Retrofit Solutions to Electric Power Sector Decarbonization in the American Midwest

by

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Abstract

Electric power system decarbonization requires phasing out existing, carbon-emitting power plants and replacing them with new, clean generation and transmission capacity. This transition presents simultaneous challenges in investment and operational costs and system reliability. In hopes of saving costs, ensuring reliability, and preserving the power plant workforce, interest has risen among states and utilities in the potential of power plant retrofits. By reusing existing equipment and infrastructure in aging coal and natural gas power plants, utilities can save costs on new greenfield developments. Several developing technologies well-equipped to reuse all or part of the facilities at these thermal power plants include firm, low-carbon power plants and long-duration storage facilities. These technologies help balance load in a high-renewables grid while employing much of the same power plant workforce. A study of retrofit options is particularly important for the American Midwest where coal makes up a large portion of the resource mix and where the potential for intermittent wind deployment is high. This thesis enables retrofit modeling in a multi-stage capacity expansion framework and uses it to evaluate the potential for retrofits to lower system costs and cumulative emissions over three modeled carbon reduction pathways from 2020 to 2040 in the Midwest and surrounding areas. Although resulting reductions in cost and emissions are modest, we observe notable system-level reductions in curtailment of renewable generation, transmission expansion, and new natural gas deployment as well as distributional impacts relating to the costs of transitioning to a low-carbon electric power system.

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It has been my pleasure to contribute to the open-source capacity expansion model GenX with the team at MITEI and at Princeton's ZERO Lab. I look forward to incorporating the additions described in this thesis to enable related work within the broader energy research community.

Thanks also to the Technology & Policy Program. I am immensely grateful for the strong community we built during such a short time together. Thanks in particular to the E17 window crew. Thesis sessions are not so hard when you have good company. For those of you who are leaving Boston for "jobs" and "assignments", I look forward to your swift return.

Thanks most of all to my family. See you soon!

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Chapter 1

Introduction

Decarbonization of the United States power grid is a necessary step to mitigate the impacts of climate change. Not only important for its size, a net zero electric power sector is particularly vital as it allows the other end-use economic sectors to decarbonize by means of electrification. However, despite the Biden administration's 2035 target for a net zero grid, the United States electric power sector is far from low-carbon.[1] In 2020, the electric power sector emitted 1.4 billion metric tons of CO_2, accounting for 32% of US emissions.[2] In addition to this domestic target, under the Paris Agreement, the United States has committed to a 50% reduction in total emissions by 2030 compared to 2010 levels.[3] Current emissions rates indicate that the US is only 13% of the way toward this goal.[4][5]

Transitioning to a net zero electric power sector requires both building out new, clean generation and transmission capacity as well as phasing out existing, carbon-emitting capacity. Since 2005, electric power sector emissions have been reduced by one third. Sixty-five percent of this reduction is attributable from a large shift from carbon-intensive coal to lower-carbon natural gas. Though natural gas combustion emits roughly half of the CO_2 per million metric British thermal units (MMBtu) as that of coal, the roughly 117 lbs CO_2/MMBtu emitted by natural gas prohibit a net zero transition by a coal-to-gas shift alone.[6] Additionally, this emissions rate fails to consider fugitive methane as well as other uncounted upstream emissions.[7] In 2021, the United States capacity mix was composed of 43% natural gas, 21% coal, 10% hydroelectric, 9% nuclear, 9% wind, and 3% solar.[7]. With limited prospects for hydroelectric and nuclear expansion, replacing the majority share of carbon-intensive technologies will require unprecedented installation rates of solar and wind, complemented by expansions in storage and transmission to manage intermittency.

Without an overarching federal strategy for the energy transition, individual states and utilities are left to devise their own plans. Though many of the nation's largest utilities have published net zero strategies, it remains unclear whether these strategies sufficiently address the question of "stranded assets".[8][9][10][11] Amid a changing economic, technological, and political environment, fossil fuel-fired generators may become politically barred or uneconomical before the ends of their useful lives. With the potential for unpaid loans on unprofitable assets, utilities risk taking on significant amounts of debt, preventing them from building the new clean energy infrastructure the country needs to meet its energy and climate goals.[12] These premature generator retirements would also cut short the jobs of power plant workers, particularly detrimental to those communities that rely on a nearby power plant for much of their employment.

Thus, decarbonization presents an expensive problem with unprecedented deployments of new capacity and the likelihood of large quantities of debt from widespread premature retirements of thermal power plants. However, this mass closure of power plants also presents an opportunity as each leaves behind useful assets all over the country including generators, turbines, water access, and grid interconnections. By "retrofitting" existing coal and natural gas assets instead of retiring them outright, we could save on investment costs, maintain power plant community employment, and ensure reliability in an increasingly intermittent grid. Among others, retrofit options include adding carbon capture and storage equipment to existing thermal power plants, refiring natural gas plants with hydrogen, replacing coal boilers with thermal energy storage, and converting coal power plants into small modular reactors. Retrofit options such as these grant salvage value to otherwise stranded assets by extending lifetimes, by allowing lower-emission generation, and by providing valuable grid services.[13][14][15][16][17][18]

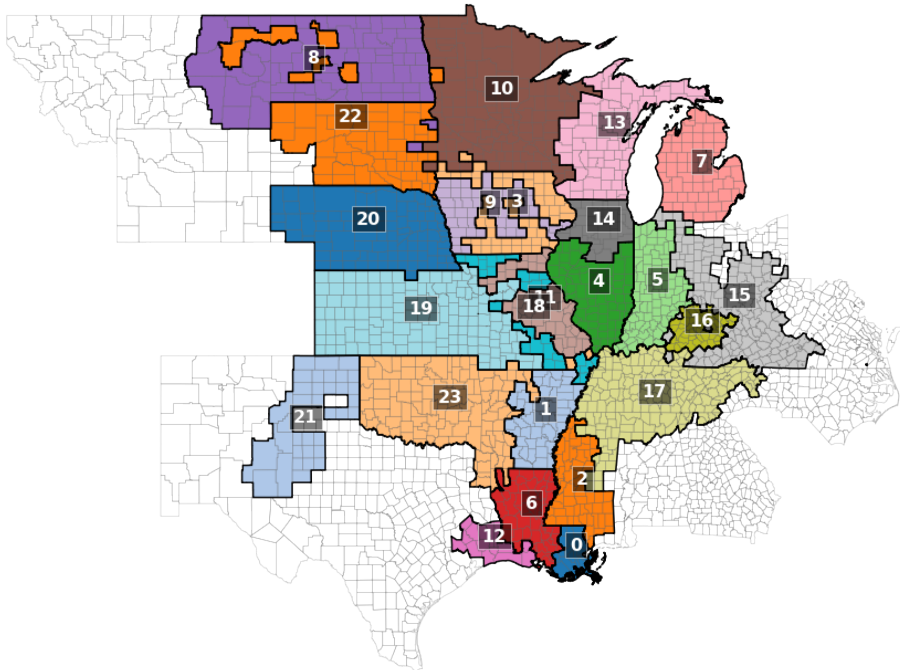

Figure 1-1: Area of study divided into 24 distinct model regions representing the Midwest and surrounding areas.

1.1 Electric Power in the American Midwest

In this study, we consider the American Midwest and surrounding areas. This region - sometimes referred to as the "Midcontinent", the "Heartland", or "Middle America" - roughly corresponds to the Mississippi River watershed, and we henceforth refer to it only as the Midwest. Specifically, the region in consideration is defined by the colored counties in Figure 1-1 with names for each region listed in Table A.1. The Midwest is particularly noteworthy with regard to the study of evolving electric power systems due to its reliance on coal, its high quality wind resource, and its diversity of involved parties.

In 2020, the Midwest capacity mix was made up of 37% natural gas (compared to 43% nationally), 32% coal (compared to 21%), 11% wind (compared to 9%), 10% nuclear (compared to 9%), 5% hydroelectric (compared to 10% nationally), <1% solar (compared to 3%) as shown in Figure 1-2.[19] The Midwest is more reliant on coal than the nation as a whole, containing 54% of the nation's coal capacity. The generation

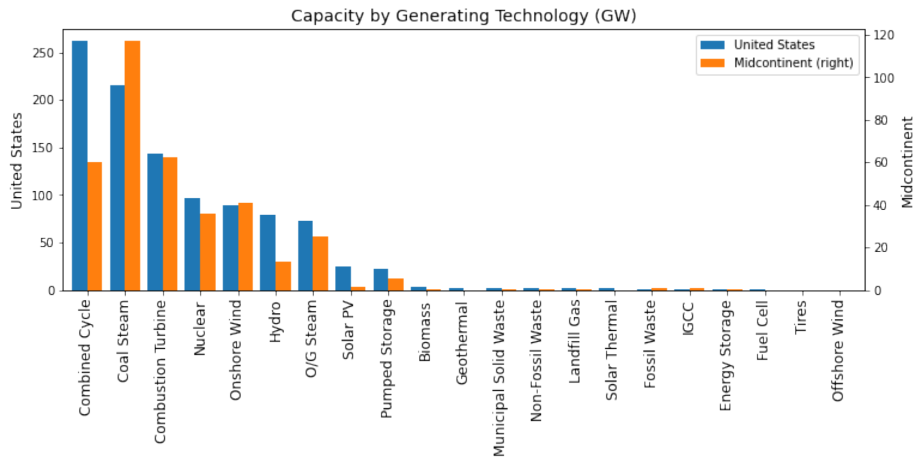

Figure 1-2: Midwest capacity mix compared with US-wide capacity mix

mix roughly reinforces this claim with 35% of regional generation from coal, 29% from natural gas, 20% from nuclear, 11% form wind, 4% from hydroelectric, and <1% from solar.[20]

In 2018, the Midwest's energy sector emitted 882 megatons of CO_2 into the atmosphere, accounting for nearly one quarter of that of the whole nation. Though emissions rates are declining faster in the region than the US at-large - falling 22.6% compared to the US's 16.7% between 2018 and 2020 - the Midwest's emissions rate per unit of generation remains much higher than the national average. The Midwest emits roughly 450 kg of CO_2 per MWh compared to the national average of 370 kg/MWh. These high emissions rates reflect the large share of CO_2-emitting technologies in the regional resource portfolio.[20]

In order to reduce coal reliance and associated CO_2 emissions, the region will need to expand variable renewable energy generation. Though the region's solar resource is not as strong as that of the Southwest, the Midwest is home to some of the strongest wind potential in the nation. Based on the methodology in Brown and Botterud (2021), Figure 1-3 shows solar PV and wind potential through a spatial distribution of capacity factors, a metric equal to the average output over a long duration compared to the maximum possible output if the asset were generating electricity at its maximum rated capacity over the full duration.[21] Variable renewable energy technologies such as solar panels and wind turbines typically have lower capacity factors than traditional power plants because “the wind does not always blow and the sun does not always shine”. Reflecting this phenomenon, US solar and wind average annual capacity factors are approximately 25% and 35% respectively.[22] Though Midwest solar capacity factors are at or below the 25% national average, much for the Midwest has an average wind capacity factor well above 40%. Wind speeds are strongest in the western half of the region, far from demand centers. Investment in network expansion may be necessary in order to leverage the decarbonizing value of this resource.[23]

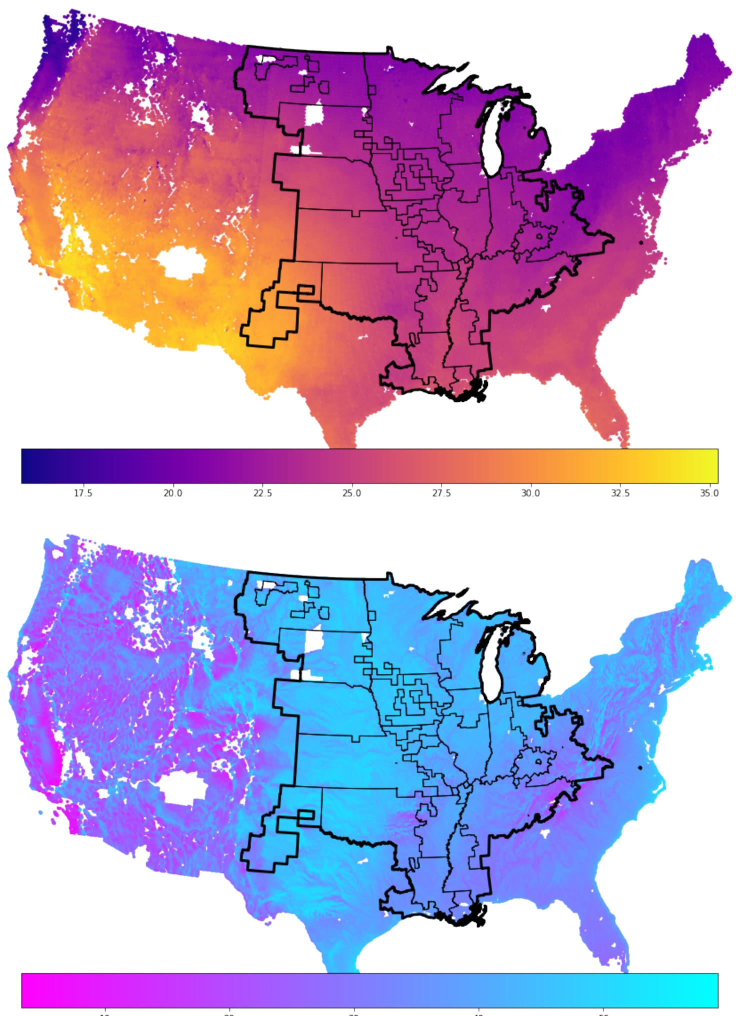

Figure 1-3: Average solar PV (above) and onshore wind (below) capacity factors

This region broad and structurally varied with 27 states, each with its own regulations, utilities, and resource availabilities. The region also includes all or part of

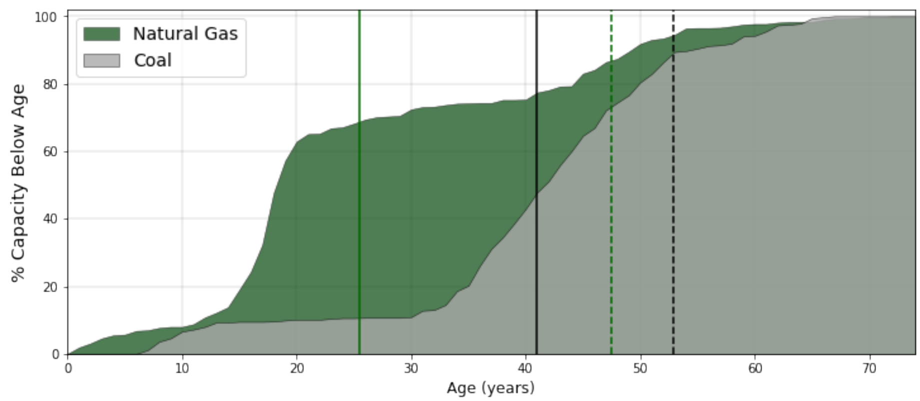

Figure 1-4: The age distribution of coal and natural gas capacity in the Midwest. Capacity-weighted ages of coal and natural gas (solid lines) show significant expected remaining operational lifetimes when compared to typical retirement ages (dashed lines).

three independent system operators - the Midcontinent ISO, the Southwest Power Pool, and PJM - as well as the federally-owned Tennessee Valley Authority and other unaffiliated parties such as Missouri-based Associated Electric Cooperative, Inc. Despite the presence of large ISOs with wholesale markets and open-access transmission systems, the region is only partially deregulated with limited consumer choice and with most states regulating rates for public utilities.[24][25][26]

1.2 Estimating Power Plant Lifetimes

In preparatory analysis, we employ a capacity-weighted averaging technique used in Grubert 2020 to examine the region's thermal fleet by age with respect to historical retirements.[12] As shown in the age distributions in Figure 1-4, the regional capacity-weighted average age for coal power plants is 42 years compared to 25 years for natural gas, each slightly older than the US at-large. When considering typical historical retirement ages in the region of 53 years for coal and 48 for natural gas, the Midwest thermal fleet could reasonably expect much of its existing capacity to remain operational for the next 10-25 years.[20] This length of time simultaneously presents advantages and disadvantages with respect to a cost-effective energy transition. First, it indicates that some existing dispatchable capacity can remain online to

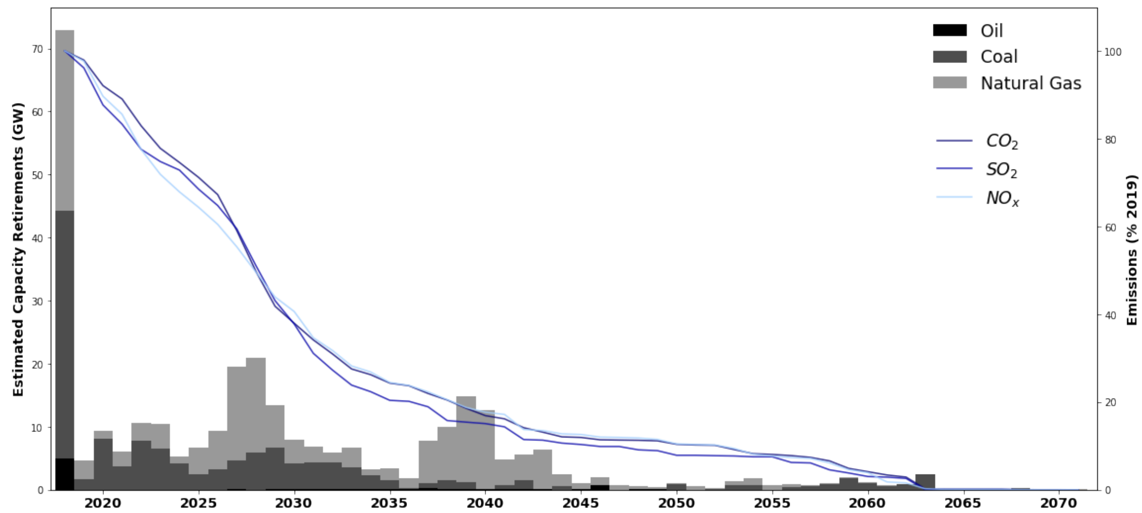

Figure 1-5: Expected retirements of coal and natural gas resources in the Midwest and associated reductions in emissions compared to a 2019 baseline.

balance supply and demand as grid penetration of renewables increases.[27][28] On the other hand, it also indicates that significant amounts of capacity will remain vulnerable to be stranded by falling renewables costs and increasingly stringent carbon policies. If plant lifespans are cut far short of their expected operational lifetimes, it may present significant costs to plant owners in the form of unpaid debts.[12][29]

The assumption that power plants will retire at a historical capacity-weighted average lifespan has substantial faults. First, considering approximately twenty years of historical retirements to infer retirement years forty or more years in the future is overly extrapolative. Changes in technology and practice may significantly alter the natural lifespan of these assets over time. Second, power plants retire for a number of reasons beyond physical deterioration including but not limited to falling renewables prices, increasing operating costs, and increasingly stringent environmental regulations. Such univariate predictions ignore factors that often drive plant retirement in practice.[13] Third, the energy sector is expected to soon undergo a significant transition where all underlying technologies, economics, and politics are subject to change. Even when disregarding the enormous uncertainties in the decades ahead, this decarbonization analysis inherently assumes that all underlying variables will shift between the period of observed retirements and the low-carbon electricity system that follows, effectively nullifying all predictive power of the historical period. Despite the faults of this practice, it is important to note that utilities expect their thermal power plants to operate beyond a typical capital recovery period. This expectation informs key decision-making with regard to transitional efforts. Because of this, it remains valuable to characterize the pacing of coal and natural gas retirements even if estimates rely on less than solid assumptions.

1.3 The Potential for Power Plant Retrofits

The concept of retrofits for thermal power plants is not new. In response to significant adverse impacts on ecosystems, human health, and infrastructure due anthropogenic emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), the U.S. Environmental Protection Agency (EPA) imposed a series of emissions regulations including the 1995 Acid Rain Program, the 2003-2008 NO_x Budget Trading Program, the 2009-2014 Clean Air Interstate Rule, and the 2015 Cross-State Air Pollution Rule.[30] These regulations forced coal power plants to decide between two options. On one hand, they could pay for emissions control retrofits - e.g., selective catalytic or non-catalytic reduction systems for NO_x and flue gas desulfurization systems ("scrubbers") for SO_2 - which would take a toll on their heat rate and operational costs.[31] On the other, they could retire their plant prematurely if it was uneconomical to continue operating under the new regulations. The EPA programs were successful, driving SO_2 and NO_x emissions down 93% and 86% respectively between 1995 and 2020.[30]

Faced with new environmental challenges, recent retrofit ideas have focused on reducing CO_2 emissions. Over the last two decades, retrofits have been responsible for much of the United States' CO_2 emissions reductions by enabling a coal-to-gas transition. Since 2011, more than one hundred coal-fired power plants convert their steam boilers to burn natural gas and other less CO_2-intensive fuels.[6][13]

In addition to reducing CO_2 emissions, the latest retrofit concepts seek to help maintain reliability in power systems with high penetrations of variable renewables. Though carbon capture and storage presents and analog to the SO_2 and NO_x era where retrofits largely considered installing additional equipment, recent ideas are can be much more transformative, often changing the operative nature of the asset.[15][14] We present a sample of current demonstration projects that illustrate the now broader concept of retrofitting as reusing or repurposing assets rather than simply supplementing existing operations with an additional emissions reduction module.

In 2021, Duke Energy announced a study to examine repurposing retiring coal plants to serve as long-duration storage systems. To do this, they partnered with thermal energy storage firm Malta, inc. Once a Google X incubator project, Malta has designed a system that uses heat pumps to store excess grid electricity as heat in molten salt tanks and repurposes coal plant steam turbines to convert that heat back into usable electricity when it is needed. Unlike lithium-ion storage which typically stores energy for about four hours, the Malta thermal energy storage system hopes to store energy for ten hours or more, a potentially valuable duration with a range of short- to long-term intermittencies. Beyond North Carolina, a demonstration project is also being considered at Xcel Energy's coal-fired Hayden Generating Station in Colorado. With thermal storage having similar operational mechanics to a coal power plant, utilities like Duke Energy and Xcel Energy hope that such projects would help retain the existing the workforce at transitioned coal plants, easing the labor concerns over the energy transition.[32][16][33]

General Electric has several projects working on transitioning natural gas power plants to burn blends of hydrogen with natural gas. Unlike natural gas, hydrogen combustion is carbon-free, burning hydrogen and oxygen and releasing only energy and water vapor. On March 30, 2022, Long Ridge Energy Terminal - a 485-MW HA-class natural gas combined cycle plant - successfully demonstrated a 5%-hydrogen blend. However, achieving higher hydrogen concentrations will require more substantial modifications to the turbine design. GE's ultimate goal is to transition natural gas plants to burn 100% hydrogen, but the pace of technological readiness is unclear. The next phase of the Long Ridge project involves a 20% blend, and even sooner, GE has another project expected to demonstrate a 10% blend in 2023.[17][34]

In 2021, the Montana state legislature approved a study that will look into constructing small modular reactors (SMRs) at retiring coal power plant sites. In addition to carbon-free, reliable generation, the Montana legislature valued such a project for its impacts on employment and economic activity, especially after witnessing the job losses from recent coal plant closures. A presentation of the Montana legislature by the Nuclear Energy Institute weighed advanced reactor designs from NuScale Power, TerraPower, and GE-Hitachi with regard to the soon-to-retire Colstrip Power Plant in eastern Montana. Compared to building new reactors at greenfield sites, construction at a coal plant site lowers costs through reuse of the turbine, reuse of the grid interconnection, and the reduction of decommissioning costs.[35][18][13] Also in 2021, a collaboration project between TerraPower and GE-Hitachi has recently selected the coal-fired Naughton Power Plant in Wyoming as the site of an advanced nuclear reactor demonstration project. The remaining units at this site were expected to retire in 2025, and TerraPower and GE-Hitachi expect to successfully demonstrate their new technology design by 2028.[36]

Though not the focus of this study, retrofit projects are not limited to generation projects for purely for the electric power sector. For example, a coal power plant in Lansing, New York is considering transitioning away from generation entirely and replacing its turbines with a data center.[37] Additionally, a recent MIT report weighs repurposing the controversial Diablo Canyon Nuclear Plant with a desalination plant.[38]

1.4 Literature Review

There is a large and growing research community examining decarbonization pathways in various geographies under a broad set of technological, political, and economic scenarios. Studies vary in their metrics of focus, depth of decarbonization considered, and granularity of spatial, temporal, and technological granularity.

