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ORIGINAL ARTICLE

Assessing compounding climate-related stresses and development pathways on the power sector in the central U.S.

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Abstract
Future configurations of the power system in the central region of the USA are dependent on relative costs of alternative power generation technologies, energy and environmental policies, and multiple climate-induced stresses. Higher demand in the summer months combined with compounding supply shocks in several power generation technologies can potentially cause a "perfect storm" leading to failure of the power system. Potential future climate stress must be incorporated in investment decisions and energy system planning and operation. We assess how projected future climate impacts on the power system would affect alternative pathways for the electricity sector considering a broad range of generation technologies and changes in demand. We calculate a "potential supply gap" metric for each pathway, system component, and sub-region of the US Heartland due to climate-induced effects on electricity demand and power generation. Potential supply gaps range from 5% in the North Central region under mild changes in climate to 21% in the Lakes-Mid Atlantic region under more severe climate change. We find increases in electricity demand to be more important in determining the size of the potential supply gap than stresses on power generation, while larger shares of renewables in the power system contribute to lower supply gaps. Our results provide a first step toward considering systemic climate impacts that may require changes in managing the grid or on potential additional capacity/reserves that may be needed.

Keywords Power generation · Electricity demand · Climate stress · US Heartland

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1 Introduction

There are a wide range of electric generation technologies that could play a major role in producing power in the central USA, sometimes referred to as the US Heartland. For our purposes, we are identifying the "Heartland" as largely the Mississippi River drainage basin. Thermal power generation (coal, gas, nuclear) plays a significant current role in this region (68% in 2020); however, large areas are also notable for having high-quality wind and solar resources, while hydropower is an important resource in other parts of the region. The costs of generation from various sources have changed over the past decades. Low natural gas prices in recent years have favored gas generation over coal. At the same time, there has been an ever greater deployment of wind turbines (38% of generation capacity added from 2010 to 2020). Then, in the past few years, the cost of solar photovoltaics has fallen, providing a greater edge for this technology. State and federal energy policy, through tax incentives and renewable energy requirements, has also contributed to a shift in generation sources, as have tighter restrictions on emissions of conventional air pollutants. Going forward, policy goals of increasing the share of clean energy could have further implications for the power generation mix. Many states have focused on renewable portfolio requirements—favoring wind and solar power. Recent legislation including the Infrastructure Investment and Jobs Act, H.R.3684 (U.S. Congress 2021), the CHIPS and Science Act, H.R. 4346 (U.S. Congress 2022a, 2022b), and the Inflation Reduction Act, H.R. 5376 (U.S. Congress 2022a, 2022b) also created support for developing and demonstrating advanced nuclear power and power generation with carbon capture and utilization or storage (CCUS).

Anticipated climate change across the US Heartland presents multiple stresses on the power system, impacting the different generation technologies as well as demand and infrastructure (US Department of Energy—DOE 2022). Higher summer temperatures, combined with lower river levels and streamflow, can lead to higher water temperatures, and limit thermal power plant operations (Kopytko and Perkins 2011; Cook et al. 2015). McCall et al. (2016) found 43 water-related incidents of thermal power plant curtailment for the period 2000 to 2015 in the USA, 18 involving coal-fired power plants and 25 involving nuclear plants, and further climate-warming trends will increase this risk. A shift away from once-through thermal cooling could reduce curtailments but would add cost. A shift to non-thermal power sources, such as wind and solar, could avoid the risks posed by higher water temperatures altogether (e.g., Baker et al. 2014), but climate change may also alter wind patterns (Schlosser et al. 2022; Jung et al. 2019; Jung and Schindler 2019; Karnauskas et al. 2018) and limit solar radiation from increased cloudiness or smoke from wildfires. In addition, the efficiency of photovoltaic conversion of sunlight to electricity declines with higher temperature (Najafi and Woodbury 2013). At the same time, rising temperatures are also likely to increase summer peak demands as a result of more intense and broad use of air conditioning (e.g., Romitti and Sue-Wing 2022), amplifying already high summer peaks in the US Heartland (Bartos et al. 2016). In addition, high temperatures and high demand pose risks for failure of critical grid infrastructure, such as large power transformers (Gao et al. 2018). Other climate-related risks also affect grid infrastructure, including ice storms, wildfires, floods, and high wind-gust events that accompany severe storms (Allen-Dumas et al. 2019; Fant et al. 2020). Notably, many climate-induced stresses to the power system may be more likely in the summer months, creating the potential for a "perfect storm" that could lead to failure of the power system.

Climate impacts on electricity supply, demand, and infrastructure have implications for investment decisions, power system operations, and the resilience of different power system evolutions. A number of studies have investigated aspects of this issue for a variety of geographic regions (e.g., Ralston Fonseca et al. 2021; Khan et al. 2021; Steinberg et al. 2020; Craig et al. 2018). We contribute to the literature by looking at four alternative electricity sector pathways in the US Heartland that were developed without considering climate impacts and constructing a "potential supply gap" metric—the percentage difference between electricity generation in these projections and potential supply losses from climate impacts and additional demand due to warmer temperatures. As such, the calculation provides a first step toward considering systemic impacts, providing an initial estimate for system planners of changes in dispatch or other operational changes, or if those are inadequate, the need for additional capacity/reserves that can offset projected losses in production or be available to meet added demand.

We investigate how the potential supply gap varies by sub-region within the US Heartland and for different electricity sector pathways and identify which components of the system are more relevant to the gap. Our approach is to use a range of energy scenarios relying more or less on fossil, nuclear, and renewable generation. We review existing work in the area to consider realistic power generation scenarios from energy modeling projections and to assess estimates in the literature of potential impacts on electricity system technologies and demand due to future changes in climate and associated extremes. Energy modeling projections usually ignore the potential climate risks on electricity demand and supply.

The approach takes a multi-sectoral dynamics perspective, considering the interconnected and co-evolving environment-human interactions at varying geographic scales and multiple sectors, requiring interdisciplinary models and efforts to understand the behavior of these systems (Moss et al. 2016).

We consider the effects of multiple climate stressors from both gradual climate change and changes in extreme events. For example, a combination of extreme heat, drought, and stagnant meteorological conditions could have significant negative effects on all generation technologies, while simultaneously increasing peak power demands across the region. While we review multiple types of climate events and discuss potential implications for the power sector, in this initial assessment, we are unable to quantify all potential risks. Energy modeling projections usually ignore the potential climate risks on electricity demand and supply. This preliminary analysis, based on existing literature, lays a foundation for follow-on work to assess what these risks might mean for capacity expansion in the region, what strategies could be employed to make the power sector more resilient, and how to incorporate climate change into electricity dispatch and capacity expansion models.

2 Power generation in the Heartland

As many have noted, the challenge with wind and solar power is that they are not dispatchable, and that alone may limit their potential contribution to the power mix—to examine whether their potential contribution requires a high time resolution representation of both demand and resource availability to assure that supply is matching demand over the course of a day, and over the year, either directly or through addition of power storage or extra dispatchable back-up capacity. Uncertainty in technology costs and federal and state energy policy creates uncertainty in the power mix, and as discussed above, every major power generation technology appears somewhat vulnerable to climate change. Given that assessment of the vulnerabilities of renewables require high resolution in time, we have chosen to examine scenarios developed using EleMod, an hourly dispatch and capacity expansion model of the US electric sector. Tapia-Ahumada et al. (2019) developed several scenarios under different technology and energy policy assumptions. Since those scenarios were completed, the cost of solar photovoltaics has continued to fall significantly (National Renewable Energy Laboratory—NREL 2022) and there are goals for the USA to achieve net zero emissions by 2050. We supplemented the above scenarios with one from the Solar Future Study developed by NREL and the Office of Energy Efficiency & Renewable Energy (SETO) from the US Department of Energy (SETO-NREL 2021) that relies more heavily on solar (SETO-NREL 2021) and achieves net zero emissions from the power sector by 2050.

