON scenario, it more than triples to $8.33 bn under the RF3.7+CAP scenario. However, this increase in expenditures on imports is relatively minor compared to total costs to satisfy U.S. demand; Canadian imports account for about 0.7% of total costs to satisfy demand under the CON scenario and 1.9% of total costs under the RF3.7+CAP scenario.

Changing temperatures and capacity mix also alter future fuel consumption with respect to the CON scenario in 2050, as shown in Fig. 13. The REF and RF3.7 scenarios show little change. Under the RF3.7+CAP scenario, fuel consumption shifts away from coal and natural gas in favor of nuclear and biomass by 2050, due to the higher cost of carbon-intensive fuels and the lower cost of lower emitting technologies under the power sector emissions cap. Coal declines by 53% while natural gas declines by 15.2% relative to the CON scenario. By contrast, biomass increases 144% while nuclear increases more than 13-fold. The very large *percentage* increases in consumption of biomass and nuclear fuel reflect the very low baseline consumption of these fuels under the CON scenario.

To demonstrate how consumers are affected under each scenario, we present projections of retail electricity prices and household electricity expenditures. Fig. 14 shows average retail prices for electricity in 2007 dollars, assuming 100% auction of CO_2 emissions allowances. Alternative assumptions about the treatment of allowances (e.g., some free distribution to generators) would result in lower retail prices. Despite the fact that household electricity demand increases far more under the REF scenario than under either the RF3.7 or RF3.7+CAP cases, the RF3.7+CAP scenario results in higher retail prices (i.e., costs are 13.4% higher in the RF3.7+CAP scenario than in the REF scenario in 2050), reflecting the inclusion of CO_2 emission costs.

Average household expenditures on electricity are shown in Fig. 15, over time and by scenario. This metric is calculated by multiplying retail prices (in 2007 dollars) by residential demand for electricity, divided by the number of households. Although annual household expenditures in the RF3.7+CAP scenario are 12–17% above

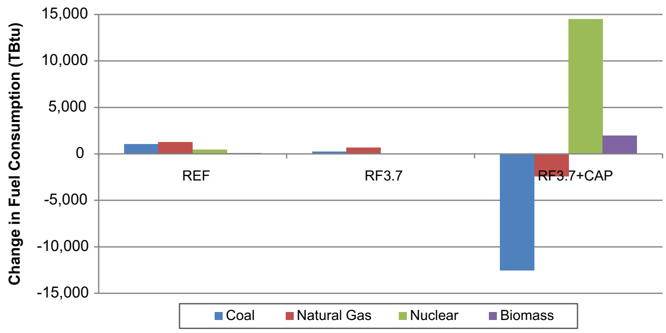

Fig. 13. Change in fuel consumption by 2050.

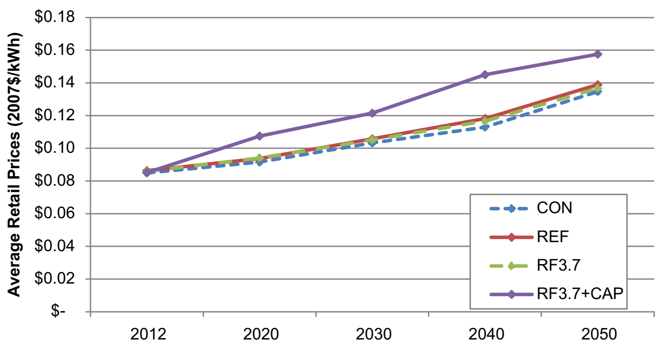

Fig. 14. Average retail prices.

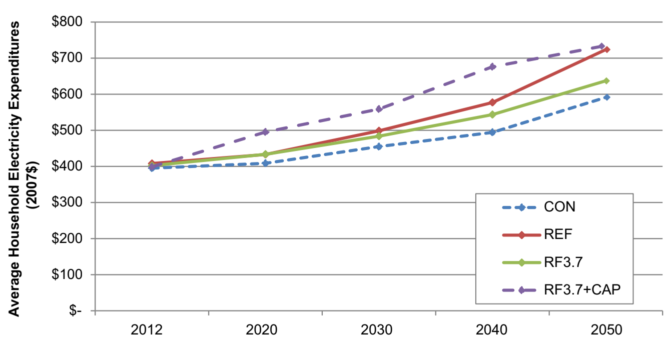

Fig. 15. Average household electricity expenditures.

the REF scenario from 2020 to 2040; by 2050, household expenditures are essentially equal under the two scenarios. The gap in expenditures between the scenarios would narrow had the analysis modeled consumers' demand response to higher prices under the RF3.7+CAP scenario, because the price elasticity of demand for electricity is negative. Taken together, Figs. 14 and 15 show that rising temperatures (e.g., under the REF scenario) have little effect on the marginal cost of generation (represented by retail prices) yet increase total household electricity expenditures because of higher demand.

