DISSERTATION

SYSTEM DESIGN ANALYSIS FOR REPLACEMENT OF COAL POWER PLANTS WITH SMALL NUCLEAR REACTORS

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ABSTRACT

SYSTEM DESIGN ANALYSIS FOR REPLACEMENT OF COAL POWER PLANTS WITH SMALL NUCLEAR REACTORS

Coal power plants are the predominant energy generation technology in many countries and are a major global source of greenhouse gas emissions. A variety of policy and economic pressures are driving the replacement of this legacy technology, but the electricity generated by retiring coal power plants must be replaced and the generation capacity must be increased to meet projected electricity demand growth. A diversity of alternatives to coal generation, including nuclear power, are key components of nearly-every study of a future sustainable electricity sector. At present, small nuclear reactors have been proposed and planned by researchers, utilities, and governments to enable on-site replacement of existing coal power generators. By directly replacing coal power plants with nuclear reactors, these programs seek to develop zero-emissions, high-reliability electricity generation, at lower cost than would be possible in green-field developments.

In order to assess the role that proposed coal-to-nuclear conversions could play in adoption of small nuclear generators, a variety of problems would need to be addressed. First, an improved understanding of the value of existing infrastructure at coal power plant sites is needed to assess the economic value of coal-to-nuclear conversion. Second, the schedule efficiencies available from the coal-to-nuclear conversion concept is, to date, unknown. The extent to which regional emissions trajectories would be accelerated or delayed by coal-to-nuclear conversion is unknown. Existing research has investigated the possibility of reusing operating infrastructure at coal power plants, including buildings and improvements, turbine plant equipment, electric plant equipment, and condenser and heat rejection systems. These studies hypothesize that costs, schedule, and overall emissions at reconstituted generation sites would be improved. However, detailed costing, scheduling and electricity sector transformation modeling evidence has not been generated, particularly at both the local and the global scale.

To address these research gaps, this investigation specifically pursues two streams of research: (1) assessing the economic value and schedule efficiencies associated with retaining the available grid connection and cooling water at potential coal-to-nuclear sites across the United States (U.S.), and (2) assessing the global decarbonization potential associated with coal-to-nuclear conversion, with a key emphasis on modeling this transition within the U.S. and India, as these are the countries having the world’s largest coal-fired power generation capacity outside of China.

Results from the first area of research indicate that, when installing a single 300 MW nuclear reactor, the use of the existing cooling water source and method can save \$6.8M - \$23.5M annually depending on the cooling method chosen at the new site, with expected savings of \$13.3M. Expected savings across the fleet are valued at \$1.7B - \$4.5B annually, depending on the number of reactors installed. The value of existing electrical grid connections for the 300 MW reactor can range from \$25M to \$53.6M, depending on geographic location, with existing grid connections across the fleet valued from \$5.3B – \$10.1B, again depending on the number of reactors installed.

In the second area of research, schedule and timelines for coal-to-nuclear conversion are assessed, and the resulting emissions reductions are determined to help better understand the impact that a fleet-scale nuclear conversion campaign could have on decarbonization goals in both the U.S. and India. Results indicate that, while the U.S. and India presently have similar installed coal generation capacity and annual emissions, India’s remaining committed emissions are approximately five times greater than those of the U.S. for both a base case and a very high-rate (46-plants across the U.S. by 2038) conversion case. Converting coal power plants to nuclear plants do realize reductions in committed GHG emissions, but the degree of national impact relies heavily on fleet composition. Nations with older generation fleets (such as the U.S.) realize annual emissions reductions from both retirements and conversions, but their committed emissions reductions are dominated by reductions due to retirements. For nations with younger fleets, coal-to-nuclear conversions have a much greater impact on committed emissions, indicating the potential of coal-to-nuclear conversion to realize global emission reductions, because the global coal fleet is relatively young (compared to the U.S. coal fleet).

Collectively, these findings suggest that while U.S. decarbonization potential resulting from coal-to-nuclear conversions is limited, existing electrical grid connections and cooling water availability at existing coal power sites represent economic value that should be considered, along with other factors, by entities considering siting alternatives for small nuclear reactor installation. Both potential emissions reductions and the economic value of repowering the site, along with other factors, should be considered in the coal-to-nuclear adoption decision.

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And my family, for their patience and support.

DEDICATION

I dedicate this dissertation to my father: Leon. Born into poverty on an Oklahoma Indian reservation, he fought to survive a turbulent childhood, fought for our country in war, and made significant personal sacrifice throughout his life to give my sister and I a chance. Through his hard work he blazed a trail so I may follow, and I stand on his shoulders.

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CHAPTER 1: INTRODUCTION

1.1 Context

The history of American power production has been firmly rooted in coal since Pearl Street Station, the first practical coal power plant developed by Thomas Edison began operation in New York City in 1882, supplying electricity for household and office lights [1]. In fact, coal was the predominant energy source for U.S. electricity production until overtaken by natural gas in 2016 [2]. Today, greenhouse gas emissions from burning fossil fuels, including the predominant energy generation method in many countries, coal power plants[1], face challenges resulting from climate policy. To meet nationally determined contributions to the Paris Climate Agreement, local policy is being established in many countries to encourage clean energy generation and dissuade greenhouse gas emissions. Extensive modeling has been performed by intergovernmental organizations such as the International Energy Agency (IEA) and the Intergovernmental Panel on Climate Change detailing scenarios to reach the Paris Climate Agreement goals, each including the drastic reduction of unabated burning of fossil fuels and a reliance on rapid electrification of all economic sectors [3, 4]. Globally, the IEA's *Net Zero by 2050* model shows electricity consumption increasing 158% by 2050 [5]. Nuclear power generation is once again being more widely considered as a way to meet this demand. Nuclear fission is a zero-emissions clean energy source of power and is the second largest source of clean electricity globally [6].

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[1] The terms power plant and power station are equivalent and used interchangeably throughout this paper. Power units are the individual generators located at a power plant, with many plants being composed of multiple units. An existing coal power site includes the existing generation and support facilities, as well as other surrounding land and water resources that are part of the generation organization's holdings.

In the United States (U.S.) and some parts of Europe, coal plants are rapidly being phased out, partly because cheaper fuels such as natural gas are abundant, and partly because of their emissions burden. In fact, the United Kingdom recently closed its last remaining coal plant. On the other hand, abandoning coal plants is having a negative impact on the ability of countries to maintain their dispatchable electricity levels, as well as a negative impact on communities whose local economies depend on the existence of those plants. Hence, repowering existing coal power sites with small nuclear reactors may offer a path to maintain dispatchable electricity levels and simultaneously reduce emissions, while providing ongoing local economic stability. Further, retaining certain components of the infrastructure at existing coal plants may offer cost savings when compared to constructing a greenfield facility at a nearby site, along with a viable path to decarbonization at fleet scale.

Chapter 2 of the dissertation provides a background discussion outlining the state of U.S. electricity generation and stated emissions reduction goals. The chapter highlights the potential for nuclear generation as a zero-emission energy source and the possibility of siting new nuclear reactors at existing coal power sites. Chapter 3 reviews the associated research questions and tasks analyzed and further discussed in Chapters 4 and 5. The document concludes with Chapter 6, discussing the research contributions made. Chapter 7 provides concluding remarks and introduces prospective avenues for further exploration.

CHAPTER 2: BACKGROUND

2.1 A Greenhouse Gas Problem

The power sector is the largest emitter of greenhouse gas emissions globally and within it, coal plants represent the biggest source of emissions [7]. A variety of policy and economic pressures are driving the replacement of this legacy technology. The Paris Climate Agreement is an international treaty on climate change adopted by 196 parties at the United Nations Climate Change Conference in Paris, on 12 December 2015 [8]. The collective goal of this agreement is to reduce greenhouse gas (GhG) emissions to limit the global temperature increase to 1.5– 2° C above 2010 levels, with each country identifying nationally determined contributions. Reducing power plant emissions below 50 gCO_2-eq/kWh, the average power plant emissions level required to meet 2015 Paris Climate Agreement goals [8], could result in hundreds of billions of tons of CO_2 emissions avoidance. To meet the national contributions to the international goal, local policies are being established to encourage clean energy generation and dissuade GhG emissions. The European Union (EU) has committed to a 55% reduction in GhG emissions by 2030 with a goal of climate neutrality by 2050 [9]. The EU Emissions Trading System (ETS), a cap-and-trade approach, limits the total amount of certain GhG emissions by electricity generation and other sectors. EU Carbon Permits have gradually increased in price from under EUR 10 per metric ton in 2018 to over EUR 100 in 2023 [10]. In addition, several EU countries have implemented carbon taxes ranging from less than €1 per metric ton of carbon emissions in Poland to more than €117 in Sweden and Switzerland. In the United States 22 individual states have enacted laws such as Washington state's Clean Energy Transformation Act calling for carbon-free power across the state's electricity sector by 2045, carbon neutrality by 2030, and the elimination of coal plants by

2025 while adopting a penalty structure to encourage compliance [11]. Meanwhile, global GhG emissions continue to rise and coal-fired generation reached an all-time high in 2021 [7].

Action is required to meet the ambitious goals described above. Extensive modeling has been performed by intergovernmental organizations such as the International Energy Agency (IEA) in its *Net Zero by 2050, a Roadmap for the Global Energy Sector* and the Intergovernmental Panel on Climate Change (IPCC) in its *Global Warming of 1.5 deg C, An IPCC Special Report,* offering multiple scenarios to reach the Paris Climate Agreement goals, each including the drastic reduction of unabated burning of fossil fuels and a reliance on rapid electrification of all economic sectors [3, 4]. The three primary energy sources accounting for over 97% of global electricity generation are fossil fuels, renewable sources, and nuclear. The predominant fossil fuels used in energy production are coal and natural gas, which, combined, account for 60% of electricity generation worldwide and in the U.S. [12, 13]. Emissions from coal and natural gas differ because coal has more carbon content per unit of energy, producing more CO_2 [14]. Burning coal for electricity generation produces 209 pounds of CO_2 per million British thermal units (MMBtu), compared with 117 pounds of CO_2/MMBtu for natural gas [15]. Coal consumption accounts for 37% of electricity generation globally and 22% in the U.S. Reducing this leading emitter in electricity generation features prominently in emissions reduction models.

The IEA's *Net Zero by 2050* roadmap envisages unabated coal fired electricity generation declining to zero by 2040. IPCC examines four possible pathway scenarios resulting in 91-97% reduction in CO_2 emissions by 2050, modeling 59-78% reduction in coal by 2030 and 73-97% reduction by 2050 from a 2010 baseline. In Europe, analysis shows all EU coal plants being phased out before 2030 [16], while in the U.S. EIA's *Annual Energy Outlook 2023 (AEO23)* reference case model shows coal use declining 59% by 2030 and 71% by 2050 compared to 2022 levels [17].