2.1 Electricity sector models

EleMod is an energy-system optimization model of the USA designed to find the most cost-effective electric generation expansion and operation subject to technical and policy constraints (Perez-Arriaga & Meseguer 1997; Tapia-Ahumada et al. 2014, 2019). EleMod has a deterministic recursive-dynamic structure and is solved as a linear programming (LP) problem, formulated to minimize the total cost of producing electricity. Optimal solutions describe capacity expansion planning, operation planning, and operation dispatch decisions, computed sequentially for every 2-year period in order to meet growing demand, replace retired units, or meet policy constraints. Regional load demands and regional wind, solar, and hydroelectricity supply profiles are provided at hourly time scales. The version of the model used here represents 12 conventional generation technologies (Table 1) as well as on-shore wind, utility scale PV, and hydro for each of 12 US regions (Fig. 1). A

Table 1 Power generation technologies represented in EleMod

Technology	Symbol
Gas combustion turbine	GasCT
Gas combined cycle	GasCC
Gas combined cycle with carbon capture and sequestration	GasCCS
Oil/gas steam turbine	OGS
Pulverized coal steam with SO_2 scrubber	CoalOldScr
Pulverized coal steam without SO_2 scrubber	CoalOldUns
Advanced supercritical coal stem with SO_2 and NOx controls	CoalNew
Integrated gasification combined cycle coal (IGCC)	CoalGCC
IGCC with carbon capture and sequestration	CoalCCS
Pulverized coal steam with SO_2 scrubber and biomass cofiring	CofiredOld
Advanced supercritical coal steam with biomass cofiring	CofireNew
Nuclear plant	Nuclear
Wind	Wind
Utility solar	Solar
Storage	PHS

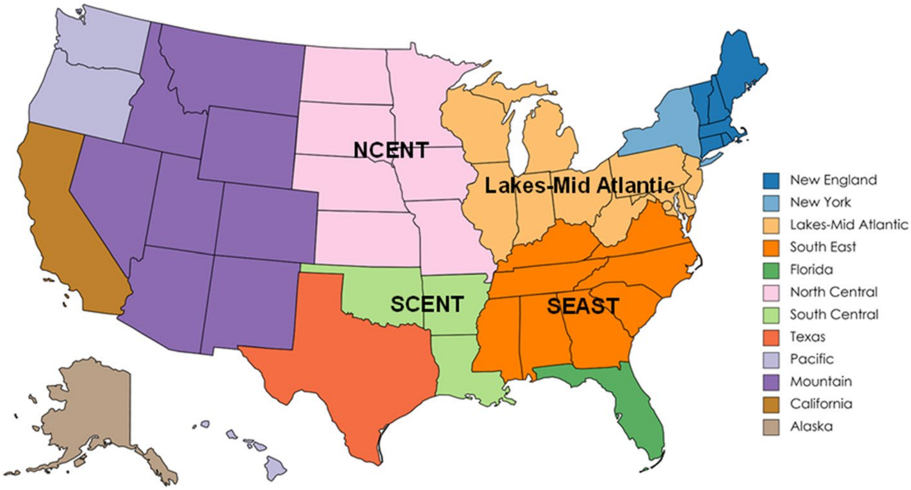


Fig. 1 EleMod regional aggregation

generic storage technology is included, based on characteristics of pumped hydro storage drawn from various sources including NREL (Short et al. 2011), ORNL (O'Connor, et al. 2015), Locatelli et al. (2015), and the Annual Energy Outlook (AEO) from the U.S. Energy Information Administration (EIA 2018), following an approach described by Meseguer et al. (1995). This essentially represents generic storage that could be batteries or other technology with similar cost and efficiency characteristics. Tables 4 and 5 in the Appendix provide more details about technology parameters and costs in EleMod.

Assumptions about costs and technical specifications determine the economic competitiveness of alternative generation sources. Costs include those for fixed and variable O&M, capital, start-up and fuel, and are region-specific. Performance characteristics such as ramping requirements, minimum loading requirement, availability factors, forced outage rates, and heat rates for thermal plants are also considered. Short- and long-term reserve requirements are exogenously specified to represent the need to manage the system at sub-hourly levels. Existing regional transmission interties are approximated. As deployed for this paper, the model allows electricity trade among regions within the same interconnect, but not among the Texas, Western, and Eastern interconnects. Electricity trade is limited to existing transmission capacity, aggregated from NREL data derived from Gridview. The total capacity for each technology in each region represents the existing installed capacity per technology in the base year. There is also a capacity reserve requirement to ensure long-term reliability of the system to unexpected peaks in demand, assumed to be between 10 and 18% depending on the region.

The Solar Future Study scenario was developed using NREL's ReEDS model (SETO-NREL 2021). The ReEDS model is well known and widely used and, similar to EleMod, was developed to represent intermittent renewable electricity generation. To capture daily and seasonal variation in demand over the course of a year, it represents demand as 17 different time slices. Both EleMod and ReEDS draw on similar renewable resource and demand data. While assumptions regarding demand growth and other factors are not identical, both models represent possible evolutions of regional power production and capacity in the USA, adequate for our preliminary assessment. Given the structure of both EleMod and ReEDs, the overall power system costs and capacity expansion decisions factor in the cost of storage, additional back-up capacity, and power spillage (production in excess of demand) that may occur with significant penetration of intermittent renewable generation capacity.

2.2 Scenarios considered

The four alternative scenarios, three from Tapia-Ahumada et al. (2019) and one from the Solar Future Study (SETO-NREL 2021), illustrate realistic, possible future generation mixes (Table 2). Here, we focus on the generation mix in the Heartland regions of the USA for the 2040–2050 decade, a period far enough in the future that the mix of generation capacities may be quite different from the mix circa 2020, and where continuing climate change is likely to exacerbate risks to the generation system. To capture the Heartland region, we include the North Central region (NCENT, which covers the Upper Mississippi River basin), Lakes-Mid Atlantic (Ohio River basin draining into the Mississippi), the South Central (SCENT), and South East (SEAST, Lower Mississippi basin) regions of EleMod. The Lakes-Mid Atlantic and SEAST regions as defined in EleMod expand beyond the Mississippi drainage basin, but we include them nonetheless. Future work might consider greater regional disaggregation. For comparison purposes, we use the same regional aggregation for the Solar Future Study scenario.

A "Current Policies" scenario is included assuming current observed, fixed seasonal and hourly profiles for renewable supply and electricity demand from NREL ATB 2016, NREL reports (see Tapia-Ahumada et al. 2019), and technology costs from EIA AEO (EIA, 2017), with wind and solar generation costs declining at 3% per year. Hydropower supply is set at average supply conditions ("normal" rainfall) with a fixed seasonal and hourly profile based on current operations. New coal plants without CCS are not allowed in any scenarios, due to regulations for CO_2 emissions from new power plants.

Alternative scenarios assume the electricity sector in the USA will transition toward a low-carbon economy. This is captured in EleMod by limiting CO_2 emissions from the power system to 90% below 2005 levels by 2050, keeping the same hydropower conditions as in the Current Policies scenario. The scenario under such conditions is labeled "Cap". An additional "Nuclear" scenario assumes the same emissions reductions as the Cap scenario, but assumes advanced nuclear costs fall by about 40% from the default costs assumed in Current Policies and Cap starting in 2030, based on the mid-range value from Energy Innovation and Reform Project (EIRP 2017). The last scenario, taken from the Solar Future Study (SETO-NREL 2021), assumes stronger development and deployment of solar and wind, and is labeled "Decarb". It assumes zero CO_2 emissions from the power sector by 2050, together with more rapid renewable cost-reduction projections.

In the Current Policies scenario, existing and planned state-level renewable portfolio standards (RPS) that existed at the time of the Tapia-Ahumada study are included. As represented in the study, these phased-in state-level RPS regulations were estimated to require national renewable generation to be 16% of total generation by 2032 and remain at that level through 2050. With falling renewable costs and low emission requirements, renewable generation capacity generally exceeds this level by the 2040–2050 period of interest in this paper in the scenarios we report.

Table 2 Overall scenarios' assumptions

Scenario	CO_2 constraint	Renewables	Other technologies	Source
Current Policies	No constraints in CO_2 emissions	Wind and solar generation costs declining at 3% per year	Hydropower supply is set at average supply conditions New coal plants without CCS are not allowed	Tapia-Ahumada et al. (2019)
Cap	Increasing limits on CO_2 emissions from the power system to achieve 90% below 2005 levels by 2050	Wind and solar generation costs declining at 3% per year	Hydropower supply is set at average supply conditions New coal plants without CCS are not allowed	Tapia-Ahumada et al. (2019)
Nuclear	Increasing limits on CO_2 emissions from the power system to achieve 90% below 2005 levels by 2050	Wind and solar generation costs declining at 3% per year	Hydropower supply is set at average supply conditions New coal plants without CCS are not allowed Lower advanced nuclear costs starting in 2030	Tapia-Ahumada et al. (2019)
Decarb	Increasing limits on CO_2 emissions from the power system to achieve zero emissions by 2050	ATB Advanced cost projections consistent with SETO's 2030 PV and CSP cost targets	ATB Advanced cost projections for other RE and storage technologies; No emitting capacity to remain by 2050	SETO-NREL (2021)

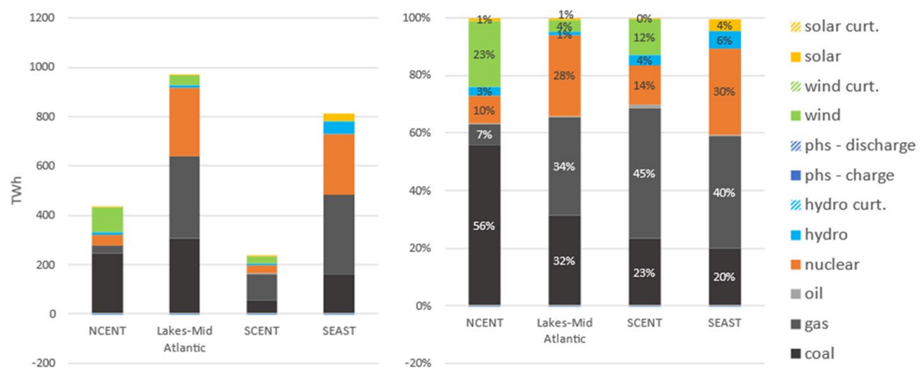


Fig. 2 Electricity generation by region in the Heartland of the USA in 2020. Source: EIA, 2022a

2.3 Future electricity generation

The 2020 electricity generation mix is dominated by coal, nuclear, and gas in most of the Heartland regions (Fig. 2). Wind generation is highest in the NCENT region, where it comprises the greatest share of generation. Solar is limited to small quantities, except in the SEAST. All regions rely mostly on fossil fuels for power generation, within nuclear power providing an important contribution in the SEAST and the Lakes-Mid Atlantic.