4. Conclusions and policy implications

This study assesses the impacts of higher temperatures on the U.S. power sector. Incorporating the effects of rising temperatures associated with a business-as-usual GHG emissions scenario (REF), our analysis shows substantial effects on electricity demand and resulting impacts on power sector investments and operating costs. Rising temperatures under a REF scenario result in a 39% increase in average annual cooling degree days by 2050, which is more than double the 18% decrease in average annual heating degree days by 2050. These temperature changes directly affect electricity demand. Under the REF scenario, annual U.S. electricity demand is 6.5% greater in 2050 than under the control scenario (CON), which assumes present-day temperatures are constant over time.

Higher demand in turn requires additional power production and associated investment. Under the REF scenario, there is a substantial incremental investment in combined cycle and combustion turbine units (of 67 GW and 30 GW, respectively) by 2050, which increases annual system costs by $51 billion, or 14%, compared to the CON scenario. Higher demand also increases the GHG emissions that contribute to climate change. The effect of higher temperatures under the REF scenario results in an increase in power sector CO_2 emissions of 5.4% in 2050 over the CON scenario. Demand for, and consumption of, electricity can therefore be substantially affected by a changing climate.

These results highlight the need for regulators, power companies, and regional transmission organizations to account for future temperature change in demand forecasts and investment planning decisions. As illustrated in this study, ignoring the influence of future temperature change may lead power sector planners and decision-makers to underestimate future electricity demand, particularly during periods of peak load.

Underlying the national findings, including the increase in electricity demand, is variation in regional and seasonal demand. This analysis shows greater percentage decreases in heating degree days across southern regions (where heating demand is currently lower), with larger percentage increases in cooling degree days in northern regions (where cooling demand is currently lower). Some regions show particularly extreme changes—for example, cooling demand in some Midwest regions increases over 90% by 2050 under the REF scenario. These regional changes further underscore the need for planners to account for temperature change in regional forecasts and planning and investment decisions.

The analysis also compares the impact of increasing temperature with the impact of emissions mitigation on the U.S. power system. Under the RF3.7+CAP scenario, in which temperature increases are lower than under the REF scenario and emissions are reduced 56% below REF levels in 2050, emissions reduction policies trigger increased investment in nuclear and renewable power production, carbon capture and sequestration retrofits of coal plants, and a shift away from coal steam and combined cycle technologies. Although the technologies are quite different, the change in total system costs by 2050 is similar to the change under the REF scenario. Under the RF3.7+CAP scenario, annual costs are $48 bn, or 13%, greater than the CON scenario. The analysis shows that although mitigation actions increase system costs relative to a baseline that assumes constant temperatures, the system costs for moderate emission reductions are slightly less than the system costs required to meet the additional demand for electricity under a business-as-usual scenario with higher temperatures.

This result illustrates the importance of adequately capturing the effect of expected temperature changes when comparing business-as-usual scenarios with mitigation policy scenarios. Importantly, climate policy analysts should include the costs of inaction in the baseline when assessing the costs of mitigation. Omitting the impact of temperature change artificially inflates the relative system cost of mitigation policies and might mislead policy makers to underinvest in mitigation. For example, the results from this study indicate that the power system costs of moderate emissions mitigation may cost less than meeting the impacts from unmitigated climate change.

This study, which focuses on temperature changes, finds substantial demand-side impacts on the electric power sector. On the supply-side, de-rating effects from higher ambient temperatures were explored and found to be smaller than the demand-side effects. However, additional analysis is needed to better assess potential supply-side impacts. In particular, future work should investigate climate change impacts on hydropower supply and climate change impacts on wet cooling of power generation plants. Additional research into the effects of extreme events on both supply and demand is also needed. Researchers, in collaboration with electric power sector decision makers, could expand the analysis to more fully capture climate change effects like these.

In addition, the results of this study are sensitive to both the assumed climate scenarios (none of which represent the highest or lowest potential changes in emissions and temperature) and the underlying assumptions in the control scenario, including demand levels and growth, fuel prices, and technology costs. It would be beneficial to broaden the range of scenarios in future studies (using multiple climate models, climate parameters, and emissions scenarios) to help bound the range of possible impacts. Future analysis could also test the sensitivities of both climate and socioeconomic assumptions, including demand elasticities, mitigation actions in neighboring countries, and load shape. Future analyses could incorporate updated data, including projections, from EIA's latest Annual Energy Outlook and use EPA's more recent IPM Base Case v5.13. Appendix A includes an explanation of the differences between EPA-IPM v4.10 and EPA-IPM v5.13. Finally, the study could be expanded to analyze impacts on the energy sector more broadly, beyond only electric power sector impacts.