Decarbonizing electricity generation faces many challenges including a projected increase in demand. Even with increased efficiency, energy demand globally is projected to increase markedly over this century [18, 19]. Globally, the IEA's *NetZero by 2050* model shows electricity consumption increasing from 23,230 TWh in 2020 to 60,000 TWh in 2050, a 158% increase averaging 3.2% per year [5]. In the United States the EIA's AEO23 forecasts electricity consumption to increase 22% averaging .7% per year from 2022 to 2050 attributable to economic growth and increasing electrification in end-use sectors [20]. Considering a projected decrease in the use of fossil fuels for electricity generation and increase in electrical consumption, fossil fuel plant capacity must be replaced, and worldwide generation increased. Roadmap models place most of this burden on an expansion of variable renewable energy sources, primarily solar and wind. The IEA *Net Zero by 2050* roadmap increases electricity generation from renewables from 29% of total electricity produced in 2020 to 61% in 2030 and 88% in 2050, resulting in a 900% increase over this timeframe. The AEO23 model increases U.S. electricity generation from renewables from 22% in 2022 to 49% in 2030 and 62% in 2050, resulting in a 248% increase in U.S. renewable energy. The variability and uncertainty of solar and wind power require coordination with other sources to meet demand [21, 22]. The IEA and AE023 models look to battery storage to provide some of the flexibility lost to retired fossil fuel plants including the addition of 1,600 GW of battery storage globally and 160 GW in the U.S. by 2050. Widespread use of utility-scale battery storage relies heavily on a sharp decline in pricing from current levels [23]. To provide highly reliable electricity within the models discussed, substantial amounts of dispatchable electricity sources will be required [19].

2.2 Nuclear as Part of the Solution

The challenges to decarbonization vary and include geopolitical concerns. In Europe, political motivation for a change in decarbonization strategies from a gradual departure from coal and replacement with wind and solar (while using Russian natural gas during the transition) to something more rapid, is necessitated by the risk of natural gas shortages and price increases following the 2022 Russian invasion of Ukraine [24]. As an alternative, nuclear power "new build" programs are being pursued in 12 European countries [25, 26] and the phasing out of existing nuclear is being re-evaluated. Nuclear is a zero-emissions clean energy source of power [27] and is the second largest source of clean energy globally [6]. Nuclear fission plants can provide baseload power, but some designs can also operate flexibly to follow loads when adjustments are made to coolant flow rate and circulation, control and fuel rod positions, and/or dumping steam [28, 29], or by integrating with thermal energy storage, without significant drops in efficiency [30]. Currently nuclear power plants in 32 countries meet 10% of the world's energy needs avoiding 60 gigatons of carbon emissions over the past 50 years [31].

An additional 60 nuclear reactors are currently under construction in 15 countries with more countries looking to join the ranks of nuclear power producers. Globally, 10 countries have made the decision to develop a new nuclear power program and are actively developing infrastructure for their first nuclear power plant; three of which have reactors currently under construction. An additional 17 countries are considering nuclear power without having made a final decision [25]. While roadmaps for emissions reduction consistent with Paris Climate Agreement goals rely heavily on a substantial increase in wind and solar electricity generation, the IEA's Net Zero Economy (NZE) modelling shows nuclear output rising by 40% to 2030 and doubling by 2050.

Beyond electricity generation, nuclear power will also be relied on to provide a clean energy source to produce heat for buildings and for hydrogen production to decarbonize other energy sectors such as transportation. Despite the ability to contribute to a decarbonized energy economy, the nuclear share of capacity in many clean energy models that rely on nuclear is not aligned with current U.S. nuclear output forecasts, suggesting an insufficient number of proposed nuclear new-build projects to replace retiring reactors and meet forecasted energy needs [32, 33].

2.3 Nuclear Challenges

While offering a reliable clean energy source, nuclear power is not without challenges. Advancements in nuclear power technology that include extra safety features meant to avoid the type of disaster at the Fukushima Daiichi Nuclear Power Plant in Japan in 2011 have resulted in new generation III+ reactor designs for large nuclear power plants, those having about 1 gigawatt capacity. While new reactor projects have been completed on schedule in China, Russia, and the United Arab Emirates in recent years, projects in the United States and Europe have experienced substantial delays and cost overruns [5]. First-of-a-kind (FOAK) nuclear plants built in U.S. and Europe in the last 20 years are 2X over budget and schedule [34]. In the most recent U.S. example at the Vogtle Electric Generating Plant in Georgia, one reactor started commercial operation in July 2023 and a second is planned to start by early 2024 with a projected price tag of $32B, up from an original cost estimate of $14B and start-up scheduled in 2016 and 2017. Schedule and cost overruns have deterred financiers and U.S. energy utilities from additional large nuclear power plant construction projects. Despite these challenges, cost reductions are expected with each subsequent plant built in series owing to the series effect; and within it, the program effect arising from the uniformity of studies, developments, qualifications, and testing of materials that can be reused, plus the productivity effect seen mainly in the supply chain where suppliers pass on gains in their prices [35]. For the FOAK AP1000 design constructed in Georgia, the projected cost for the next plant in the U.S. is $4,300-$6,800/kWe and the 10th plant is expected cost $2.900-$4,500/kWe, a 53% reduction [36]. Additionally, the long operational life of a nuclear power plant and relatively low fuel cost compared to fossil alternatives contributes to levelized cost of electricity (LCOE) over 40-60 years of less than $30/MWhr, a price that is competitive with other electricity sources [36, 37].

2.4 Repowering of Coal Plants – An Existing Opportunity

An existing barrier to construction of nuclear power plants in some countries is cost. Constructing new nuclear reactors at existing coal power sites may offer cost savings when compared to construction at a greenfield site. One method to achieve cost savings and reduced emissions levels involves replacing all or portions of the existing generation system with a nuclear reactor [38]. Preliminary siting analysis found that many existing coal power sites surveyed are conducive for siting advanced nuclear reactors in the U.S. [39], Poland [40], and China [41]. Recent research by the U.S. Department of Energy (DOE) indicates that 80% of U.S. coal power plant sites evaluated are amenable to advanced reactor siting based on initial criteria [39]. Parameters considered by DOE when determining if a site was amenable include population density, safe shutdown during earthquakes, the presence of faults, topography ad slope, history of landslides, proximity to protected lands, wetlands, open water, and floodplains, and the presence of hazardous facilities nearby. Existing coal plants have infrastructure elements that could be re-used in a retrofit application, potentially making these sites an attractive option because of the value they represent.

The same U.S. DOE study [39] makes some estimates of possible construction savings attributable to infrastructure reuse, arriving at possible project savings from 15-35% based on different retrofit scenarios. An industry publication from NuScale, an advanced reactor vendor planning to complete a demonstration plant at Idaho National Laboratory by 2030, also provides estimates of potential savings from repurposing coal plant infrastructure, indicating an average power plant savings of $100 million [42]. In its white paper series, *Coal Repowering,* the Electric Power Research Institute (EPRI) indicates that coal plant infrastructure elements having the most value for nuclear repowering include the grid interconnection, cooling water supply, and transportation access [43]. In another industry white paper, *Repowering the Global Coal Fleet by 2050,* nuclear solutions integrator Terra Praxis similarly states that existing coal-fired power plants potentially offer enormous value by virtue of their grid connections, cooling water access, and real estate holdings [44].

Nonetheless, differences do exist among the infrastructure elements that these reports suggest represent the most value, as well as the extent of that value. Some of them may result from how the system is defined and what is included. The cost to engineer, procure, and construct (EPC) a new facility does not typically include owner's costs such as grid connection, cooling water supply, transportation, and utility connections. Further, project costs composing the fixed cost of electricity do not consider marginal costs like annual operating expenses for power, water, and maintenance that are heavily influenced by the decisions made during the design. All these costs are part of the power system that spans production to consumption, and all are ultimately borne by the consumer. Therefore, a systems engineering approach, examining existing infrastructure in the context of the entire system is necessary for a comprehensive understanding of the value existing infrastructure elements represent.

Small modular reactors (SMR) may offer a nuclear solution for repowering coal plants. While still in development, SMRs may prove to be more cost competitive when compared with large nuclear power plants due to factors such as economy of scale, multiple units, learning, construction schedule, unit timing, and plant design [45, 46]. SMRs may also offer additional sources of grid reliability compared to coal plants [47]. Compared to a greenfield site, repowering existing coal plants with a nuclear reactor may reduce the time needed to construct the facility and to connect to the grid because of the ability to reuse existing infrastructure. In particular, it is not yet known if SMR project schedules will benefit from reusing infrastructure elements having a lengthy project timeline.

In addition, the cost of financing during construction is a significant portion of the LCOE and is directly related to the length of the project. Interest during construction for a large nuclear power plant can account for 20% of the LCOE compared to only 11% for the overnight construction costs [35]. Hence, a better understanding of how existing infrastructure contributes to the overall project schedule of nuclear retrofits at coal plants will allow for improved estimates of savings from these schedule efficiencies and aid stakeholders in project decisions.

CHAPTER 3: RESEARCH QUESTIONS AND TASKS

3.1 Introduction

The U.S. power system is challenged with replacing retiring electrical generation capacity and meeting growing demand while simultaneously decarbonizing the electricity generation sector. Technological solutions will include variable renewable energy sources, energy storage, and nuclear power generation. One particular alternative, using small nuclear reactors constructed on the sites of existing coal plants, is examined in this dissertation.

Based on the state of the field discussed in Chapter 2, there is a clear need for additional research to determine if converting existing coal plants to nuclear power plants can provide a viable solution to carbon emissions reduction goals. To answer this question, investigation is needed to determine whether sites with existing coal plants offer cost and schedule efficiencies that would make them attractive candidates for the installation of a nuclear reactor, thus creating a viable path to more rapid decarbonization. It also needs to be determined whether widespread coal-to-nuclear conversion has significant potential to accelerate national and global decarbonization. When evaluating decarbonization potential, this research will focus on the committed emissions reductions available from converting operating coal plants to nuclear reactors in the U.S. Those results are then compared with those from a similar analysis for India, another country with comparative coal generating capacity but a different coal fleet profile.

The following research questions address the proposed problem statement above.

3.1.1 Research Question 1

Chapter 4 addresses Research Question 1, which is stated as follows: *Does constructing a nuclear power plant at the site of an existing coal power plant provide construction cost efficiencies related to specific infrastructure elements when compared to constructing a nuclear power plant at a greenfield site?* The following tasks are encompassed within Research Question 1.

Task 1: Define the categories at the coal power site to be evaluated in the context of a new nuclear reactor installation.

Task 2: Define existing coal sites with possibility for conversion from coal to nuclear plants.

Task 3: Define prospective alternative sites.

Task 4: Determine the value of grid connection at the coal power sites and alternative sites.

Task 5: Determine the value of the availability of existing cooling water supply at coal power sites.

Task 6: Analyze the value of grid connection and cooling water availability at existing coal power sites compared to nearby alternative sites.