The four mid-century (2040–2050) scenarios offer varying regional generation configurations (Fig. 3). Under the Current Policies scenario, wind becomes the most important power generation source in the Heartland, except in the SEAST where fossil energy from gas and coal remains the main source. While wind power is the dominant source, significant production from fossil fuels remains in this Current Policies scenario. Under the Cap scenario, coal power generation decreases in all regions, being replaced by more wind in the Lakes-Mid Atlantic and SCENT and gas and solar in the SEAST. Electricity output is.

somewhat lower in NCENT, due to lower exports to other regions. With lower costs for nuclear generation (Nuclear scenario), it becomes the second most important power source in the Lakes-Mid Atlantic and the major source in SEAST. Under the Decarb scenario, solar is the largest energy source in the SEAST and on par with wind in the SCENT. Solar is second, behind wind, in the NCENT and Lakes-Mid Atlantic regions.

As a summary, these scenarios show the NCENT and SCENT to rely heavily on wind generation by mid-century, providing at least 73% and 61% of the power, respectively. The Lakes-Mid Atlantic region has more mixed generation sources including wind (31 to 58%), nuclear (7 to 35%), and/or fossil generation (31 to 61%). Gas or nuclear power are more dominant in the SEAST (8 to 52%), but solar is also a non-trivial source, ranging from 14 to 24%, and up to 54% in the Decarb scenario. Fossil fuel generation remains a considerable share of the mix in each region, except in the most stringent emission reduction scenario (Decarb). However, none of these alternative future scenarios account for effects of potential changes in weather and climate conditions on generation or capacity expansion.

3 Climate change challenges and risks

We reviewed existing literature to gather insights and estimates of potential impacts of future changes in climate and extreme events on the electricity system and different technologies, which we can then apply to the electricity projections from our four scenarios. While several recent papers have focused on climate impacts on electricity in other regions of the USA, such as the West or Texas (e.g., Cohen et al. 2022a,b; Webster et al. 2022; Dyreson et al. 2022; Turner et al. 2021, 2019; Voisin et al. 2020, 2016) or on climate impacts averaged across the USA (e.g. Craig et al. 2018), here we focus on literature with estimates of impacts for the Heartland regions. A summary of this review is provided in Table (4).

3.1 Threats to thermal power (coal, gas, nuclear, biomass)

Hotter air and water temperatures will adversely impact electricity production from thermal power plants, including fossil, biomass, and nuclear, due to the water requirements for cooling and changes in the efficiency of the generation cycle. For example, a review by Wilbanks et al. (2008) found that gas turbines would lose roughly 0.5 percentage point in efficiency and 3 to 4% in power output per each 10 °F (5.6 °C) increase in water temperature (~0.5 to 0.7% loss per °C). Lakovic et al. (2010) estimate efficiency losses averaging 0.2% per 1 °C increase in water temperature in thermal power plants due to thermodynamic effects. Henry and Pratson (2016) statistically estimated the loss in efficiency in 20 coal and gas power plants in the USA due to observed changes in cooling water, which excludes potential higher temperatures in a future climate impact scenario. Central estimates range from − 0.005 to − 0.108% per 1 °C increase in temperature.

Regarding cooling water temperature effects on nuclear power, Attia (2015) found decreases of 0.15% in the thermal efficiency and 0.44% in the power output for each 1 °C increase in water cooling temperature. Other estimates of losses in thermal efficiency in nuclear power plants indicate similar values, such as linear decreases per 1 °C increase of 0.12% (Durmayaz and Sogut 2006), 0.15% (Ibrahim et al. 2014), and a mean decrease of 0.45% (Hamanaka et al. 2009). Kopytko and Perkins (2011) also discuss temperature effects on nuclear power, identifying adaptations needed to improve cooling systems in reactors as well as protect them from flooding, which may increase with climate change. Some studies found linear decreases in efficiency (Durmayaz and Sogut 2006; Ibrahim et al. 2014), while others found non-linear decreases (Hamanaka et al. 2009).

van Vliet et al. (2012) investigates the climate change impacts associated with lower river flows and higher temperatures for river water cooling during summer on 61 power plants in the central and eastern parts of the USA. The summer average usable capacity may reduce by 12–16% in the 2040s. In another study, van Vliet et al. (2016) extended the investigation to the entire globe and to hydropower plants, but addressing the annual changes in usable capacity by 2050 rather than summer changes. It found annual losses varying from 0 to − 10% in thermal power plants in the US Heartland under mild climate impacts (RCP2.6), and as strong as − 15% under stronger climate change scenarios (RCP8.5). Liu et al. (2017) estimate a reduction in the US average thermal power generating capacity due to climate change by 2060 between 2 and 3%. If environmental regulations on thermal effluents are enforced, the average loss would reach 10 to 12%. Beyond thermal cooling effects, biomass-based generation is also threatened by climate-driven changes in land productivity and water availability (Baker et al. 2014; Hallgren et al. 2013; Gernaat et al. 2021).

Fig. 3 Electricity generation by source in the US Heartland by 2040–2050 (average) under alternative scenarios. curt., curtailment; phs, pump-hydro; phs, charge shows as negative. Source: Tapia-Ahumada (2019), SETO-NREL (2021)

3.2 Changes in wind power

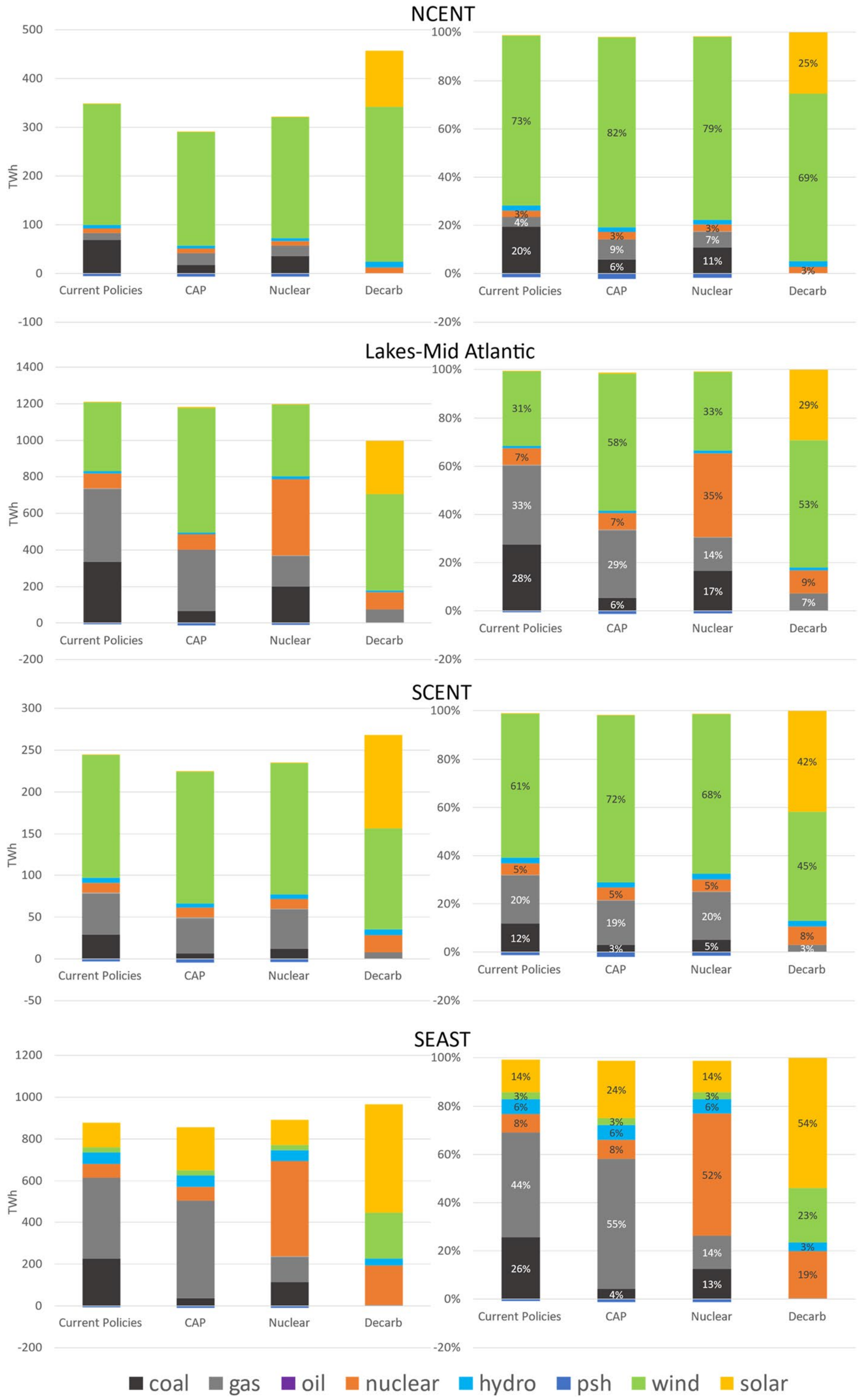
Estimating human-forced climate change impacts on wind power resource availability is challenged by the need of climate-model data that is of sufficient spatial and/or temporal granularity to represent local wind speed and atmospheric profiles across a range of turbine heights as well as technical specifications (i.e., generation capacities and power curves). As such, a number of studies have relied on proxy-based assessments using near-surface windspeed information combined from historical data and simulations of future climates.

