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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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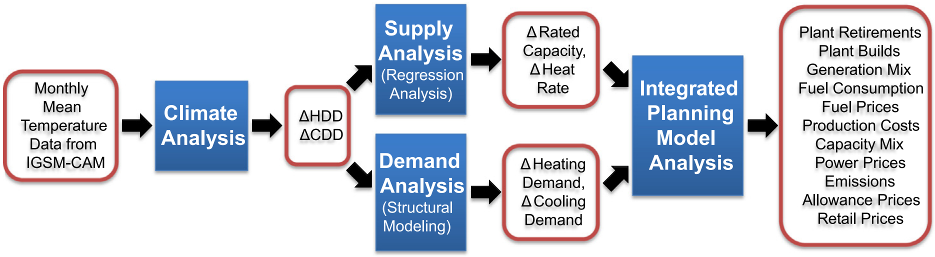

Fig. 1. Study components.

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

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[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—