The existing infrastructure categories to be considered for re-use with a new advanced nuclear reactor are electrical grid connection and cooling water supply. These infrastructure elements were selected because they may represent an important opportunity for both cost and schedule savings (to be discussed in Research Question 2). The power generating industry will benefit from better understanding of the value of these two infrastructure elements. When considering the diagram of a coal power plant in Figure 1, electrical grid connection and cooling water are shown in the green shape. This research proposes to examine these two infrastructure elements. Reuse of other infrastructure elements in the diagram, as well as infrastructure outside the diagram like land, commercial buildings, transportation, etc. will be left for future work.

Reusing elements inside the orange shape (Figure 1), most likely the turbine island, relies on specific steam conditions, and is a possible future opportunity. Turbine plant equipment represents a significant portion of direct construction costs in both nuclear and coal-fired generator applications. The U.S. Department of Energy's Energy Economic Data Base (EEDB) Program, using construction cost data from the 1970s and 1980s attributes turbine plant equipment to about 19% of direct capital costs of a coal generator and 22% for nuclear [48, 49]. Research performed primarily in Poland where the burning of coal accounts for about 75% of the country's energy production shows that the value of the existing turbine plant in a nuclear conversion scenario depends heavily on the technology of nuclear reactor selected. Most coal plants studied require a supercritical steam where temperature conditions are approximately 600° C. High temperature SMRs such as the Kairos Power KP-FHR and X-Energy XE-100 have been developed where the coolant medium reaches these temperatures using primary coolants salt and gas respectively. The SMRs that are closest to commercialization today such as the NuScale VOYGR and GE-Hitachi BWRX-300 use water as a coolant, the same as most nuclear units in operation globally. Reactor outlet coolant temperatures from these water-cooled units do not exceed 300° C, making them incompatible with supercritical steam turbines without significant, costly modifications that reduce efficiency. U.S. coal plants will likely experience little to no value from turbines at existing coal plants in a near-term nuclear conversion but projects further into the future may consider repurposing their turbines as additional advanced reactor options come to market and turbine repurposing is better understood. It is for this reason further exploration of reusing the turbine island will not be performed in this research.

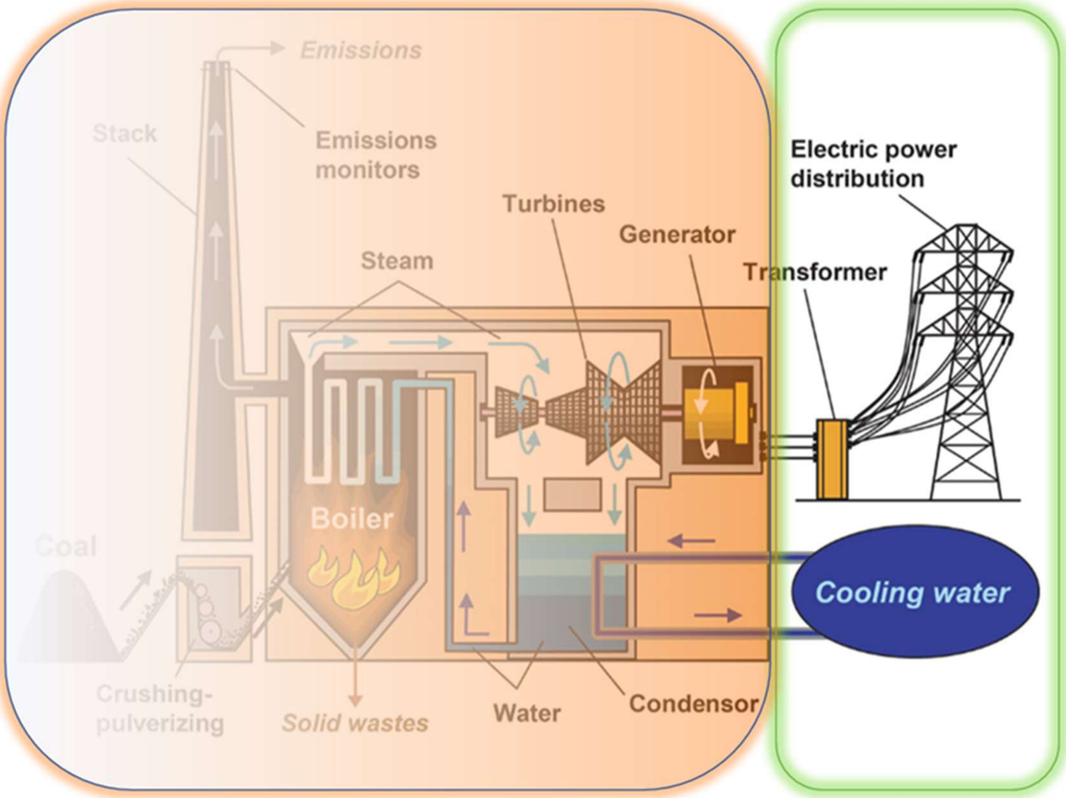

Figure 1. Coal power plant infrastructure elements. (adapted from original figure provided by [50])

Figure 2 shows a generalized diagram of a nuclear power plant, after the coal-to-nuclear conversion. The grid connection and cooling water infrastructure elements are again shown in the green shape. These are proposed to be reused from the coal power plant in the conversion case. The items in the orange box in Figure 2 would be new in the coal-to-nuclear plant conversions considered in this study.

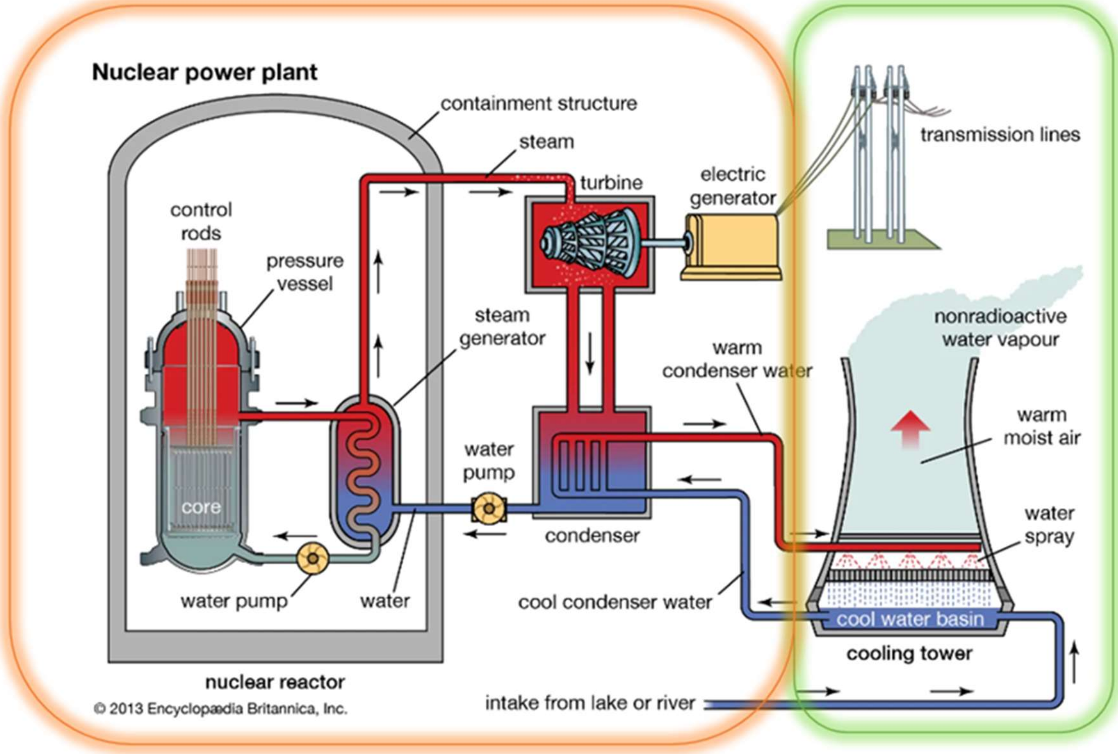

Figure 2. Nuclear power plant infrastructure elements. (adapted from [51])

3.1.2 Research Question 2

Chapter 5 addresses Research Question 2, which is stated as follows: *Does constructing a nuclear power plant at the site of an existing coal power plant provide schedule efficiencies when compared to constructing a nuclear power plant at a nearby site? If overall schedule improvements exist, what are the financial implications of the time savings?* The following tasks are encompassed within Research Question 2.

Task 1: Define a baseline greenfield project schedule.

Task 2: Define a coal power plant conversion project schedule.

Task 3: Determine if coal power sites provide reduced project timelines compared to new sites.

In addition to considerations related to potential savings from increased schedule efficiency, the individual project schedule for plant conversions defined in Research Question 2 sets up the research proposed in Research Question 3.

3.1.3 Research Question 3

Chapter 5 also addresses Research Question 3, which is stated as follows: *Cost savings and shorter schedule timelines resulting from use of existing infrastructure could further accelerate a proposed schedule to decarbonize. What quantity of committed emissions will be avoided by converting coal power plants to nuclear?* The following tasks are encompassed within Research Question 3.

Task 1: Define the subset of U.S. coal power plants amenable to conversion to nuclear power plants.

Task 2: Determine the year that generators at coal plants in both datasets above began operating, emissions per unit generated, and capacity factor of coal power plants.

Task 3: Develop a timeline to convert U.S. coal plants to nuclear plants.

Task 4: Calculate committed emissions from coal power plants using a base case where no plants are converted, as well as those for the conversion case where all amenable plants are converted, and all non-amenable plants operate until end-of-life.

Committed emission reductions are analyzed, including their possible contribution(s) to U.S. national goals, and compared with reductions potential in another country. The analysis considers the case where coal plants operate as normal until the end of their lives, as well as the alternative case where nuclear is phased in, eventually replacing all amenable coal plants. The notion of committed emissions provides insight into the possible carbon emission reductions available over time.

CHAPTER 4: DESIGN ANALYSIS OF COOLING WATER AND ELECTRICAL GRID INTERCONNECTION AVAILABILITY AT U.S. COAL-FIRED POWER PLANT SITES IN A NUCLEAR POWER CONVERSION[2]

4.1 Introduction

Coal-fired power plants account for 16% of electricity generated in the U.S. but produce an outsized quantity of the harmful criteria emissions that pollute the environment and damage human health [3, 52-54]. Electricity production from coal in the U.S. is expected to decline by over 80% in the coming 15 years due to plant retirements while electricity consumption is expected to increase 22% from 2022 to 2050 [5, 55]. Retiring coal plants are asserted to enable cost savings in a coal-to-nuclear site conversion through reuse and repurposing of on-site infrastructure and resources. Recent research has investigated the possibility of reusing operating infrastructure at coal plants including buildings and improvements, turbine plant equipment, electric plant equipment, and condenser and heat rejection systems [24, 38-41]. Recent work [56] finds the availability of water, land, and electrical transmission may be the most valuable resources available from an existing coal plant when considering on-site development of a nuclear plant. However, recent proposals and reports considering the construction of a nuclear reactor at an existing coal power site suggest that this evaluation of an existing site is nuanced and multivalued. In its early site permit filings to the U.S. Nuclear Regulatory Commission (NRC), Duke Energy identifies locations currently being evaluated for siting small nuclear reactors at the existing Belews Creek Station in North Carolina [57]. In construction permit filings to the NRC, TerraPower's Natrium

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[2] This chapter has been submitted for publication in IOPscience's *Environmental Research: Energy*.

project proposes to construct a small nuclear reactor on the site of the existing coal-fired Naughton Power Plant in Wyoming [57]. Both filings propose a nuclear reactor location on the same site as, but some distance from, the existing coal plant. Both note the importance of water and transmission availability in site selection. In a recently conducted feasibility study, nuclear reactor company X Energy evaluated siting a small nuclear reactor at a coal power plant site in Maryland [58]. In this case, the study recommended reactor facilities be located on an undeveloped part of the site away from the existing coal plant and reuse of no existing operating equipment. All three projects would use the existing water supply and connect to existing transmission circuits. No known projects have been proposed to date with meaningful reuse of coal power plant infrastructure beyond transportation, water access, and connection to the electric grid.