Overall, this analysis illustrates the potential costs to the U.S. power system due to temperature change impacts and emissions mitigation. Even under the assumption of perfect foresight, annual costs to the power sector by mid-century are projected to be about 14% greater than if temperatures were not changing. The magnitude of these impacts justifies incorporating the effects of rising temperatures on the power sector into power sector and climate policy decision-making. Regulators, power companies, and regional transmission organizations, as well as climate policy decision makers, would benefit from additional studies that address the limitations of this study to better understand future scenarios and how they might impact key decisions. By taking an active role in the crafting of research questions for future studies, power sector decision makers will be better prepared to proactively adapt the system to account for projected future conditions through policy and investment decisions.

Acknowledgments

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Appendix A. Overview of IPM

IPM is a well-established model of the electric power sector designed to help government and industry analyze a wide range of issues. The model characterizes economic activities in key components of energy markets—fuel markets, emission markets, and electricity markets. Since the model captures these integrated linkages it is well-suited for developing integrated analyses of impacts on the power sector.

As such, IPM has been used by government and industry for over 30 years in support of analyses related to environmental policy making, resource planning, and compliance and investment decision-making. It has been used extensively by the U.S. Environmental Protection Agency in support of economic analysis for all of the major environmental regulations promulgated in the last two decades including the NOx SIP Call, the Clean Air Rules of 2004 (CAIR, CAMR, and CAVR), the Mercury and Air Toxics Standards (MATS), and the GHG New Source Performance Standards (NSPS), among others (U.S. Environmental Protection Agency, 2013). In addition, IPM has been used recently for a number of climate- and energy policy-related studies including Natural Resource Defense Council's (NRDC) "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters" (Lashof et. al., 2013), the Regional Greenhouse Gas Initiative (RGGI) (2013) IPM Analysis: Amended Model Rule, and the 2014 Draft New York State Energy Plan (New York State Energy Planning Board, 2014).

IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting electricity and peak demand requirements over a specified period. More specifically, IPM's objective function is to minimize the total, discounted net present value (in this study a discount rate of 6.15% is used) of the costs of meeting demand, generating system operational constraints, and environmental regulations over the entire planning horizon (in this case, 2012–2054). The objective function represents the summation of all the costs incurred by the electricity sector. The total resulting cost is expressed as the net present value of all the component costs. These costs, which the linear programming formulation seeks to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs.

IPM solves for a number of decision variables (the model's outputs) including variables related to generation, capacity, transmission, emission allowances, and fuel. IPM projects total generating capacity additions and economic retirements; generation dispatch; emissions for SO_2, NO_x, Hg, and CO_2; permit prices (in $/ton) for capped emissions; natural gas and coal consumption and prices; and production costs, including total expenditures for fuel, variable operation and maintenance (VOM) costs, fixed operation and maintenance (FOM) costs, and annualized capital investments. In its solution, the model considers a number of key operating or regulatory constraints (e.g., emission limits, transmission capabilities, renewable generation requirements, and fuel market constraints) that are placed on the power, emissions, and fuel markets.

EPA-IPM v4.10 represents the electricity demand, generation, transmission, and distribution within 32 regions (see Section 2.3) as well as the inter-regional transmission grid for the continental United States. The entire existing utility power generation fleet of approximately 15,000 units, including renewable resources, as well as independent power producers and cogeneration facilities that sell electricity to the grid are represented.

IPM provides a detailed representation of new and existing resource options, including fossil fuel generating options (coal steam, gas-fired simple cycle combustion turbines, combined cycles, and oil/gas steam), nuclear generating options, and renewable and non-conventional (e.g., fuel cells) resources. Renewable resource options include hydropower, wind, landfill gas, geothermal, solar thermal, solar photovoltaic, and biomass. IPM incorporates a detailed representation of fuel markets and endogenously forecasts fuel prices for coal, natural gas, and biomass by balancing fuel demand and supply for electric generation. The model also includes detailed fuel quality parameters to estimate emissions from electric generation.