For example, Brown and Botterud (2021) explore the role of transmission coordination on the cost of decarbonization. Their capacity expansion effort modeled 95%, 99%, and 100% reductions in carbon emissions emissions using one stage of capacity investment, one year of operations at an hourly resolution, and covering the full United States in 11 model regions. Their analysis revealed that inter-regional coordination in transmission expansion can significantly reduce deep decarbonization costs even in the absence of advanced technologies such as flexible nuclear power and long-duration storage.[21] Babaee and Loughlin (2018) investigate the factors driving the deployment of combined cycle natural gas with carbon capture and storage (NGCC-CCS) through the energy transition under the assumption that CCS becomes available in 2025. Examining the full United States in 9 model regions, they use MARKAL - a multi-stage, hourly-resolution capacity expansion model - to find that NGCC-CCS deployment is highly sensitive to the methane leakage rate, the CO_2 capture rate, and the natural gas price. However, exploring only 30%, 40%, and 50% reductions in greenhouse gas emissions, their study fails to model sufficiently low-carbon electricity systems.[39] Seeking to decarbonization as deep as Brown and Botterud (2021) with the temporal complexity of Babaee and Loughlin (2018), Schwartz (2021) explores key sensitivities to natural gas deployment in the Southeastern United States using a multi-stage adaptation of the GenX capacity expansion model under 90%, 95%, and 99% emissions reduction trajectories. This study found that (1) decarbonization costs are most sensitive to solar and wind investment costs and the extended lifetimes of existing nuclear plants, (2) that new natural gas deployments are greatest if nuclear plants close without receiving second lifetime extensions, and counterintuitively, (3) that cumulative emissions through the energy transition can be higher under strict carbon policies than under more lenient carbon policies due to their influence on the deployment of new natural gas and the extended lifetimes of existing coal power plants.[40] Also using the GenX capacity expansion model, Duenas-Martinez et al. (2021) conduct a study of the "Midcontinent" region using a single-stage model with hourly resolution. Exploring 70%, 80%, and 90% emissions reduction over 18 model regions, they find that (1) wind deployment is significant in the region with or without a carbon policy, (2) carbon prices push out coal but natural gas remains necessary to balance a highly renewable grid, and (3) renewables mandates do displace coal- and gas-fired capacity but fail to remove the highest emitting coal plants, removing zero-carbon existing nuclear plants instead. However, they acknowledge that modeled decarbonization pathways might be adjusted with consideration of transmission expansion, advanced technologies like CCS or flexible nuclear, or retrofits for thermal assets.[25]

With the limited exception of CCS, the above studies primarily consider the deployment of conventional technologies including solar PV, onshore wind, natural gas, and transmission. However, the transition to and operation of a low- to -zero carbon electricity system may be significantly influenced by newly developing technologies that are better equipped to match supply in demand in a grid with high penetrations of variable renewable technologies such as solar and wind. For example, Sepulveda et al. (2018) consider the value of low-carbon, "firm" technologies - such as NGCC-CCS, biomass, geothermal, or flexible nuclear - that are able to reliably dispatch power at any hour in any season. Modeling regions representative of New England and Texas with a full year of hourly grid operations in a single-stage GenX capacity model, they find that the availability of low-carbon, firm technology available can reduce full decarbonization costs by 10-62%. Additionally, Sepulveda et al. (2021) consider the value of long-duration energy storage technologies - such as hydrogen storage, thermal storage, and pumped hydroelectric storage - which are able to store power over days or weeks as opposed to only hours. Using GenX to simulate over one thousand different combinations of cost and efficiency parameters for several long-duration storage technologies, they find that long-duration storage value is most driven by low energy storage capacity costs and high discharge efficiencies.[27]

However, the value of advanced firm and storage technologies is distinct from the value of associated retrofits due to potential cost savings, operational performance differences, and availability limitations. The literature surrounding power plant retrofits is a limited subset of electricity systems modeling research, but this subset is growing in recognition of how low-carbon electric power systems may be more likely to evolve in practice. In addition to factors discussed above, Babaee and Loughlin (2018) used capacity expansion modeling to evaluate deployment of CCS retrofits for NGCC power plants. They find that deployment is highly sensitive to the retrofit efficiency penalty and that CCS retrofits are most attractive in the Midwest as well as southern central states including AR, LA, OK, and TX.[39] Though not a capacity expansion modeling analysis, Qvist et al. (2020) consider "retrofit decarbonization" of the Polish coal power sector, evaluating coal power plant repurposing and repowering options including CCS, natural gas with CCS, biomass, and advanced nuclear technologies. They find that retrofitting coal plants with SMRs offers the best economic outcomes, reducing overnight capital costs by 28-35% compared to greenfield installations. Their discussions include informative capital cost breakdowns of coal plant and advanced technologies, the trials of estimating typical lifespans of power plants from historical data, and the carbon reduction potential of a global implementation of retrofit decarbonization.[13]

1.5 Research Contribution

In this study, we aim to demonstrate the potential of decarbonization-enabled decarbonization pathways in the Midwest and surrounding areas. Using the multi-stage capacity expansion model GenX, we show how the electric power system transforms from its current state to a 2040 future system with 90%, 95% and 99% reductions in CO_2 emissions. By considering advanced technologies as retrofits and greenfield capacity, we aim to differentiate the value of retrofits from the value of advanced firm and storage technologies as discussed by Sepulveda et al. (2018, 2021). By considering the Midwest and surrounding areas with 24 model regions, we aim to contribute to existing literature - including Duenas-Martinez et al. (2021) and Babaee and Loughlin (2018) among others - with a depth and breadth that showcase how regional differences affect retrofit deployment and decarbonization outcomes.

Beyond this introduction, we will include (2) the methodology and capacity expansion framework used to explore retrofit-enabled decarbonization solutions in the Midwest; (3) the data required to characterize the electric power system and its evolution; (4) the resulting costs, cumulative emissions, and capacity deployments from now through 2040; and (5) a discussion of key outcomes, limitations of the methodology, and future work.

Chapter 2

Modeling

2.1 Capacity Expansion Modeling

In this study, we use GenX - an open-source, high resolution, least-cost capacity expansion model - as described in Jenkins et al., 2021.[41] Though traditionally used to model a single year of grid operations including a single investment stage, GenX newly offers a multi-stage planning environment using the well-known dual dynamic programming (DDP) algorithm as described in Lara et al. 2018.[42] A multi-stage model also allows us to plan for an evolving power system by incorporating dynamic cost information and lifetime retirements for new and existing capacity. GenX has been used in numerous studies to examine electric power system decarbonization as noted in Section 1.4.[40][25][28][27]

We configured the capacity expansion model with four five-year investment stages spanning from 2020 to 2040, set carbon policies with rate-based emissions caps, and enabled network expansion. We used two main strategies to enable computational tractability of the resulting multi-stage model. First, detailed unit commitment of thermal power plants as well as spinning and operating reserves were not modeled due to the substantial increase in memory and computational time that this requires. Second, we employed time domain reduction - described later - to represent the annual grid operations per stage using a set of representative days and notable extreme days at an hourly resolution.[43]

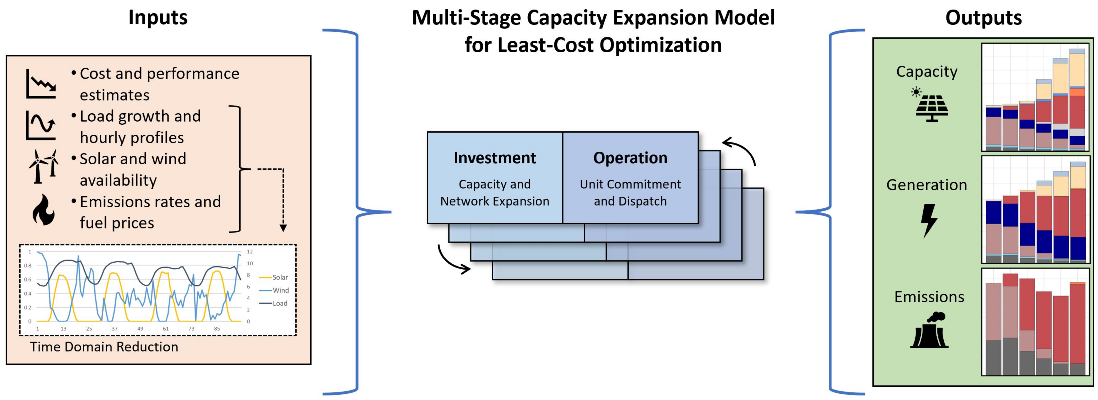

Figure 2-1: Our study employs dual dynamic programming to enable least-cost optimization of a multi-stage energy system, balancing long-term investment planning and short-term economic dispatch over four five-year stages.

2.2 Retrofit Modeling

In order to include retrofits, a capacity expansion model such as GenX needs to model transitions of capacity from one technology to another. Because (1) a given technology could be retrofitted into a number of possible new technologies and (2) a given retrofit technology may have a number of eligible source technologies, these transitions in capacity must be modeled as individual flows from specific source technologies to specific destination technologies to ensure that capacity is transitioned properly without pooling effects. We introduce two new constraints into the capacity expansion modeling framework to manage these capacity flows. First, we ensure that the amount of capacity retrofitted out of each technology does not exceed the amount of capacity of that technology retired in that stage:

$$\sum_{r \in RF(y)} R_{y,r} \leq \Delta_y \qquad \forall y \in Y$$

where $RF(y)$ is the set of possible retrofit options for technology y, $R_{y,r}$ is the capacity transitioned from technology y to retrofit technology r, and Δ_y is the amount of capacity retired of technology y in the given stage. This implies that capacity retrofitted out of a given technology is considered within the subset of "retired" from the perspective of that technology, allowing these transitions to count towards exogenous and endogenous retirements described in later sections.

Second, we ensure that the amount of new installed capacity of each retrofit technology is equal to the sum of retrofitted capacity directed from each of its eligible source technologies, subject to an optional efficiency penalty:

$$\sum_{y\,:\,r\in RF(y)} R_{y,r}\cdot ef_{y,r} = \Omega_r \qquad\qquad \forall r \in RF(Y)$$

where $RF(Y)$ is the set of all retrofit options, Ω_r is the amount of capacity installed of retrofit technology r in the given stage, and $ef_{y,r}$ is an efficiency factor equal to the ratio of incoming discharge nameplate capacity of retrofit technology r to the outgoing discharge nameplate capacity of the source technology y. Such an efficiency factor is helpful when parameterizing retrofits with parasitic loads. For example, when adding CCS to a coal or natural gas plant, a fraction of the nameplate capacity is used to power the additional processes for CO_2 capture and compression. In this case, one might set an efficiency factor of 0.9 for a CCS retrofit technology in order to model a 10% reduction in capacity due to this parasitic load. In most cases, an efficiency factor of 1 is used to maintain the same discharge nameplate capacity through the retrofit transition.

Modeling retrofits in this manner does not consider discrete decisions to retrofit specific power plants or generators. This continuous handling of capacity is better suited for a large-scale application such as this where one modeled "technology" considers several generators of a specific type in a given region. This method effectively captures the value of specific retrofit types over a reasonable resolution of space and time. Modeling discrete power plant retrofit decisions with this framework is possible by modeling each power plant as its own technology within the capacity expansion model, but such an approach is computationally intractable when modeling at the scope of the energy transition of the Midwest.

To balance computational tractability with customizability, the retrofit framework permits the user to specify multiple sources for a given retrofit technology, each with its own investment cost. Allowing a retrofit technology to have multiple sources

	Dispatchable, Low-Carbon	Long-Duration Storage
NGCC Retrofits	Carbon Capture CCS	Hydrogen Storage H2
Coal Retrofits	Small Modular Reactors SMR	Thermal Energy Storage TES

Figure 2-2: The advanced technologies considered by this study include dispatchable, low-carbon thermal technologies and long-duration energy storage technologies. One of each is available as a retrofit option for both coal and natural gas.

greatly reduces the number of associated variables when compared to modeling one-source retrofit options, and this is a simpler option if the only meaningful difference between two retrofit types is their investment cost, not the operational characteristics or O&M costs of the resulting retrofit technology. However, because operational characteristics are specified for each individual technology, it is necessary to define multiple technologies to differentiate between sources if the resulting operational characteristics of the generator are different. For example, it might make sense to model one H2 retrofit technology with brownfield NGCC as one source at one investment cost with greenfield NGCC as a second source at a lower investment cost. However, it would not make sense to model a CCS retrofit with an NGCC source and a coal source as one technology because the heat rates, capacity sizes, and O&M costs of the resulting retrofit technology would be substantially different depending on the source.

2.2.1 Retrofit Options

This study considers four low- to zero-carbon advanced technologies: carbon capture and storage, hydrogen storage, small modular reactors, and thermal energy storage. Two - CCS and SMR - are firm technologies that can be reliably dispatched at any hour of day or time of year, regardless of geography, without needing to manage a stored energy inventory. Two - H2 and TES - are long-duration energy storage technologies that are capable of storing sufficient energy to balance supply and demand over days and weeks rather than hours.

In addition to greenfield deployment of these advanced technologies, we consider each as a retrofit option. Starting in 2030, either greenfield or brownfield NGCC capacity can be retrofitted with CCS or H2. Likewise, Coal capacity can be retrofitted with SMR or TES. We model retrofitted capacity with the same operational characterization as analogous greenfield capacity but with a discounted investment cost representing the cost savings of reusing existing plant infrastructure.

Carbon capture and storage (CCS) is modeled using assumptions from the 2019 National Energy Technology Laboratory (NETL) Cost and Performance Baseline for Fossil Energy Plants. These assumptions consider a 2017 F-class combustion turbine-based NGCC power plant with 90% CO_2 capture. The removal, purification, and compression of flue gas CO_2 reduces the net plant efficiency by approximately 6%. Emissions of other pollutants - including Hg, SO_2, NO_x, and PM - are minimal due to natural and contractual pipeline natural gas supply standards as well as through the use of dry low NO_x burners and selective catalytic reduction. To retrofit existing NGCC power plants with CCS, we assume that the investment cost includes the full cost of flue gas cleanup, primarily including the Cansolv CO_2 removal system. In addition to these costs, we assume that the investment cost also includes a small portion of all other costs - e.g., costs for the turbine, cooling, instrumentation, heat recovery systems, etc. - to account for maintenance and adaptation.[44]

Hydrogen storage (H2) is modeled using assumptions of a "Power-to-Gas-to-Power" system such as that described in Sepulveda et al. (2021) and Glenk and Reichelstein (2022). Such a system modularly combines two processes: (i) the conversion of power to hydrogen through water electrolysis and (ii) the conversion of hydrogen to power through combustion in a combined cycle. The combination of these two one-directional reactions creates one reversible process in which energy can be stored for long durations in a chemical state, either in high-pressure tanks or in underground geologic storage. At the cost of round-trip efficiency, this enables the shifting of supply from periods of supply excess to periods of scarcity. When paired with an electrolyzer, an existing NGCC power plant can be retrofitted to serve the latter process of hydrogen combustion through only minor adaptations.[27][45]

Small modular reactors (SMR), such as the NuScale SMR and GE-Hitachi BWRX-300, leverage a more compact and simplified design in order to supply firm, carbon-free power while simultaneously resolving the popular concerns of conventional nuclear power's inflexibility, safety, and cost. Where conventional nuclear plants supplied primarily baseload power, SMR design features allow for more flexible operations to adapt to rapid shifts in load and generation as well as longer-term forecasted trends. The latest SMR designs outperform existing, lifetime-extended conventional reactors in terms of safety using Gen III passive safety features including self-cooling and isolated reactor buildings designed to withstand extreme external events such as earthquakes, floods, hurricanes, and tornadoes. By incorporating pump-free natural cooling water circulation processes that do not require initial power from the grid, SMRs are able to offer black start capability, a critical system reliability feature which most conventional nuclear, solar, and wind resources cannot provide. Through the above design features, SMRs are expected to have a lower levelized cost when compared conventional nuclear plants and can be installed in a fraction of the time. Retrofitting a coal power plant with an SMR offers significant cost savings through the reuse of existing infrastructure including steam cycle, control, and electrical equipment as well as civil structures.[46][13][47][48]

Thermal energy storage (TES), like H2, stores excess energy from the grid and redistributes it when needed. Whereas H2 stores energy chemically, TES stores energy as heat. Though many mechanisms are available for charge, storage, and discharge, we model TES under assumptions of a two-tank molten salt system such as that described in the upcoming MIT Future of Storage study. In this system, resistance heating is used to convert grid power into heat which stored in molten salt and finally reconverted into usable electricity using a steam turbine. The costs of the modeled TES system can be alleviated by retrofitting a coal power plant, primarily reusing its steam turbine for discharge as well as pumps, cooling tower, and electrical equipment.[14][49][50]

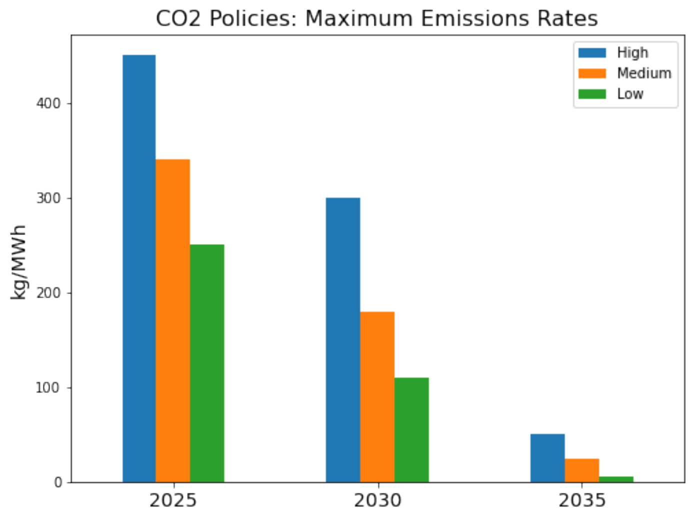

Figure 2-3: High, Medium, and Low Rate-Based CO_2 Policies

2.2.2 Model Scenarios

We evaluate each of these technologies under three carbon policies of increasing stringency as well as the absence of a carbon policy. Including a reference case without advanced technologies, considering each technology with each policy introduces twenty simple scenarios as shown in Table 2.2.2 used to evaluate the potential of retrofit-enabled energy transition pathways in the Midwest. We evaluate each scenario by (1) the net present cost of grid investment and operations and (2) the cumulative emissions produced. In addition to these key metrics, we also examine the spatiotemporal distribution of retrofit installations in order to gain insights into the value of retrofits in the context of the broad Midwest region and the pace of thermal power plant retirements.

	CO2 Policy			
	None	High	Medium	Low
Reference Case	0	1	2	3
CCS Retrofits	4	5	6	7
H2 Retrofits	8	9	10	11
SMR Retrofits	12	13	14	15
TES Retrofits	16	17	18	19

Table 2.1: Model Scenarios

The carbon policies considered enforce rate-based emissions caps declining from baseline levels in 2020 to 90%, 95%, and 99% reductions by 2040. We refer to these policies as High, Medium, and Low in increasing order of stringency. As discussed in Chapter 1, the regional emissions in recent years has been approximately half a metric ton per MWh of electricity produced. The Medium policy, intended to model steady progress over time, considers linear reductions from this baseline to a 95% reduction, 25 kgCO_2/MWh, in the final model period. The High policy, intended to model delayed and lenient trajectory to net zero, considers slower initial declines and most progress between the final two model stages, reaching a 90% reduction, 50 kgCO_2/MWh, in the final model period. Lastly, the Low policy, intended to model a more aggressive trajectory, considers significant initial progress leading to a 99% reduction, 5 kgCO_2/MWh, in the final model period. The 2020 model stage is unconstrained under each policy. The stage-level targets are shown in Figure 2-3 and in Table A.2.

Chapter 3

Data

3.1 The American Midwest

This study considers 24 distinct regions covering the Midwest and surrounding areas as shown in Figure 1-1. The boundaries of these regions - sourced from the U.S. Environmental Protection Agency (EPA) Power Sector Modeling Platform v6 Integrated Planning Model (IPM) - cover the territories of MISO and SPP as well as parts of PJM.[51]

We characterize existing supply using the EPA National Electric Energy Data System (NEEDS) v6 which holds relevant information - e.g., nameplate capacities, heat rates, etc. - for all operational generators in the United States as of 2021.[19] We aggregate this detailed representation to the technology-zone level using the 24 selected IPM regions and 12 base technology types. These technology types include coal ("Coal"), combined cycle natural gas ("NGCC"), combustion turbine natural gas ("NGCT"), steam turbine natural gas ("NGST"), nuclear ("Nuclear"), biomass ("Biomass"), run-of-river hydroelectric ("Hydro_RoR"), reservoir hydroelectric ("Hydro_Res"), pumped hydroelectric storage ("PHS"), lithium-ion battery storage ("Li-ion"), photovoltaic solar ("SolarPV"), and onshore wind ("Wind"). Capacity by zone is described further in the next section and is shown in Figure 3-2.

We characterize current and future demand using load profiles and projected growth from the 2018 NREL Electrification Futures Study.[52] Using assumptions of

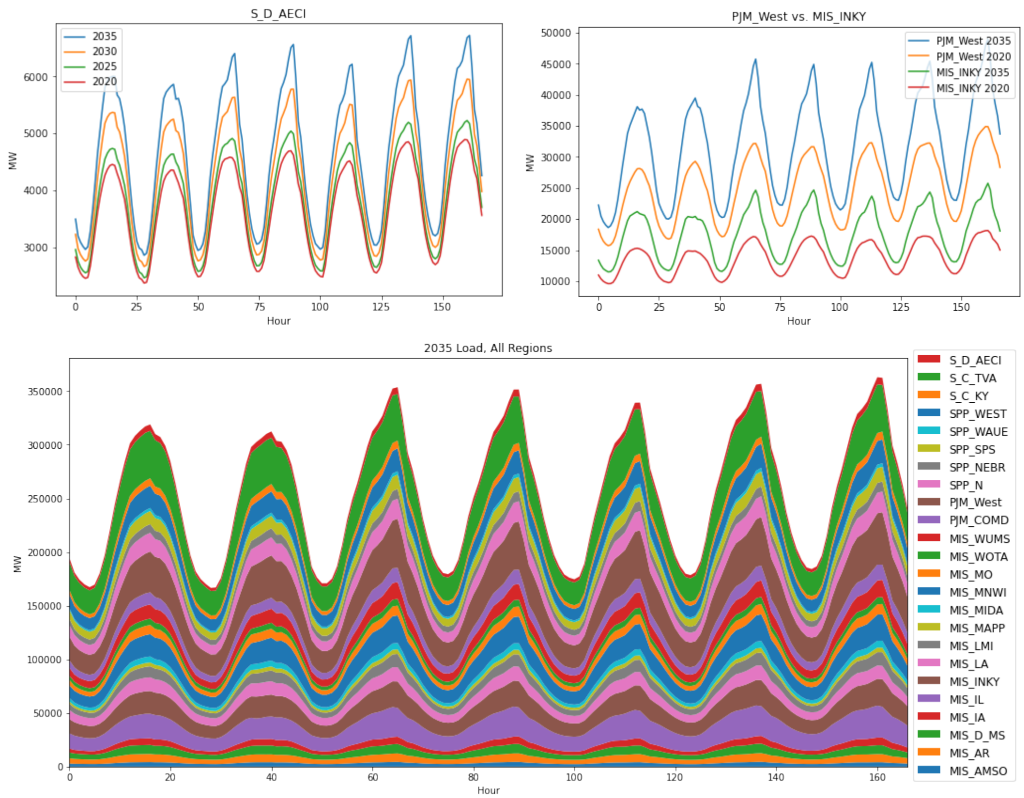

Figure 3-1: A representative summer week of load (1) showing growth over time in one model region, (2) comparing two regions' hourly load patterns, and (3) compiling the load contributions from each region.

high electrification and medium technological advancement, we acquired projections of electric load by state and by hour for years 2020, 2030, and 2040. To estimate load in 2025 and 2035, we applied linear interpolation on the even numbered years. We converted these state-level load profiles to load profiles for each model region using an area-based approximation where each state contributed load to an overlapping IPM region according to the proportion of its area that overlaps with the IPM region. Specifically, we used the overlapping area percentages shown in Figure B-1 to map load from states to IPM regions. Using this spatial aggregation method and temporal interpolation, we compute projection of load by hour for each model region for each model year - 2020, 2025, 2030, and 2035 - as visualized in Figure 3-1.

In our capacity modeling framework, we require that all demand is met with no allowance of lost load.

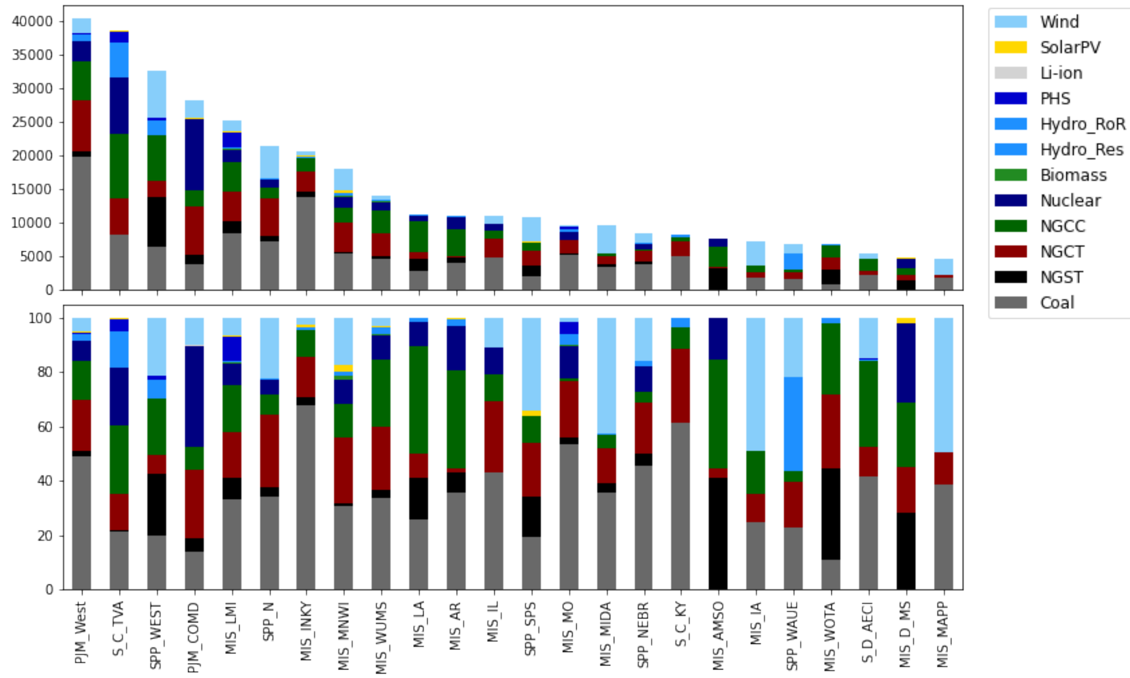

Figure 3-2: Absolute (MW, above) and proportional (%, below) capacity mix in each of the model regions.

3.2 Conventional Technologies

3.2.1 Brownfield Capacity

Brownfield capacity was primarily derived from the EPA NEEDS v6 dataset including nameplate capacity by resource and the heat rates of thermal generators.[19] To reduce computational complexity, NEEDS entries for waste technologies, geothermal, and offshore wind were removed as these technologies had no or negligible nameplate capacity in the Midwest and would not be considered for greenfield development. The remaining technologies were grouped into 11 base technologies. Because the NEEDS dataset does not differentiate between reservoir and run-of-river hydroelectric capacity, we use the 2020 Oak Ridge National Laboratory (ORNL) Existing Hydropower Assets dataset to categorize hydroelectric assets into "Hydro_Res" and "Hydro_RoR" technology types.[53] Divided into 12 base technologies, the brownfield capacity by zone is shown in Figure 3-2.

A limited spatial distribution of brownfield capacity mix is shown in Figure 3-3.

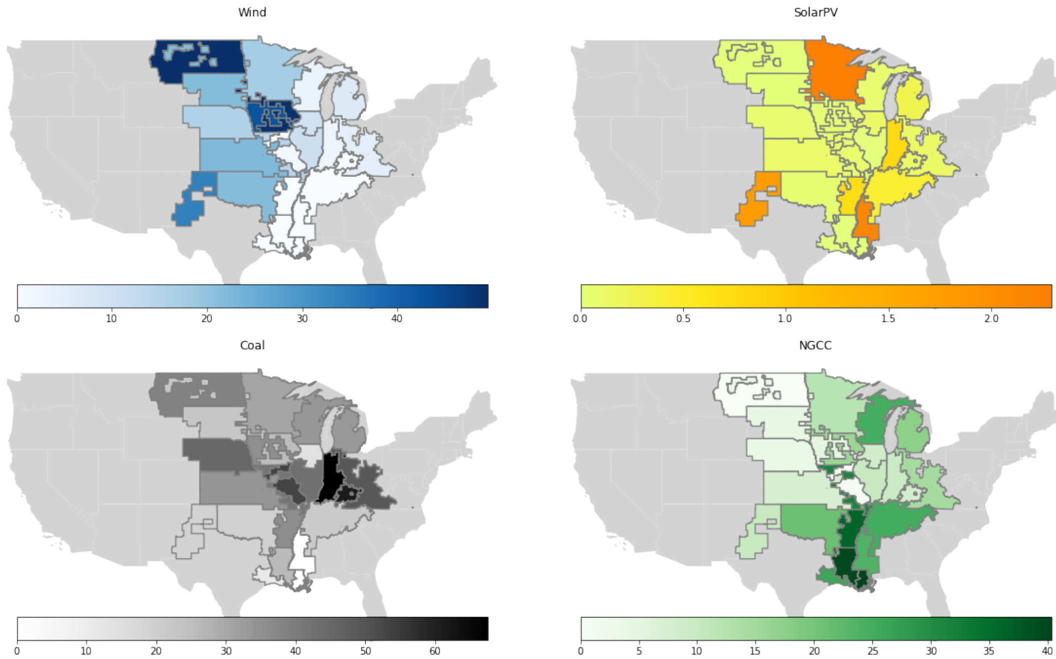

Figure 3-3: Wind (top left), SolarPV (top right), Coal (bottom left), and NGCC (bottom right) as a percentage of each region's generating capacity.