In June 2024 the U.S. Congress passed H.R. 6544 Atomic Energy Advancement Act requiring the Nuclear Regulatory Commission to evaluate which modifications of regulations or policy are needed to enable efficient, timely, and predictable licensing reviews for siting a nuclear reactor at the site of a fossil fuel plant to support the reuse of infrastructure including electrical switchyard components, transmission infrastructure, heat-sink components, steam cycle components, roads and railroad access, and water availability [59].

Converting coal plants to nuclear plants has the potential to replace firm, dispatchable energy sources that pollute with firm, zero-emissions energy sources that have higher reliability [60]. An increasing number of commercial proposals and the government actions above suggest the possibility of broad adoption of this approach. In response, an understanding of the costs and benefits of availability of cooling water and electrical grid interconnection at retiring U.S. coal plants is needed to evaluate the role these sites could play in future energy projects. This paper proposes a comprehensive assessment of the value of existing cooling water and electrical grid infrastructure at U.S. coal-fired power plants. The costs and benefits of applying this infrastructure to on-site nuclear power plants is then assessed for an example power plant site. Discussion focuses on cooling methods and water sources used at new and existing sites, and grid interconnection as a replacement generator compared to entering the electrical transmission organization's grid interconnection queue at new sites.

4.2 Methods

The existing system of operating U.S. coal power plants consists of 424 units at 205 sites [61]. To better understand infrastructure values across the fleet, operating coal power plants were examined to assess the value of the existing electrical grid connections and cooling water availability in a coal-to-nuclear conversion.

For the electrical grid connections, methods are presented to evaluate the transmission spur line connecting the generator's main step-up transformers to the interconnection point, the point of grid interconnection, and the broader transmission network. For cooling water, the cooling method at existing sites, cooling solutions at new sites, and the cost of alternatives are evaluated considering capital, operational, and penalty costs. The analysis assumes the use of GE Hitachi BWRX-300 reactors, which is a 300 MW electric, water-cooled, small modular reactor undergoing licensing activities with the NRC [13].

4.2.1 Electrical Transmission

In a thermal power plant, heat from combustion, nuclear reaction, or other sources produces steam used to drive a turbine generator. The electricity produced by the generator is then transformed to the transmission system voltage and routed to a nearby substation via a spur transmission line, where a connection is made to the transmission network. The component categories needed to route the electricity from the generator to a load node on the transmission network include [62, 63]:

- main step-up transformers
- spur transmission
- point of interconnection (POI)
- bulk transmission network

The following sections detail methods used to determine the value of availability of existing electrical infrastructure at coal power plants for consideration of their reuse in a coal-to-nuclear conversion.

4.2.1.1 Plant Electrical Equipment

Plant equipment discussed below includes the main step-up transformers and transmission spur line. Both components are typically outside the scope of the transmission operator's grid interconnection [64], and are instead the responsibility of the plant owner.

4.2.1.1.1 Main Step-up Transformers

A power plant's main step-up transformers change the AC voltage from the generator voltage to the transmission voltage. In the electrical circuit that includes generation to transmission, these occur after the steam turbine generator at the coal plant.

Power transformer normal life expectancy is defined under continuous loading at rated output under usual conditions [65]. Any operation beyond nameplate rating (for short or long-duration emergencies, or planned periods), reduces life expectancy [65]. The presence of oxygen, water levels in the transformer, and maintenance history also strongly influences transformer ageing [66]. A transformer's condition and ageing process is difficult to model, and residual life of identical transformers with the same period of service is uncertain [66]. Considering these complexities, the lifetime of a power transformer is often described as 20-40 years [67-69], while some models suggest up to 50-year life [70].

Operating U.S. coal plants have an average age of 45 years (calculated from [61], suggesting that many plants have transformers nearing the end of life. Because of the importance of reliability of the main step-up transformers, it is assumed transformers at existing coal plants are not retained for use in a nuclear conversion, but it is acknowledged they may represent some residual value due to their potential to be refurbished and used on other projects or maintained as spares.

4.2.1.1.2 Transmission Spur Line

The transmission spur line is a relatively short length of line connecting the step-up transformers to the transmission substation. Black and Veatch [71] describes a method for estimating spur line construction costs considering the number of circuits, voltage, distance, structure type, and terrain. Both coal and nuclear generation technologies have a technology reliability multiplier requirement, which results in construction of a double circuit spur line [63]. The calculation for determining spur line construction cost, exclusive of right of way costs, is shown in Eq 1. below [71].

$$TSLC = BTC * CM * SM * LLM * TM * D, \tag{1}$$

where TSLC = Total spur transmission line cost

BTC = Base transmission cost

CM = Conductor multiplier

SM = Structure multiplier

LLM = Line length multiplier

TM = Terrain multiplier

D = Distance (miles)

An example calculation using Eq. 1 is given in Table 3 in the *Results* section.

4.2.1.2 Interconnection

In 1996 the Federal Energy Regulatory Commission (FERC) issued Order No. 888 requiring public utilities to provide open access transmission service on a comparable basis to the transmission service they provide themselves [72]. As a result, independent system operators (ISO), and later, regional transmission organizations (RTO) were created in many regions of the country to comply with FERC orders in their deregulated power markets. At present, two-thirds of the U.S. electricity load is served by seven ISO/RTOs [73, 74]. The remaining load, in the Northwest, Southwest and Southeast, is served by a regulated market that operates under a traditional vertically integrated market structure, with some areas having the option of voluntary participation in deregulated markets through the Western Energy Imbalance Market [73, 75].

The connection of an electric generator to the transmission system is made through a grid interconnection. In deregulated markets, a grid interconnection is a one-time project with cost paid by the generation owner to the grid operator to connect a generation source to the grid. Grid interconnection is a process beginning with an interconnection request, followed by a series of engineering studies to determine what grid system upgrades are needed before a project connects to the grid, an interconnection agreement between the generation owner and grid operator with pricing derived from the studies, and finally, commercial operation after executing the interconnection agreement [76]. In most ISO territories, the grid interconnection has two main cost components: point of interconnection (POI) costs and network costs. POI costs include the interconnection station and transmission line extensions to that station. Network costs include transmission network upgrades triggered by reliability or stability violations caused by a new generator [64].

In addition to interconnection costs, prospective generators must enter interconnection queues, the lists of projects seeking to connect to the grid. The duration projects must wait in these interconnection queues has increased significantly in recent years. In the last decade the amount of generation and storage in the interconnection queue across all 7 ISO/RTOs plus non-ISO balancing areas increased every year, from 325 GW in 2014 to 2,598 GW in 2023, representing nearly 12,000 projects in the interconnection queue at the end of 2023, and a median time in the interconnection queue of 55 months for projects with more than 200MW capacity [76].

In this context, existing grid interconnections at coal power plants have two sources of value. First, because interconnection is established, most construction and capital cost can be avoided, under conditions where the replacement generator is of similar or smaller capacity. Second, because the new generator is considered to be a replacement to an existing generator, the project needn’t enter the interconnection queue, reducing schedule risk due to uncertainty in the duration of a project’s time in the queue, and financial risk due to the wide range of interconnection cost estimates that force many projects to abandon their plans and leave the queue. While it is acknowledged there is value in reducing the risk of entering the interconnection queue, this paper concentrates on evaluating the potential cost savings in POI and network charges.

At each site considered in this study, POI and network costs are considered for a case where a single 300 MW nuclear generator is installed and a second case where coal power plant sites replace the electrical capacity with 300 MW nuclear generators. The system of existing interconnections in a fleet-wide conversion to nuclear power is then evaluated.

4.2.2 Cooling System

4.2.2.1 Cooling System Types

Operating coal and nuclear power plants generate electricity by means of the Rankine cycle whereby mechanical work can be extracted from a fluid as it moves between a heat source and a heat sink [77]. In existing coal and nuclear plants heat is used to produce steam which drives a turbine connected to a generator that converts the mechanical energy to electricity. The steam exits the turbine and is condensed back to water and is available to enter the process again to be made into steam. Heat must be rejected from the steam by way of a condensing heat sink. The cooling system for coal and nuclear plants has three primary design alternatives: once-through cooling, recirculating wet cooling, and dry cooling. Hybrid wet/dry systems also exist using two of the three primary methods, supplementing dry cooling with water in the hottest months of the year. The following paragraphs provide a basic description of the cooling alternatives to clarify the types of systems evaluated in this study. Comprehensive explanations of cooling systems utilized in plants using steam to generate electricity are available in textbooks such as [78].

4.2.2.1.1 Once-through Cooling

In a once-through cooling system water is withdrawn from a water source, typically an ocean, river, or lake, and passed through a steam condenser where it absorbs the latent heat of exhausted steam before it is returned to the water source. The discharged water is warmer than when withdrawn. No water is consumed or evaporated in this process, although evaporation occurs near the discharge plume [79]. Once-through cooling is the simplest and most cost-effective cooling method, and formerly the most common alternative at U.S. power plants [80, 81]. Today, once-through cooling is rarely permitted for new plants due to environmental concerns [82].

4.2.2.1.2 Recirculating Wet Cooling

Recirculating wet cooling also uses steam condensers, but the cooling water heated by the condenser is circulated through a cooling component such as a cooling tower or pond to reject heat before it is recirculated through the steam condenser. Recirculating wet cooling requires less water volume than once-through systems but consumes more water due to evaporation, requiring constant additions of "make-up" water [80].

4.2.2.1.3 Dry cooling

Dry cooling is accomplished by either direct or indirect means. In a direct dry cooling system steam is delivered to an air-cooled condenser (ACC) where it is condensed inside finned tubes as heat is rejected to the environment by blowing air across the finned surfaces, typically with fans. In an indirect dry cooling system, circulating cooling water absorbs heat from exhausted steam in a condenser, like once-through and wet recirculating systems. The heated water is then cooled by ambient air indirectly through air-cooled heat exchangers [83].