IPM is a flexible modeling tool for obtaining short- and long-term projections of dispatch, capacity investments, and emissions in the electricity generation sector. The model uses a detailed engineering-economic approach, which forecasts all major parameters in the power sector—wholesale electricity prices, generation dispatch, transmission flows, capacity expansion decisions, fuel consumption and prices, environmental compliance decisions, and allowance prices, among other factors. It uses a linear programming approach to maximize profit, subject to operational

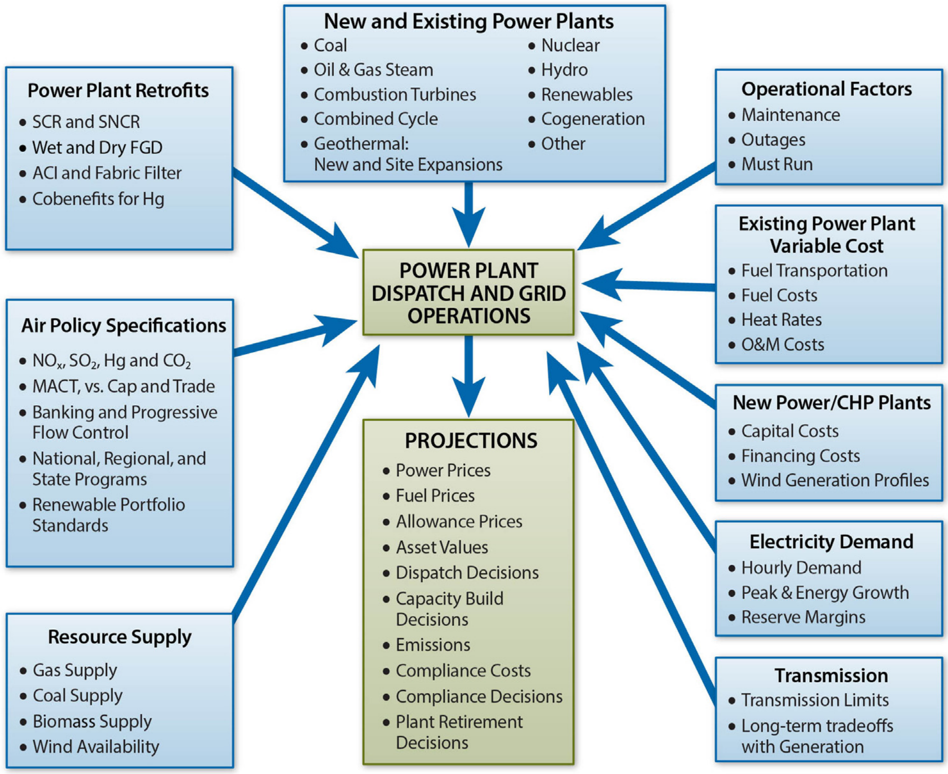

Fig. A.1. Key inputs and outputs in IPM .

constraints. Importantly, the projections obtained using IPM are not statements of what will happen but what might happen given the assumptions and methodologies used.

IPM is flexible with respect to data and input assumptions. In general, all inputs to the model are user-defined and case-specific. In general, key parameters are defined to be consistent with the policy question or market analysis being addressed. IPM requires input parameters that characterize the U.S. electricity system, economic outlook, fuel supply, and air regulatory framework. Fig. A1 shows the key input parameters required by IPM, as well as IPM's output projections.

At the time this work was initiated, the most current available IPM modeling case was EPA's Base Case v4.10_MATS (U.S. Environmental Protection Agency, 2011a,b, U.S. Environmental Protection Agency, 2010a). Since that time, EPA has completed its periodic update of the datasets and assumptions supporting its application of the IPM model and used in its regulatory analysis. There are differences between the underlying assumptions in EPA's Base Case version 4.10 and 5.13 and the Base Case results from each. These different assumptions include lower rates of electricity demand growth as taken from the EIA Annual Energy Outlook (AEO) (0.085 % annual average rate of growth (AARG) in v4.10 based on AEO 2010, vs. the 0.078% AARG in v5.13 based on AEO 2013) and lower delivered natural gas prices in the long term ($7.64/MMBtu in 2040 in v4.10 vs. $6.87/MMBtu in v5.13). Nuclear capacity levels in v4.10 are higher than in v. 5.13 in 2050 due to the addition of about 6 GW of new capacity in the former case. There are also structural differences between the cases (such as the regional structure) and differences in policy environment. Base Case v5.13 includes the implementation of MATS and the Clean Air Interstate Rule (CAIR) while v4.10 includes MATS and the Cross States Air Pollution Rule (CSAPR).

Because of these differing assumptions, projected generation mix and emissions levels, among other things, differ between the two cases. For example, the lower natural gas prices result in a much higher share of the generation mix being fueled by natural gas (42% share of the generation mix in 2050 in v4.10 vs. 53% in v5.13). Carbon emissions are about 15% lower in 2050 in the v5.13 case as compared to emissions in the v4.10 case.