Haupt et al. (2016) made projections on wind speed for 2060, and found lower wind speed during mornings in most of the USA in the spring season, decreases of 6 to 10% in the SEAST and part of the Lakes-Mid Atlantic regions in the fall, decreases in SEAST and SCENT during the winter, and increases in parts of the NCENT and Lakes-Mid Atlantic. During summers, they found that wind speed may increase in the SCENT and SEAST between 2 and 10%, and decrease as much as 10% in northern parts of NCENT and Lakes-Mid Atlantic regions. Jung and Schindler (2019) estimated that mean wind speed would decrease for large parts of the USA by − 0.1 m/s in the medium term (2046–2072) and from − 0.2 to − 0.3 m/s in the long run (2073–2099), due to a warmer weather compatible with the representative concentration pathway RCP8.5.

With the availability of more detailed information from climate models, other work has been able to construct more explicit prognoses on future wind power resources. For example, Jung et al. (2019) investigated historical trends in the long-term variability of wind resources, considering data from 1971 to 2010, and estimated decreases in relative annual wind energy potential in the USA of 0.96%. They found several states around the Great Lakes to be among the most affected regions. Karnauskas et al. (2018) projected a decline in the area-averaged wind power in the central USA by 8% by 2050 and 14% by 2100 under the RCP4.5 scenario. The estimated decline could reach 10% by 2050 and 18% by 2100 under the RCP8.5 scenario. Schlosser et al. (2022) investigated the likelihood of shifts in the global patterns of wind power density (WPD) due to human-forced changes in climate, and degree of consensus among different climate model results. Averaged over the contiguous United States, the results indicate that decadal averaged annual WPD could decrease by as much as 5% in the 2050–2059 period relative to 2010–2019, yet these decreases are primarily attributed to regional trends over the Northeast and Northwest portions of the USA. For the US Heartland, the change in the annual mean trend is small with little consensus on any notable trend, which is a result of off-setting seasonal mean changes. During the summer months (June–August), the US SCENT and SEAST are likely to experience increases in WPD of 5–10% by mid-century due to human-forced climate change, while WPD may decrease by 5–20% in parts of the NCENT and Lakes-Mid Atlantic.

3.3 Potential effects on solar PV

Solar energy planning generally assumes past observations on annual solar radiation, although several studies and evidence have shown variation of solar radiation incidence over time (Müller et al. 2014). Uncertainties regarding future changes


NCENT
Lakes-Mid Atlantic
SCENT
SEAST
TWh
Current Policies
CAP
Nuclear
Decarb
coal
gas
oil
nuclear
hydro
psh
wind
solar

in solar energy are large, since photovoltaic (PV) energy systems depend on the amount of solar radiation reaching Earth's surface, which is influenced by cloud cover optical thickness, water vapor, air pollution, and aerosol emissions (Hou et al. 2021).

While future changes in solar radiation reaching solar panels is highly uncertain, Wild et al. (2015) note that PV power output could change negatively under higher ambient temperatures. There is a direct relationship between efficiency of PV modules and temperature. Each 1 °C increase in temperature lowers panel efficiency by about 0.5%, although the effect varies among manufacturers and technologies (Patt et al. 2013). Long-term exposure to heat also reduces the lifetime of the panel, and some materials may be damaged by short peaks of very high temperatures.

Haupt et al. (2016) projected future changes in available solar radiation at the surface by 2060. Some areas of the Lakes-Mid Atlantic region are expected to have the largest reductions in solar radiation during the winter (−10%), while all regions are expected to get higher solar radiation (2 to 4%) during the summer.

Crook et al. (2011) projected changes in PV output by 2080 relative to 2010 due to changes in temperature and insolation. Their results suggest negative changes (−1 to −4%) in PV output in most of the NCENT region and some parts of SCENT and minor areas of Lakes-Mid Atlantic, and slightly positive changes (2 to 4%) for the SEAST and most of the Lakes-Mid Atlantic regions.

Concentrated solar power (CSP) would also be affected by changes in solar radiation. Wild et al. (2017) finds an increase in surface solar radiation in most of the US Heartland, but this would imply median increases of only 0.1% in CSP between 2006 and 2049 from projections of 39 CMIP5 models under the RCP8.5 scenario. Crook et al. (2011) suggests as much as 5% increase in CSP output in NCENT and SCENT, and between 5 and 15% in SEAST and Lakes-Mid Atlantic by 2080 relative to 2010 due to changes in temperature and insolation. That said, CSP development has largely focused on the desert southwest because of the consistent level of solar radiation.

3.4 Threats to hydropower

Drought in the Western USA is a well-known threat to hydropower production there (in California in 2021, production was more than 50% below the 10-year average (EIA, 2022b)), but hydropower production has also been cut significantly in the Heartland (in 2007, production in the Tennessee Valley Authority was down about 50% due to drought (Electricity Forum 2007)).

Boehlert et al. (2016) estimate changes in hydropower generation for more than 500 US hydropower facilities under future climate scenarios. Annual hydropower generation in the US Heartland river basins may drop from 0 to 13% on average by 2050 under current climate change trends. During summer months, the losses in hydropower may vary from 0 to −3% in Lakes-Mid Atlantic and SEAST river basins, while in NCENT, changes can be from 0 to −13% and in SCENT from −5 to −14%.

van Vliet et al. (2016) found that power production from hydropower plants in the US Heartland could decrease by 0% to as much as 10%, but usually by less than 5% under mild and strong climate impacts (RCP2.6 and RCP8.5).

3.5 Changing demand

Climate change is generally expected to increase electricity demand in the USA, mainly through higher temperatures increasing demand for air conditioning. Just taking the average changes in temperature as an example and ignoring extreme events, some simple calculations can illustrate the challenge ahead. The IPCC AR6 WGI shows tahat annual mean surface air temperature in RCP8.5 may increase between 2 °C and 5 °C in the period 2070–2099 relative to 1970–1999 in most of the South Central and South East US regions, while in the North Central and Lakes-Mid Atlantic regions, it may increase between 2 °C and 7 °C (Gutiérrez et al. 2021). During the summer, increases in temperature between the periods 2041–2070 and 1971–2000 are expected to be as high as 6 °C in several parts of the US Heartland, and at least 4.5 °C higher in most of the region (DOE 2013). These higher temperatures will drive increased demand for building cooling. Importantly, these demand increases can occur while high temperatures are simultaneously causing decreases in electricity supply.

Kopp et al. (2014) estimates that average US residential and commercial electricity demand will increase from 2.3 to 4.9% by mid-century under a higher climate change scenario (RCP8.5), and from 1.2 to 4.1% even under moderate changes in climate (RCP4.5). The SCENT and SEAST regions are among the most impacted in that study, achieving average increases around 7.5%, while the NCENT and Lakes-Mid Atlantic regions would face 5% increases on average. Rastogi et al. (2021) project future electricity demand increases from 13 to 32% in the Southeast US states during the summer due to the non-linear impact of warming on heat stress, including changes in humidity.

Ralston Fonseca et al. (2019) estimate average increases of 6% in hourly electricity demand in the Tennessee Valley Authority due to climate change by year at the end of the century, and of 20% during the summer, which would impact the current patterns of power plants at summer time, requiring fossil generation capacity factors which would be 8 to 84% higher than expected. Auffhammer et al. (2017) finds that climate change affects peak load electricity demand far more than average load, with the upper tail of peak load increasing by 7.2% by end of century at moderate changes in climate (RCP4.5) and by 18% at stronger climate change (RCP8.5), while average generation requirements would increase only by 2.8%.

Van Ruijven et al. (2019) projected energy demand increases between 52 and 82% by 2050 in North America due to changes in the frequency of hot and cold days under the RCP8.5 climate change scenario and between 22 and 46% under RCP4.5.

3.6 Extremes

Some of the most consequential effects of climate change on electricity supply and demand will likely be due to changes in weather extremes. The potential threat of changes in extreme weather events has already come up in previous sections; however, because of the potential risk of catastrophic failure, further discussion of the effect of extremes is warranted.