This study considers conversion of coal power plants to nuclear plants using the GE Hitachi BWRX-300, a boiling water reactor. The main condenser in this reactor is a two-shell unit with each shell located beneath its respective low-pressure turbine [84]. In all three cooling alternatives, circulating water flows through the condenser tube bundles to condense the turbine exhaust steam. While direct dry cooling is the primary method currently used in U.S. power plants [85], indirect dry cooling is the only dry cooling method considered here for nuclear plants. In a boiling water reactor, direct dry cooling would take turbine exhaust steam and condense it in air-cooled condensers, creating a direct path from the reactor core to the air-cooled condensers and is not considered for safety reasons.

Dry cooling has the least water consumption and has the highest capital cost and operating costs compared to other cooling systems [86]. It has rarely been used at steam plants in the U.S. until recently [79]. No operating nuclear power plants in the U.S. utilize dry cooling and only a single operating example exists worldwide at the Bilibino site with three 11MWe units located in the Arctic permafrost region of Siberia [87].

Small nuclear reactor installations at new sites must consider the possibility that water scarcity or environmental regulations compel the use of dry cooling despite financial considerations favoring a wet system. The Carbon Free Power Project launched in 2015 by the Utah Associated Municipal Power Systems planned to build a nuclear power plant on the Idaho National Laboratory site using NuScale Power's small modular reactor (SMR) technology. The project studied wet recirculating cooling, dry cooling, and a hybrid approach [88], ultimately opting to pursue dry cooling, citing water scarcity as the deciding factor [89]. The project, which would have been the first commercial SMR deployment in the U.S., was cancelled in 2023 after price estimate increases, citing insufficient subscription to continue toward deployment [90]. Other developers of SMR technology including GE Hitachi BWRX-300 and Holtec SMR-160 also advertise the ability to include dry cooling in their designs [84, 91].

4.2.2.2 Cooling System Application

Cooling options vary depending on conditions at individual sites, primarily the availability of water that can be used for cooling. The cooling system method used at operating coal plants was investigated. Of the 217 U.S. coal plants operating in 2022, wet recirculating cooling is utilized by 63% of plants, 35% use once-through cooling, and less than 2% use dry cooling [81] as illustrated in Figure 3.

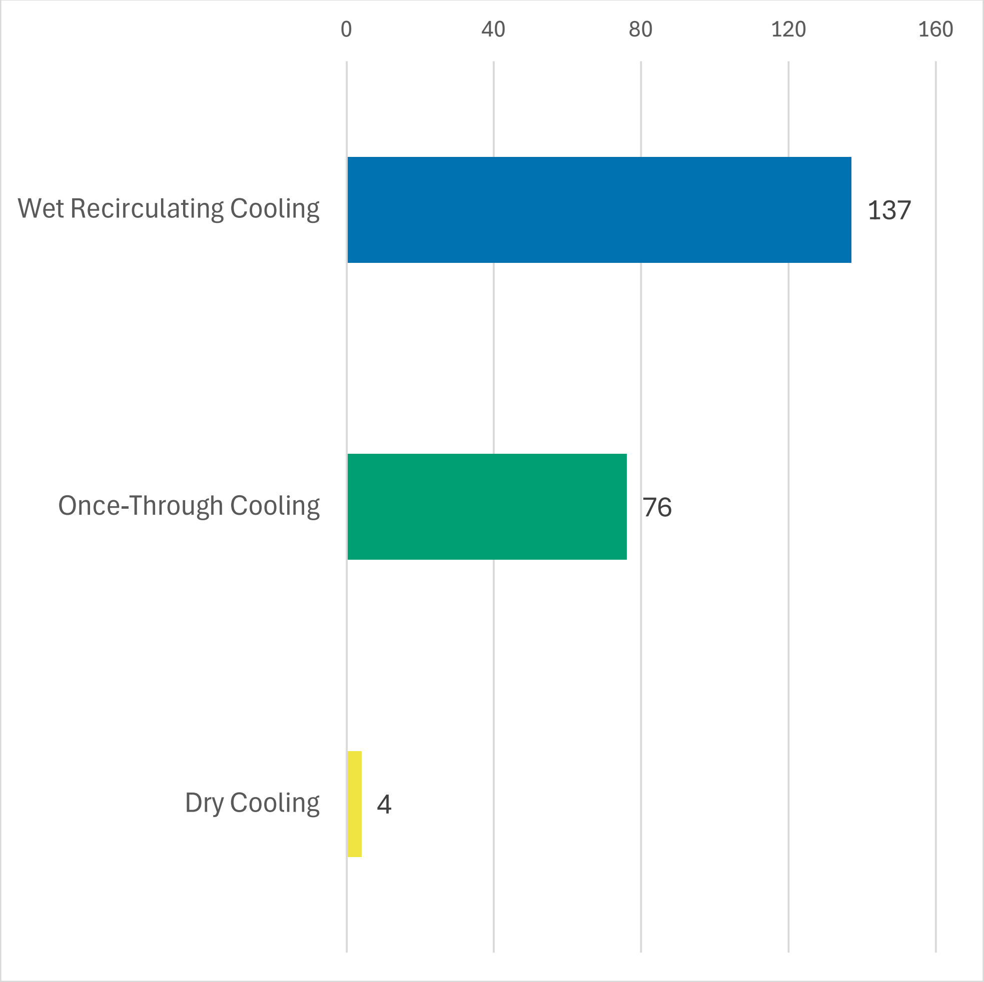

Figure 3. Number of operating coal plants using each cooling system type in 2022 in the U.S.

The last two U.S. new coal plants larger than 300 MW were installed in 2013 and no new plants are planned [61] in the U.S. To examine recent trends in cooling alternatives, new electric power plants with a steam cycle are evaluated. The percentage of once-through cooling in new electric power plants with a steam cycle has declined beginning in the 1970s [81]. In the ten years from 2013 to 2022, wet recirculating cooling was the most-utilized cooling option, installed at 57% of new plants, while dry cooling accounted for 34%, once-through cooling was installed at 6%, and a dry hybrid solution was used at 3% of plants. While the use of wet recirculating cooling has declined slightly when comparing existing coal plants and new steam plants, once-through cooling has experienced a significant decline in use, and dry cooling a significant increase. The analysis does not consider the use of once-through cooling at new sites. Once-through cooling system installations are rare and difficult to permit for environmental reasons [82]. Of the five installed in the period from 2013 – 2022, one was at an existing site, and three were situated on an ocean coast able to withdraw water from the sea. Only a single plant withdrew from an inland water source [61]. The analysis assumes new sites will use wet recirculating or indirect dry cooling, the most common cooling solutions at new plants. The distribution of cooling system types for those beginning operation from 2013 to 2022 and in use at electrical plants using a steam cycle are shown in Figure 4.

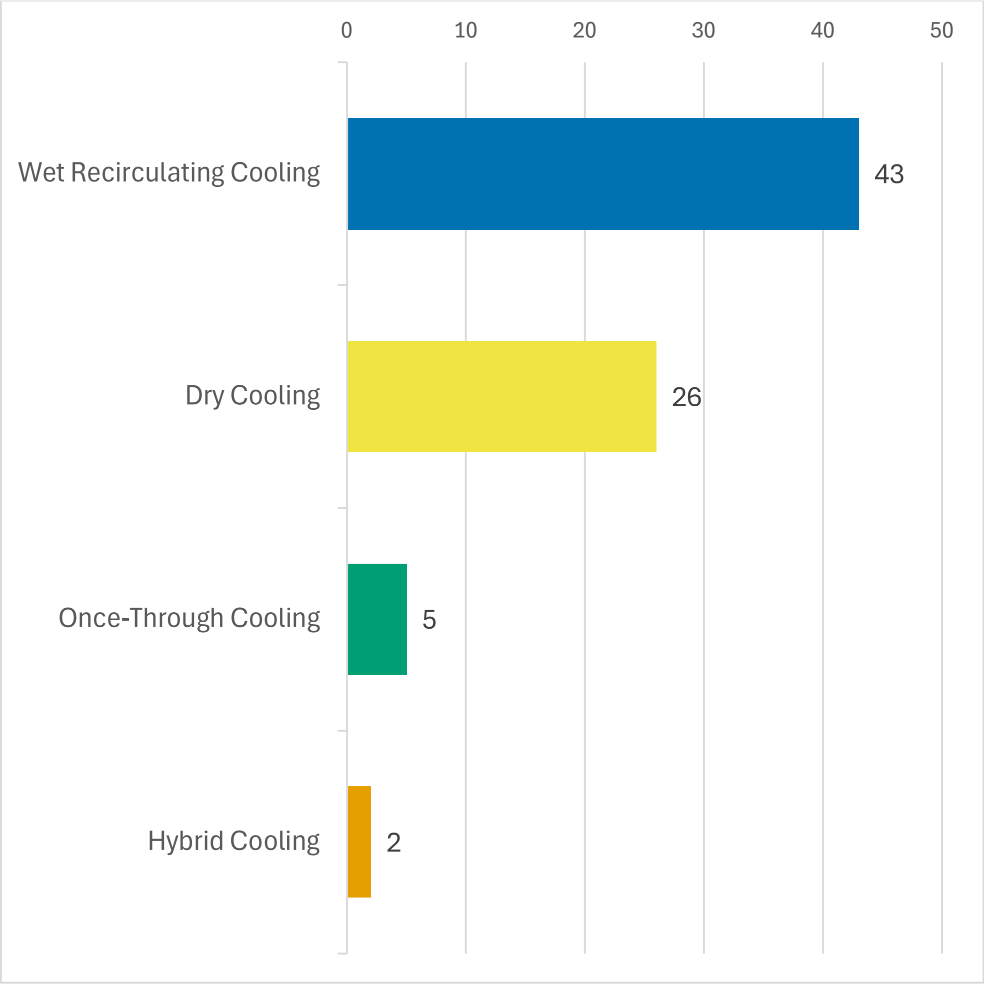

Figure 4. Number of steam-powered electricity generating plants using each cooling system for those beginning operation from 2013 to 2022 in the U.S.

The methodology and computational procedures used to estimate many of the cooling system parameters and costs for power plants in this paper are explained in detail in [79, 82]. In [82] cooling alternatives are evaluated at five sites representing different climate types. The present study refers to climate types as: hot-arid, hot-humid, arid with extreme temperature ranges, moderate (cool and dry), and moderate (warm and humid). To analyze U.S. coal power sites, one of these five climate types is assigned to each site. The existing cooling method is identified using government mandated annual plant surveys [81, 92]. Once-through, wet recirculating, and indirect dry cooling are evaluated for each climate area for scenarios where a single nuclear reactor is installed at coal power sites and where multiple reactors are installed. Potential cost savings are evaluated separately for those resulting from the cooling method used and from those using existing cooling water sources.

4.2.2.3 Cooling System Costs

Cooling system costs are made up of three components: capital costs, operating costs, and penalty costs, which are evaluated as follows.