The western half of the model region has remarkably high wind speeds, and onshore wind capacity is already well developed. Wind accounts for 49% of MIS_MAPP's installed generating capacity and 47% of MIS_MIDA's annual generation. Photovoltaic solar is underdeveloped in the Midwest with no region having more than 3% solar capacity or generation. Coal is most prevalent in the eastern half of the model region where coal accounts for 68% of capacity and 75% of generation in MIS_INKY and 61% of capacity and 79% of generation in S_C_KY. Combined cycle natural gas is most prevalent in the south where NGCC accounts for 40% of capacity and 37% of generation in MIS_AMSO. Generation values, not included in NEEDS, reflect values from the 2019 EPA Emissions & Generation Resource Integrated Database (eGRID) released in 2021.[19][20]

Fixed and variable operations and maintenance (O&M) costs for brownfield thermal technologies were derived from Tables 4-8 and 4-9 of the EPA Power Sector Modeling Platform v6 Summer 2021 Reference Case. These tables assign O&M costs to biomass, coal steam, combined cycle, combustion turbine, and oil/gas steam generators - mapped to Biomass, Coal, NGCC, NGCT, NGST model technology types respectively - according to their age and their control measures for SO_2, NO_x, and Hg emissions. These costs were mapped to all thermal power plants included in the NEEDS database according to relevant plant attributes and then aggregated to the technology-region level using a capacity-weighted average of the fixed O&M (FOM) and variable O&M (VOM) costs of all generating units of a given technology type in each model region. These costs are visualized in Figures B-4 and B-3.[54][19]

Current and projected fixed and variable operations and maintenance (O&M) costs for brownfield SolarPV, Wind, Li-ion, and hydroelectric generators - as well as all conventional greenfield technologies - are primarily derived from the 2021 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).[55] Operations and maintenance costs for discharge capacity and generation are derived from the ATB according to the designations listed in Table 3.2.1. Starting in the 2025 model stage, all investment and fixed costs are derived from cost projections for five years prior to reasonably reflect the project financing timeline. In addition to the these tabulated costs, nuclear O&M costs are sourced from Sepulveda et al. (2018) with fixed O&M (FOM) costs of \$111.2/kWyr and variable O&M (VOM) costs of \$2.2/MWh.[28]

In addition to these discharge capacity FOM costs in \$/kWyr, Li-ion is also subject to storage capacity FOM costs in \$/kWhyr. As stated in an NREL 2020 update on utility-scale battery storage, discharge and storage FOM costs are approximately equal to 2.5% of the investment costs for discharge and storage costs respectively, resulting in \$4645/MWyr for discharge FOM and \$404/MWhyr for storage FOM.[56] Additionally, although the ATB indicates a VOM cost of \$/MWh for Li-ion, we use a VOM charge and discharge cost of \$1/MWh in order to prevent needless cases of simultaneous charging and discharging.

All costs here and after reflect dollar-year 2020. We annualized all fixed costs using an after-tax weighted average cost of capital (WACC) of 4.5% and a capital recovery period (CRP) of 30 years for all conventional technologies with the exceptions of Li-ion which uses a CRP of 20 years and transmission which uses a CRP of 40 years.

Because of the large number of units and their consideration for greenfield devel-

GenX Technology	ATB Technology	ATB Tech Detail	FOM ($/kWyr)	VOM ($/MWh)
NGCC	NaturalGas_FE	CCAvgCF	27.9	1.8
NGCT	NaturalGas_FE	CTAvgCF	21.4	5.1
NGST	NaturalGas_FE	CTAvgCF	21.4	5.1
Hydro_Res	Hydropower	NPD2	77.9	0.0
Hydro_RoR	Hydropower	NSD2	45.1	0.0
PHS	Pumped Storage	Class 2	18.0	0.5
Li-ion	Utility-Scale Battery	4Hr Battery	0.6	0.5
SolarPV	Utility PV	Class 9	23.6	0.0
Wind	Land-Based Wind	Class 3	44.1	0.0

Table 3.1: Generating technologies, Fixed O&M (FOM) costs, and Variable O&M (VOM) costs mapped to corresponding entries in the NREL Annual Technology Baseline. Displayed costs are 2025 costs, but the model reflects ATB cost projections for each model year.

opment, the typical capacity size of NGCC and NGCT generators is determined by the average generator size at the regional level. Similarly, heat rates for all thermal generators are also determined at the regional level using a capacity-weighted average of stated heat rates from EPA NEEDS.[19] To account for mandatory maintenance downtime, we employed consistent capacity factors of 92% for nuclear technologies and 90% for all other thermal technologies.[57][55]

Modeling unit commitment requires parameterizing certain operational characteristics of thermal generators including ramp rates, minimum up times and down times, costs entailed by a start-up, fuel requirements for start-up, minimum stable output, and typical generator size. Due to computational constraints, we do not model detailed unit commitment in our case study, but future studies could consider the operational characteristics listed in Table A.5 in the Appendix.[40][28][58]

	Charge Efficiency (%)	Discharge Efficiency (%)	Minimum Duration (Hrs.)	Maximum Duration (Hrs.)	Self-Discharge (%/Hr.)
Li-ion	92	92	0.25	200	0.002
PHS	89	89	12	12	0

Table 3.2: Operational characteristics for storage technologies.

Operational characterization of storage technologies was informed by the 2021 NREL ATB, the 2020 NREL Regional Energy Deployment System (ReEDS) model documentation, discussion with electrochemical researchers the upcoming MIT Future of Storage study, and from Schwartz (2021).[55][59][14][40] These values are indicated in Table 3.2.1. For these technologies, we employed a consistent capacity factor of 100%.

3.2.2 Technology Lifetimes and Brownfield Retirements

We assigned operational lifetimes to technologies equal to the economic lifetimes used in investment cost annualization calculations with a small number of exceptions. These lifespans are used to manage endogenous retirements of greenfield capacity within the capacity expansion model, but because the modeled time period for greenfield development spans only fifteen years, these retirements are not witnessed in the results. Consistent across model regions, these operational lifetimes are 20 years for Li-ion, 100 years for hydroelectric technologies, 80 years for Nuclear, and 30 years for other technologies.[55][40] Under the 80-year lifetime assumption where all existing nuclear power plants receive lifetime extensions, no nuclear plants in the region retire during the model horizon as shown in Table A.4 in the Appendix.[19] Likewise, due to long lifespans, we do not consider retirements of non-storage hydroelectric capacity.

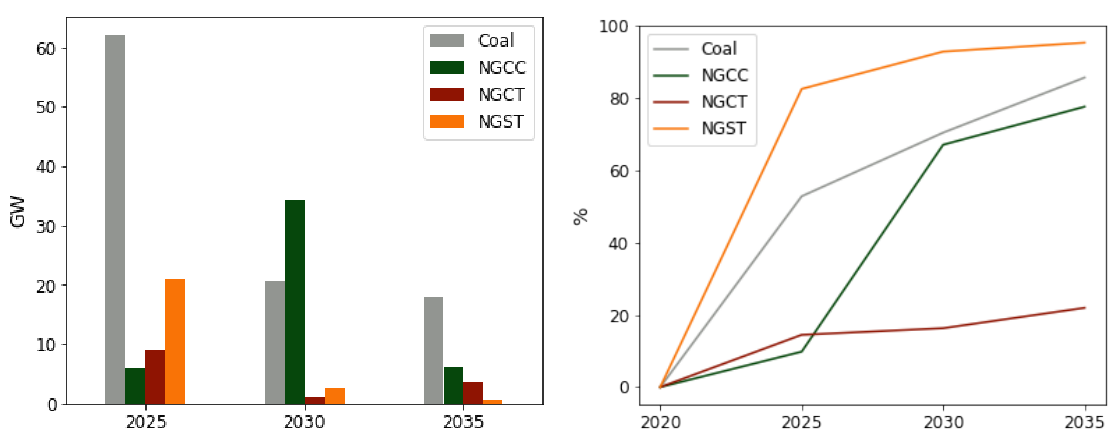

Figure 3-4: Exogenous retirements of brownfield thermal capacity in GW by stage (left) and as a percentage of initial capacity (right).

Because our study focuses on the phasing out of existing thermal capacity, we observe greater detail in considering the pace of thermal retirements. Although 30-year capital recovery periods are frequently used for thermal power plants, the operational lifespans are often much longer. According to EPA NEEDS, the historical capacity-weighted averages of Midwest thermal power plants at retirement over the last twenty years are approximately 52 years for coal and steam turbine natural gas and approximately 40 years for non-steam turbine natural gas.[19] Following the method in Grubert (2020) of estimating thermal power plant retirements using capacity-weighted average ages at retirement, we used these operational lifespans to predict probable retirement years of all thermal power plants in the Midwest.[12] The timeline of expected retirements of thermal capacity and associated emissions is shown in Figure 1-5. We employ these predictions as stage-level exogenous retirements of brownfield capacity within the capacity expansion model as shown in Figure 3-4. For a power plant predicted to retire in a specific year, we allocate that plant's nameplate capacity to the minimum amount of capacity that must retire within or before the following model stage. For example, if a 500-MW coal plant came online in 1972, then we would estimate its retirement in 2024 and require an additional 500 MW to retire during the 2025 model stage. Because we do not consider capacity installations and retirements in the first model stage, all capacity expected to retire during the first stage is instead allocated to second stage retirements.

Determined using the above methods, we show the current age distribution of coal and natural gas capacity in Figure 1-4. This distribution displays the quicker pace of coal retirements compared to natural gas which influences retirements and retrofits within the capacity expansion model. This quick pace may be a limiting factor for coal retrofits as much of the existing Midwest coal fleet may retire before advanced technology retrofits become available.

3.2.3 Greenfield Capacity

Our study considers five conventional technologies for greenfield development: onshore wind ("Wind"). photovoltaic solar ("SolarPV"), lithium-ion battery storage

("Li-ion"), combined cycle natural gas ("New_NGCC") and combustion turbine natural gas ("New_NGCT"). The Wind resource is broken into two bins to capture variability of wind resource in the region. These bins ("Wind_1" and "Wind_2") are differentiated according to estimated wind speeds and interconnection costs. Due to the timing of the study and to allow for typical financing and permitting timelines, we do not consider any greenfield development nor any capacity retirements in the first model stage spanning 2020 to 2024.

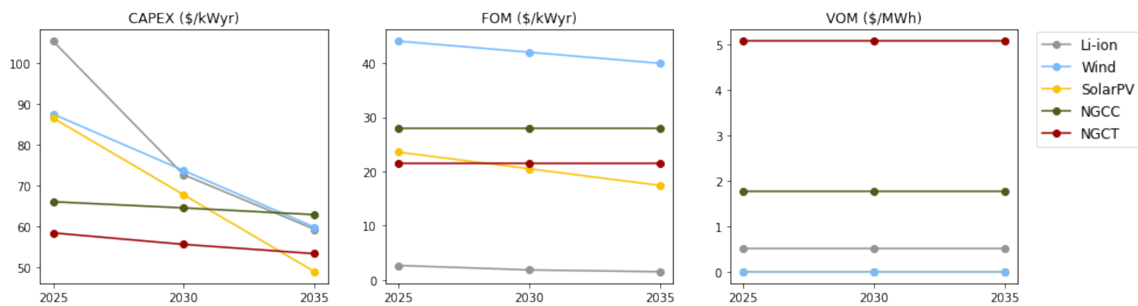

Figure 3-5: Investment and O&M costs for greenfield technologies.

Costs for greenfield technologies are also primarily derived from the NREL 2021 ATB. Using the same designations listed in 3.2.1, cost assumptions through the modeling period are shown in Figure 3-5. In addition to the national average overnight costs provided by the ATB, we apply Energy Information Administration (EIA) regional multipliers to capture variations in investment costs over the model region as shown in Figure 3-6.[60]

Greenfield NGCC and NGCT are characterized using the operational parameters listed in Table A.5. Using estimates from the ATB, new NGCC and NGCT capacity operates with heat rates of 6.4 and 7.16 MMBTu/MWh respectively.[55] Likewise, greenfield Li-ion storage follows the operational characterization described in Table 3.2.1. Greenfield Li-ion storage is also subject to investment and fixed costs for storage capacity. These fall from 2025 overnight and FOM costs of $20.5/kWhyr and $0.5/kWhyr to 2035 overnight and FOM costs of $11.5/kWhyr and $0.3/kWhyr. The Li-ion costs in Figure 3-5 combine discharge and storage costs under the assumption of a 4-hour duration, but the capacity expansion model is permitted to vary this

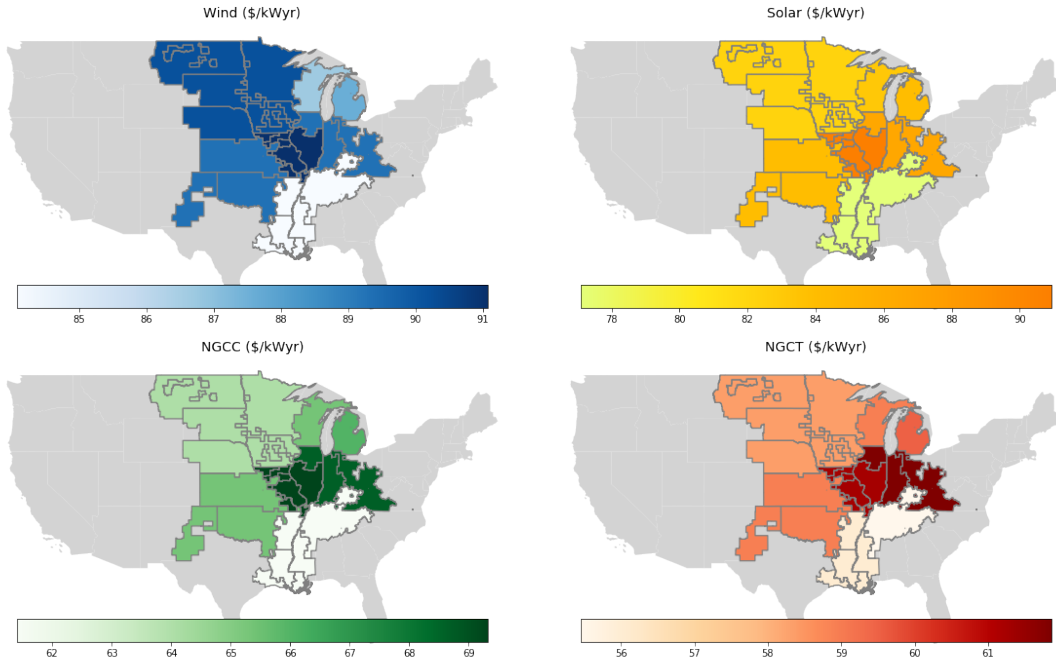

Figure 3-6: Investment costs for greenfield technologies by region.

duration within the stated bounds to decrease system costs.

3.2.4 Variable Renewable Energy

We employ methods from Brown and Botterud (2021) to characterize the operation and development of greenfield SolarPV and Wind. These methods include calculating hourly capacity factor profiles, interconnection costs, and maximum developable capacity of SolarPV and Wind in each model region.[21]

Using 2007-2013 historical weather data from the NREL National Solar Radiation Database and the WIND Toolkit, Brown and Botterud (2021) generate hourly capacity factor profiles for SolarPV and Wind. Through this methodology, the model region is divided up into a grid of approximately 4x4km sites. For each site, hourly irradiance and wind speeds are translated into hourly capacity factors using power curves consistent with horizontal 1-axis-tracking PV and 100-m Gamesa:G126/2500 turbines. These site-level profiles are compiled, weighted according to each site's developable area and optionally binned according to the quality of the resource. For this study, we use two bins to differentiate between higher and lower quality wind re-

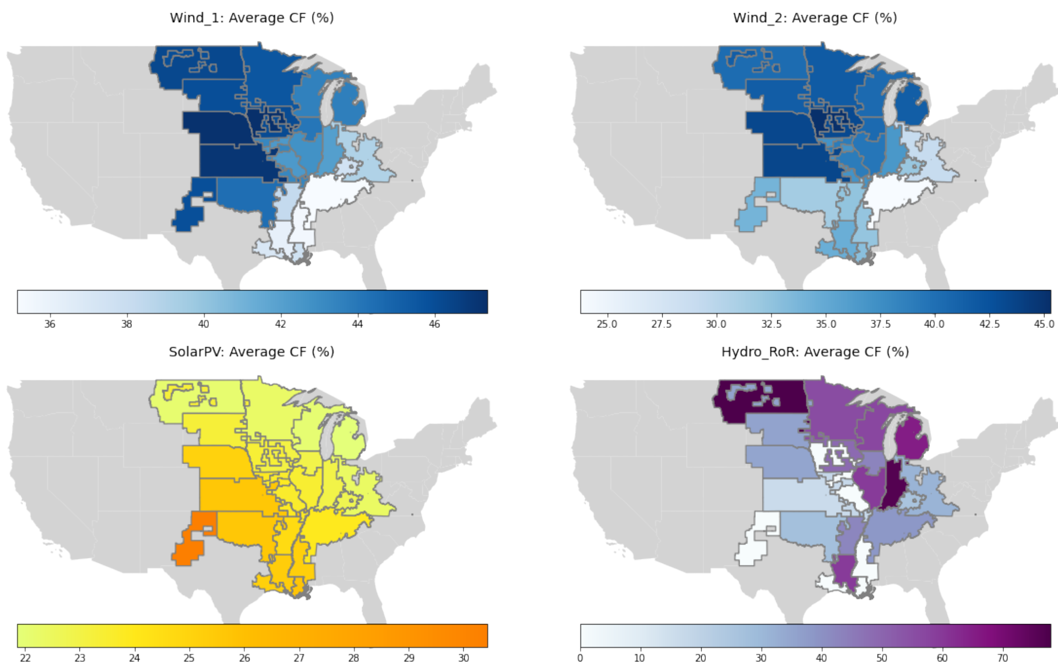

Figure 3-7: Average capacity factors for Wind, Solar, and Hydro_RoR.

source throughout the Midwest.[21][61][62] Average annual capacity factors are shown in Figure 3-7.

Interconnection cost adders, intended to internalize the cost of connecting distributed resources to the existing transmission system, are calculated using "spur-line" distances from developable area to the nearest substation,"trunk-line" distances from each substation to the nearest urban center, and per-km capital costs for the expansion of $\geq$230 kV AC lines. The resulting interconnection costs are shown in Table A.7, annualized using a 4.5% WACC and a typical lifetime of 50 years for inter-state, trunk-line transmission lines. These interconnection costs are added to the base investment costs provided by the NREL ATB shown in Figure 3-5. Also shown in Table A.7, maximum developable capacities are calculated using by considering the developable land within each model region and employing typical areal power densities for 100-m Gamesa:G126/2500 turbines and horizontal 1-axis-tracking PV.[21]

Seasonal run-of-river hydroelectric capacity factors for each model region were derived from the EPA Platform v6 power system operation assumptions documentation.[51] Winter capacity factors were mapped to December, January, and February; summer capacity factors were mapped to June, July and August; and shoulder capacity factors were mapped to the remaining months. This documentation excludes a small number of model regions, but this is considered acceptable as these regions do not have existing run-of-river capacity and greenfield development of hydroelectric capacity is not considered in this study.[19]

3.3 Advanced Technologies and Retrofits

To demonstrate this retrofit modeling framework, we consider the availability of four different advanced technologies: i. NGCC with carbon capture and storage (CCS), ii. hydrogen-fired gas turbines (H2), iii. small modular reactors (SMR), and iv. thermal energy storage (TES). These technologies are included in the model both as greenfield technologies and as retrofit options with CCS- and H2-retrofits available for NGCC and with SMR- and TES-retrofits available for coal. This selection of technologies therefore includes one "firm, low-carbon" retrofit option and a second long-duration storage retrofit option for both coal and natural gas which are scheduled to be phased out of operation at meaningfully different rates within the model period.

The costs, operational characteristics, and availabilities of each of these technologies is inherently speculative. The parameterization included here is not intended to be predictive but to indicate the potential of certain technological pathways in enabling a smooth energy transition. For the purposes of this study, we consider that these technologies become available and scalable at the beginning of the 2030 model stage. Additionally, we set a 30-year economic and operational lifetime for each advanced and retrofit technology.

	Heat Rate (MMBtu /MWh)	**Emissions Rate (kg/MMBtu)**
CCS	7.2	5.3
SMR	10.4	0

Table 3.3: Heat Rates and CO_2 Emissions Rates for Advanced Thermal Technologies

Costs and operational characteristics for CCS were sourced primarily from the National Energy Technology Laboratory (NETL) Cost and Performance Baseline for Fossil Energy Plants and supplemented by Sepulveda et al. (2018), Schwartz (2021), and the 2021 NREL ATB.[44][28][40][55] We model this technology as a 2017 F-class combustion turbine-based NGCC power plant with 90% CO_2 capture. Self-powering the carbon removal and compression results in plant output at 93% of the same plant without CCS. Its investment and operating costs are included in Tables 3.3 and 3.3. Accounting for 90% carbon capture, the CO_2 emissions rate is reduced to 5.29 kg/MMBtu compared to 52.91 kg/MMBtu for an NGCC generator without carbon capture, and the fuel cost reflects an additional $3.5/MWh accounting for the transport and storage of captured CO_2, roughly equivalent to $10/ton of CO_2 captured. According to the NETL capital cost breakdown, greenfield CO_2 capture equipment accounts for 44% of the overnight capital cost of a greenfield power plant, but this cost does not sufficiently capture all retrofit costs. Though dated, the 2013 NETL report on the Cost and Performance of Retrofitting NGCC Units for Carbon Capture suggests that the retrofit cost should be approximately 57% of the greenfield cost. We conservatively assume that a CCS retrofit for a NGCC plant will cost 70% of the overnight cost of a greenfield NGCC-CCS plant, accounting for the full cost of CO_2 removal systems as well as nearly half of all other costs to address maintenance and adaptation. [44][15]

As with conventional thermal technologies, we do not consider a detail unit commitment characterization for advanced thermal technologies, but future work that wishes to include this feature could use the operating characteristics listed in Table A.6.

	Charge Efficiency (%)	**Discharge Efficiency (%)**	**Minimum Duration (Hrs.)**	**Maximum Duration (Hrs.)**	**Self-Discharge (%/Hr.)**
H2	53	64	0.25	200	0
TES	97	35	0.25	200	0.04

Table 3.4: Operational Characterization of Advanced Storage Technologies

Costs and operational characteristics for H2 were sourced primarily from the Sepulveda et al. (2021) and supplemented by Hernandez and Gençer (2021), Öberg et al. (2022), and the 2021 NREL ATB. Our H2 characterization models a "power-to-gas-to-power", long-duration energy storage system using grid power for electrolytic production and a combined cycle for combustion. Cost and operational parameters for H2 are located in Tables 3.3, 3.3, and 3.3. Discharge costs account for the turbine, charge costs account for the electrolyzer, and storage costs account for geological storage.[27] The FOM cost for discharge combines fixed costs for the turbine and the electrolyzer.[63] The VOM cost accounts for combined cycle operations and maintenance.[55] Although combined cycle combustion of hydrogen should ideally follow operational patterns of thermal assets bound to unit commitment, this capacity expansion model framework does not support technologies that are simultaneously "thermal" and "storage" technologies. Without unit commitment characterization, the modeled H2 system behaves as a highly dispatchable resource, an optimistic but not unreasonable assumption. Because electrolysis does not emit CO_2 and because electrolysis is powered by the grid, H2 is not assigned its own emissions rate. Its effective emissions rate relates instead to the marginal technologies used to power the electrolysis. Lastly, according to Öberg et al. (2022), upgrading an existing natural gas turbine to burn 100% hydrogen should be expected to cost about 25% of the base capital cost of a greenfield turbine.[64] H2 discharge is assumed to be zero-carbon, but its effective emissions rate is that of the marginal power used to produce hydrogen.

	Discharge Overnight Cost ($/kW)	**Storage Overnight Cost ($/kWh)**	**Charge Overnight Cost ($/kW)**	**Retrofit Cost (% Base)**
CCS	2,510	-	-	70
H2	1,000	8	810	25
SMR	6,766	-	-	70
TES	290	22	3	75

Table 3.5: Investment Costs for Advanced Technologies

Costs for SMR, sourced primarily from the 2022 EIA Annual Energy Outlook, are included in Tables 3.3 and 3.3.[65] These costs reflect a much more conservative evaluation than other estimates of Nth-of-a-kind reactor costs from Ingersoll et al. (2020), Weimar et al. (2021), Stewart and Shirvan (2021), and from SMR design firms.[57][66][67][68] Operating characteristics, sourced primarily from Ingersoll et al. (2020) and Weimar et al. (2021), are included in Table A.6.[57][66] Values not found reflect those for greenfield NGCC.[55] Uranium fuel is assumed to be zero-carbon. Qvist et al. (2020) consider a breakdown of SMR capital costs and find that retrofitting a coal power plant has the potential to save 28-35% of overnight capital costs compared to a purely greenfield development. Cost savings included 80-97% of steam cycle costs, 25-35% of instrumental and control equipment and plant auxiliaries costs, 50-70% of electrical equipment costs, and 40-50% of civil structure costs. We consider retrofit savings of 30%, on the conservative side of this estimate range.[13]

	Discharge Fixed O&M ($/kWyr)	**Storage Fixed O&M ($/MWhyr)**	**Variable O&M ($/MWh)**	**Average Fuel Cost ($/MMBtu)**
CCS	67	-	6	4.3
H2	89	0	2	-
SMR	98	-	3	0.7
TES	16	124	0	-

Table 3.6: Operating Costs for Advanced Technologies

Costs and operational characteristics for TES were sourced primarily from the upcoming MIT Future of Storage study.[14] Investment costs for charging via resistance heating, storage via a two-tank molten salt system, and discharge via a heat exchanger and a steam turbine are included in Table 3.3. Operations and maintenance costs for each of these subsystems is included in Table 3.3. Storage operating characteristics, including efficiencies and durations, are included in Table 3.3. Retrofit costs for TES discharge are conservatively assumed to be 75% of greenfield development costs based on discussions in the upcoming MIT Future of Storage study reflecting steam turbine reuse, reuse of other equipment, and maintenance and adaptation of other subsystems.[14][50] Like H2, TES discharge is assumed to be zero-carbon but effectively reflects the emissions rate of the excess power stored as heat.