All power sources are vulnerable to physical damages under severe storms and heavy precipitation events. Heat weaves and increasing hot air temperature reduce thermoelectric plant efficiency, while higher water temperature decreases thermal plant efficiency and available generation capacity, and may require shut down due to thermal discharge limits. Droughts may reduce water availability, impacting hydropower and thermoelectric generation capacity. Hydropower plants are also at higher risks of physical damage and changes in operations due to flooding. Higher air temperatures reduce the efficiency of solar panels, and as previously noted, short periods of extreme heat can damage the panels. Transmission and distribution systems can lose efficiency under higher ambient air temperature, but extreme wind storms, tornados, and ice storms can increase physical damage risks (US DOE 2013). As an example, Gao et al. (2018) investigate how increases in summertime hot days would affect large power transformers, critical components of the power grid, in the Northeast United States. They found that each 1 °C increase in temperature reduces the lifetime of transformers by 10% (4 years). Under RCP4.5 and RCP8.5 scenarios, it would imply lifetime losses between 20 and 40% by 2070–2092. Under extreme heat events, these impacts can double. Capital costs associated with maintenance, replacement, and equipment losses, together with risks of interruption in power services, would result in additional costs or economic loss.

In general, the chance of exceeding a given extreme temperature or precipitation value rises non-linearly with temperature increase. In the Central North-America, the IPCC AR6 report (Seneviratne et al. 2021) estimated that current maximum daily temperatures would be exceeded 5 times more frequently with 1 °C warming over a 50-year period, while at 4 °C warming, the extreme temperature exceedance becomes 20 to 40 times as frequent. In Eastern North-America, similar trends in extreme hot days are expected, although with expected daily exceedance in the range of 15 to 45 times more likely under a 4 °C warming. This means more frequent hot days, longer duration heat events, and/or greater frequency. This can have a non-linear effect on cooling demand because buildings accumulate thermal mass with longer heat events, and when nights remain warm. Annual maximum daily precipitation extremes are also likely to increase, with the annual extreme exceeded between 1 and 6 times in a 50-year period under a 4 °C warming in the Central North-America, and between 2 and 7 times in the Eastern North-America. In other work, Monier and Gao (2015) find that increases in the frequency and intensity of extreme heat and precipitation events over most of the USA are to be expected in the coming decades. They test several features in their projections and highlight that mitigation choice is the main source of uncertainty, particularly at the longer time horizons.

While average changes are relevant to inform future trends on power demand, critical to capacity expansion, planning is how peak demand may change with changing temperature extremes. Allen et al. (2016) estimate changes in July peak demand by service areas in SCENT and SEAST states by 2050 relative to 2011. In SCENT states, peak demand is estimated to increase at least by 10.5% in Louisiana and 21.3% in Oklahoma and Arkansas, but some service areas may experience increases as high as 35.8% in Louisiana and 44.7% in Oklahoma and Arkansas. In the SEAST states of Mississippi, Alabama, Georgia, and Tennessee, changes in peak demand are projected to reach at least 17.2%, 11.5%, 6.0%, and 5.9%, respectively. The maximum peak for some service areas are 34.2%, 35.4%, 24.2%, and 31.4%. The mean increase in demand in service areas is between 20.7% and 33.1% in SCENT states and between 18.1% and 24% in SEAST states.

Despite concerns around extreme weather threats, Novacheck et al. (2021) found a high mix of renewable generation to be relatively robust, at least when analyzed against various historic extreme weather events.

4 Potential supply gaps

Projections of electricity generation in the Heartland of the USA show alternative pathways for expansion and deployment of several technologies. Given falling costs, and policies to support their deployment, renewables appear likely to achieve a major role in most regions, especially under scenarios focused on decarbonization of the energy mix. However, thermo-electric generation from either fossil fuels or nuclear energy may remain relevant in some regions, depending on their cost and how fast the expected energy transition will proceed. Whatever the future development of the power system in the US Heartland, future climate changes can present multiple stresses on the power system. While there are many studies highlighting these risks, these climate feedbacks on the power sector are usually neglected in most projections of capacity expansion, generation, and demand. As discussed in the previous section, several studies have estimated potential impacts of changing climate conditions on overall electricity demand and alternative power sources. None of these, however, have considered these impacts all together, failing to capture the potential compounding effects and spatial teleconnections among them and the true risks faced by the electricity system in the US Heartland.

As a preliminary attempt to highlight the importance of considering such systemic impacts, we combine climate impact estimates from the literature with electricity mix projections from our scenarios to calculate preliminary estimates of potential supply gaps that could appear due to climate impacts on supply and demand as reviewed in Section 3. These potential supply gap estimates vary given the possible reliance of the power sector on different generating technologies in the four future power sector scenarios we considered in Fig. 3. We multiplied the annual energy projection by region from models discussed in Section 2 by a specific climate impact chosen from the literature review. Table 3 presents the overall assumptions and climate impacts used to calculate the potential supply gaps, which were formulated given the summary of the literature review (Table 6 in the Appendix). We avoided combining projections from different papers in some sort of median or max, since papers in the literature have too many differences in approach and assumptions, including modeling strategies, time and spatial dimensions, and climate scenario considered. For some energy sources, the number of papers is too narrow. These aspects make it virtually impossible to assign probability distribution functions and assess uncertainties. The potential supply gaps assume that the planned power system and its operations were not modified to eliminate or reduce the gap. Simple changes in operations, bringing more capacity on line to meet demand, may be sufficient to meet such potential gaps in many cases, while in other cases, more or different capacity might be required. The scenarios used in this paper were developed by a standalone version of EleMod (Tapia-Ahumada et al. 2019) which treats electricity demand as exogenous taken from the EIA'a Annual Energy Outlook (AEO) 2017. The scenario simulated by ReEDs similarly uses an exogenous demand scenario, based on EIA AEO 2020 (SETO-NREL 2021).

Figure 4 shows the potential supply gaps estimated based on climate impacts on each of the power sources and electricity demand (Fig. 5 in the Appendix decomposes these supply gaps by source in TWh, while Fig. 6 shows total supply gaps relative to model results in Fig. 3). The "medium-risk" calculation assumes climate scenarios compatible with RCP4.5 or similar, while "high risk" assumes RCP8.5 climate impacts. Under medium risks, potential supply gaps range from 5 to 6% in the NCENT region in

Table 3 Assumptions to calculate supply gaps given the potential impacts from the literature discussed in Section 3 and summarized in Table 6 in the Appendix

Impact on:	High temp. increase	Mod. temp. increase	Source	Details
NCENT				
Fossil	−12.50%	−7.50%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Nuclear	−12.50%	−7.50%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Hydro	−7.45%	−4.18%	Boehlert et al. (2016)	Change in annual hydropower generation due to decreases in generation during summer, reference and POL4.5 scenarios
Wind	−1.10%	−0.84%	Scholosser et al. (2022)	Change in annual wind power density by mid-century, reference, and 2 °C stabilization target
Solar	−2.00%	−1.00%	Patt et al. (2013)	Change in efficiency due to a 1 °C increase in air temperature
Demand (low)	4.58%	2.29%	Kopp et al. (2014)	Median change in electricity demand by 2040–2059 from 2012 levels, scenario RCP8.5 and half of RCP8.5 assumed under moderate temperature increase
Demand (high)	8.50%	3.45%	Auffhammer et al. (2017)	Change in intensity of peak load by end of century, scenarios RCP8.5 and RCP4.5
	Lakes-Mid Atlantic			
Fossil	−15.00%	−7.50%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Nuclear	−15.00%	−7.50%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Hydro	−4.18%	−0.06%	Boehlert et al. (2016)	Change in annual hydropower generation due to decreases in generation during summer, reference and POL4.5 scenarios
Wind	−1.40%	−1.07%	Scholosser et al. (2022)	Change in annual wind power density by mid-century, reference and 2 °C stabilization target
Solar	−2.00%	−1.00%	Patt et al. (2013)	Change in efficiency due to a 1 °C increase in air temperature

Table 3 (continued)

Impact on:	High temp. increase	Mod. temp. increase	Source	Details
Demand (low)	4.58%	2.29%	Kopp et al. (2014)	Median change in electricity demand by 2040–2059 from 2012 levels, scenario RCP8.5 and half of RCP8.5 assumed under moderate temperature increase
Demand (high)	9.25%	3.73%	Auffhammer et al. (2017)	Change in intensity of peak load by end of century, scenarios RCP8.5 and RCP4.5
	SCENT			
Fossil	−15.00%	−12.50%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Nuclear	−15.00%	−12.50%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Hydro	−2.28%	−7.45%	Boehlert et al. (2016)	Change in annual hydropower generation due to decreases in generation during summer, reference and POL4.5 scenarios
Wind	0.00%	0.00%	Karnauskas et al. (2018)	Change in annual mean wind power in 2020–2040 relative to baseline, RCP8.5 and RCP4.5 scenarios
Solar	−2.00%	−1.00%	Patt et al. (2013)	Change in efficiency due to a 1 °C increase in air temperature
Demand (low)	4.75%	6.00%	Kopp et al. (2014)	Median change in electricity demand by 2040–2059 from 2012 levels, scenario RCP8.5 and half of RCP8.5 assumed under moderate temperature increase
Demand (high)	10.75%	2.38%	Auffhammer et al. (2017)	Change in intensity of peak load by end of century, scenarios RCP8.5 and RCP4.5
	SEAST			
Fossil	−10.00%	−5.00%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Nuclear	−10.00%	−5.00%	van Vliet et al. (2016)	Impacts of climate and water resources change on annual mean usable capacity of thermoelectric power plants in 2040–2069 relative to 1971–2000, scenarios RCP8.5 and RCP4.5
Hydro	−0.06%	−2.28%	Boehlert et al. (2016)	Change in annual hydropower generation due to decreases in generation during summer, reference and POL4.5 scenarios