4.2.2.3.1 Capital Costs

Capital costs include the purchase and installation of cooling system equipment. To compare cooling systems, capital costs are annualized over an assumed life of 30 years using an annual cost of capital rate of 7%. The components included in capital estimates are described below for each cooling alternative. Capital costs were estimated using published cost data when available. Capital costs from previous years were inflated to \$2024[3] using an annual construction inflation rate of 4.7% [93]. Some costs inflated using this method, including the condenser for the once-through case and air-cooled heat exchanger for the indirect dry cooling case, were validated with vendors as part of the present study and found to be adequate for budgetary estimating; the level of precision throughout this work. The cooling system capital costs for all cooling alternatives were

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[3] \$2024 refers to the dollar value in year 2024. Values from other years are inflated to their 2024 value to provide consistent valuation for comparison.

increased by 5% over the reactor design requirements to include auxiliary cooling for other plant heat loads in addition to the condenser.

4.2.2.3.1.1 Once-through cooling system components

Once-through capital costs include condenser, pump, piping, intake and discharge facilities, and electrical hookups and controls. A cooling water flow rate of 600 gpm/MW is assumed [82]. Equivalent head was estimated based on extending the existing intake depth [81] and pressure drop across the piping and condenser. Pump power was estimated using Equation 2 below and the calculation shown in Table 5.

$$P = \frac{q*h*SG}{396*n} . \tag{2}$$

where P = *Pump power (hp)*

q = *Flow (gpm)*

h = *head (ft)*

SG = *specific gravity*

n = *pump efficiency*

Pump pricing was assumed at $521/BHP, intake and discharge facilities were estimated at $4,170/MW of generator capacity [82], and electrical hookup and control were set at $1.5M. To size the system, a 20° F temperature range is assumed, and cold-water intake temperature was based on the average maximum monthly intake temperature in the hottest month. Condenser costs were established using condenser area as the variable in a polynomial equation produced from vendor-supplied budget cost information in [94].

4.2.2.3.1.2 Wet recirculating cooling system components

Wet recirculating cooling capital costs encompass the condenser and the cooling tower, including cold water basin, circulating water system, electrical hookups and controls, auxiliary cooling system, and make-up intake and blow-down discharge facilities. Steam condenser costs include transportation, assembly and installation, and air-removal equipment. The use of water-cooled, shell-and-tube surface steam condenser coils with a mechanical draft, counter-flow, and in-line configuration wet cooling tower is assumed. A cooling pond could also be used in place of the cooling tower, as is the case at some existing coal-fired power plants. Capital costs and power use for wet recirculating and dry cooling systems in each climate area were calculated for a 600 MW nuclear power plant in [94]. This cost data was scaled to the heat load for a 300 MW nuclear plant and inflated to $2024 for use in the analysis below.

4.2.2.3.1.3 Dry Cooling System Components

Dry cooling capital costs for the indirect dry cooling system include the costs for shell and tube condenser, air-cooled heat exchanger, circulating water pumps, and circulating water lines. Within these four costs are the necessary fans and motors, support structure, piping and valves, electrical and control equipment, and installation, including startup costs.

4.2.2.3.1.4 Operating Costs

Operating costs include the costs of electricity needed to operate the cooling system's pump and fan motors, water costs, and maintenance. The analysis assumes 8,000 hours of operation annually corresponding with a capacity factor of 92%, the capacity factor of the U.S. nuclear fleet [52]. Electricity is valued at $95/MWh, a predicted cost of electricity for small nuclear reactors in [95]. Once-through cooling system pumping costs were calculated by multiplying the pump power by annual operating hours and the cost of electricity. Maintenance costs of 1.5% of capital costs are part of the annualized operating cost for each alternative. Water costs are also included in operating costs and are discussed below.

4.2.2.3.1.5 Water Costs

There is no strong consensus on the volume of water consumed during the production of electricity. Most water consumed in electricity generation is the result of evaporation [96]. In the case of wet recirculating cooling, the method with the most water consumption, approximately 1-2% of the circulating water flow rate is evaporated, while blowdown accounts for 0.1 – 1% loss and drift accounts for less than 0.01%, as reported in [82]. Primary literature estimates of water use are consolidated in [97]. That report suggests that (1) water withdrawal and consumption estimates vary greatly across sources and (2) improved power plant data and further studies are needed for greater resolution. The literature detailing water consumption for nuclear and coal-fueled power plants that use the "once-through" and "recirculating with cooling tower" cooling methods is also summarized in [97] and shown in Table 1.

Table 1. Water consumption estimates by fuel and cooling system type from [97].

	Once-through Cooling (nuclear)	Once-through Cooling (coal)	Recirculating Cooling with Tower (nuclear)	Recirculating Cooling with Tower (coal)	Dry Cooling (from other fuels)
gal H_2O/MWh (max)	400	317	845	1100	35
gal H_2O/MWh (median)	269	250	672	687	20
gal H_2O/MWh (min)	100	100	581	480	5

Dry cooling water consumption was not reported for nuclear power plants [97], likely because it is not utilized in any U.S. nuclear plants. Dry cooling consumption was estimated here based on median values reported for other fuel types at electricity plants using a steam cycle. The minimum, median, and maximum consumption values reported in [97] are used to calculate the annual water consumption for a 300 MW nuclear power plant considering a 92% capacity factor, with results displayed in Figure 5.

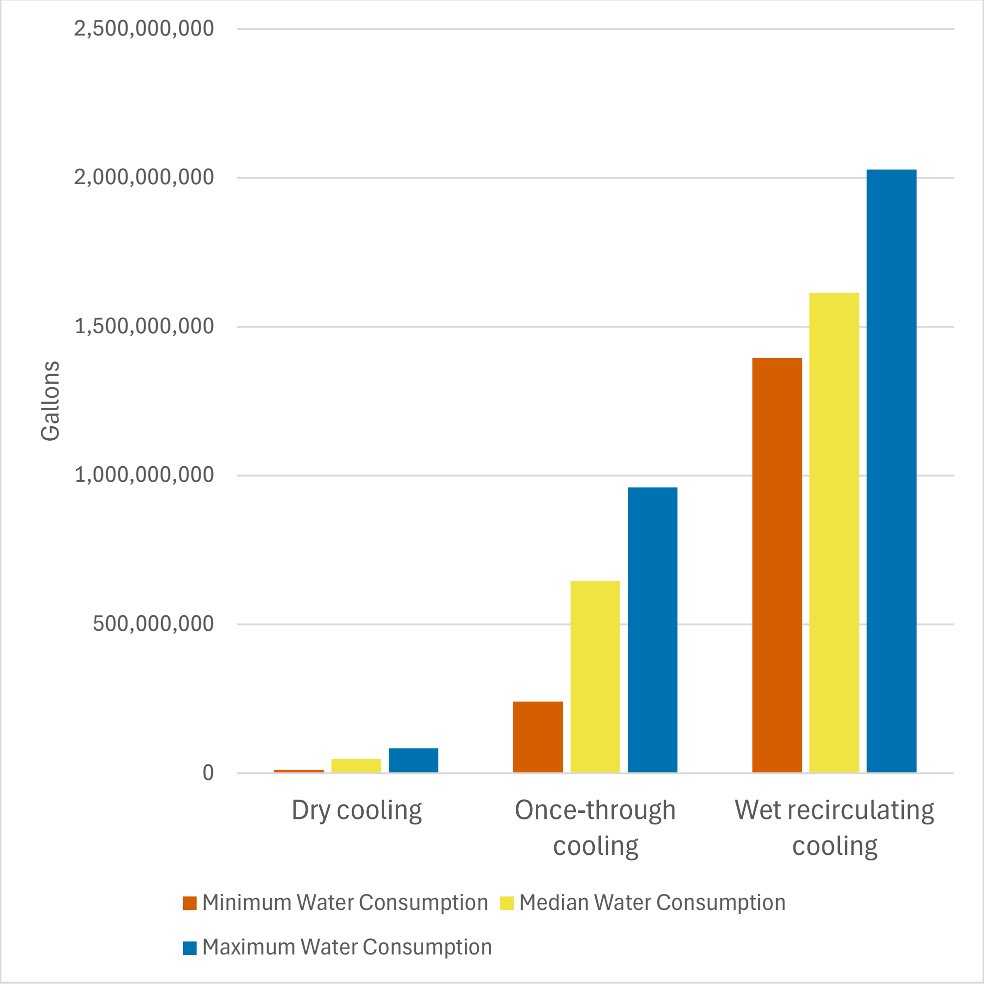

Figure 5. Expected range of annual water consumption by cooling method for 300 MW nuclear plant based on minimum, median, and maximum water consumption estimates reported in [97].

The value of water at a particular site is hard to predict. Water costs are composed of acquisition costs, delivery costs, in-plant treatment costs, and discharge/disposal costs. At existing coal power sites, it is assumed existing rights to withdraw and discharge water from and to rivers, lakes, and oceans would remain in place if generation was replaced with a nuclear reactor. The delivery of the water from the source to the existing sites is included in the annualized costs for the cooling system. In-plant treatment costs vary depending on the quality of the water available and the requirements for the cooling system.

At new power plant sites water could be acquired through the purchase of water directly from a municipal source or other provider where the site would pay for water based on volume, or through the purchase of water rights. In the case of direct purchase, the delivery costs to the site are included in the water purchase price. With a water right, delivery costs may be included in the annual operational costs for the cooling system if the water is withdrawn onsite, or as an additional cost to deliver to the site. Discharge of water at new sites depends on local regulations ranging from permitting discharge to the source, to zero liquid discharge constraints where all waste streams must be managed onsite.

A total of 61 electric generating plants that use a once-through or wet recirculating cooling system beginning operation during 2013 to 2022 were evaluated. For plants with a river, lake, ocean, or groundwater source (such as a well), it is assumed water acquisition comes from a water rights permit. For plants having either a municipality or wastewater supply, a municipal source is assumed. A permitted water source was used by 61% of plants with cooling systems beginning operation in this period, while 39% used water from a municipal source, as illustrated in Figure 6.