As with conventional technologies, we applied EIA regional capital cost multipliers to base discharge overnight in order to capture regional variability. In the absence of dedicated categories for these advanced technologies, we employed mapping "Adv. CC w/CCS", "Adv. CC", "Nuclear", and "Solar Thermal" to CCS, H2, SMR, and TES respectively.[60]

3.4 Fuels and Emissions

Fuel price projections for natural gas and coal are derived from the EIA Annual Energy Outlook (AEO) 2022 Reference Case.[69] Prices for natural gas and sub-bituminous coal were taken from the Midcontinent-Central region while prices for bituminous coal were taken from the PJM-West region. Using the spatial distribution of coal capacity by coal type, we assume that all coal capacity in PJM_West, S_C_KY, S_C_TVA, MIS_INKY use bituminous coal while all other model regions use subbituminous coal.[70] In order to capture monthly variability in natural gas price, we used standardized EIA-sourced monthly natural gas prices as multipliers to scale AEO-projected annual prices.[71] We modeled natural gas with CCS as a separate fuel with the same price projections and profile but with \$0.48/MMBtu added across the board to account for transport and storage of captured CO_2. This is in line with the National Energy Technology Laboratory's estimate of \$3.5/MWh, equivalent to \$10/ton of captured CO_2, when using their estimated heat rate of 7.16 MMBtu/MWh.[44] The 2021 NREL ATB models biomass with a constant fuel cost of \$42.4/MWh and a constant heat rate of 13.5 MMBtu/MWh over the course of the model horizon, resulting in a constant modeled biomass fuel price of \$3.14/MMBtu. Lastly, the 2021 NREL ATB models uranium with a slowly increasing fuel cost of \$0.69/MMBtu to \$0.72 over the course of the model period.[55]

Emissions rates were supplied by the EIA list of Carbon Dioxide Emissions Coefficients.[72] CCS is modeled with 90% capture. Uranium and biomass are considered to be carbon neutral.[4] Emissions rates and annual price projections for each fuel type are included in Table 3.4.

	Emissions Rate	Price Projections			
	(kg/MMBtu)	2020	2025	2030	2035
Coal, Bituminous	93.17	1.96	1.99	1.96	1.94
Coal, Subbituminous	97.13	1.87	1.78	1.77	1.77
Natural Gas	52.91	3.24	3.72	3.86	3.85
Natural Gas with CCS	5.29	3.72	4.20	4.34	4.33
Biomass	0	3.26	3.26	3.26	3.26
Uranium	0	0.69	0.70	0.71	0.72

Table 3.7: Annual average prices ($/MMBtu) and CO_2 emissions rates by fuel type.

3.5 Transmission Network

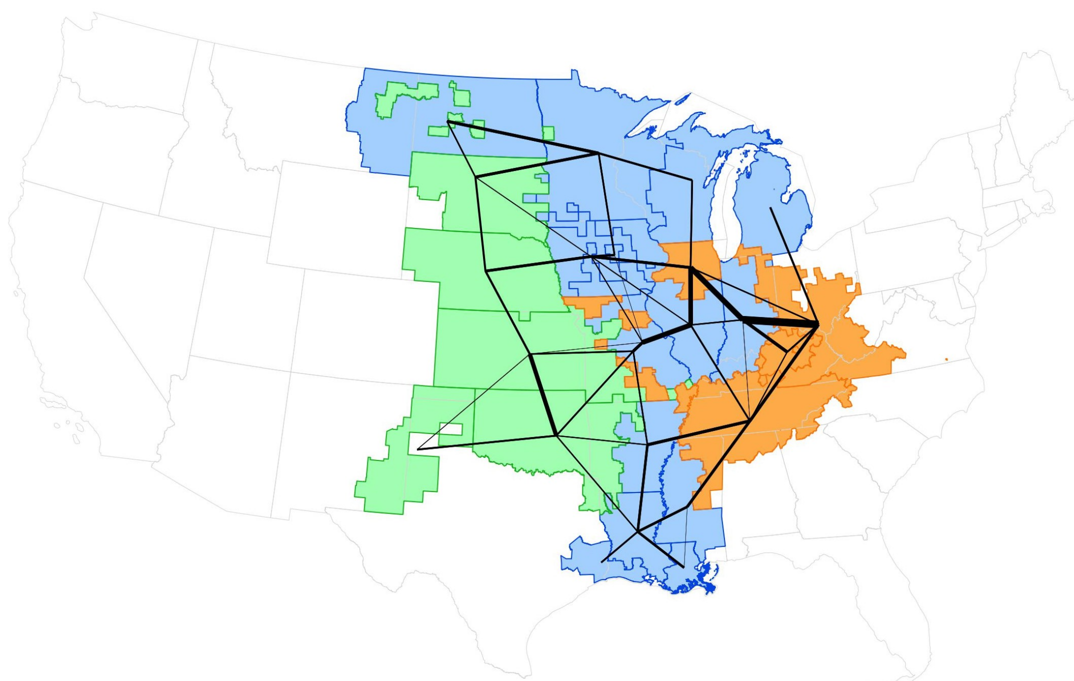

Figure 3-8: Transmission lines from the 2022 Annual Energy Outlook with MISO in blue, SPP in green, and other model regions in orange. Edge widths reflect the transmission capacity of each line included in Table A.8 in the Appendix.

For this purposes of this study, we structurally represent the power grid through inter-regional transmission lines and assume that existing intra-regional distribution is sufficient to deliver power within each model region. Imports and exports from outside the Midwest region are not considered. Existing transmission capacity between model regions is derived from the Table 3-28 of the EPA Platform v6 Reference Case.[69]

Each transmission line and its maximum capacity is included in Table A.8 in the Appendix.

We configure the capacity expansion model with network expansion, allowing the model to reinforce these transmission lines at a cost of $960/MW-km, drawn from the 2019 NREL ReEDS documentation, up to a maximum expansion of 1 GW per model stage.[73][40] For transmission expansion, we use a WACC of 4.5% and a CRP of 40 years.

3.6 Time Domain Reduction

In order to analyze a model with increased technological complexity and geographic breadth, we maintain manageable model size through a reduction in temporal complexity. To achieve this, we employ time domain reduction as described in Mallapragada et al. (2018). This method uses k-means clustering to identify representative time periods within a long duration of variable load, capacity factor, and fuel price profiles. In preparation, we compile seven years of wind and solar hourly capacity factors from Brown and Botterud (2021), NREL EFS hourly load profiles, and 2022 EIA AEO hourly fuel price profiles as discussed above.[21][52][69] We employ the time domain reduction algorithm to identify a set of seven representative days at an hourly resolution. Within this set of representative days, we include three extreme days representing the days with peak load, minimum wind potential, and minimum solar potential. Including these extreme periods forces the model to consider the full breadth of demand requirements and resource availability, ensuring that the resource portfolio is equipped to handle the variability of circumstances as they evolve in practice. Each representative day is weighted according to the number of total days that each represents in the full dataset of capacity factors, loads, and fuel prices in order to capture the relative prevalence of varying circumstances.[43]

Chapter 4

Results

4.1 Reference Case

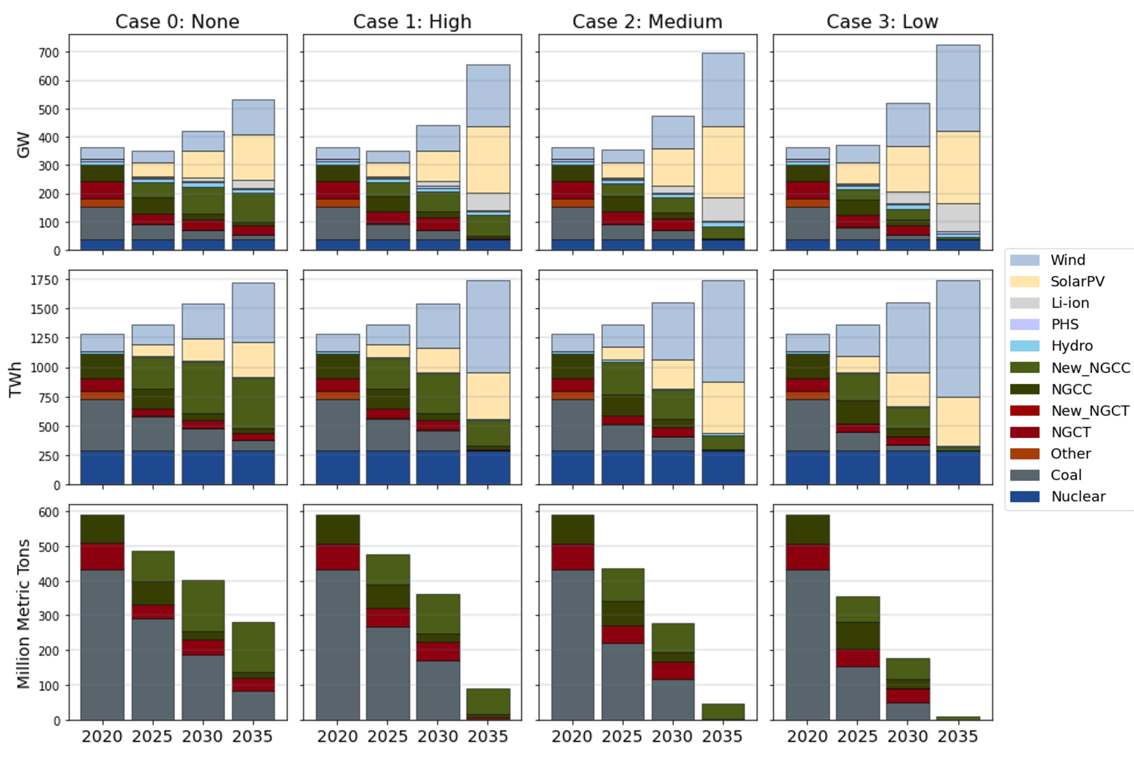

Figure 4-1: Capacity, Annual Generation, and Annual Emissions: Reference Case

Even in the unconstrained reference case - i.e., the case without a CO_2 policy and without any advanced technologies enabled - we observe a significant deployment of variable renewable energy including 89 GW of Wind and 156 GW of SolarPV which are balanced with 17 GW of Li-ion. As shown in Figure 4-1, in addition to new renewables, this case deploys 78 GW of new natural gas, almost entirely NGCC. Economic retirements of brownfield capacity are minimal, but even lifetime retirements of Coal, NGCC, NGCT, and NGST are sufficient to reduce the annual emissions rate by 52% from 591 million tons to 282 million tons over the course of the model period. These shifts in capacity are noticeable in annual generation. In 2020, generation was dominated by Coal with 34% and Nuclear with 23% compared to only 13% from all renewables. In 2035, renewables made up a much larger share with 30% from Wind, 27% from NGCC, 17% from Nuclear, 17% from SolarPV, and only 5% from Coal. In order to accommodate these new renewables, region-wide transmission capacity expands by 26 GW.

Under High, Medium, and Low CO_2 policies respectively, net present costs grow by 2%, 4%, and 8% with respect to the unconstrained case. These policies lead to reductions in cumulative CO_2 emissions of 13%, 23%, and 35%. From High to Low, the system deploys 78-146% more Wind, 47-60% more SolarPV, and 105-238% more Li-ion capacity with Wind growing to account for 57% of annual generation under the Low policy. New natural gas deployments are highest in the unconstrained case at 99 GW and decline to a minimum of 38 GW under the Low policy as the carbon cap tightens. Likewise, brownfield coal capacity retires slightly faster rate as the carbon cap tightens. As shown in Figure 4-3 comparing network expansion without a policy and under the Low policy, transmission expands by 31-150% more than the unconstrained case to balance the greater deployment of intermittent renewables. As shown in Figure 4-9, curtailment of variable renewable energy (VRE) - including SolarPV, Wind, and Hydro_RoR - increases dramatically as the carbon policy becomes more constraining.

Final regional generation mixes for Wind, SolarPV, Li-ion, and NGCC are shown in Figure 4-2. In the capacity-generation-emissions figures (such as Figure 4-1), the generation plots do not include storage resources (including Li-ion, Hydro_Res, PHS, H2, and TES) so as not to "double-count" generation that is used to charge these storage resources. However, in geospatial plots (such as Figure 4-2), we include storage

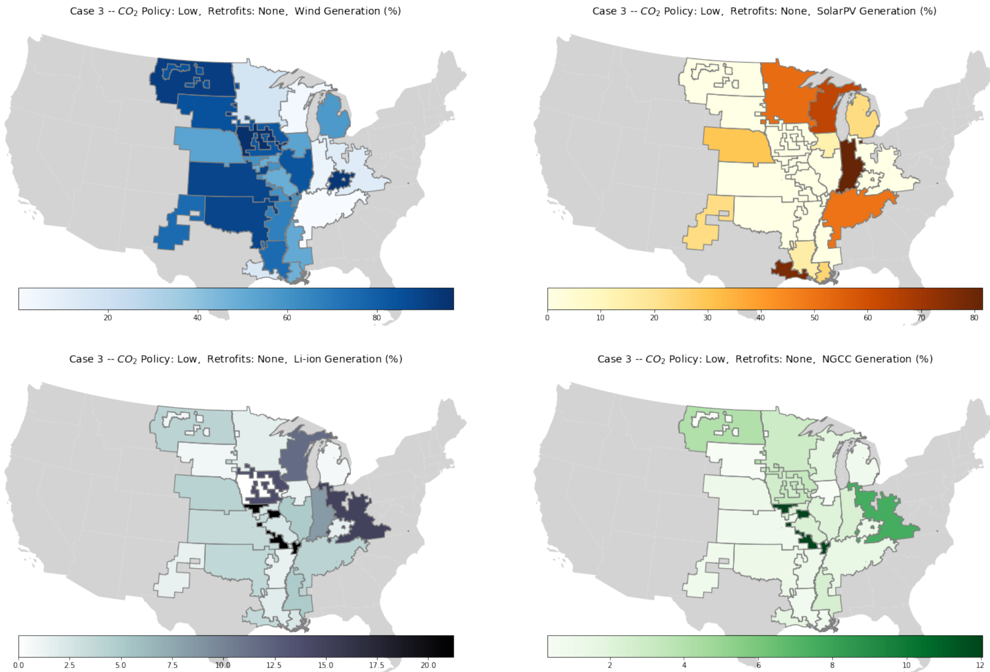

Figure 4-2: 2040 Regional Generation Mix of Wind, SolarPV, Li-ion, and NGCC: Reference Case with Low CO_2 Policy

discharge in generation percentages in order to visualize the spatial distribution of storage use.

As expected, Figure 4-2 shows substantial Wind penetration in the western half of the Midwest model region where wind speeds are notably higher, with each region owing more than half of its final system generation mix to Wind. SolarPV is prevalent in regions without the same strong wind potential including MIS_INKY, MIS_WOTA, MIS_WUMS, MIS_MNWI, and S_C_TVA. Li-ion storage helps balance renewables in nearly all regions, but a small number - including S_D_AECI, PJM_West, MIS_IA, and MIS_WUMS - have notably higher storage use, potentially serving as storage hubs for surrounding regions. Under the Low policy, NGCC is largely phased out with a few regions - including S_D_AECI and PJM_West - still meeting demand with NGCC composing up to 12% of their mix. Under the Low policy, Coal, NGCT, and NGST generation is entirely phased out by the end of the model period.

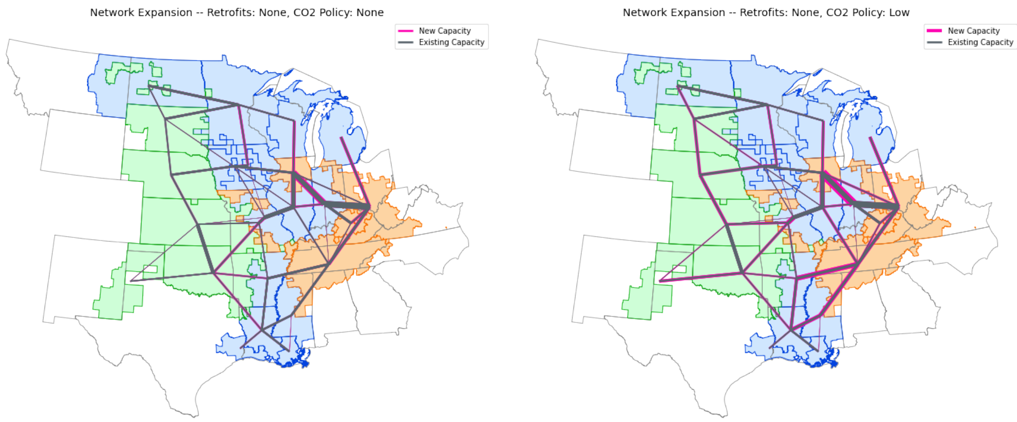

Figure 4-3: Network Expansion: Reference Case with No Policy (left) and Low Policy (right)

4.2 Carbon Capture and Storage (CCS)

Without a constraint on CO_2, CCS does not offer value to a least-cost resource mix, but CCS-enabled systems moderately reduce the net present costs of transition by up to 2% with respect to the reference case with greatest savings under the Low policy. As shown in Figure 4-4, we observe deployments of 31 GW, 51 GW, and 74 GW of CCS retrofits under the High, Medium, and Low policies, demonstrating greater need for firm, low-carbon generation as emissions grow more constrained. No greenfield NGCC-CCS is deployed, potentially due to higher costs and the ubiquity of either pre-existing or newly-built retrofittable NGCC capacity across regions. Thus, through retrofit deployments alone, CCS accounts for 6-11% of 2035 generation under carbon-constrained scenarios.

Despite these non-insignificant deployments, the introduction of CCS has a minimal impact on increasing economic retirements of existing thermal capacity with respect to the reference case, even keeping over 1 GW of coal operational into the final model stage under the High policy. As a result, cumulative emissions are only reduced by up to 1% across policies. This result is somewhat consistent across trials, likely because the carbon constraint was binding or near binding in most stages and in most regions. However, CCS deployment does reduce installations of new natural gas capacity by 6-20% with respect to policy-equivalent reference cases, reducing regional

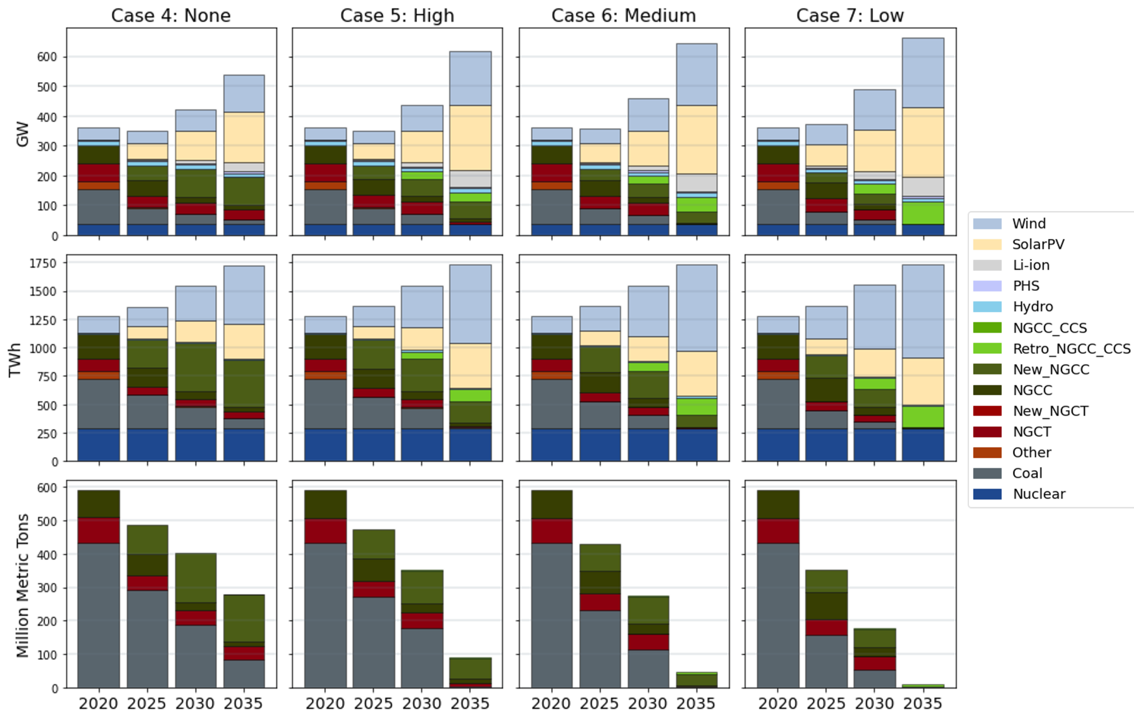

Figure 4-4: Capacity, Annual Generation, and Annual Emissions: CCS

exposure to stranded asset risk.

Compared to policy-equivalent reference cases, CCS retrofit deployments largely displace some new NGCC but primarily a mix of Wind, Solar, and Li-ion capacity. However, as shown in Figure 4-9, the availability of CCS reduces VRE curtailment by up to 41%. This indicates that although VRE deployment is reduced, new VRE capacity can used more efficiently when paired with low-carbon, firm capacity. Additionally, as shown in Figure 4-10, CCS deployments reduce transmission expansion by up to 11%, indicating that dispatchable NGCC-CCS capacity helps balance supply and demand with reduced need for inter-regional transmission to distribute variable renewable generation.

As shown in Figures 4-11 and 4-12, deployments of CCS retrofit capacity are highest in S_C_TVA with 16 GW and PJM_West with 9 GW under the Low policy. In addition to being the two largest regions by initial nameplate capacity, these are among the regions with the highest brownfield NGCC capacity. CCS accounts for the highest percentages of regional generation, 30-55% in the final model stage, in

S_D_AECI, PJM_West, and MIS_D_MS. These regions may host the greatest deployments and usage of CCS due to its high levels and concentrations of NGCC capacity as well as higher brownfield costs for NGCC generators when compared to surrounding regions as shown in Figures B-3 and B-4.

4.3 Hydrogen Storage (H2)

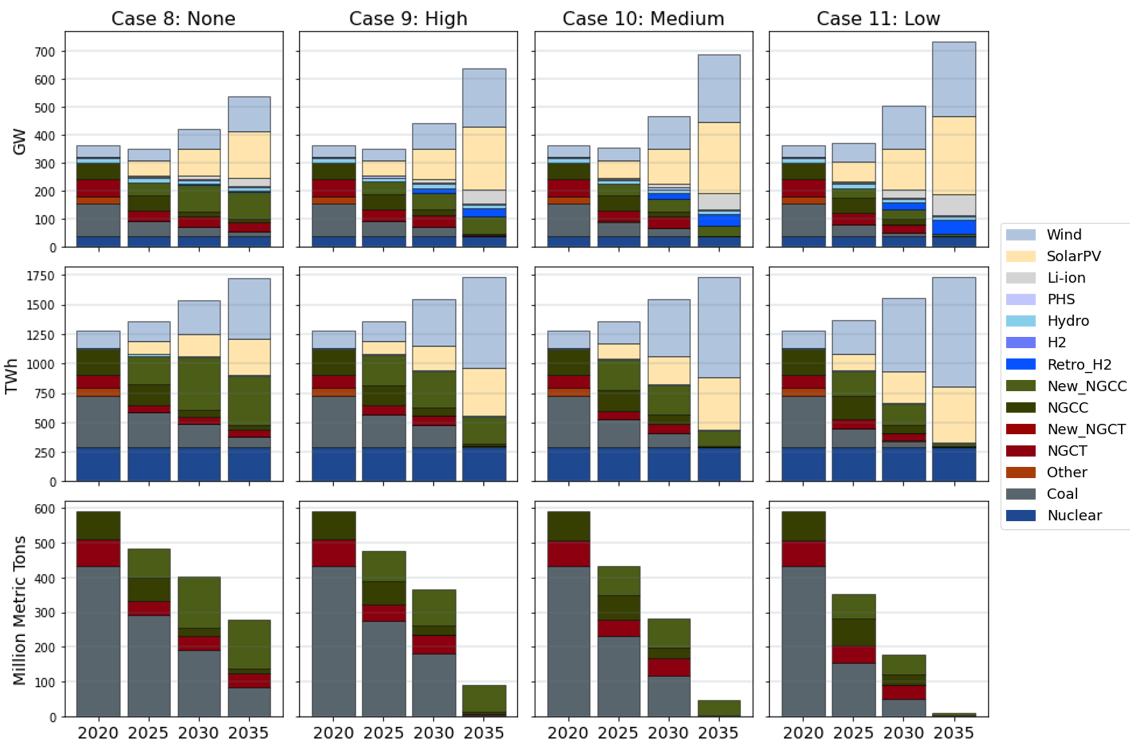

Figure 4-5: Capacity, Annual Generation, and Annual Emissions: H2

H2 availability leads to a limited deployment 3 GW of H2 retrofits even in the unconstrained case, but net present costs and emissions are both improved by <1%. Constrained scenarios lead to larger deployments of H2 retrofits with 29, 40, and 50 GW under the High, Medium, and Low policies. There are no greenfield H2 installations in any scenario, potentially due undiscounted capital costs and the availability of retrofittable NGCC capacity. Despite these large deployments in constrained cases, net present costs only improve by up to 2% with respect to policy-equivalent reference cases.

Despite these non-insignificant deployments, the introduction of CCS has a minimal impact on increasing economic retirements of existing thermal capacity with respect to the reference case, even keeping nearly 1 GW of coal operational into the final model stage under the High policy. As a result, cumulative emissions are only reduced by <1% in the unconstrained case and under the Low policy, and emissions are even slightly increased by <1% under the High and Medium policies. Altogether, the cumulative emissions with H2 availability are roughly the same as those in the reference case and with CCS availability. However, H2 deployment does reduce installations of new natural gas capacity by 4-17% with respect to policy-equivalent reference cases, reducing regional exposure to stranded asset risk.

Compared to policy-equivalent reference cases, H2 retrofit deployments largely displace a similar quantity of capacity from new NGCC, Wind, and Li-ion. H2 availability even leads to slightly increased SolarPV deployment under the unconstrained case and Low policy. However, as shown in Figure 4-9, the availability of H2 reduces VRE curtailment by up to 28%. This indicates that although Wind deployment is reduced, new capacity can used more efficiently when paired with long-duration storage capacity. Moreover, new long-duration storage capability can increase economically efficient renewables penetrations, particularly SolarPV in this case.

However, unlike with CCS, H2 does not significantly relieve the transmission system. As shown in Figure 4-10, transmission expansion is reduced by approximately 5% with respect to unconstrained and Low-policy reference cases, but transmission expansion increases by approximately 1% under the Medium and High policies. This may indicate that spatiotemporal load-balancing with both transmission and storage may be worth more than the sum of its component parts - i.e., temporal load-balancing with only storage and spatial load-balancing with only transmission.