Table 3 (continued)

Impact on:	High temp. increase	Mod. temp. increase	Source	Details
Wind	−0.80%	−0.61%	Scholosser et al. (2022)	Change in annual wind power density by mid-century, reference and 2 °C stabilization target
Solar	−2.00%	−1.00%	Patt et al. (2013)	Change in efficiency due to a 1 °C increase in air temperature
Demand (low)	6.25%	3.13%	Kopp et al. (2014)	Median change in electricity demand by 2040–2059 from 2012 levels, scenario RCP8.5 and half of RCP8.5 assumed under moderate temperature increase
Demand (high)	10.60%	5.80%	Auffhammer et al. (2017)	Change in intensity of peak load by end of century, scenarios RCP8.5 and RCP4.5

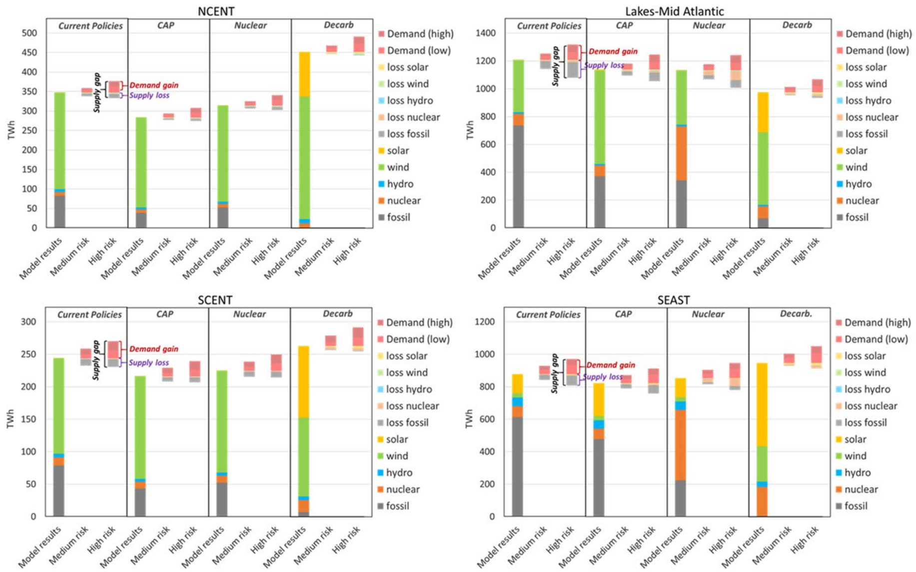


Fig. 4 Original EleMod and NREL electricity projections and potential supply gaps due to future changes in climate. Demand (low): median changes in demand; Demand (high): additive to Demand (low) and assumes higher increase in electricity demand (see Table 3)

comparison to power generation displayed in Fig. 3, 6 to 9% in the Lakes-Mid Atlantic, 8 to 11% in the SCENT, and 8 to 10% in the SEAST. Under high risks, potential supply gaps can reach between 11 and 12% in the NCENT, 14% and 21% in the Lakes-Mid Atlantic, 14% and 16% in the SCENT, and 15% and 19% in the SEAST. The additional electricity demand from climate impacts has a greater effect on the potential supply gaps than the losses suffered in energy supply in all scenarios, except in the Lakes-Mid Atlantic region under the Current Policies scenario, where its reliance on thermal power generation is higher than in other regions. Scenarios relying more on renewables are subject to lower potential supply gaps, since overall climate impacts on renewables mentioned in the literature are lower compared to those on thermal and hydropower. It may indicate higher resilience of renewables to climate impacts, but may also reflect a less-developed literature on climate impacts on renewables given these sources are relatively new in the power system and much less investigated than thermal and hydro power. It is also important to note that these potential supply gaps are based on estimated changes in annual supply and demand, whereas more serious threats with compounding impacts could arise with extreme events. For example, large-scale meteorological blocking events during summer months would support higher heat stress, reduce wind power, threaten thermal power generation, greatly increase peak power demand when there was little or now available excess capacity, and might involve periods of increased pollution/aerosol haze that reduce solar radiation reaching the surface.

5 Limitations of the current study and future research directions

The current study set out to determine *potential* supply gaps between the amount of electricity produced and used in US Heartland regions in scenarios that optimized dispatch and deployment of various supply technologies, under various policy assumptions, assuming climate was unchanged. Based on a review of the literature, we identified how demand and different supply technologies could be affected by changes in climate by mid-century. In general, most of these impacts resulted in reduced electricity production, given technology deployment and dispatch in the various scenarios we examined, and an increase in demand. We described the resulting difference between electricity production and use as potential supply gaps, which are meant to provide a useful first-order metric of the potential magnitude of the compounding effects of climate change on the electricity system (e.g., the impacts that could result if climate change is not appropriately factored into electricity system planning and/or adaptive responses are not properly pursued). However, they are only *potential* supply gaps as we recognize that utilities serving these regions have a variety of options at their disposal that they can adopt to ensure that electricity demand can be met each year and continuously over the course of a year. These options include short-term responses such as changing dispatch to make use of extra capacity, reserves and existing storage, options such as demand management and load shifting that may require somewhat more time to implement, and, because we are looking forward to mid-century, investing in extra reserve capacity, more storage, a different mix of generations options, or efforts to limit climate impacts on various production technologies (e.g., moving away from once-through cooling for thermal power plants, or different location decisions for wind turbines).

A clear limitation of our approach is that it does not identify the mix of options that could (would likely) be used to close this potential gap. Hence, it would be useful for future work to go a next step to produce new scenarios with an hourly dispatch and capacity expansion model, such as EleMod or a similar model, that would consider, first, whether changing dispatch and use of existing extra production and storage capacities (for 2050 as simulated with the model without climate change) were alone adequate to eliminate these supply gaps. A second step could then look at the potential role of load management via further improved efficiency beyond that simulated in the base scenarios and load shifting to help close potential supply gaps. A third step could then assess how changes in the investment mix of technologies, additional storage, and/or overall production capacity over the years leading up to mid-century could result in a system better optimized for the changed climate conditions. To optimize the system on the basis of expectations of future conditions would require a stochastic, forward-looking approach: forward looking because investment decisions in years leading up to mid-century would need to anticipate future conditions and stochastic because the details of future conditions are uncertain. Climate projections at relevant regional levels remain highly uncertain as do technology costs and the direction of GHG and conventional pollutant mitigation efforts that would affect the mix of production technologies. Electricity demand is also uncertain because the overall path of development (economic and population growth) is uncertain as is electricity demand growth because of competing influences (e.g., improved efficiency and increased electrification) and the impacts of climate change. Various decision-making under uncertainty approaches should be investigated, including robust decision making (e.g., Lempert et al. 2013), stochastic dynamic programming (e.g., Bellman 1957; Puterman 2005), stochastic programming (Birge & Louveaux 1997), approximate dynamic programming (e.g., Powell 2011), stochastic dual dynamic programming (e.g., Pereira and Pinto 1991), robust optimization (e.g., Ben-Tal et al. 2009), and others.

The other major limitation of the current study is the coarse resolution in time and space. While we reviewed the potential changes in extreme events that could affect the system, these extremes typically occur over short time periods, and may occur over very limited space. While extreme heat may spread over a large region, even over the entire mid-section of the country, it has different implications in different regions given the infrastructure in place in different regions. And, the effects of extremes such as floodin, depend on whether specific infrastructure is located in the flooded area or not. Clearly, extreme heat in mid-summer, when air conditioning demand tends to result in an annual peak in electricity demand even without climate change, that could also affect thermal power plant production and may be associated with low wind turbine output, would create greater stresses on the electricity grid than unusually warm weather in spring or fall, when wind turbine output may be strong, and there exists excess thermal power capacity because demand is relatively low in these periods. Further, changes in climate and in electrification will likely affect the seasonal and diurnal pattern of electricity demand. Warmer winters could reduce power demand then because of less heating and less use of fans and blowers in forced air heating systems, while warmer summers could increase demand then due to more air conditioning use. This could lead to a more extreme seasonal peaking profile. On the other hand, greater electrification through use of heat pumps could increase winter electricity demand, perhaps reducing the difference between winter and summer demand. Further electrification of the vehicle fleet is considered in the base scenarios we investigated, but electric vehicles recharging could shift diurnal patterns of demand, or by controlling when vehicles are recharged, perhaps through time of day pricing, could create greater load shifting capabilities.

Of course, a strength of the power grid in the major US Heartland regions are the interconnections that allow excess power capacity in one area to be used and transmitted to other areas facing capacity shortages, and so while greater spatial resolution is needed, there is also a need to consider the broader regions, existing and possible new interconnections, as well as interconnections to regions beyond the Heartland regions. While these are important limitations, we believe the *potential* gap analysis helps point the way for future research while also serving as an alert to those responsible for managing the grid in these regions that they may face challenges from changing climate over coming decades and they need to evaluate the resiliency of their systems to potential changes.