Given the complexity of the power system and other differences between the cases, it is difficult to speculate on the potential impacts of these differences on the results of the study. Given the changes in the timing and level of demand and differences in relative fuel prices, it might be the case that the total impacts of higher temperatures would be lower. For example, lower absolute levels of demand in the v.5.13 case and lower growth would be expected to lower the impacts of temperature change in absolute terms. It is more difficult to speculate on how capacity expansion and dispatch might change as a result of the differences, particularly given the changes in regulations.

Although it is the case that there would be differences in this study's absolute results due to the differences in the Base Case assumptions, we expect that the relative impacts for the REF and RF3.7 cases – measured as the percentage differences between the control scenario and the temperature change scenarios – would be similar.

Future supply and demand analyses using AEO 2013 demand forecasts as a benchmark should also be aware of a change in the treatment of climate in the AEO forecasts. Prior to AEO 2013, the AEO demand analysis assumed HDD and CDD remained constant. The AEO 2013 adjusts residential and commercial heating and cooling demand by linearly extrapolating the 30-year trend of HDD and CDD for each state. Note that the temperature trends in the present analysis are rising exponentially; a linear trend based on historic temperatures would be biased low.

Appendix B. Emissions-constrained scenario

The underlying pathway of emissions reduction (shown in Fig. 9) for this study is based on the percentage reduction in power sector emissions found in Calvin et al. (2013), between the REF and RF3.7

scenarios. This U.S. power sector emission reduction is therefore in line with the reduction that would likely be required to achieve the radiative forcing assumed in both the RF3.7 and RF3.7+CAP scenarios. The RF3.7+CAP scenario includes annual emission reductions compared to business-as-usual of 3% in 2015, 4% in 2020, 9% in 2030, 25% in 2040, and 56% in 2050, which results in the aforementioned 21% cumulative reduction. To see the translation of these percentages into absolute terms, see Fig. 9. For perspective, this cumulative reduction level in the power sector is less stringent than the levels seen in analyses of U.S. legislative proposals such as the American Power Act, which exceeded 80%. Under the RF3.7+CAP scenario, full banking is allowed, wherein emission reductions below the cap may be saved and used in future years. Meanwhile, borrowing is not allowed, wherein emissions allocations from future years are applied to meet the current year cap. Note that the RF3.7+CAP scenario limits emissions only in the U.S. Canadian emissions are not capped.

Appendix C. Incorporating load shifts into IPM

Monthly changes in demand, calculated using the structural equations described in Section 3.2.1, were used to modify the IPM's regional load duration curves, which represent the distribution of demand across the year. Monthly changes in demand were applied uniformly to load duration curves under the simplifying assumption that the absolute change in monthly demand for each region would be uniform across the days and hours in each region for that same month.

This assumption was tested in a separate sensitivity analysis using temperature data from another general circulation model (GCM). The analysis found that the estimates of change in HDD/CDD do not differ substantially when using daily or monthly values. For all segments of the regional load duration curves, except the top 1%, the daily and monthly HDD and CDD values differ by less than 6% and typically 3% over all of the regions. For the top 1% of the load duration curve, the daily and monthly CDD values show a similar difference except for Northeast (monthly is 20% higher than daily) and Northwest (monthly is 20% lower than daily). The top 1% of the daily and monthly HDD values are within 3% of each other except in the Midwest in which the monthly HDD estimates are 12% higher.

The differences between daily and monthly HDD/CDD values may not necessarily hold true for all GCMs and depends upon the difference in intra-monthly variability between the GCMs. Given the other assumptions (e.g., regional aggregation, number of load curves), this particular assumption is reasonable. IPM captures load curves using two seasonal, 6-segment representations of demand. IPM converts the representative 8760 hour load curve for each region by splitting it into two seasons (a five-month summer – May through September, and a seven-month winter – October through April), and then ordering the hourly loads from highest to lowest and cutting them into six segments representing the average loads for those blocks of hours. Figs. C.1 and C.2 show the change in national load duration curves for summer and winter by 2050 under each scenario. The increased summer demand, resulting from increased cooling demand, is clearly evident in the altered load duration curves,