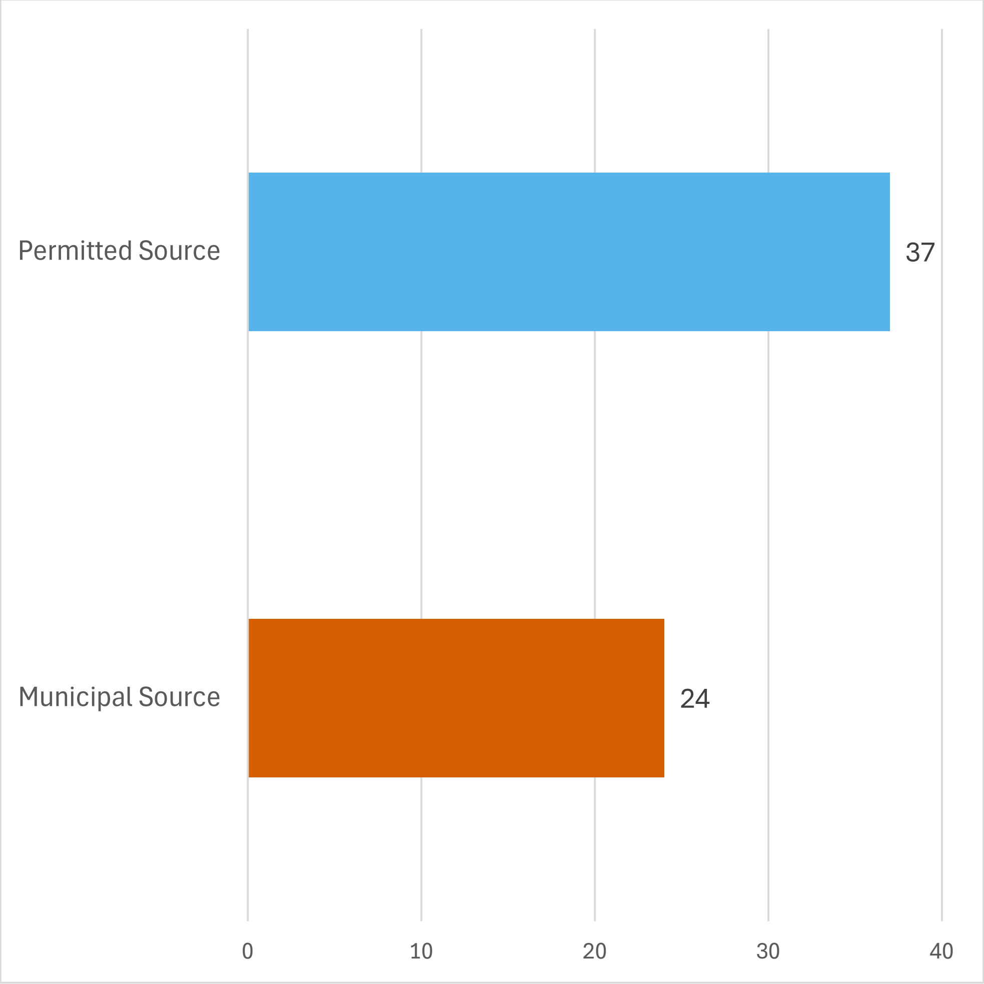

Figure 6. Cooling water source for 61 electric plants using a once-through or wet recirculating cooling system beginning operation during the 2013 to 2022 timeframe

Water costs are evaluated in [82] based on previously published prices for water rights sales and leases. Costs are evaluated for minimum, low, medium, and high scenarios. Minimums occur at sites where acquisition and delivery costs are zero and only treatment and delivery are included. Low-cost sites have a short pipeline (approximately two miles) from surface water with no elevation change, medium-cost sites have longer pipelines (approximately 10 miles) and some elevation change (roughly 500 feet) from surface water, and high-cost sites may have a long pipeline (approximately 20 miles) and significant elevation change (approximately 1,000 feet) [82].

Total water costs from water right purchases or leases reported in [82] range from a low cost of \$1.42, a medium cost of \$4.71, and a high cost of \$14.17 per thousand gallons, when inflated to \$2024 using the U.S. Bureau of Labor Statistics Consumer Price Index annual inflation rate of 2.6% [98] and are shown in *Table 2*.

In a recent study, industrial water costs were analyzed for 112 water utilities and 76 wastewater utilities across the U.S. [99]. Industrial water rates were reported to range from \$1.46 - \$10.74/kgal. Wastewater rates varied from \$1.60 - \$14.52/kgal not including one supplier reporting wastewater rates at \$21.65/gal. Results in [82] and [99] suggest similar water cost ranges for permitted and municipal sources.

At existing plants, continued use of the existing water source is assumed and only water treatment costs are considered. Water treatment costs were estimated using the International Atomic Energy Agency's Water Management Program in Nuclear Power Plants (WAMP) tool [100] for the 300 MW reactor. Annual water treatment costs for wet recirculating cooling are estimated at \$1.1M. Annual water treatment costs for once-through cooling are estimated at \$770,000. The water treatment costs per gallon differ drastically between these two methods. Once-through cooling will withdraw 87.4B[4] gallons of water from the cooling water source and discharge that same amount back to the source at a warmer temperature. The treatment requirements for once-through cooling are lower than for wet recirculating cooling, resulting in a per-unit water treatment cost of \$0.009/kgal. In the case of wet recirculating cooling, the 1.6B

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[4] Annual water withdrawal assuming cooling water flow rate of 180,000 g/min for 8,000 hours of operation per year.

gallons of water withdrawn assuming median water use rates described above is all consumed and none is returned to the source, resulting in a treatment cost of $0.68/kgal.

Table 2. Water costs (in units of 2024 USD/kgal) by component category for minimum, low, medium, and high-cost cases reported in [82] and calculated using [100] and inflated to $2024. The low-medium cost case is introduced as the midpoint of the low and medium cost cases.

	minimum	low	**low-medium**	medium	high
Acquisition	**$0.00**	$0.84	**$1.46**	$2.09	$5.01
Delivery	**$0.00**	$0.22	**$0.58**	$0.95	$2.01
Treatment / Disposal	**$.009 - $.68**	$0.37	**$1.02**	$1.67	$7.15
Total	**$.009 - $.68**	$1.42	**$3.07**	$4.71	$14.17

Understanding that water costs at a new site are hard to predict and that the value of water ranges dramatically, depending on acquisition, delivery, and treatment and discharge costs, this analysis takes a conservative approach in valuing water for new sites. Given the potential expense of water, it is likely that power project developers will consider water costs when making siting determinations and will disregard sites with high water costs whenever possible. For analysis of new sites, this study disregards the high-cost case and establishes a low-medium cost rate, a value at the midpoint of the low and medium-cost cases. The low-medium water cost is used as the water cost for wet recirculating cooling systems at new sites and for dry cooling at all sites, assuming median water consumption levels at both. Once-through cooling is not considered for new sites. The resulting annual water costs for each cooling method are shown in Figure 7.

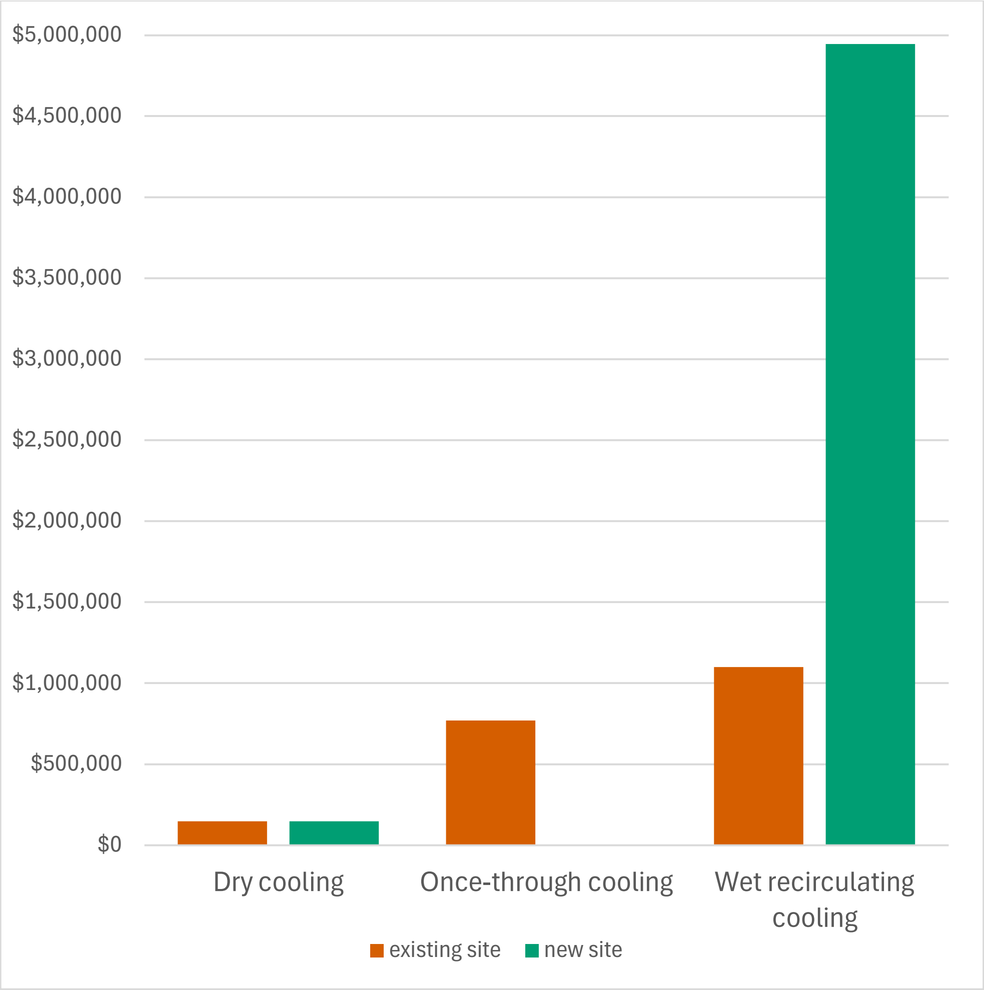

Figure 7. Expected annual water costs for each cooling type assuming median consumption levels for wet recirculating and dry cooling. Once-through cooling is not used at new sites.

4.2.2.3.2 Penalty Costs

Penalty costs are the costs experienced due to reduced plant output when using one cooling method compared to another. The baseline cooling method for the calculation of penalty costs is wet recirculating. No penalty costs are incurred for wet recirculating or once-through cooling. Penalty costs for dry cooling include a heat rate penalty and capacity penalty. The heat rate penalty results from reduced plant efficiency at high ambient temperatures. The capacity penalty is incurred when the cooling system is not able to keep turbine backpressure within the operating range and plant operation must be curtailed to avoid damage.

Generation penalties for dry cooling were calculated for a 600 MW nuclear power plant in [94] using annual meteorological data for the five climate areas evaluated. Dry cooling costs vary geographically based on temperature and humidity conditions in different climate areas. A generic modified-conventional turbine curve not specific to the GE Hitachi BWRX300 was used to determine heat rate and capacity losses. These penalties were scaled to the heat load for a 300 MW nuclear plant and penalty costs were calculated using an energy cost of \$95/MWh and a 92% capacity factor as discussed in the *Operating Costs* section.

4.2.3 Sites Evaluated

This study considers 148 operating coal power sites. Methods above are applied and results for the Belews Creek Station site are shown as an example of the process used to evaluate all sites to arrive at the fleet analysis results. Belews Creek is one of two operating coal power sites where early site permit filings have been submitted to the NRC proposing to install a nuclear reactor [57]. In its filing material, Duke Energy proposes to site a new small nuclear reactor at the site of existing Belews Creek Station and begin nuclear operation in 2034. The proposed site is located at the southern end of Belews Lake, which is adjacent to the existing generating plant [57]. The Belews Creek Station currently operates two coal units with 1080 MW capacity each. The units began operation in 1974 and 1975.