As shown in Figures 4-11 and 4-12, deployments of H2 retrofit capacity are highest in PJM_West and MIS_INKY with about 7 GW each. Also, while H2 discharge makes up a very limited portion of total generation in any given region, relative H2 discharge rates are highest in S_D_AECI and MIS_AR. Each of these regions has large capacities and concentrations of existing NGCC capacity (as shown in Figure

3-2) as well as high O&M costs for existing NGCC capacity (as shown in Figures B-3 and B-4), meaning that NGCC retrofits in these regions are more available and more attractive than in surrounding regions.

4.4 Small Modular Reactors (SMR)

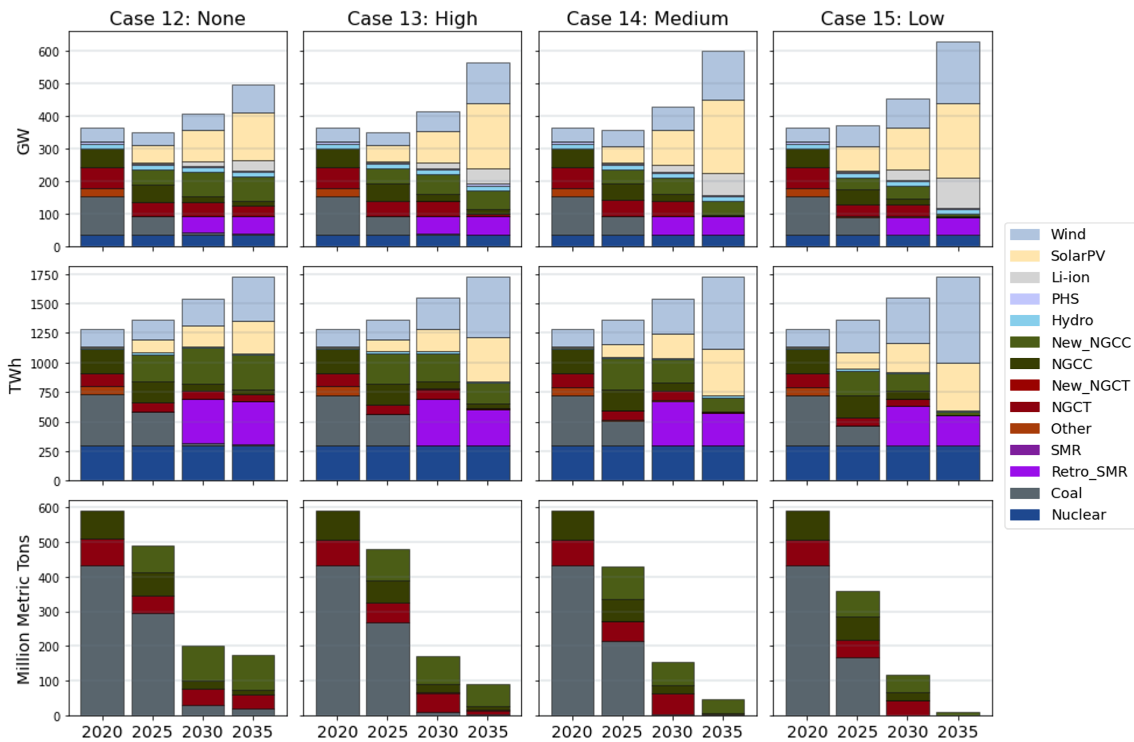

Figure 4-6: Capacity, Annual Generation, and Annual Emissions: SMR

Even without a carbon policy, SMR deployment is significant with 51 GW of SMR retrofits in the unconstrained case and 54-55 GW of SMR retrofits in the constrained cases as shown in Figure 4-6. Though not as large a deployment as CCS, SMR retrofits are limited only by availability with just over 55 GW of Coal available to be retrofitted given the modeled paces of Coal retirements and SMR technological readiness. But despite limited retrofit availability, greenfield SMRs are still not deployed, presumably due to undiscounted capital costs. This deployment of SMR retrofits reduces net present costs of investment and operations by 1% in the unconstrained case and 3-4% in the constrained cases.

In the SMR case, Coal capacity that would otherwise retire in 2025 remains online until 2030 when SMR retrofits become available in order to be retrofitted. This is particularly true under the Low policy where 10 GW of Coal remain online for an additional model stage. Despite this, SMR availability reduces cumulative carbon emissions substantially more than other cases with a 17% reduction in the unconstrained case and 5-12% reductions in the constrained cases when compared to analogous reference cases. This large SMR deployment and decrease in emissions indicates that SMR retrofits are economic even in the absence of a carbon policy and that carbon policies are not binding in all modeled regions and stages.

With an influx of zero-carbon dispatchable capacity, there remains a niche for new natural gas under a rate-based policy. Thus, SMR availability leads to the only retrofit case in which new natural gas exceeds that of the reference case, only under the Low policy, with an increase of 4% as shown in Figure 4-10. In less constrained cases, new natural gas deployments are reduced by 5-24%.

Compared to policy-equivalent reference cases, SMR retrofit deployments primarily displace a similar or greater quantity of Wind capacity as well as SolarPV, Li-ion, and new NGCC capacity. However, as shown in Figure 4-9, SMR deployment dramatically reduces VRE curtailment by 79-95%. This indicates that zero-carbon, dispatchable capacity can greatly improve the efficiency of VRE resources.

Even more the CCS, SMR availability provides relief to the transmission system. As shown in Figure 4-10, SMR retrofit deployments reduce transmission expansion by up to 17%, further indicating that low- and zero-carbon dispatchable capacity helps balance supply and demand with reduced need for inter-regional transmission to distribute variable renewable generation, even when carbon policies are tightened.

As shown in Figures 4-11 and 4-12, deployments of SMR retrofit capacity are highest in PJM_West, MIS_INKY, SPP_WEST, and SPP_N with 5-8 GW each under the Low policy. Also under the Low policy, SMR accounts for 44-48% of final model stage generation in PJM_West, MIS_INKY, S_D_AECI, and MIS_AR. Though these regions include some with large quantities and concentrations of Coal capacity, this list excludes others like MIS_MO and MIS_LMI. Though some of these regions have relatively high O&M costs for brownfield Coal capacity, others do not, notably including SPP_WEST. If these were the only two factors driving retrofit installations, we would expect higher SMR deployments and generation in other regions such as S_C_TVA, PJM_COMD, MIS_MAPP, MIS_MO and MIS_LMI. We can distinguish these excluded regions and those with high SMR deployments and generation by the age of each region's Coal fleet. As discussed in Section 3.2.2, we include exogenous lifetime retirements for thermal capacity computed using on capacity-weighted average lifetimes in the Midwest and the online year of each thermal power plant in the region. The regions that might be expected to have relatively large SMR deployments but do not - including S_C_TVA, PJM_COMD, MIS_MAPP, MIS_MO and MIS_LMI - expect 67-100% of their respective Coal fleets to retire before the SMR technology becomes available in the model. This compares to 0-58% among the regions where larger SMR deployments and penetrations do occur, with the only listed exception of S_D_AECI which, though it has notably high O&M costs and Coal concentrations in its capacity mix, expects 70% of its Coal capacity to retire before 2030.

This phenomenon helps to illuminate an important concept. Coal capacity is phasing out as it ages, setting an upper bound on the timing of coal retrofits. Simultaneously, technological development and scalability of key low-carbon and long-duration storage technologies set a lower bound on the timing of coal retrofits. These bounds designate a narrow window in which retrofits can deliver maximum value. Moreover, these upper and lower bounds are far from certain, and holding this retrofit window open relies on affirmative, multilateral action in the present time to ensure readiness of these technologies and to continue to operate these carbon-emitting thermal assets. The multilateral nature presents an additional game theoretical dilemma: (1) the investments in retrofit development and demonstration will be wasted if all the coal plants disappear before scalability is achieved, and (2) urgent transitional efforts will be delayed and more carbon will be emitted than necessary if coal lifetimes are significantly extended without low-carbon or long-duration storage retrofits ready to reuse its equipment and infrastructure. Taking advantage of the narrow retrofit opportunity will require a coordinated effort.

4.5 Thermal Energy Storage (TES)

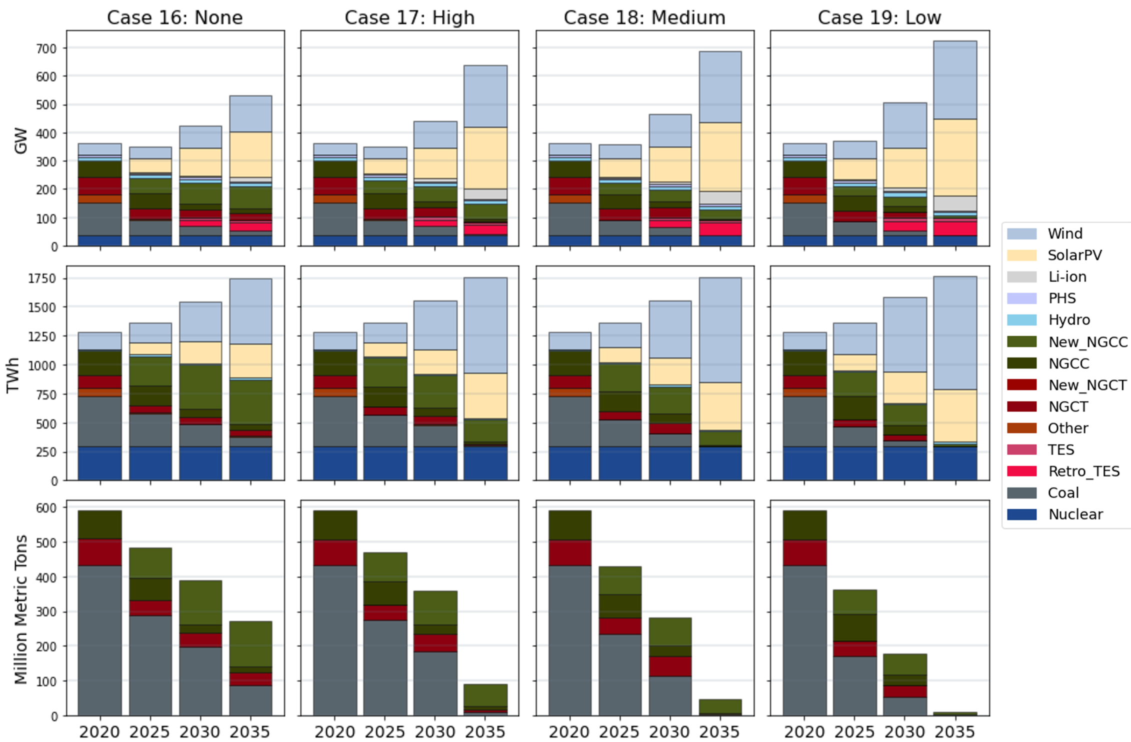

Figure 4-7: Capacity, Annual Generation, and Annual Emissions: TES

Even without a carbon policy, TES deployment is significant with 31 GW of TES retrofits in the unconstrained case, 34 GW under the High policy, 46 GW under the Medium policy, and 51 GW under the Low policy as shown in Figure 4-7. Unlike with the previously discussed advanced technologies, greenfield TES is also deployed with 7 GW in the unconstrained case, 10 GW under the High policy, 8 GW under the Medium policy, and 10 GW under the Low policy. This TES deployment reduces net present costs of investment and operations by 1% in the unconstrained case and 1-3% in the constrained cases.

With TES, as with SMR, Coal capacity that would otherwise retire in 2025 remains online until 2030 when TES becomes available in order to be retrofitted. This is particularly true under the Low policy where 8 GW of Coal remain online for an additional model stage. TES availability largely fails to reduce reduces cumulative carbon emissions with reductions of just over 1% in the unconstrained case, <1% under High and Medium policies, and an increase in cumulative emissions of <1% under the Low policy. Though leaving cumulative emissions effectively unchanged with respect to the reference case, TES deployments limit new natural gas deployments more than other advanced technologies as shown in Figure 4-10 with reductions of 7-29% with respect to policy-equivalent reference cases, mitigating the risk of stranding new natural gas assets in an uncertain economic and political environment.

Compared to policy-equivalent reference cases, TES deployments primarily displace new NGCC and Li-ion capacity as well as a smaller, policy-dependent mix of SolarPV or Wind. However, as shown in Figure 4-9, TES deployment reduces VRE curtailment by 26-51%, helping to improve the efficiency of VRE resources.

Like with H2, TES availability does not appear to reduce the need for transmission expansion, increasing expansion by 2% in the unconstrained and High cases and reducing expansion 3% and 5% under the Medium and Low policies. Beyond H2 in particular, this indicates that long-duration storage resources likely have a greater value proposition when paired with transmission.

Similar to SMR, as shown in Figures 4-11 and 4-12, deployments of TES retrofit capacity are highest in PJM_West, MIS_INKY, SPP_WEST, and SPP_N with 5-8 GW each under the Low policy. In addition, as shown in Figure B-15, six regions in total developed greenfield TES including MIS_MO, SPP_N, SPP_WEST, MIS_AMSO, MIS_D_MS, and SPP_SPS with up to 3 GW each under the Low policy. Relative TES discharge levels are highest in MIS_D_MS and MIS_AMSO, accounting for 5% and 3% of generation in the final model stage. These regions include no or low Coal capacity (e.g., MIS_D_MS), regions with large but old Coal fleets (e.g., MIS_MO), as well as regions with large and young enough Coal fleets which also develop significant TES retrofit capacity (e.g., SPP_WEST). Because they are influenced by many of the same factors, many of these regions are also where SMR deployments were high.

4.6 Comparison

As stated previously, the modeled costs and operational characterizations of these advanced technologies and retrofits are inherently speculative. This makes it challenging to compare retrofit options head-to-head, so we will focus on more general trends that unify the above results and those that differentiate them.

Retrofits of each modeled variety are deployed in every carbon constrained case in non-negligible capacities. Despite constraints on location and quantity, the system installs retrofits without greenfield development in each case with the limited exception of TES where retrofit capacity still far outnumbers greenfield capacity. These deployments necessarily indicate cost reductions. Though cost reductions appear low when expressed in net present terms with first advanced technology and retrofit deployments already discounted by ten years, the trend is clear from Figure 4-8 that costs improve with any advanced technology availability and that retrofit availability stabilizes costs of transition in the most carbon-constrained scenarios.

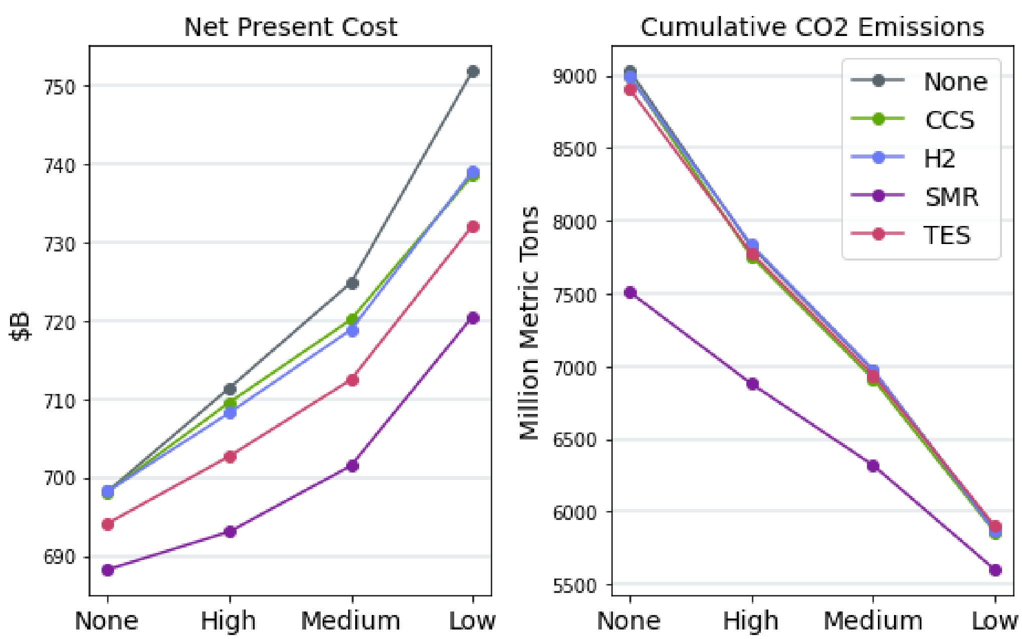

Figure 4-8: Net Present Cost and Cumulative Emissions by Carbon Policy and Technology Availability

Potentially due to the binding or near-binding nature of the constraint in each stage and model region, cumulative emissions through the modeling period remain largely unchanged with the exception of SMR. With advanced technologies becoming available in 2030, even the less strict carbon policies are tight. Though with 90% carbon reductions with respect to NGCC, NGCC-CCS still has a non-negligible emissions rate with respect to these modeled carbon policies. Alternatively, SMR is able to offer zero-carbon and flexible generation, allowing it to decouple from the policy-dependent cumulative emissions trajectories.

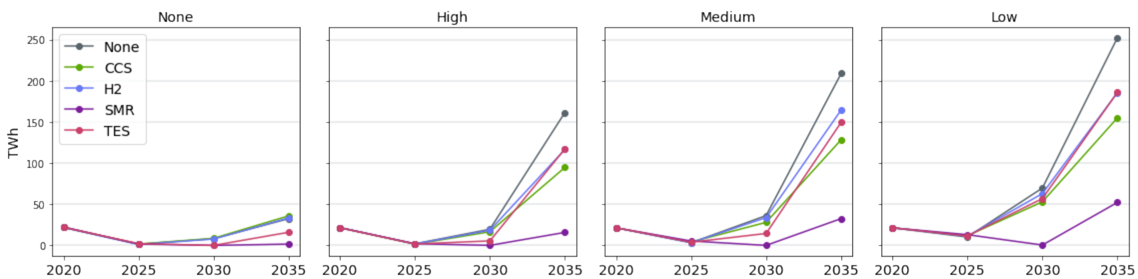

Figure 4-9: Curtailment of Variable Renewable Energy by Carbon Policy, Technology Availability, and Model Stage

Beyond costs and emissions, unifying themes include curtailment reductions and new natural gas deployment reductions. As shown in Figure 4-9, curtailment of VRE generation is reduced by 21-90% in retrofit-enabled constrained scenarios with respect to the policy-equivalent reference cases, indicating that retrofits complement VRE usage even when they reduce the need for greater VRE capacity installation. As shown in Figure 4-10, with the exception of only the SMR case under the Low policy, retrofit availability reduces new natural gas deployments by 4-29%. Without advanced technologies, natural gas may be necessary to help balance an intermittent grid and ensure reliability, but due to the potentially strict future carbon policies and the falling costs of renewables, any new natural gas power plants are more likely to become stranded within their lifetimes, imposing costs on utilities and surrounding communities. Retrofits appear to reduce reliance on new natural gas, thus also reducing our exposure to stranded asset risk.

As shown in Figure 4-11, the retrofit options are also unified by the spatial distribution of deployments. A small number of model regions - including PJM_West, MIS_INKY, and SPP_WEST - have large retrofit capacity deployments in each case. Though these regions are relatively large, these large deployments are not indicative of their size alone as their are other larger regions - including S_C_TVA, PJM_West, and MIS_LMI - which either do not deploy significant quantities of retrofits or are more differentiating in which retrofits are worth installing. Additionally, other regions - including PJM_West and S_D_AECI - rely on retrofits for relatively large portions of their energy mix over most or all retrofit types.

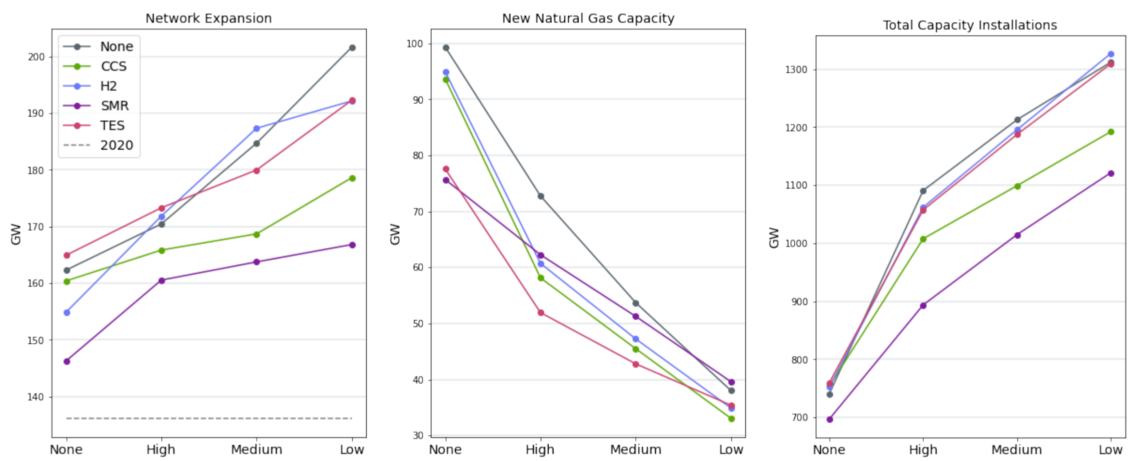

Figure 4-10: Network Expansion (left), New Natural Gas Capacity (center), New Capacity Installations (right) by Carbon Policy and Technology Availability

Retrofit options can be differentiated by their technology type (Low-carbon firm vs. long-duration storage) and by their source technology (Coal vs. NGCC).

The availability of firm retrofit types (CCS and SMR) and long-duration storage types (H2 and TES) result in notable differences in both generation and transmission capacity expansion. As shown in Figure 4-10, the total amount of new capacity installations is lower among the firm retrofit options, especially as carbon grows more constrained. This is because higher capacity factor thermal technologies are displacing lower capacity factor technologies like SolarPV and Wind, and because these thermal technologies are dispatchable, the system does not need to build excess capacity in order to ensure the supply can meet demand. Moreover, storage retrofit types reduce the effective cost of renewable generation above load, granting salvage value to excess generation reduced only by round-trip efficiency of the storage mechanism. Thus, adding storage retrofits increases the economically efficient capacity installations of VRE resources, resulting in total capacity installations close to the reference case. In addition to generating capacity installations, firm retrofit technology availability also reduces network expansion by up to 17% with respect to policy-equivalent reference cases. This compares with storage retrofits reducing network expansion by up to 5% but also in some cases increasing network expansion by up to 5%. This indicates that the most effective use of temporally load-balancing storage requires complementary spatially load-balancing transmission. Alternatively, due to the decoupled investment costs of charge, storage, and discharge capacity, it may be economic only to build large hubs for storage in a select few regions as opposed to building in a more even distribution, thus requiring transmission to and from hub regions to help balance load in the spoke regions.

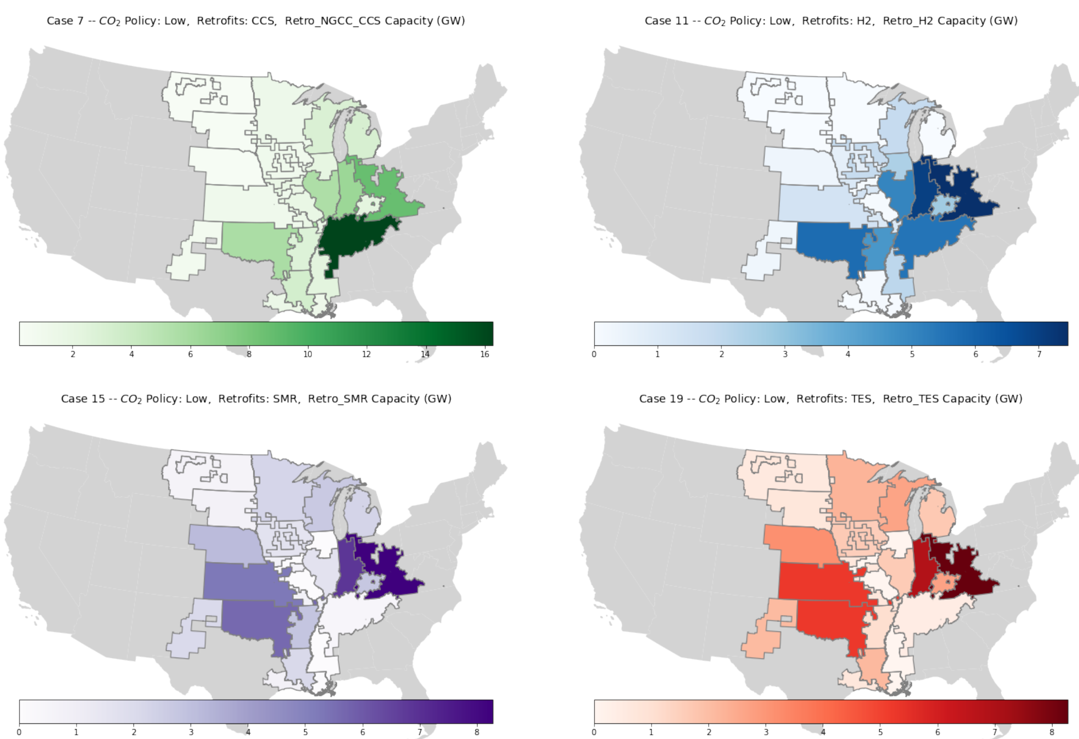

Figure 4-11: Retrofit Capacity (GW) under Low CO_2 Policies

Coal and NGCC retrofits can be differentiated by the spatial distribution of deployments and generation. As shown in Figure 4-11, SPP_N installs more Coal retrofits whereas S_C_TVA installs more NGCC retrofits, due to the size, costs, and age of brownfield Coal and NGCC fleets as discussed above. Similarly, other smaller regions are distinguished by relying on retrofits for a large portion of their energy mix. Though total deployments in capacity terms are not as large, this signals a greater relative dependence on retrofit solutions. As shown in Figure 4-12, MIS_D_MS favors NGCC retrofit types whereas SPP_NEBR favors Coal retrofit types.