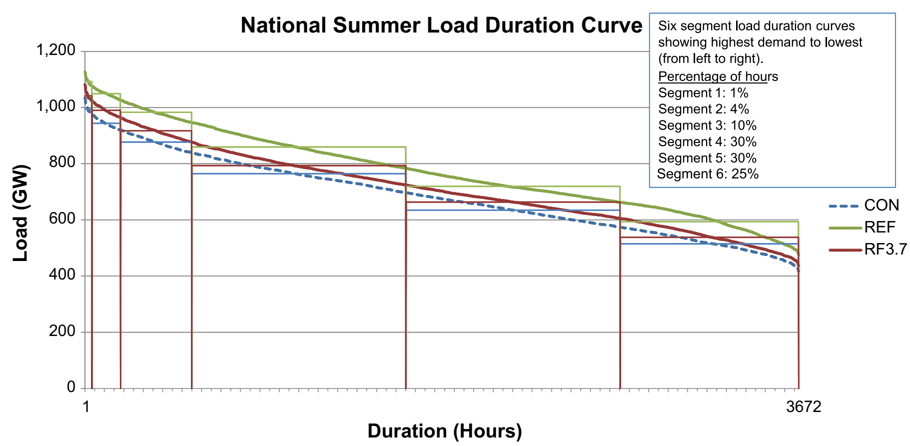

Fig. C.1. National load duration curve for summer, showing changes by 2050 under the REF and RF3.7 scenarios .

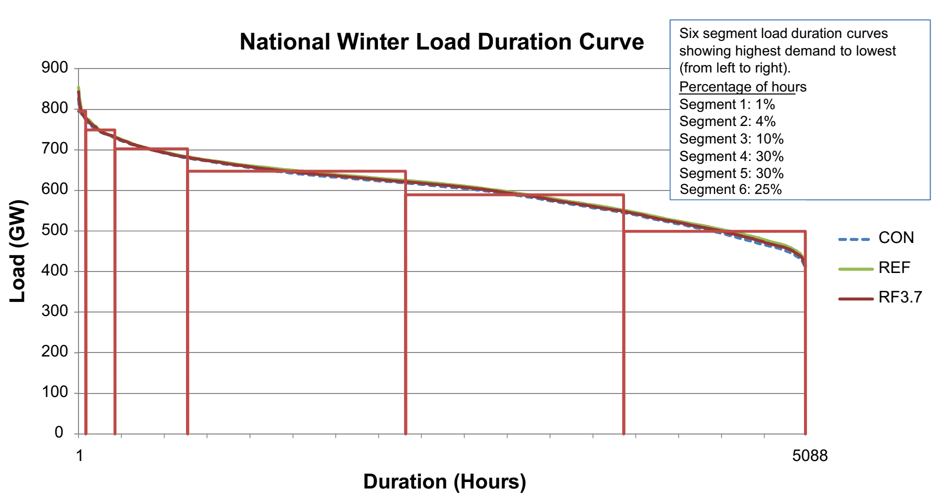

Fig. C.2. National load duration curve for winter, showing changes by 2050 under the REF and RF3.7 scenarios .

particularly for the REF scenario. Meanwhile, the change in winter demand is relatively minor and actually shows a slight increase, due to the low electricity intensity of decreased heating demand and increased cooling demand during parts of the seven-month winter load duration curve.

Appendix D. Demand Analysis Data Sources and Intensity Factors

The data sources for the population, employment, and square footage terms in Eqs. (3)–(6) are shown in Table D-1. These factors change over time, driven by assumptions about regional population growth and its concomitant effect on employment, households, and workspace. Details about processing performed to convert these variables into the appropriate spatial or temporal terms (e.g., converting state-level demand data and projections into estimates for IPM regions) are presented in Appendix E.

The heating and cooling Intensity Factor terms in Eqs. (3)–(6) represent the consumer demand for electricity per physical unit per degree-day. For heating, the physical unit is square feet of floor space. For cooling the physical unit is buildings. Intensity was derived from regional scale data regarding past and projected demand for heating and cooling; past observations of HDD/CDD; and past and projected information about population, employment, and building space. Although intensities can change over time and vary among regions, the historic HDD and CDD data used to calculate the Intensity Factors are static (a 10-year average of observed HDD and CDD from 2000 to 2009), and do not include any information about future change in temperature. Thus, the Intensity Factors can be thought of as a semi-empirical measure of the technology, efficiency, and consumer preference that drive demand in a particular region.

Appendix E. Processing data to appropriate spatial terms

Many of the non-climate data described in Table D-1 are aggregated at the Census region level and required processing to map them to the appropriate IPM geographic basis used in the demand and power sector modeling. To appropriately map data inputs, a series of *mapping shares* were developed. These indicate what share of the Census region's data should be mapped to an IPM region. For example, this mapping tells us what percentage of the Northeast Census region's electricity demand should be mapped to the IPM LILC region. Mapping shares were developed based on a set of historical data and applied for the entire forecast period.