6 Conclusion

The literature indicates a variety of impacts on power production and demand in the US Heartland from changing climate, which affects all power generation technologies. In general, this literature suggests increases in demand and a reduction in power production. We reviewed these estimates and made some preliminary calculations of how these various effects might combine to affect the power sector, developing a potential supply gap metric. The largest potential supply gap achieves 21% of total power generation projected by models for the 2040–2050 period, and is observed in the Lakes-Mid Atlantic region, due to potential large climate impacts both on energy demand and thermal power generation.

While the impact on demand is expected in all the US Heartland, those sub-regions and scenarios counting on larger share of renewables in the power system tend to experience lower impacts on total power generation from the supply side, since the scientific literature on climate impacts on power technologies has indicated that thermal power will be more negatively affected than renewables.

These preliminary estimates are an indication of possible stresses on the power sector that may compound and can reach, on an annual basis, a potential supply gap of at least 5% in the NCENT region under a mild change in climate (consistent with RCP4.5). This will require operators to develop strategies such as changes in dispatch or other operations or, if those are insufficient, changes in the mix of generation, or more generation or storage capacity. Our calculation does not factor in all of the potential changes identified in the literature because in many cases, there is not yet solid quantification of some of them. Also, we have not attempted to quantify the risks from extreme events to the power sector infrastructure. We recognize that there are many uncertainties and a lack of consensus in the literature about the climate impacts on the various power technologies, as also as there is a relatively low number of climate impact estimates for some technologies, such as wind and solar. As a result, our supply gap measure should be taken as a first approximation of the potential risks climate may pose to the power system.

There are important aspects of our assessment that warrant further refinement, as mentioned in Section 5. First, we are looking at a regionally coarse representation. While this study provides initial insights on the potential impacts of compounding stressors that lead to potential supply gaps, future work should consider more disaggregated resolution and check if the electricity mix at state (or local) level is as vulnerable as at the US Heartland regional level. Second, while we are addressing annual potential supply gaps, it is expected that climate change will pose salient seasonal threats, especially in summer, when prolonged higher water temperatures, stagnant air, and dry conditions could reduce thermal power plant efficiency or require scaled back operations to meet regulations on water discharge. A key challenge will be the ability to faithfully predict changes in the extent, intensity, and occurrence of meteorological "blocking" events that cause these severe and compounding conditions. The ability to predict atmospheric blocking events under human-forced climate change remains a challenge (e.g., Lupo 2021), but recent evidence indicates that a warmer climate will cause blocking events to become larger in spatial extent (e.g., Nabizadeh et al. 2019). Third, while trends in the improvement in technologies such as solar and wind as well as efficiency improvements in end use and continuing trends in electrification were incorporated in baseline electricity demands, potential further responses due to climate change are not considered in most studies. Future work needs to consider technological improvements in the energy system in combination with climate shocks impacting demand. Overall, such improvements may allow a better integration of climate risks and electricity pathway options. It may also help to answer relevant questions, related to the best generation portfolio choice (more diverse or reliance on less vulnerable sources), the need for backup and storage capacity, water cooling options, chances of grid failure, or how costs may change to deal with these challenges.

Appendix

Table 4 Conventional generation technologies: operational parameters and performance

	Minimum plant loading (%)	Availability factor (p.u.)	Forced outage rate (p.u.)	Electric heat rate (MMBtu/kWh)	CO_2 emission (metric ton/MMBtu)
Gas combustion turbine	0%	0.9215	0.0300	0.010033	0.0540
Gas combined cycle	0%	0.9024	0.0400	0.006682	0.0540
Gas combined cycle with carbon capture and sequestration	0%	0.9024	0.0400	0.007525	0.0081
Oil/gas steam turbine	40%	0.7927	0.1036	0.098400	0.0805
Pulverized coal steam with SO_2 scrubber	40%	0.8460	0.0600	0.010400	0.0930
Pulverized coal steam without SO_2scrubber	40%	0.8460	0.0600	0.011380	0.0930
Advanced supercritical coal steam with SO_2 and NOx controls	40%	0.8460	0.0600	0.008784	0.0930
Integrated gasification combined cycle coal	50%	0.8096	0.0800	0.010062	0.0930
IGCC with carbon capture and sequestration	50%	0.8096	0.0800	0.010062	0.0140
Pulverized coal steam with SO_2 scrubber and biomass cofiring	40%	0.8463	0.0700	0.010740	0.0930
Advanced supercritical coal steam with biomass cofiring	40%	0.8463	0.0700	0.009370	0.0930
Nuclear plant	100%	0.9024	0.0400	0.010452	–

Yuan et al. (2021)

Table 5 Technology costs (in US$ 2018)

	Annualized capital and fixed costs ($/kW)	Variable O&M ($/kWh)	Lifetime (year)
Gas combustion turbine	103.22	0.0128	30
Gas combined cycle	177.44	0.0033	30
Gas combined cycle with carbon capture and sequestration	270.2	1.235	30
Oil/gas steam turbine	146.81	0.0036	50
Pulverized coal steam with SO_2 scrubber	196.07	0.0084	60
Pulverized coal steam without SO_2 scrubber	159.83	0.0125	60
Advanced supercritical coal steam with SO_2 and NOx controls	362.28	0.0042	60
Integrated gasification combined cycle coal	795.95	0.0072	60
IGCC with carbon capture and sequestration	624.83	1.235	60
Pulverized coal steam with SO_2 scrubber and biomass cofiring	216.18	0.0125	60
Advanced supercritical coal steam with biomass cofiring	377.8	0.0084	60
Nuclear plant	791.07	0.0042	40
Wind onshore	313.09	-	20
Wind offshore	623.15	–	–
Utility solar	254.23	0.0135	30
Pumped hydro storage	115.96	0.0088	50

Table 6 Summary of potential impacts to electricity power generation and demand

Impact on	Specific variable	Change in	Timing	US	Lakes-Mid Atlantic	SEAST	NCENT	SCENT	Climate scenario	Source
Demand	Electricity	Average	By midcent	4.90%	4.58%	6.25%	4.58%	4.75%	RCP8.5	Kopp et al. (2014)
Demand	Electricity	Average	By midcent	1.20%	2.29%	3.13%	2.29%	2.38%	RCP4.5	Kopp et al. (2014)
Demand	Electricity	Average, summer	By 1971–2100			13.00%			RCP8.5	Rastogi et al. (2021)
Demand	Electricity	Mean change during peak, July	By 2050			21.05%		26.90%	RCP8.5	Allen et al. (2016)
Demand	Electricity	Minimum change during peak, July	By 2050			11.55%		15.90%	RCP8.5	Allen et al. (2016)
Demand	Electricity	Maximum change during peak, July	By 2050			29.80%		40.25%	RCP8.5	Allen et al. (2016)
Demand	Electricity	Average yearly	By 2060			2.50%			RCP8.5	Ralston Fonseca et al. (2019)
Demand	Electricity	Hourly demand in summer	By 2060			11.00%			RCP8.5	Ralston Fonseca et al. (2019)
Demand	Electricity	Daily peak load	By end of the century	9.60%	9.25%	10.60%	8.50%	10.75%	RCP8.5	Auffhammer et al. (2017)
Demand	Electricity	Daily peak load	By end of the century	3.50%	3.73%	5.80%	3.45%	6.00%	RCP4.5	Auffhammer et al. (2017)
Wind power	Wind power density	Annual (decadal averaged)	By 2050–2059	−1.70%	−1.40%	−0.80%	−1.10%	8.30%	Reference	Scholosser et al. (2022)
Wind power	Wind power density	Annual (decadal averaged)	By 2050–2059	−1.30%	−1.07%	−0.61%	−0.84%	6.35%	2C	Scholosser et al. (2022)
Wind power	Wind energy potential		From 1971 to 2010	−0.96%						Jung et al. (2019)
Wind power	Wind speed (mean, m/s))	Year	2046–2070	−10.00%	−10.00%				RCP8.5	Jung and Schindler (2019)
Wind power	Wind power (area averaged, kW)	Annual mean	By 2050				−1.50%	0.00%	RCP8.5	Karnauskas et al. (2018)

Table 6 (continued)