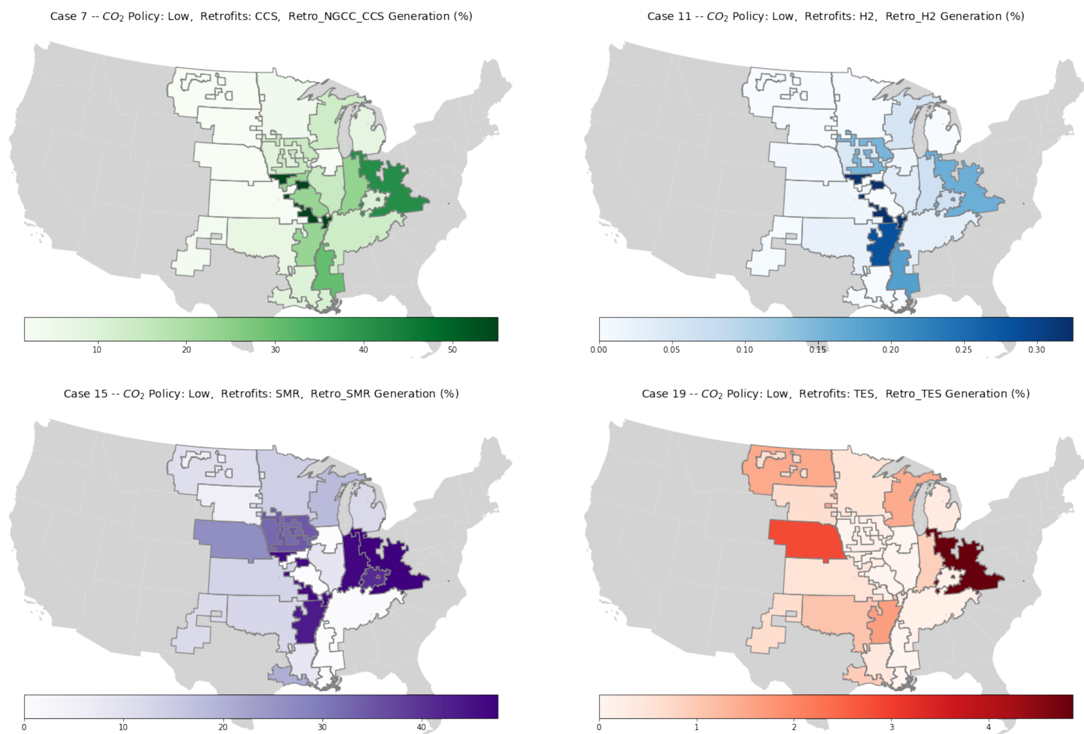

Figure 4-12: Retrofit Generation as a Percentage of Total Generation under Low CO_2 Policies [Issue: Storage resources double-count generation]

Because differences in costs and emissions are small, it is worth also considering the distributional impacts of retrofit availability. For this, we develop a metric called the relative capacity growth difference (RCGD) which considers the net growth in capacity over the modeling period for each region with respect to net growth in the reference case and normalized by the initial capacity of the region. Mathematically, it is defined:

$$RCGD_{r,z} = \frac{N_{r,z} - N_{0,z}}{I_z} \qquad \forall z \in Z, r \in R$$

where Z is the set of model regions, R is the set of advanced technologies, $N_{r,z}$

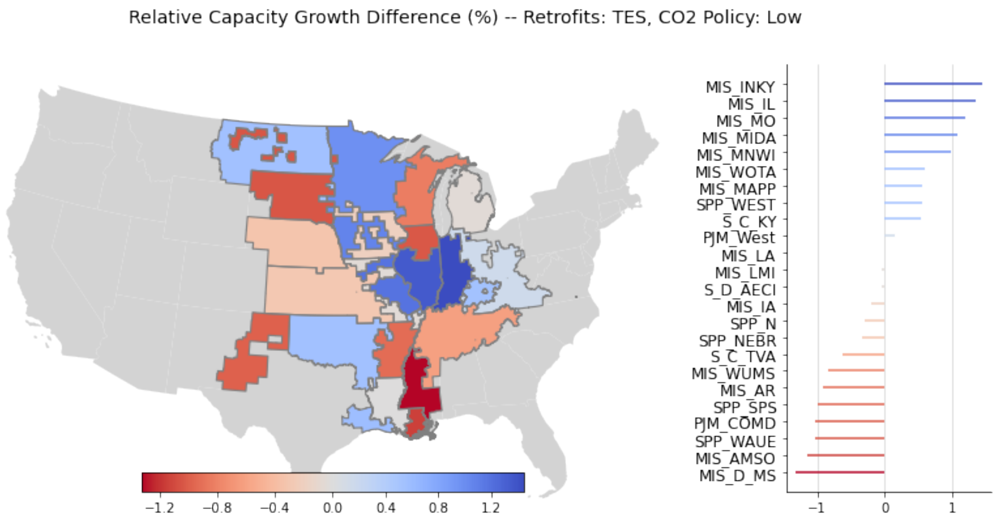

Figure 4-13: Relative Capacity Growth Difference under the Low Policy with TES

is the net capacity growth between 2020 and 2040 in region z when technology r is available, the subscript 0 designates the non-retrofit reference case, and I_z designates the total nameplate capacity in region z at the beginning of the modeling period in 2020.

RCGD can be read in many ways. As discussed above, retrofit availability lowers the total capacity required to transition to a low-carbon grid, so RCGD will be negative for most regions. This can be taken positively as the cost of transition is reduced. However, electric power sector jobs are roughly proportional to nameplate capacity, indicating that higher RCGD values indicate higher job growth. Although, this should be considered with the added nuance that some technologies - particularly VRE technologies - create more initial construction phase jobs whereas others - particularly thermal technologies - create more long-lasting operational phase jobs.[12]

For example, RCGD in the TES Low policy case is visualized in Figure 4-13 with higher relative growth in blue and declines in red. Growth is higher in regions where TES availability encourages greater expansion relative to the existing size of the region. In this case, this includes MIS_INKY and MIS_IL which rely more on SolarPV than Wind or Li-ion which TES is more likely to displace. On the other hand RCGD is lower in MIS_D_MS and MIS_AMSO where TES is expected to compose much of the final energy mix, indicating that TES's potential to reduce the required capacity for the energy transition is particular true at a local level. All Low-policy RCGD maps are included in Figure B-16. Some regions - such as MIS_MAPP, MIS_MNWI, and SPP_WEST - are expected to see higher capacity growth as well as potentially higher job growth if any firm and long-duration storage retrofits become available. Other regions - such as SPP_WAUE, MIS_D_MS, and SPP_SPS - are expected to see lower capacity growth and potentially lower transition costs in any retrofit case. Yet others - including MIS_WOTA and MIS_LA - could expect widely varied impacts based on the types of retrofits the become available. We also include maps for non-normalized capacity growth differences in Figure B-17

Chapter 5

Discussion

The retrofit modeling framework successfully incorporated retrofit capacity transitions into a capacity expansion environment, and the Midwest case study demonstrated the potential of coal and NGCC retrofits to impact key transitional outcomes and effects over a broad and varied region of the United States. Though the characterizations of these advanced technologies are speculative, clear themes arise when retrofit options become available.

Across technology alternatives, retrofits appear to enable carbon reduction pathways at modestly reduced costs. Simultaneously, retrofit deployment is expected to improve system efficiency and reduce risk exposure by decreasing curtailment of variable renewable energy, reducing the optimal deployment of new natural gas, and providing new operational avenues for otherwise retiring thermal capacity.

Low-carbon firm retrofit options, by balancing intermittency with dispatchable generation, help ensure that demand will be met with adequate supply, even with much lower deployments of solar, wind, and lithium-ion storage as well as with less investment in transmission expansion. Long-duration storage retrofit options, co-existing with sufficiently different shorter-duration lithium-ion storage, complement renewables-based systems through temporal redistribution of intermittent solar and wind generation to match load, especially when paired with baseline transmission expansion. Determined by the size, cost, and age of thermal fleets in each region, the geographic distribution of retrofit deployments has varied implications for transitional costs, capacity needs, and job potential.

Given that greenfield deployment of the modeled advanced technologies was non-existent or limited, the above results indicate that firms developing these advanced technologies should focus on retrofit solutions. As explored above, these firms should accelerate development timelines in order to capture the greatest value. Utilities and other generating firms should evaluate potential retrofit solutions as they plan for power plant retirements and could even consider partnering with advanced technology design firms for demonstration projects. As aging power plants retire, the maximum pool of retrofits decreases. Especially for coal-based retrofits, there may only be a narrow window of opportunity where technologies will be mature and coal plants will still be operational and retrofittable. If this window is missed, a net zero transition may entail larger generating capacity installations, larger investments in transmission, greater exposure to stranded asset risk, and higher variability in supply.

With only one parameterization each of a small number of advanced technologies and without a rigorous sensitivity analysis, this case study of retrofit pathways may ask more questions than it answers. However, with this retrofit framework soon to be available in the open-source GenX capacity expansion model, the door is open for retrofit-enabled capacity expansion modeling. Researchers can test an innumerable set of retrofit options among an expansive set of economic, political, and technological environments. Utilities can explore which retrofit alternatives offer the most value for their portfolios and determine the optimal selection and timing of power plant transitions. Regulators can evaluate which retrofits advance their energy and climate policy goals and potentially allocate federal or state funds to projects with high social value.

5.1 Limitations and Future Research

The research contributions above are only the beginnings of a healthy exploration of the possibilities of thermal power plant retrofits in the Midwest and beyond. The existing and updated capacity expansion framework is equipped to accept many of these assumptions and research questions but may require further adaptation to explore others. The following are considerations for improvements of the existing work as well as suggestions for future work on the subject.

First, as discussed above, significant simplifying modeling assumptions were made to reduce computational expense to a manageable level in order to examine a large model region over a long span of time with a broad set of available technologies. First, the capacity expansion model simulated system operation without a detailed characterization of unit commitment and without consideration for operating reserves. From preliminary runs, we expect these considerations would increase system costs without dramatically altering the key findings, but these greatly enhance modeling detail and would grant more credibility in the resulting solutions. The unit commitment characterizations we would have used for our modeled conventional and advanced thermal technologies are included in the Appendix.

Second, retrofit projects will be highly unique to the specific plant and project type and thus evade accurate high-level modeling. Future modeling efforts could consider grouping similar projects into "bins" as we do for variable renewable energy in order to represent a slightly more detailed picture of the distribution of project costs and operational characterizations of the retrofit resource. Moreover, our case study considers that advanced technologies become available for deployment in 2030, only limited by the size of each region's Coal and NGCC fleet. However, this availability timeline is just one possibility and may result in substantially different outcomes compared to other earlier or later dates. Additionally, although we chose advanced technologies that we would expect would be less limited by geography, plant size, and other considerations, we acknowledge that not all operational coal and natural gas power plants should be considered retrofittable, and future work would benefit from a detailed characterization of retrofit feasibility, potentially creating retrofit supply curves showing retrofittable capacity at rising project costs.

Third, in addition to high plant-level variation in retrofit project costs, the investment and overnight costs are highly speculative and uncertain. For example, future SMR cost estimates in the literature vary by nearly an order of magnitude. Future work should develop a sensitivity analysis on the costs of these or other technologies, determining maximum costs for deployment or evaluating which costs may be most determinative in the economic viability of greenfield or retrofit developments.

Fourth, as discussed in the literature, forecasting power plant retirements is highly relevant to the study of retrofits, but it presents a challenge. It inherently requires extrapolation from a narrow historical view into a large, uncertain, and necessarily different future. These estimations are likely to be very wrong, but failing to characterize them at all would miss a core supply-determining factor. Instead of directly forecasting retirements, future work could demonstrate how a range of potential distributions impacts retrofit deployment and other key transitional outcomes.

Fifth, we considered one retrofit savings factor for each advanced technology type in order to capture costs saved through the reuse of existing equipment and infrastructure. It would be worth considering a rigorous sensitivity analysis of these particular values to determine which factors make retrofits of specific types worth building and which do not. This is also likely to be highly dependent upon geography and timing.

Sixth, we discuss a window limiting the timing of retrofits, but CCS has an additional policy window. If carbon is not sufficiently constrained, it is not economic to build. On the other hand, if carbon is too heavily constrained, 90% capture will not be sufficient, and current CCS technology will be politically barred from operation. Future work could consider which range of policies are favorable to CCS deployment, whether future outcomes likely to be in this range, and whether the determine outcomes are desirable and worth pursuing.

Seventh, our case study does not consider decommissioning costs. The existing capacity expansion modeling framework does not include decommissioning costs for plant retirements, but this factor is likely highly relevant to the efficiency of individual and system-level retrofit decisions. However, it is likely that retrofit projects will still have to pay some portion of the decommissioning cost. Because the size of this portion is uncertain and likely highly project-dependent, we leave out this factor for simplicity. Future work should examine how sensitive retrofit value is to decommissioning costs in order to get a more detailed understanding of this highly practical concern.

Appendix A

Tables

ID	Region	ID	Region
0	MIS_AMSO	12	MIS_WOTA
1	MIS_AR	13	MIS_WUMS
2	MIS_D_MS	14	PJM_COMD
3	MIS_IA	15	PJM_West
4	MIS_IL	16	S_C_KY
5	MIS_INKY	17	S_C_TVA
6	MIS_LA	18	S_D_AECI
7	MIS_LMI	19	SPP_N
8	MIS_MAPP	20	SPP_NEBR
9	MIS_MIDA	21	SPP_SPS
10	MIS_MNWI	22	SPP_WAUE
11	MIS_MO	23	SPP_WEST

Table A.1: Identifiers for each model region

	High	Medium	Low
2025	450	340	250
2030	300	180	110
2035	50	25	5

Table A.2: Modeled Carbon Policies: Rate-based CO_2 caps by stage in kg/MWh

Region	**Nu**	**Co**	**Ot**	**CT**	**CC**	**Hy Ro**	**Hy Re**	**PH**	**Li**	**So**	**Wi**
PJM_West	2.97	19.74	0.90	7.52	5.88	0.40	0.54	0.24	0.04	0.05	2.08
S_C_TVA	8.33	8.31	0.02	5.31	9.68	1.19	3.93	1.70	0.00	0.17	0.03
SPP_WEST	0.00	6.44	7.35	2.35	6.83	0.82	1.34	0.47	0.00	0.02	6.97
PJM_COMD	10.52	3.90	1.41	7.10	2.44	0.02	0.00	0.00	0.11	0.03	2.76
MIS_LMI	1.92	8.37	2.10	4.26	4.40	0.04	0.05	2.30	0.00	0.07	1.66
SPP_N	1.18	7.25	0.80	5.62	1.61	0.08	0.00	0.00	0.00	0.02	4.76
MIS_INKY	0.00	13.90	0.63	3.07	2.02	0.14	0.08	0.00	0.02	0.16	0.54
MIS_MNWI	1.66	5.51	0.35	4.42	2.18	0.12	0.19	0.00	0.00	0.41	3.13
MIS_WUMS	1.20	4.70	0.54	3.25	3.45	0.18	0.18	0.00	0.00	0.01	0.45
MIS_LA	0.97	2.93	1.70	1.02	4.48	0.19	0.00	0.00	0.00	0.00	0.00
MIS_AR	1.82	3.98	0.78	0.18	4.03	0.04	0.20	0.00	0.00	0.08	0.00
MIS_IL	1.07	4.76	0.00	2.89	1.12	0.01	0.00	0.00	0.00	0.00	1.22
SPP_SPS	0.00	2.09	1.61	2.14	1.11	0.00	0.00	0.00	0.00	0.19	3.71
MIS_MO	1.19	5.15	0.28	1.99	0.08	0.00	0.37	0.44	0.00	0.01	0.15
MIS_MIDA	0.00	3.43	0.32	1.26	0.49	0.00	0.00	0.00	0.00	0.00	4.13
SPP_NEBR	0.77	3.80	0.38	1.61	0.34	0.11	0.07	0.00	0.00	0.01	1.32
S_C_KY	0.00	5.04	0.00	2.22	0.66	0.17	0.09	0.00	0.00	0.01	0.00
MIS_AMSO	1.17	0.00	3.15	0.26	3.09	0.00	0.00	0.00	0.00	0.00	0.00
MIS_IA	0.00	1.82	0.00	0.73	1.16	0.00	0.00	0.00	0.00	0.00	3.58
SPP_WAUE	0.00	1.57	0.00	1.16	0.29	0.10	2.30	0.00	0.00	0.00	1.50
MIS_WOTA	0.00	0.75	2.30	1.89	1.78	0.00	0.14	0.00	0.00	0.00	0.00
S_D_AECI	0.00	2.29	0.00	0.60	1.73	0.00	0.03	0.03	0.00	0.00	0.81
MIS_D_MS	1.40	0.00	1.35	0.81	1.13	0.00	0.00	0.00	0.00	0.10	0.00
MIS_MAPP	0.00	1.78	0.00	0.55	0.00	0.00	0.00	0.00	0.00	0.00	2.29

Table A.3: Existing Regional Capacities (GW)

Plant Name, Unit		State	Region	Cap.	Onl.	Ret.
Arkansas Nuclear One	1	AR	MIS_AR	833.3	1974	2054
Arkansas Nuclear One	2	AR	MIS_AR	984.5	1980	2060
Beaver Valley	2	PA	PJM_West	901	1987	2067
Braidwood Generation Station	1	IL	PJM_COMD	1183	1988	2068
Braidwood Generation Station	2	IL	PJM_COMD	1154	1988	2068
Browns Ferry	1	AL	S_C_TVA	1265.5	1974	2054
Browns Ferry	2	AL	S_C_TVA	1268.4	1975	2055
Browns Ferry	3	AL	S_C_TVA	1269.6	1977	2057
Byron Generating Station	1	IL	PJM_COMD	1164	1985	2065
Byron Generating Station	2	IL	PJM_COMD	1136	1987	2067
Callaway	1	MO	MIS_MO	1190	1984	2064
Clinton Power Station	1	IL	MIS_IL	1065	1987	2067
Cooper Nuclear Station	1	NE	SPP_NEBR	771.5	1974	2054
Donald C Cook	1	MI	PJM_West	1009	1975	2055
Donald C Cook	2	MI	PJM_West	1060	1978	2058
Dresden Generating Station	2	IL	PJM_COMD	902	1970	2050
Dresden Generating Station	3	IL	PJM_COMD	895	1971	2051
Fermi	2	MI	MIS_LMI	1141	1988	2068
Grand Gulf	1	MS	MIS_D_MS	1401	1985	2065
LaSalle Generating Station	1	IL	PJM_COMD	1135.4	1984	2064
LaSalle Generating Station	2	IL	PJM_COMD	1133.9	1984	2064
Monticello Nuclear Facility	1	MN	MIS_MNWI	617	1971	2051
Palisades	1	MI	MIS_LMI	783.5	1972	2052
Point Beach Nuclear Plant	1	WI	MIS_WUMS	598.1	1970	2050
Point Beach Nuclear Plant	2	WI	MIS_WUMS	597.9	1972	2052
Prairie Island	1	MN	MIS_MNWI	521	1974	2054
Prairie Island	2	MN	MIS_MNWI	519	1974	2054
Quad Cities Generating Station	1	IL	PJM_COMD	908	1972	2052
Quad Cities Generating Station	2	IL	PJM_COMD	911	1972	2052
River Bend	1	LA	MIS_LA	967.5	1986	2066
Sequoyah	1	TN	S_C_TVA	1152	1981	2061
Sequoyah	2	TN	S_C_TVA	1125.7	1982	2062
Waterford 3	3	LA	MIS_AMSO	1165.4	1985	2065
Watts Bar Nuclear Plant	1	TN	S_C_TVA	1123	1996	2076
Watts Bar Nuclear Plant	2	TN	S_C_TVA	1122	2016	2096
Wolf Creek Generating Station	1	KS	SPP_N	1175	1985	2065

Table A.4: Capacities (MW) and estimated retirement years for existing nuclear power plants in the Midwest.

	Start Cost ($/MW /start)	**Start Fuel (MMBtu/ MW/start)**	**Ramp Up (%)**	**Ramp Down (%)**	**Up/ Down Time (Hrs.)**	**Min. Output (%)**	**Cap. Size (MW)**
Coal	120	13.7	57	57	24	30	370
NGCC	52	0.2	100	100	4	30	500*
NGCT	79	9	100	100	1	20	200*
NGST	75	9	30	30	6	30	120
Biomass	75	9	30	30	6	50	20

Table A.5: Additional unit commitment characteristics for conventional thermal technologies.

	Start Cost ($/MW / start)	**Start Fuel (MMBtu /MW/start)**	**Ramp Up/Down (%)**	**Up/Down Time (Hrs.)**	**Min. Output (%)**	**Cap. Size (MW)**
CCS	84	0.2	100	4	50	389
SMR	52	0.2	100	4	0	500

Table A.6: Additional unit commitment characterization for advanced thermal technologies

	Maximum Developable Capacity (GW)			Interconnection Cost Adders ($/kWyr)		
	Wind-1	**Wind-2**	**PV**	**Wind-1**	**Wind-2**	**PV**
MIS_AMSO	6.8	57.8	1276.5	6.6	3.4	4.3
MIS_AR	2300.5	886.2	56000.1	8.0	10.0	8.6
MIS_D_MS	1968.5	1171.9	55329.7	10.4	13.2	11.5
MIS_IA	5268.5	812.1	106689.6	13.1	25.1	14.7
MIS_IL	3758.0	1616.7	94459.7	6.7	10.8	7.9
MIS_INKY	3468.1	1411.4	86065.8	4.2	6.5	4.9
MIS_LA	943.6	843.3	31574.6	6.5	10.0	8.2
MIS_LMI	1458.1	813.8	45528.4	5.5	14.5	9.2
MIS_MAPP	6507.8	3296.2	177065.6	19.7	41.3	27.3
MIS_MIDA	2250.5	1686.8	69045.0	7.7	10.9	9.1
MIS_MNWI	7896.2	5238.5	243055.9	9.9	17.6	13.3
MIS_MO	2380.3	1500.1	68028.4	9.5	15.6	11.8
MIS_WOTA	115.5	65.4	3225.6	4.7	9.2	6.3
MIS_WUMS	3815.7	724.8	92498.7	10.9	33.4	16.1
PJM_COMD	1429.2	179.0	28358.7	4.6	9.1	5.1
PJM_West	14957.0	6016.0	370007.7	5.6	9.3	6.7
SPP_N	13688.7	6905.7	361149.7	10.4	28.8	16.6
SPP_NEBR	7267.1	4102.2	199239.7	14.6	39.5	23.6
SPP_SPS	2718.7	758.8	60957.1	15.2	27.3	17.9
SPP_WAUE	8996.9	3898.1	226463.5	19.7	30.3	22.9
SPP_WEST	24726.5	5031.9	522353.9	10.1	16.6	11.2
S_C_KY	1223.8	604.9	32087.2	7.1	11.8	8.7
S_C_TVA	31096.2	5061.1	635237.4	8.2	7.6	8.2
S_D_AECI	3862.3	1051.8	86144.0	12.5	19.3	14.0

Table A.7: (Left) Maximum developable capacities of Wind and SolarPV and (Right) interconnection cost adders for Wind and Solar, calculated according to Brown and Botterud (2021).

From	To	Maximum Flow (MW)
MIS_AR	MIS_LA	1732
MIS_AR	S_D_AECI	1039
MIS_AR	SPP_WEST	792
MIS_AR	S_C_TVA	2143
MIS_IL	S_C_TVA	1200
MIS_IL	PJM_COMD	3200
MIS_IL	MIS_INKY	956
MIS_IL	MIS_MIDA	716
MIS_IL	MIS_MO	3400
MIS_INKY	S_C_KY	2245
MIS_INKY	S_C_TVA	300
MIS_INKY	MIS_IL	956
MIS_INKY	PJM_West	5441
MIS_INKY	PJM_COMD	2044
MIS_IA	MIS_MIDA	1616
MIS_IA	MIS_MO	223
MIS_IA	MIS_MNWI	1195
MIS_MIDA	SPP_NEBR	1912
MIS_MIDA	MIS_IA	1616
MIS_MIDA	MIS_IL	716
MIS_MIDA	MIS_MO	716
MIS_MIDA	SPP_WAUE	600
MIS_MIDA	PJM_COMD	2000
MIS_LA	MIS_WOTA	1200
MIS_LA	SPP_WEST	905
MIS_LA	MIS_AR	1732
MIS_LA	MIS_D_MS	1732
MIS_LA	MIS_AMSO	1699
MIS_LMI	PJM_West	1400
MIS_MNWI	MIS_WUMS	1480

Table A.8: Brownfield Transmission Capacities in MW (1 of 3)

From	To	Maximum Flow (MW)
MIS_MNWI	MIS_IA	1195
MIS_MNWI	MIS_MAPP	2150
MIS_MNWI	SPP_WAUE	2000
MIS_D_MS	MIS_LA	1732
MIS_D_MS	MIS_AMSO	200
MIS_D_MS	S_C_TVA	1949
MIS_MO	SPP_N	300
MIS_MO	MIS_IA	223
MIS_MO	MIS_IL	3400
MIS_MO	MIS_MIDA	716
MIS_MO	S_D_AECI	2100
MIS_MAPP	MIS_MNWI	2150
MIS_MAPP	SPP_WAUE	1000
MIS_AMSO	MIS_LA	1699
MIS_AMSO	MIS_D_MS	200
MIS_WOTA	MIS_LA	1200
MIS_WUMS	PJM_COMD	1200
MIS_WUMS	MIS_MNWI	1480
PJM_West	S_C_TVA	2119
PJM_West	S_C_KY	1214
PJM_West	PJM_COMD	980
PJM_West	MIS_LMI	1400
PJM_West	MIS_INKY	5125
PJM_COMD	PJM_West	980
PJM_COMD	MIS_WUMS	1200
PJM_COMD	MIS_IL	3200
PJM_COMD	MIS_INKY	3840
PJM_COMD	MIS_MIDA	2000
S_C_KY	PJM_West	1214
S_C_KY	MIS_INKY	2245

Table A.9: Brownfield Transmission Capacities in MW (2 of 3)

From	To	Maximum Flow (MW)
S_C_KY	S_C_TVA	764
S_C_TVA	MIS_IL	1200
S_C_TVA	PJM_West	2119
S_C_TVA	MIS_INKY	300
S_C_TVA	S_C_KY	764
S_C_TVA	MIS_D_MS	1949
S_C_TVA	MIS_AR	2143
S_D_AECI	MIS_MO	2100
S_D_AECI	MIS_AR	1039
S_D_AECI	SPP_N	1130
S_D_AECI	SPP_WEST	1172
SPP_NEBR	SPP_N	1433
SPP_NEBR	SPP_WAUE	1440
SPP_NEBR	MIS_MIDA	1912
SPP_N	SPP_WEST	2903
SPP_N	SPP_NEBR	1433
SPP_N	SPP_SPS	469
SPP_N	MIS_MO	300
SPP_N	S_D_AECI	1130
SPP_SPS	SPP_WEST	1289
SPP_SPS	SPP_N	469
SPP_WEST	SPP_N	2903
SPP_WEST	SPP_SPS	1289
SPP_WEST	MIS_AR	792
SPP_WEST	MIS_LA	905
SPP_WEST	S_D_AECI	1172
SPP_WAUE	MIS_MNWI	2000
SPP_WAUE	MIS_MAPP	1000
SPP_WAUE	MIS_MIDA	600
SPP_WAUE	SPP_NEBR	700

Table A.10: Brownfield Transmission Capacities in MW (3 of 3)

Appendix B

Figures

	AL	AR	GA	IA	IL	IN	KS	KY	LA	MI	MN	MO	MS	MT	NC	ND	NE	NM	OH	OK	SD	TN	TX	VA	WI	WV	WY
MIS_AMSO	0	0	0	0	0	0	0	0	19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_AR	0	61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_D_MS	0	0	0	0	0	0	0	0	0	0	0	0	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_IA	0	0	0	51	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_IL	0	0	0	0	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_INKY	0	0	0	0	0	81	0	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_LA	0	0	0	0	0	0	0	0	58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_LMI	0	0	0	0	0	0	0	0	0	41	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_MAPP	0	0	0	0	0	0	0	0	0	0	0	0	0	25	0	88	0	0	0	0	2	0	0	0	0	0	0
MIS_MIDA	0	0	0	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_MNWI	0	0	0	0	0	0	0	0	0	1	94	0	0	0	0	0	0	0	0	0	2	0	0	0	30	0	0
MIS_MO	0	0	0	1	0	0	0	0	0	0	0	38	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MIS_WOTA	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0
MIS_WUMS	0	0	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	55	0	0
PJM_COMD	0	0	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM_West	0	0	0	0	0	19	0	32	0	2	0	0	0	0	0	0	0	0	55	0	0	1	0	25	0	44	0
SPP_N	0	0	0	0	0	0	99	0	0	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SPP_NEBR	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	99	0	0	0	0	0	0	0	0	0	0
SPP_SPS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18	0	8	0	0	10	0	0	0	0
SPP_WAUE	0	0	0	0	0	0	0	0	0	0	1	0	0	3	0	12	0	0	0	0	84	0	0	0	0	0	0
SPP_WEST	0	39	0	0	0	0	0	0	3	0	0	3	0	0	0	0	0	0	0	92	0	0	1	0	0	0	0
S_C_KY	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S_C_TVA	18	0	5	0	0	0	0	22	0	0	0	0	28	0	6	0	0	0	0	0	0	99	0	2	0	0	0
S_D_AECI	0	0	0	0	0	0	0	0	0	0	0	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure B-1: Percentage of each state load profile assigned to each model region calculated by percentage of each state's overlapping area.