Various proxies are used to map the Census region-based data to the IPM regions depending on what data is being mapped. For example, historical electricity sales are a good proxy for future electricity demand but a poor proxy for housing square footage. Housing stock is a better proxy in the latter case. Similarly, translating CDD and HDD from census to IPM region is best done based on population as a proxy for exposure to climate changes.

This approach for translating data on one geographic basis to the IPM regional structure is routinely done in this type of analysis. For example, electricity forecasts from EIA on a Census region are mapped to IPM regions on the basis of EIA sales data as reported by utilities (Form 861). In this case, historic sales data reported by each utility is allocated to each state (and to counties where states do not wholly reside in an IPM region) in which the utility operates. These allocated data are summed for all the states and counties in an IPM region (which generally includes data from one or more utilities). Based on these assignments, several mapping shares can be developed, including Census-to-IPM region and state-to-IPM region. Similar processes were followed for other mapping shares.

The residential and commercial demand mapping shares were created using EIA sales data as described above. The population mapping shares were created using 2008 Census county level population data mapped to IPM regions. The result was a share of each Census region that should be allocated to each IPM region.

Households and total household square footage was calculated using the household regional mapping share. Employment, commercial floor stock, commercial buildings, and CDD and HDD were mapped from the Census region-level to the IPM regional-level using the population mapping share.

Appendix F. Temperature impacts on gas turbine engines and steam turbine generators

The study analyzed the impacts of temperature for 7786 gas turbine engines and 2,401 steam turbine generators located in the contiguous United States, as contained in U.S. EPA's National Electric Energy Data System (NEEDS) version 4.10.16 (U.S. Environmental Protection Agency, 2010b).

Table D.1
Data sources for non-climate inputs to the demand equations.

Input	Source
Population	U.S. Census Bureau (2005)
Number of households	U.S. Energy Information Administration (2005a)
Residential total square footage	U.S. Energy Information Administration (2005a)
Average U.S. home size	U.S. Census Bureau (2012)
Average total square footage for U.S. housing units	U.S. Energy Information Administration (2003a)
Regional weighting for degree days	NOAA (2009)
Heating demand per household	U.S. Energy Information Administration (2005b)
Cooling demand per household	U.S. Energy Information Administration (2005c)
Residential heating and cooling demands	U.S. Energy Information Administration, 2010a,b Annual Energy Outlook 2010, personal communication with William Comstock, 2011
Residential housing	U.S. Energy Information Administration, 2010a,b Annual Energy Outlook 2010, personal communication with William Comstock, 2011
Commercial heating and cooling demands	U.S. Energy Information Administration, 2010a,b Annual Energy Outlook 2010, personal communication with William Comstock, 2011
Commercial floor stock, commercial buildings, median square feet per commercial building	U.S. Energy Information Administration (2003b)
Employment	U.S. Energy Information Administration, 2010a,b Annual Energy Outlook 2010, personal communication with William Comstock, 2011
Number of malls (assumed all are cooled with electricity)	U.S. Energy Information Administration (2003b)
Number of non-mall buildings cooled with electricity	U.S. Energy Information Administration (2003c)

Gas turbine engines

At higher ambient temperatures, air becomes less dense. Because gas turbines take in air at a constant volumetric rate, the mass flow of air is less at higher temperatures, reducing the turbine's capacity. Published information on performance characteristics with respect to ambient temperature conditions are available on these unit types, including from the original equipment manufacturer (OEM) (e.g., Smith et. al., 2001) and from technical publications, such as the Electric Power Research Institute's Technical Assessment Guide (TAG) (EPRI, 1993). To quantify this impact, general data on temperature-performance relationships published EPRI's 1993 TAG were used. This document provides performance data on both capacity and heat rate impacts as a function of temperature. It includes information on both combined cycle and simple cycle gas turbine engines.

The present study used the following approach to estimate the impact of temperature change on rated capacity and heat rate for each gas turbine engine included in the EPA NEEDS database.