Impact on	Specific variable	Change in	Timing	US	Lakes-Mid Atlantic	SEAST	NCENT	SCENT	Climate scenario	Source
Wind power	Wind power (area averaged, kW)	Annual mean	By 2050				−1.00%	0.00%	RCP4.5	Karnauskas et al. (2018)
Wind power	Wind speed (area averaged)	Annual mean	By 2060		−1.84%	−0.74%	−1.25%	−0.05%	A2	Haupt et al. (2016)
Hydropower	Average change in 2050 generation	Winter average	By 2050		0.32%	0.26%	−1.42%	0.46%	REF	Boehlert et al. (2016)
Hydropower	Average change in 2050 generation	Spring average	By 2050		−0.13%	−1.13%	1.58%	−2.88%	REF	Boehlert et al. (2016)
Hydropower	Average change in 2050 generation	Summer average	By 2050		−0.06%	−0.90%	−2.14%	−3.71%	REF	Boehlert et al. (2016)
Hydropower	Average change in 2050 generation	Fall average	By 2050		−0.19%	−0.51%	−2.20%	−1.32%	REF	Boehlert et al. (2016)
Hydropower	Average change in 2050 generation	Winter average	By 2050		0.20%	0.21%	−1.62%	0.34%	POL4.5	Boehlert et al. (2016)
Hydropower	Average change in 2050 generation	Spring average	By 2050		−0.11%	−0.88%	0.50%	−2.21%	POL4.5	Boehlert et al. (2016)
Hydropower	Average change in 2050 generation	Summer average	By 2050		−0.26%	−0.70%	−2.34%	−2.94%	POL4.5	Boehlert et al. (2016)
Hydropower	Average change in 2050 generation	Fall average	By 2050		−0.12%	−0.30%	−2.08%	−0.96%	POL4.5	Boehlert et al. (2016)
Hydropower	Usable capacity	Annual mean	By 2050		−2.50%	−2.50%	−1.00%	−2.50%	RCP8.5	van Vliet et al. (2016)
Hydropower	Usable capacity	Annual mean	By 2050		0.00%	−1.00%	0.00%	−1.00%	RCP4.5	van Vliet et al. (2016)
Power transformers	Lifetime of power transformers	Overall lifetime loss	By 2070–2092	−40.00%					RCP8.5	Gao et al. (2018)
Power transformers	Lifetime of power transformers	Overall lifetime loss	By 2070–2092	−20.00%					RCP4.5	Gao et al. (2018)

Table 6 (continued)

Impact on	Specific variable	Change in	Timing	US	Lakes-Mid Atlantic	SEAST	NCENT	SCENT	Climate scenario	Source
Power transformers	Lifetime of power transformers	Lifetime loss for each 1 °C increase		−10.00%						Gao et al. (2018)
Thermal power plants	Gas turbines efficiency	Loss due to a 10 °F (5.6 °C) increase		−0.50%						Wilbanks et al. (2008)
Thermal power plants	Gas turbines output	Loss due to a 10 °F (5.6 °C) increase		−3 to −4%						Wilbanks et al. (2008)
Thermal power plants	Not specified	Loss due to 1 °C water temp. increase		−0.20%						Lakovic et al. (2010)
Thermal power plants	Gas and coal power plants	Loss due to 1 °C water temp. increase		−0.005 to −0.11%						Henry and Pratson (2016)
Thermal power plants	Nuclear power	Efficiency loss due to a + 1 °C in water temp		−0.15%						Attia (2015)
Thermal power plants	Nuclear power	Output loss due to a + 1 °C in water temp		−0.44%	−0.88%	−0.88%	−0.88%	−0.88%		Attia (2015)
Thermal power plants	Nuclear power	Efficiency loss due to a + 1 °C in water temp		−0.12%						Durmayaz and Sogut (2006)
Thermal power plants	Nuclear power	Efficiency loss due to a + 1 °C in water temp		−0.15%						Ibrahim et al. (2014)
Thermal power plants	Nuclear power	Efficiency loss due to a + 1 °C in water temp		−0.45%						Hamanaka et al. (2009)
Thermal power plants	Generating capacity	Annual average	By 2060	−12.00%					RCP8.5	Liu et al. (2017)
Thermal power plants	Generating capacity (envir. regul. enforced)	Annual average	By 2060	−3.00%					RCP4.5	Liu et al. (2017)
Thermal power plants	Generating capacity	Annual average	By 2060	−10.00%					RCP8.5	Liu et al. (2017)

Table 6 (continued)

Impact on	Specific variable	Change in	Timing	US	Lakes-Mid Atlantic	SEAST	NCENT	SCENT	Climate scenario	Source
Thermal power plants	Generating capacity (envir. regul. enforced)	Annual average	By 2060	−2.00%					RCP4.5	Liu et al. (2017)
Thermal power plants	Usable capacity	Summer average	By 2030–2061	−16.00%	−13.00%	−19.00%	−22.00%	−10.00%	A2	van Vliet et al. (2012)
Thermal power plants	Usable capacity	Summer average	By 2030–2061	−16.00%	−3.39%	−4.82%	−5.79%	−2.57%	A2	van Vliet et al. (2012)
Thermal power plants	Usable capacity	Summer average	By 2030–2061	−12.00%					B1	van Vliet et al. (2012)
Thermal power plants	Usable capacity	Annual mean	By 2050		−15.00%	−10.00%	−12.50%	−15.00%	RCP8.5	van Vliet et al. (2016)
Thermal power plants	Usable capacity	Annual mean	By 2050		−7.50%	−5.00%	−7.50%	−12.50%	RCP4.5	van Vliet et al. (2016)
Solar PV	Solar PV efficiency	Efficiency loss due to a 1 °C increase		−0.50%						Patt et al. (2013)
Solar PV	Solar PV output	Output, annual	By 2080		2.00%	2.00%	−2.00%	0.00%	SRES A1B	Patt et al. (2013)
Solar energy	Solar irradiance (area averaged)	Annual mean	By 2060		−0.51%	0.65%	−0.53%	0.35%	A2	Haupt et al. (2016)

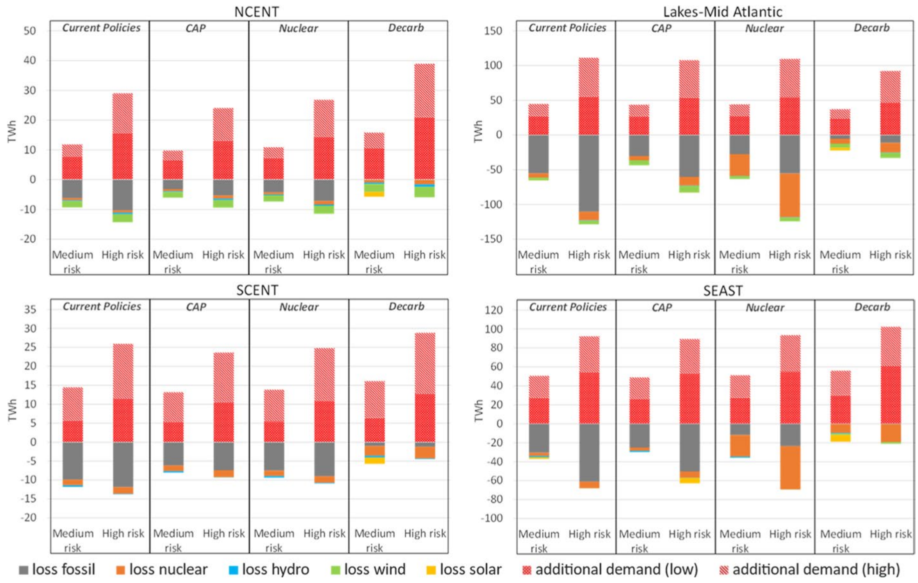


Fig. 5 Potential supply gap from losses in supply by electricity sources and additional demand. Demand (low): median changes in demand; Demand (high): additive to Demand (low) and assumes higher increase in electricity demand (see Table 3)

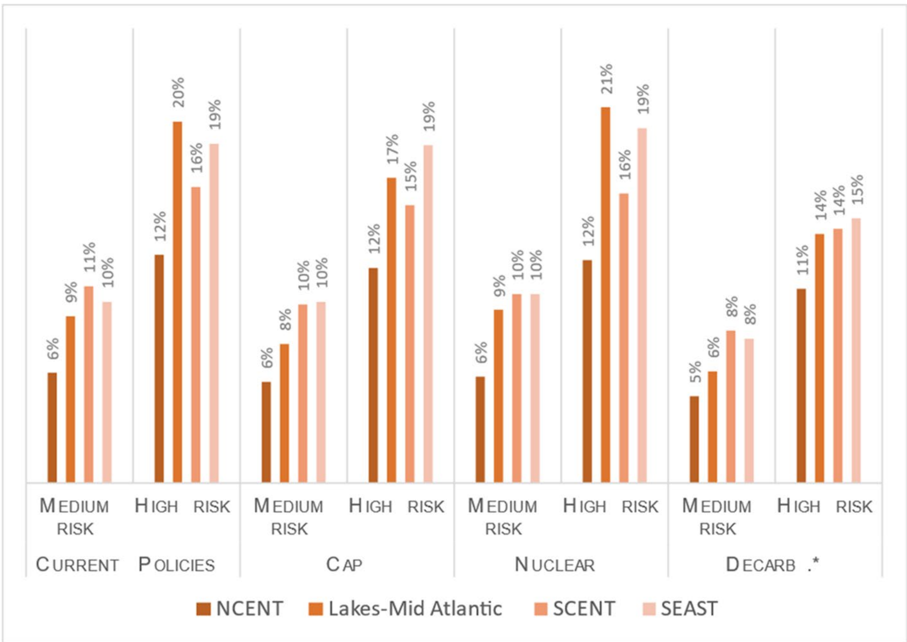


Fig. 6 Potential supply gaps relative to regional power generation in Fig. 4

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Data availability The datasets generated during and/or analyzed during the current study are available from the corresponding author on reasonable request.

Declarations

Conflict of interest Karen Tapia-Ahumada contributions to the paper were performed when she was a Research Scientist at Massacussetts Institute of Technology, Cambridge, MA. The authors have no other competing interests to declare that are relevant to the content of this article.

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