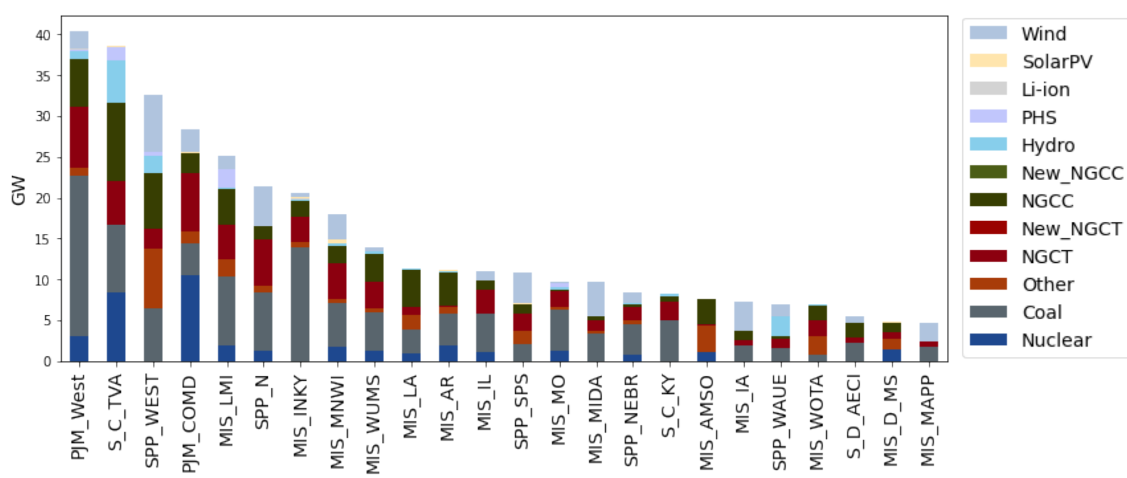

Figure B-2: Existing Capacity by Model Region (GW)

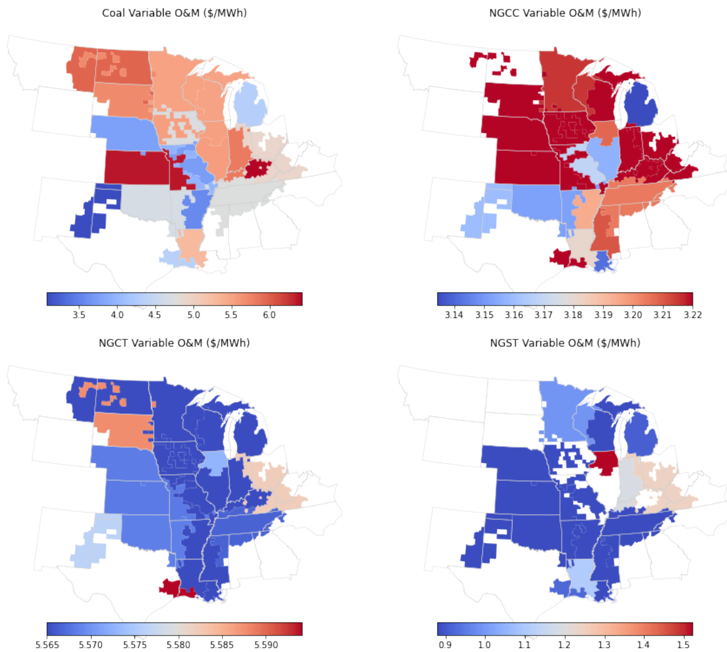

Figure B-3: Variable O&M Costs for Brownfield Thermal Resources by Region

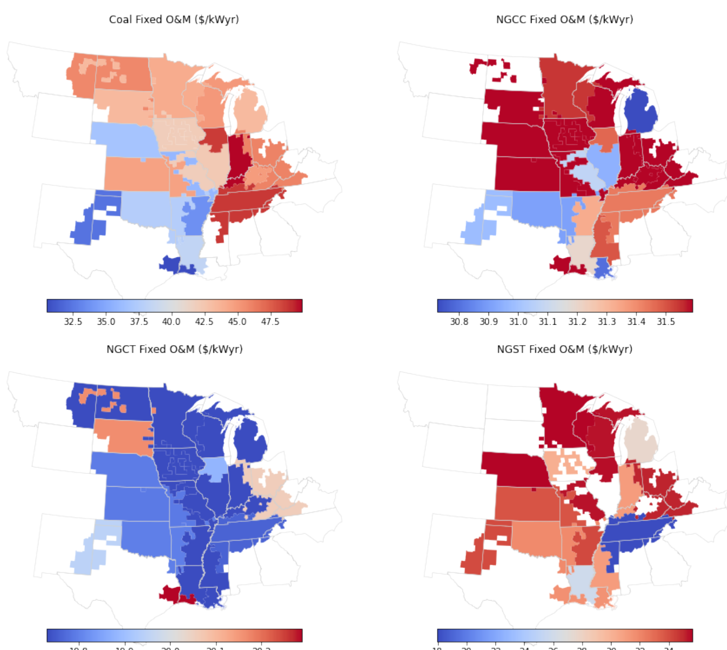

Figure B-4: Fixed O&M Costs for Brownfield Thermal Resources by Region

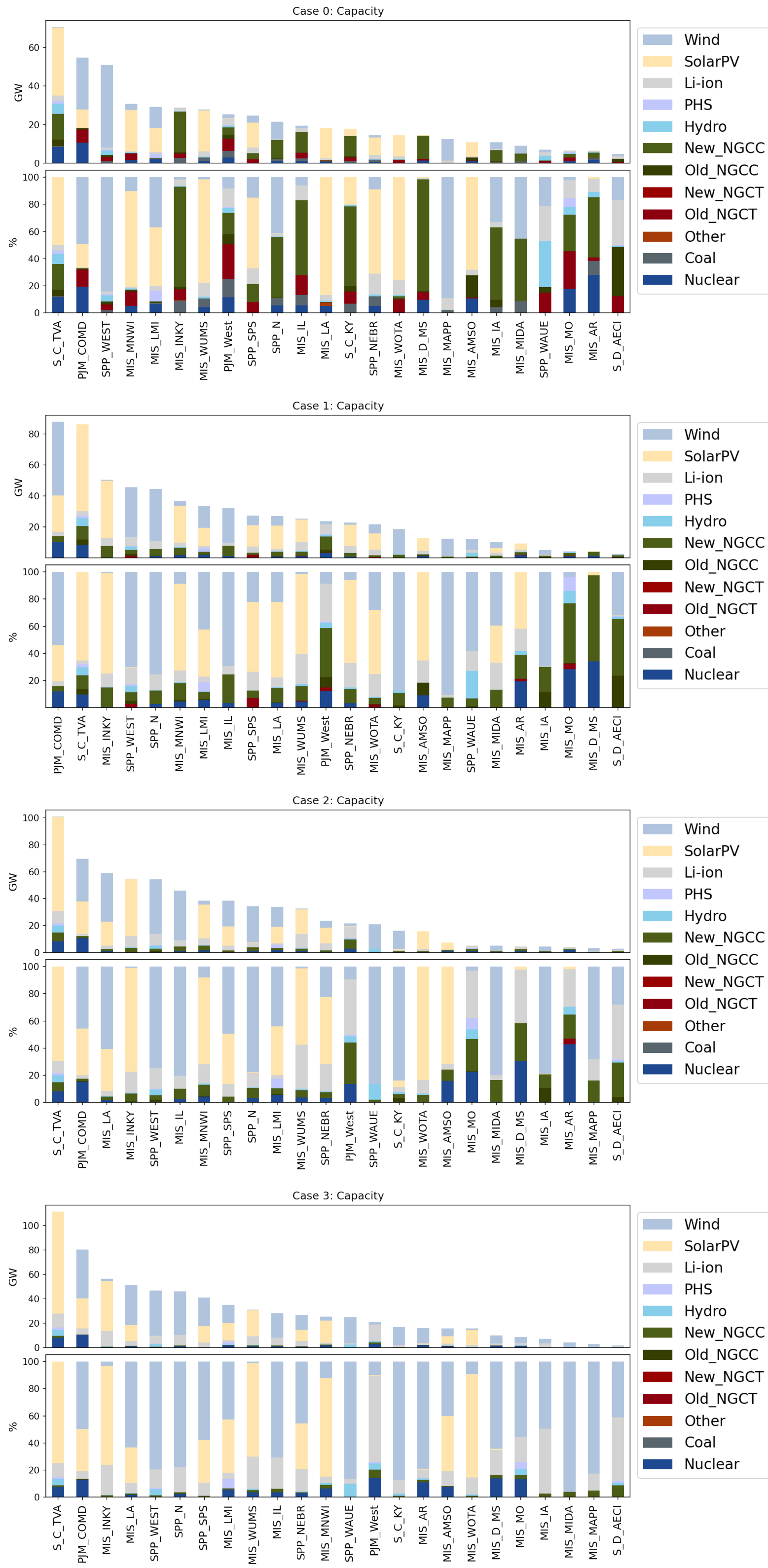

Figure B-5: Final Regional Capacities (GW,%) in the Reference Case: None, High, Medium, Low

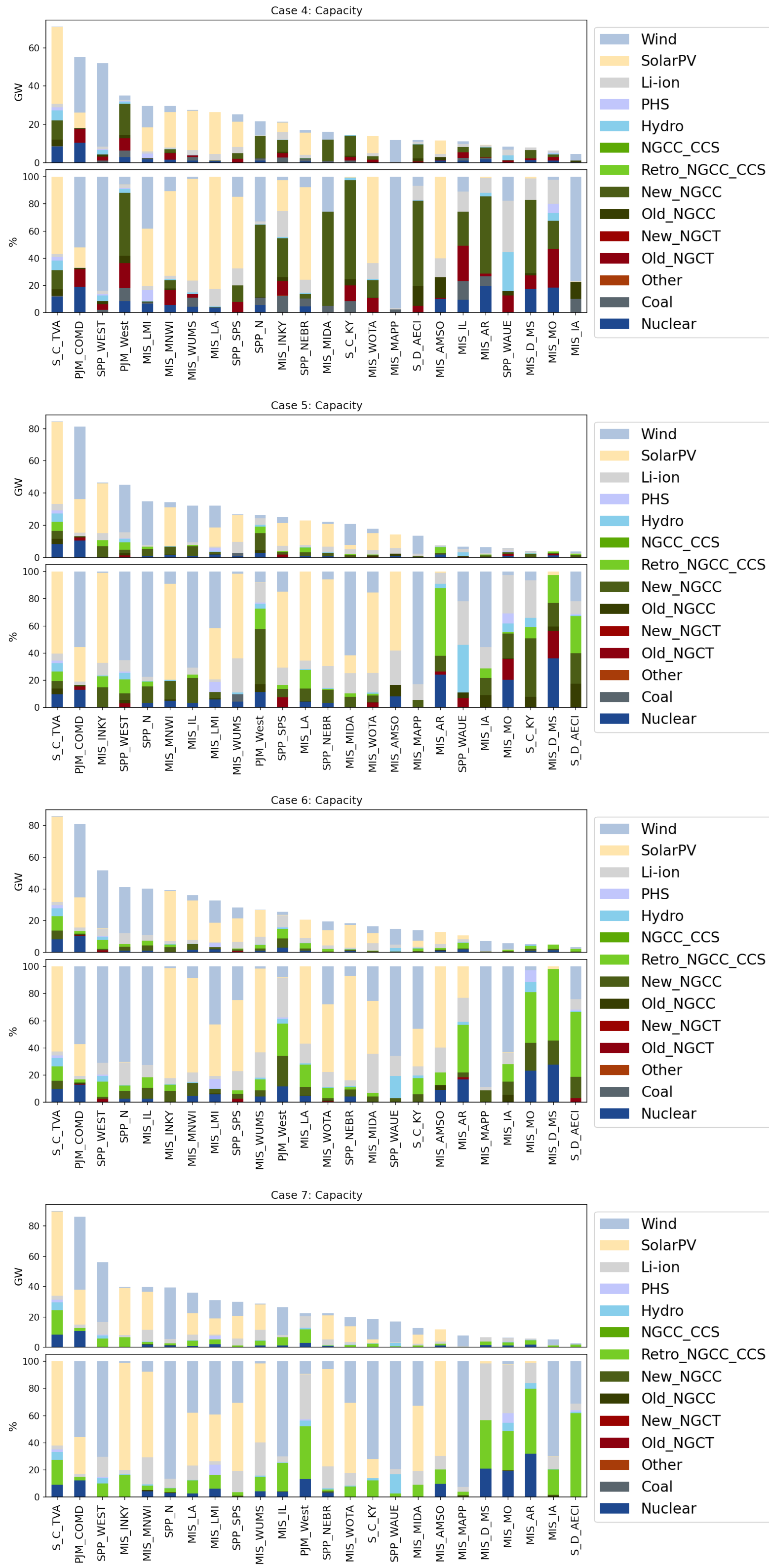

Figure B-6: Final Regional Capacities (GW,%) with CCS: None, High, Medium, Low

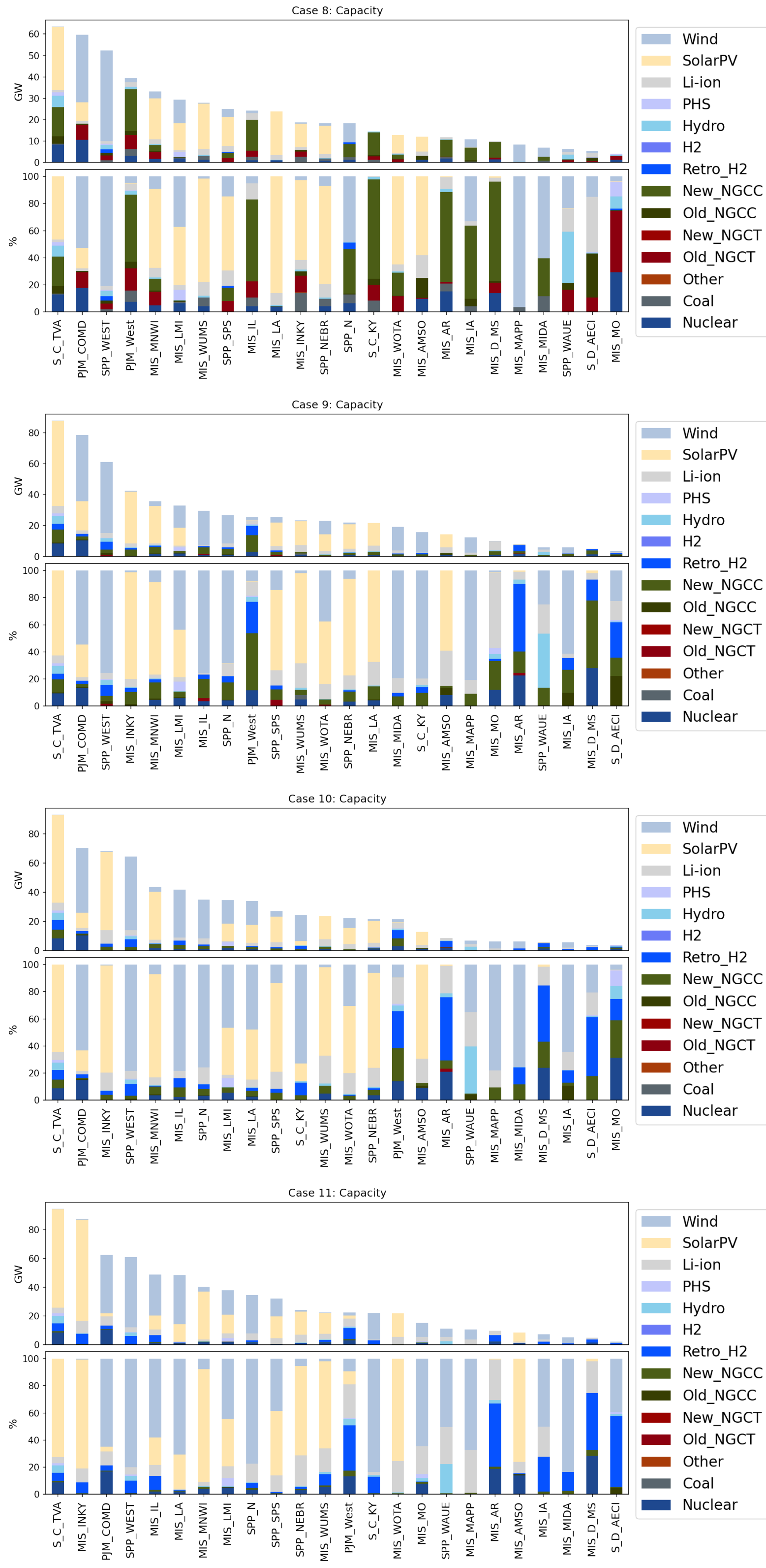

Figure B-7: Final Regional Capacities (GW,%) with H2: None, High, Medium, Low

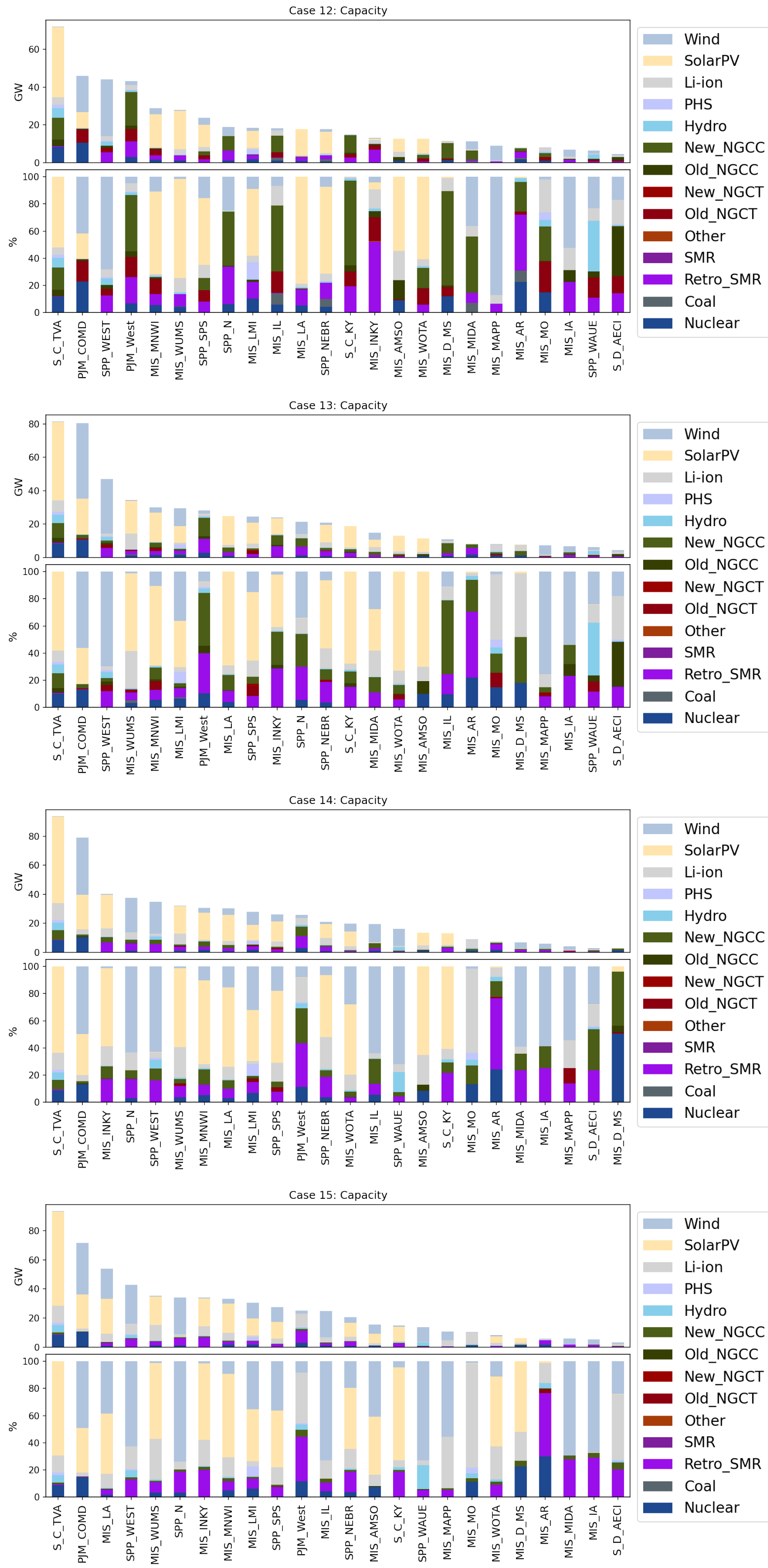

Figure B-8: Final Regional Capacities (GW,%) with SMR: None, High, Medium, Low

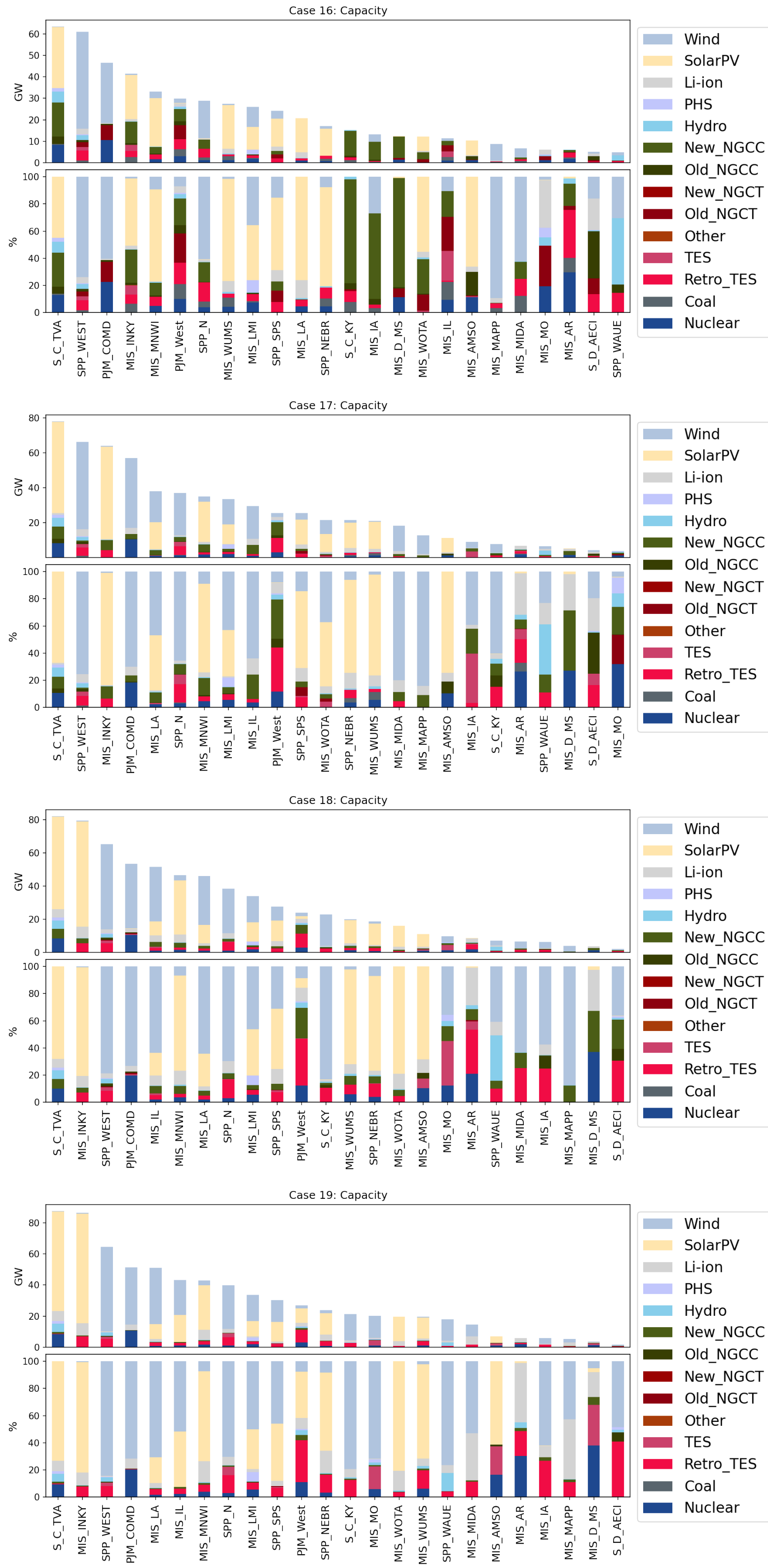

Figure B-9: Final Regional Capacities (GW,%) with TES: None, High, Medium, Low

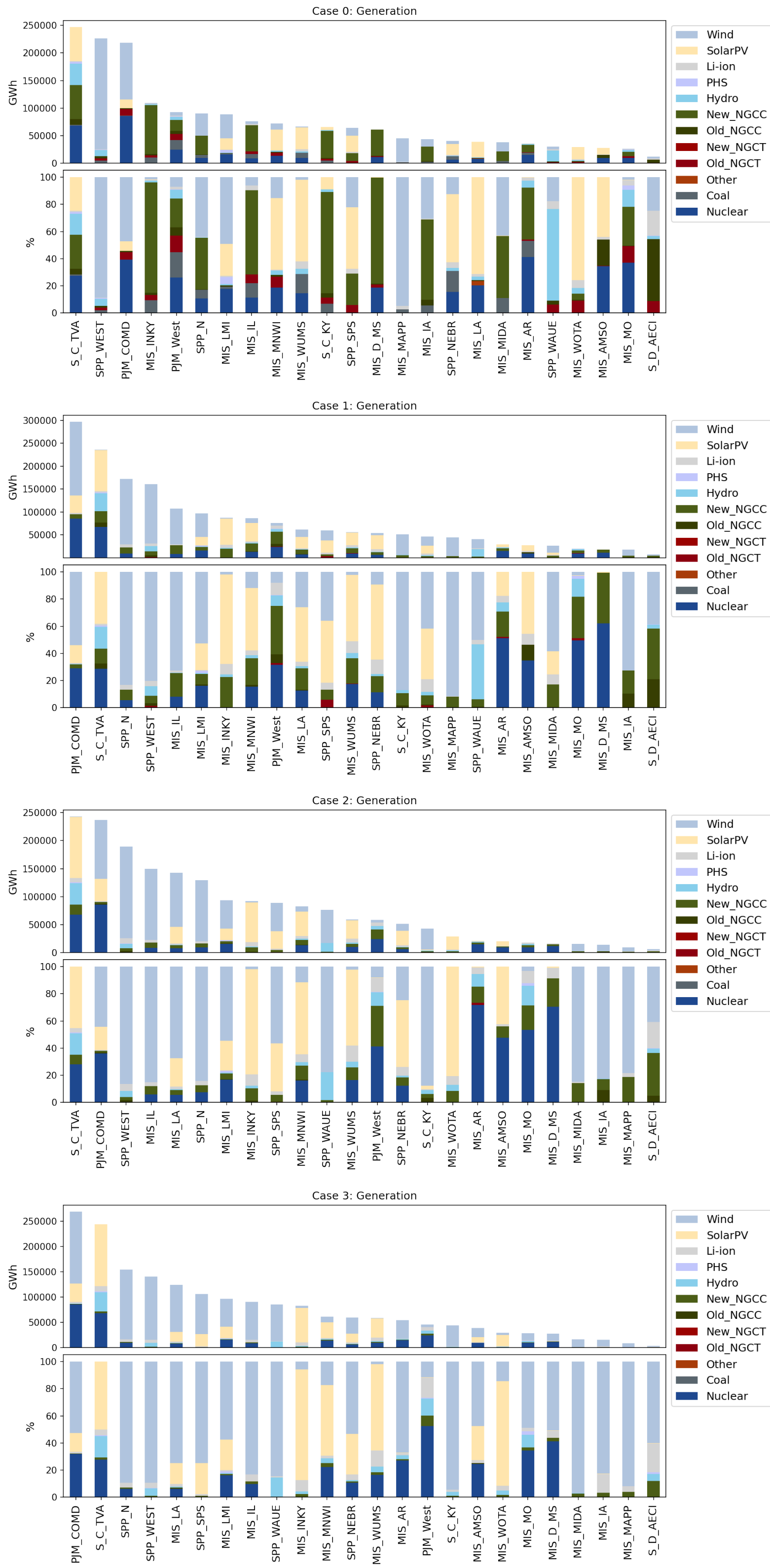

Figure B-10: Final Regional Generation (GWh,%) in the Reference Case: None, High, Medium, Low