1. First, regression equations were fitted to the representative performance data for combined cycle and simple cycle gas turbines as provided in technical publications. For each of these technologies, equations relating capacity and heat rate to ambient temperature were derived. The equations are applied using CON scenario temperatures and temperatures under each of the climate scenarios. The difference between each climate scenario and the CON scenario represents the change in capacity (or heat rate) due to the temperature change. Illustrative baseline regression equations for existing units and their application are shown below. The actual equations that are applied are unique to each unit, with unique intercepts and coefficients, as the results are scaled to account for each unit's capacity and full load heat rate, relative to the reference unit.

$$\begin{aligned}\text{Climate Scenario Capacity} &= -0.37 \times (\text{Control Temperature}(^\circ F) \\ &\quad + \text{Climate Scenario Temperature Increase}(^\circ \text{F})) \\ &\quad + 122\end{aligned}$$

$$\text{Impact on Capacity} = \text{Climate Scenario Capacity} - \text{Baseline Capacity}$$

$$\begin{aligned}\text{Climate Scenario Heat Rate} &= 5.02 \times (\text{Control Temperature}(^\circ \text{F}) \\ &\quad + \text{Climate Scenario Temperature Increase}(^\circ \text{F})) \\ &\quad + 9908\end{aligned}$$

$$\text{Impact on Heat Rate} = \text{Climate Scenario Heat Rate} - \text{Baseline Heat Rate}$$

2. Baseline temperature data sets were developed from PRISM (http://www.prism.oregonstate.edu/) using average summer temperatures from 1990 to 2010. PRISM's high resolution monthly datasets of average daily maximum and minimum temperatures allowed mapping of summer temperatures to summer capacity ratings of each unit. These monthly averages were divided into summer and winter seasons (according to the seasonal splits defined in Appendix C—a five-month summer of May through September and a seven-month winter of October through April); in addition, an annual average was created.

Steam turbine generators

Steam turbines use steam as the working fluid, rather than a combusted mixture of air and fuel, and thus are not as affected as gas turbines by ambient temperature conditions. Warmer ambient temperatures decrease the ability to create a vacuum in their cooling condensers and thus unit capacity is affected to a limited degree. For steam turbine generators, most of the fabrication work is done on-site, and thus performance characteristics vary on a case-by-case basis and are not readily available. As a result, empirical data based on EIA 860 were used to estimate the relationship between temperature and capacity and heat rates. Note that this study does not analyze the impact on steam turbines from changes in water temperature, which is more substantial than the impact from changes in ambient temperatures.

The following process was used to estimate the impact of temperature change on rated capacity and heat rate for each IPM steam-turbine based unit.

1. First, the summer and winter rated capacity and geographic coordinates were obtained at the county level for all steam-turbine based power stations from Energy Information Administration Form 860 (U.S. Energy Information Administration, 2010a,b). These are the same plants currently modeled in EPA-IPM v4.10.
2. Next, the plants were mapped by their latitude and longitude coordinates and matched to a specific temperature-grid cell. This location information was then matched with an associated summer and winter average temperature from 1990 to 2010 as performed in step #2 for the gas-turbines.
3. Next, regression equations were developed for a typical steam turbine generator based on historical temperature and rated capacity data points from EIA 860 data. The equations are applied using CON scenario temperatures and temperatures under each of the climate scenarios. The difference between each climate scenario and the CON scenario represents the change in capacity (or heat rate) due to the temperature change. Illustrative baseline regression equations and their application are shown below. The actual equations that are applied are unique to each unit, with unique intercepts and coefficients, as the results are scaled to account for each unit's capacity and full load heat rate relative to the reference data.

$$\begin{aligned}\text{Climate Scenario Capacity} &= -0.21 \times (\text{Control Temperature}(^\circ F) \\ &\quad + \text{Climate Scenario Temperature Increase}(^\circ F)) \\ &\quad + 215\end{aligned}$$

$$\text{Impact on Capacity} = \text{Climate Scenario Capacity} - \text{Baseline Capacity}$$

$$\begin{aligned}\text{Climate Scenario Heat Rate} &= 10.30 \times (\text{Control Temperature}(^\circ F) \\ &\quad + \text{Climate Scenario Temperature Increase}(^\circ F)) \\ &\quad + 9281\end{aligned}$$

$$\text{Impact on Heat Rate} = \text{Climate Scenario Heat Rate} - \text{Baseline Heat Rate}$$

Regional results

Regionally under the REF scenario, impacts by 2050 on net dependable capacity vary from a decrease of 1.0% in FRCC (Florida) to a decrease of 3.3% in MRO (Midwest) for gas turbine engines and from a decrease of 0.3% in FRCC (Florida) to a decrease of 0.9% in WUMS (Wisconsin-Upper Michigan) for steam turbine generators.

Regionally under the REF scenario, impacts by 2050 on heat rate will vary from an increase of 0.1% in FRCC (Florida) to an increase of 0.2% in NWPE (Northwest Power Pool East) for gas turbine engines and from an increase of 0.2% in FRCC (Florida) to an increase of 0.5% in NWPE (Northwest Power Pool East) for steam turbine generators.

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