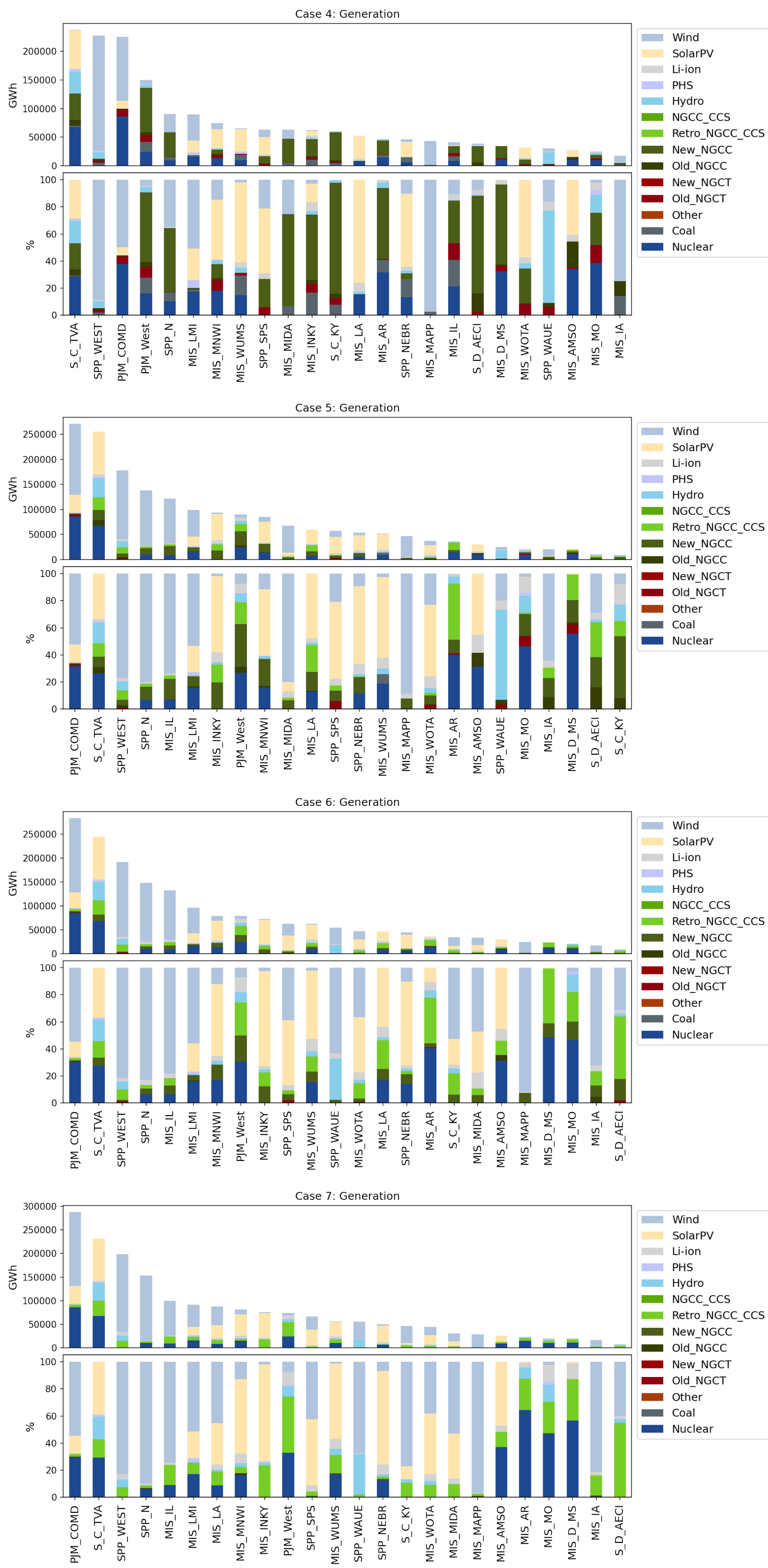

Figure B-11: Final Regional Generation (GWh,%) with CCS: None, High, Medium, Low

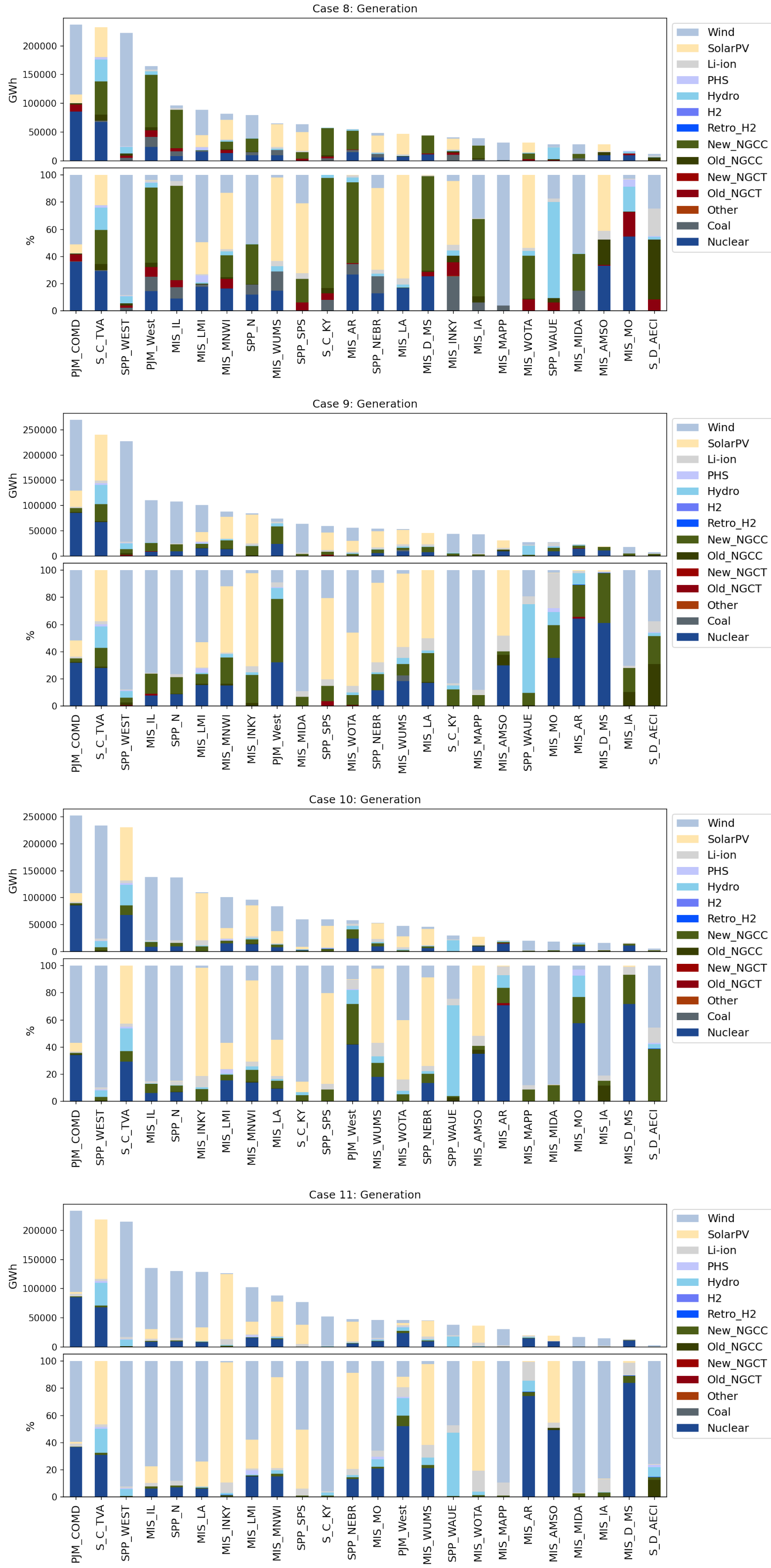

Figure B-12: Final Regional Generation (GWh,%) with H2: None, High, Medium, Low

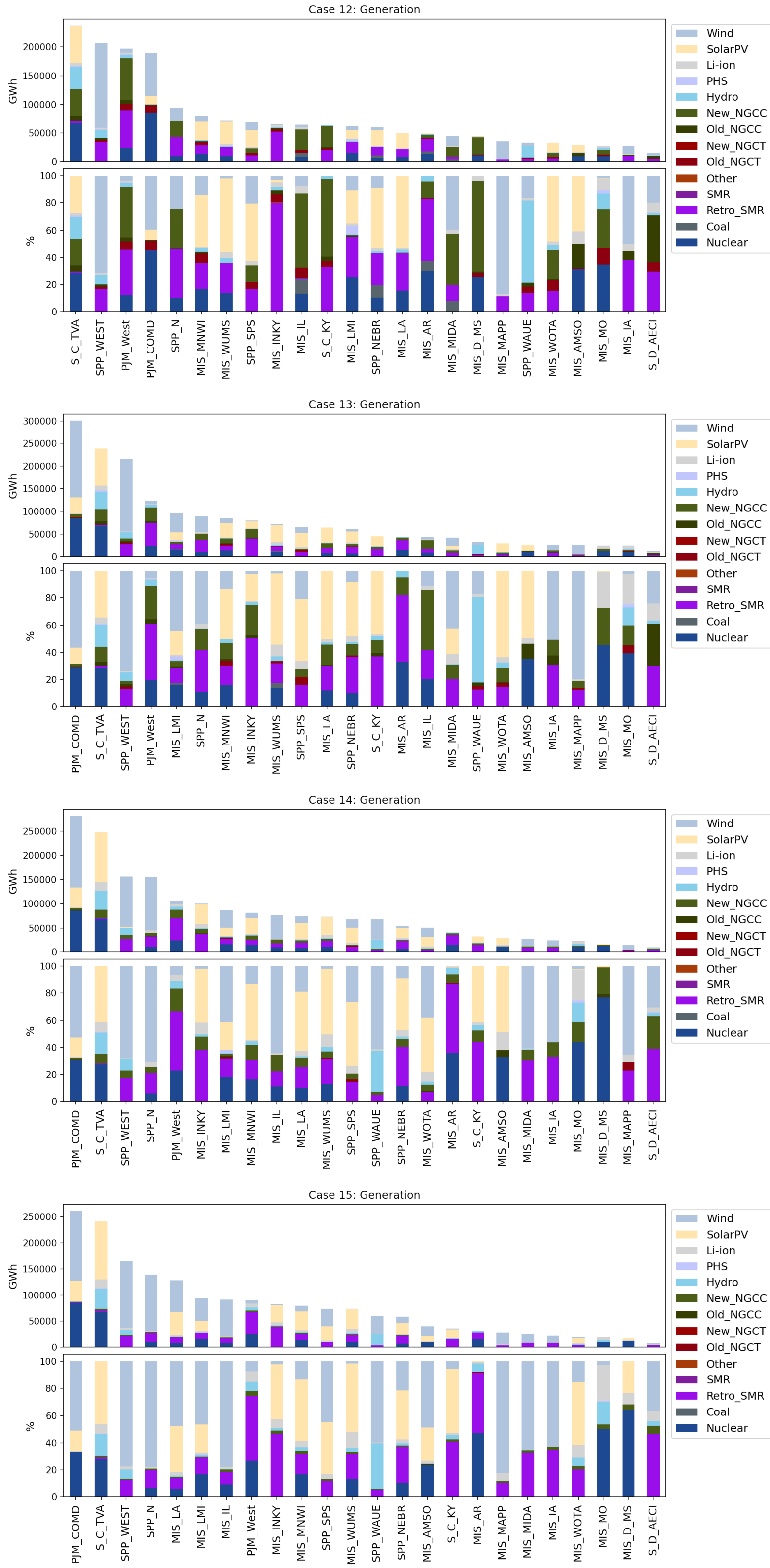

Figure B-13: Final Regional Generation (GWh,%) with SMR: None, High, Medium, Low

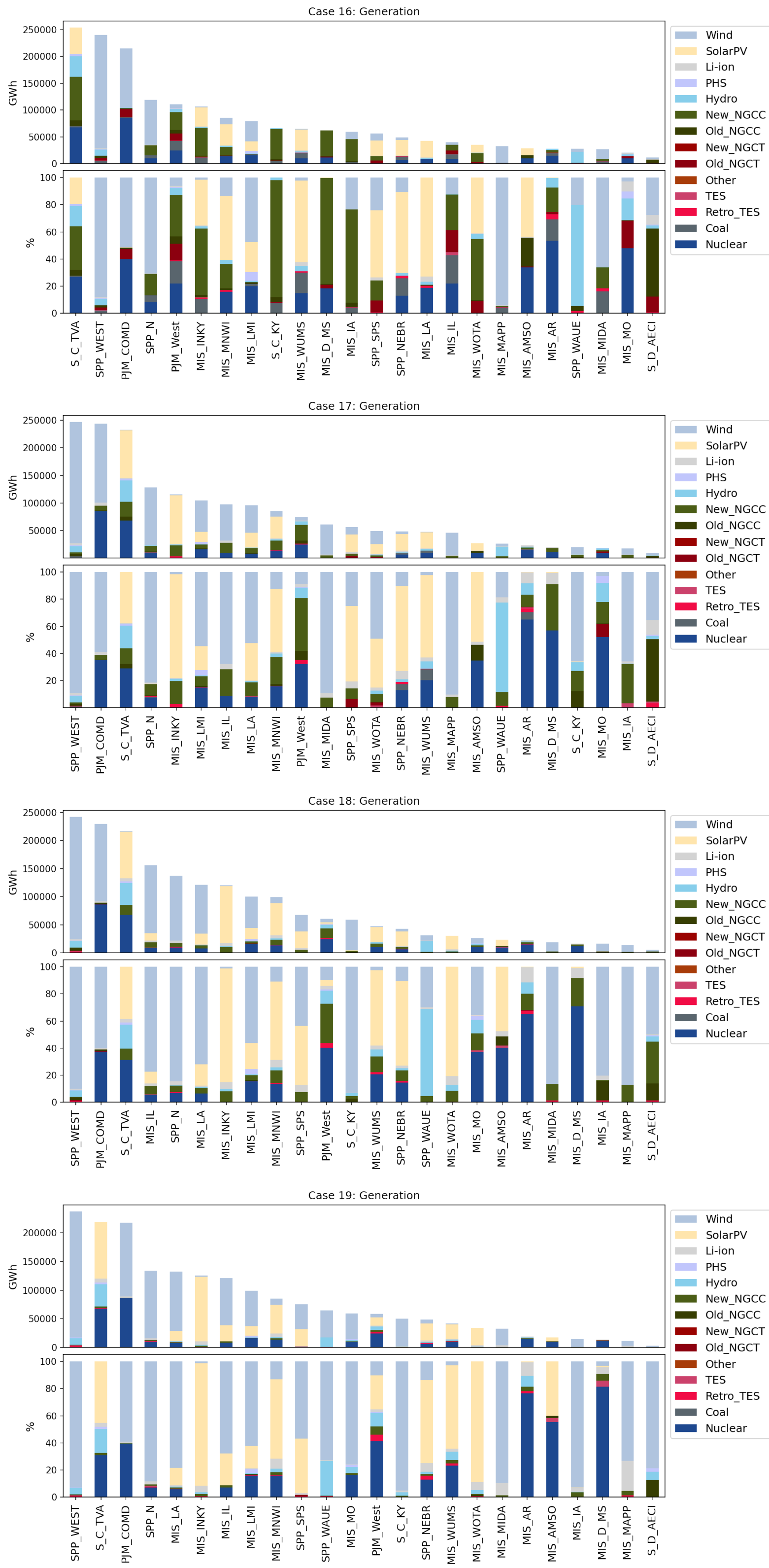

Figure B-14: Final Regional Generation (GWh,%) with TES: None, High, Medium, Low

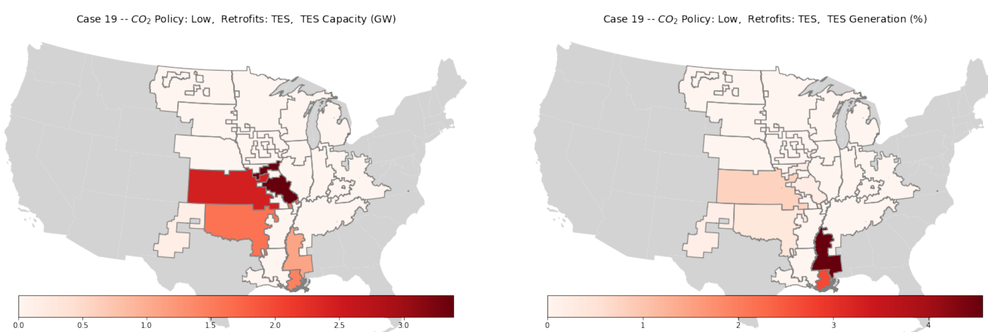

Figure B-15: Greenfield TES Deployment under the Low Policy: Capacity (GW, left) and Generation (%, right)

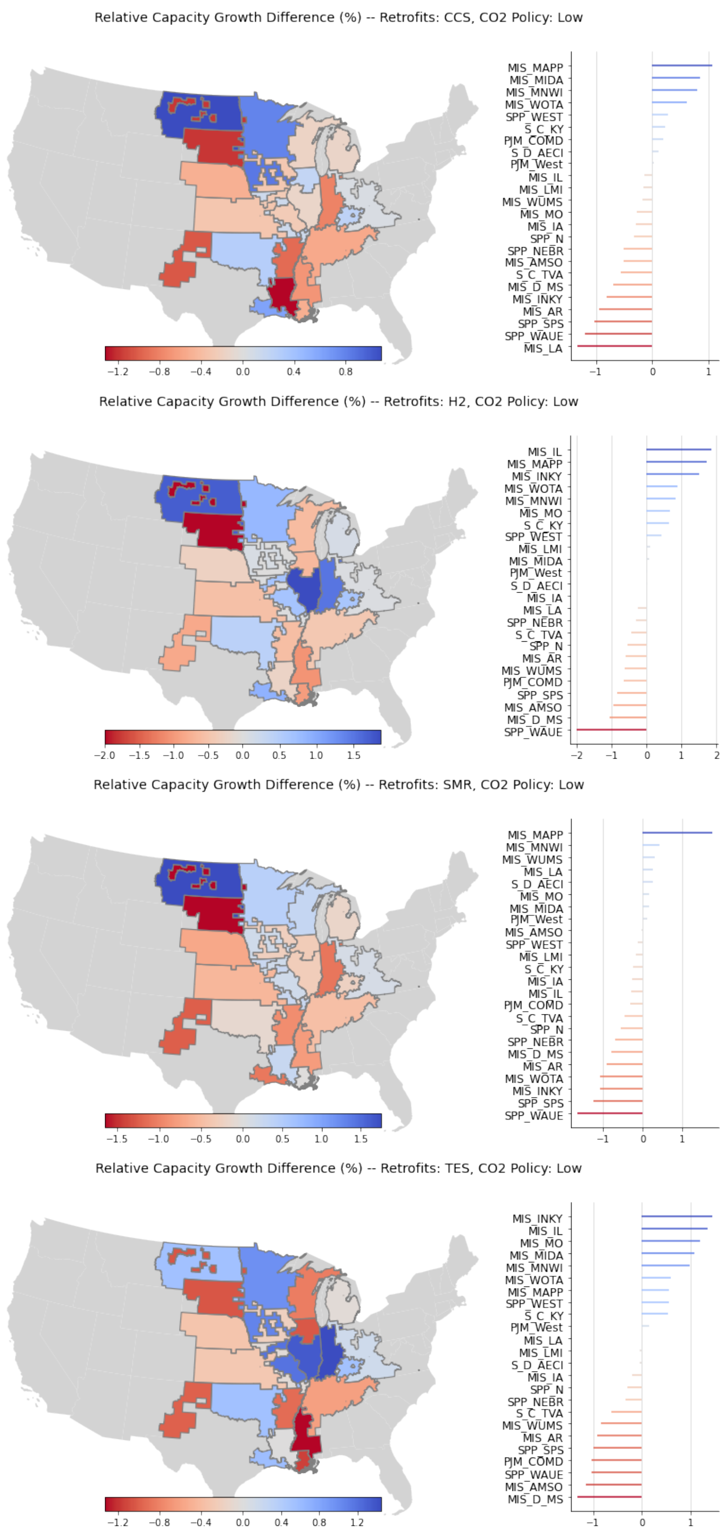

Figure B-16: Relative Capacity Growth Difference under the Low Policy by Technology Availability

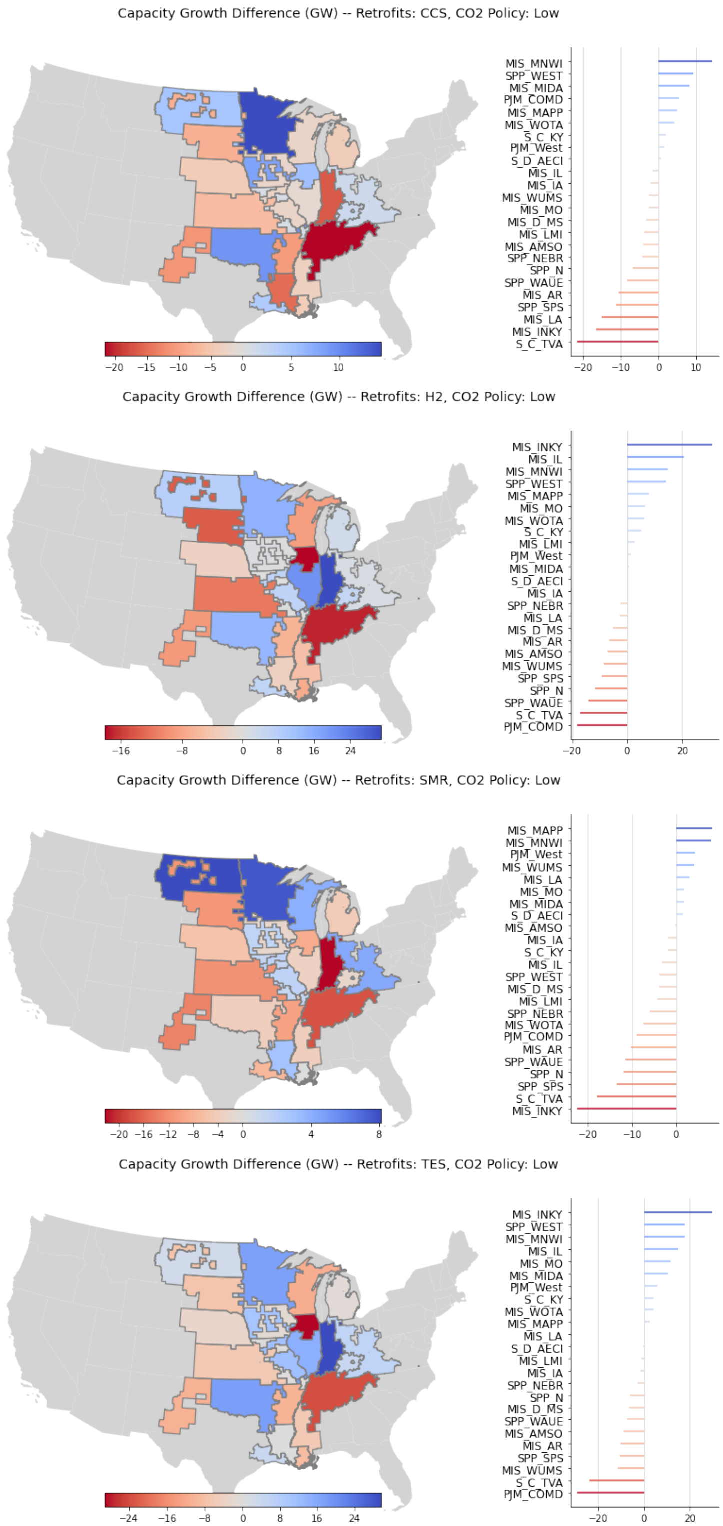

Figure B-17: Capacity Growth Difference under the Low Policy by Technology Availability

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