When considering sites for a small nuclear reactor, each site will have opportunities and challenges. The present analysis particularly considers the opportunities of electrical grid and cooling water availability at existing coal power sites. It is assumed that new nuclear reactors will be constructed near the existing coal units on the property owned by the coal plant owner, but on a different part of the site. Building the new plant on a different part of the site takes advantage of access to the existing transmission connection point and cooling water. The work here is intended to increase understanding of the potential value of the availability of these infrastructure elements by using site-specific information for plants composing the nation’s coal plant fleet. A plant owner pursuing a coal to nuclear conversion would use site-specific information in the development of a feasibility study and preliminary safety analysis report. Detailed instructions on the development of these studies and reports are found in [101, 102].

Plants eligible for conversion were studied by [39], which evaluated operational U.S. coal plants considering the following inputs: population, earthquake potential, faults, protected land, slope, landslide potential, and the presence of wetlands and open water, floodplains, and hazardous facilities. That research found that 80% of coal plants in operation at the time of the study were amenable to further consideration for siting an SMR. Examination of the datasets in [39] reveal that population density was the most influential discriminator and the only factor that resulted in an existing plant not being considered for further SMR site evaluation.

When considering values of electrical grid connection and cooling water availability for the U.S. coal plants in this study, operating plants were evaluated for nearby population and existing plant capacity. To be considered as part of the fleet eligible for further consideration for conversion to nuclear power, an existing coal plant was required to meet three criteria:

- Operational in 2023
- Population, where more than 50% of the area in a four-mile radius around the existing plant does not have a population density greater than 500 people per square mile[5]
- Plant capacity of 300 MW or more[6]

4.3 Results and Discussion

4.3.1 Electrical Results

Electrical results include a discussion on routing a new transmission spur line from a new nuclear generator to the existing transmission substation, and potential cost savings from reusing the existing grid interconnection. Cost savings potential is evaluated for a single unit and for maximum units based on existing coal plant electrical capacity, first for the Belews Creek site, then for 148 sites across the U.S. coal fleet served by one of eight transmission service areas.

4.3.1.1 Plant Electrical Equipment

4.7.1.1.2 Transmission Spur Line

Figure 8 shows a portion of the Belews Creek site including the existing coal plant, existing substation, existing spur line, the area being considered for installation of a nuclear reactor, and a possible new spur line installation. In a conversion to nuclear power, the existing spur line connecting the main step-up transformers and the substation would be removed. A new spur line from the new transformers to the existing substation would be installed. An estimate for the cost of this spur line assuming a length of one mile, adequate to reach most of the area under

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[5] The population density metric is introduced in [39]. Datasets from [39] were used to determine where coal-fired power plants are suitable for conversion to nuclear power.

[6] The replacement generator considered in the present study is the GE Hitachi BWRX-300 with capacity of 300 MW.

consideration, is \$5.1M. In the absence of published cost data for the Belews Creek site location, the spur transmission line cost is estimated using those published for the Western Electric Coordinating Council (WECC) in [71], with the understanding that there may be construction cost differences between regions in the U.S. The cost calculation using Equation 1 is shown in Table 3.

Table 3. Spur transmission line cost calculation for proposed new nuclear generator at Belews Creek Site[7]

Factors:

- *Base transmission cost, 345 kV double circuit: 3,420,133 \$/mile*
- *Conductor multiplier, assuming ACSR conductor: 1*
- *Structure multiplier, assuming lattice structure: 1*
- *Line length multiplier, < 3 miles: 1.5*
- *Terrain multiplier, assuming scrub/flat terrain: 1*
- *Distance: 1 mile*

$$Total\ spur\ line\ construction = 3{,}420{,}133\,\frac{\$}{mi} * 1 * 1 * 1.5 * 1 * 1\ mi = \$5{,}130{,}200$$

When considering a new site, a transmission spur line would be installed from new transformers to a new or existing substation where the grid interconnection is made. It is assumed the length and design characteristics for the spur line at a new site would be similar to the spur line at the existing coal power site. When analyzing other sites, this same assumption is made, and no value is assigned to the existing spur line at coal power sites when considering a nuclear conversion. A possible exception to this assumption is a case where a power plant operator installs a nuclear

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[7] Base transmission costs published in [71] were inflated to \$2024 using a 4.7% construction inflation index [93]. Multipliers to calculate cost based on design conditions are further described in in [71].

reactor at a new site near an existing coal site and installs a much longer spur transmission line from the new reactor to the existing substation at the coal plant to establish the grid interconnection. This scenario would likely be considered an example of "replacement generation" by the transmission operator, which allows the generator to avoid entering the interconnection queue. While not specifically evaluated in this study, the nuclear power project would weigh the costs of purchasing land or utility easements and installing a lengthy transmission spur line against the cost of entering the interconnection queue as a new generator, along with other factors like water availability as previously discussed.

Figure 8. Aerial view of Belews Creek site showing existing coal plant location, location under consideration for new nuclear plant, existing transmission substation, existing spur lines, and potential new spur lines.

4.3.1.2 Interconnection

Several recent papers have examined interconnection costs and wait times for the largest grid operators in the U.S. [76, 103-108]. Historic interconnection information for Pennsylvania-New Jersey-Maryland Interconnection (PJM), the largest regional grid operator in the U.S., serving 65 million people in parts of Mid-Atlantic, Midwest, and Southern United States [109] is discussed in [103]. Over 4,000 requests for interconnection service were made to PJM during the 2008 to 2020 timeframe. The process whereby a generator attempts to connect to the grid involves securing the land, developing and submitting a request, and initiating the process of preparing a series of progressively detailed studies [103]. Specifically, after an initial engineering test study, an initial interconnection estimate is established. After the second study, which completes remaining engineering tests and updates costs, the interconnection estimate is updated. Developers have the option to withdraw from the queue throughout the process, or to remain and fund the study in the next step. Generators with a high interconnection cost estimates were found to be more likely to withdraw their application [103]. After the third study detailing engineering specifications, a final update is made to the costs, exclusive of permitting costs and right of way. Developers then have the option to agree to the project and costs, or to exit the queue [103].

Recent research [104-108] examined interconnection costs in independent system operators (ISOs) in the U.S.: PJM, New York Independent System Operator (NYISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), and New England's Independent System Operator (ISO-NE). For the present research, coal power plant sites meeting criteria for conversion consideration were organized into one of ten U.S. transmission areas. Of the 148 coal power sites evaluated, 97 plants are located in one of the five ISOs studied. Figure 9 shows the coal power plant distribution across transmission service areas.

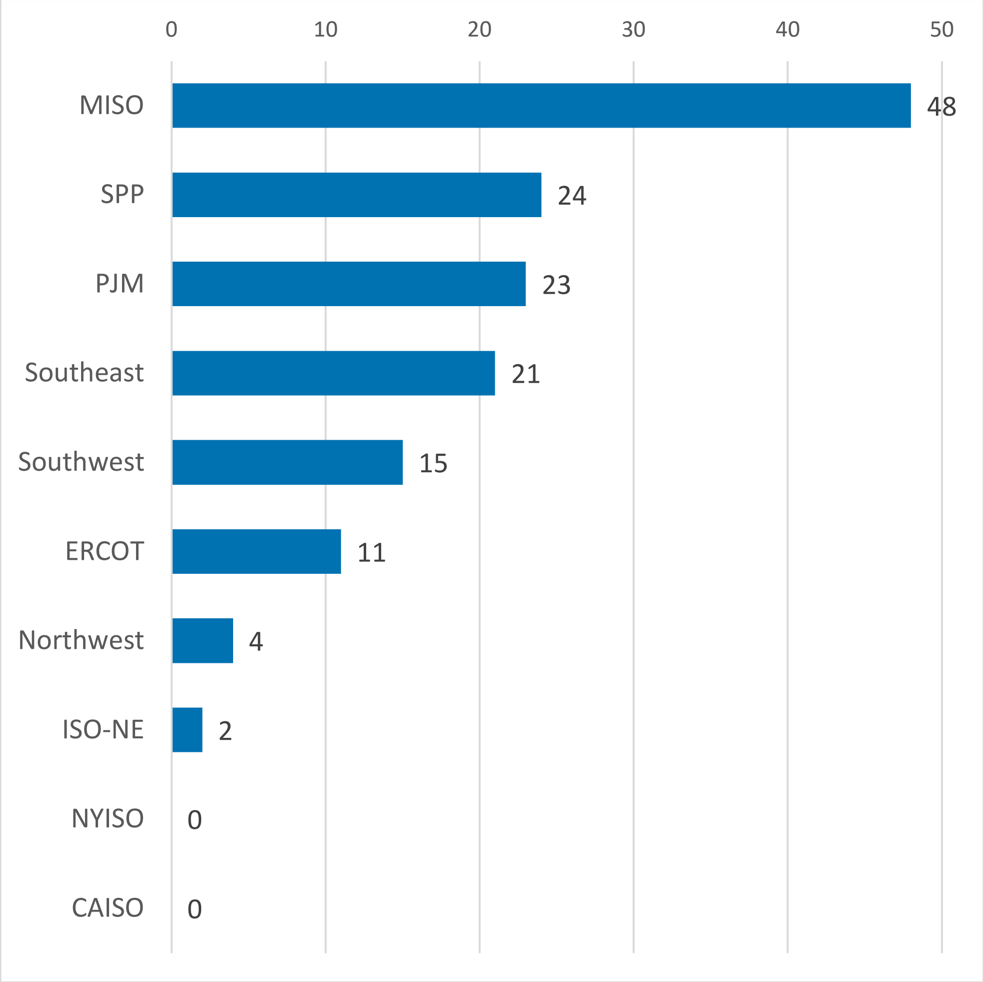

Figure 9. Number of coal power sites evaluated in each transmission service area; total of 148.

Interconnection costs in PJM were investigated in [107], which found projects that had completed the interconnection studies between 2020 to 2022 had interconnection costs of \$84,000/MW, and projects that were moving through the interconnection queue had costs of \$240,000/MW. In the MISO service area covering 15 states, interconnection costs have escalated as the number of requests have increased [105]. For complete projects, mean interconnection costs for the period 2019 to 2021 were \$102,000/MW, nearly double that for the period 2000 to 2018

[105]. Estimates for projects still active in the MISO queue tripled from 2018 to the period 2019 to 2021, and projects that have withdrawn from the queue have interconnection cost estimates about four times higher than complete projects [105]. In the SPP territory covering all or part of fourteen states, mean interconnection cost for projects completed between 2020 to 2022 was $57,000/MW, with little change from $54,000/MW in the period 2002 to 2009 [106]. Projects still moving through the SPP queue have average costs of $106,000/MW [106]. In the NYISO territory covering the entire state of New York, mean interconnection cost for projects completed between 2017 to 2021 was $167,000/MW [104], and in ISO-NI mean interconnection cost for projects completed between 2018 to 2021 was $114,000/MW. In all ISOs except NYISO, many more projects withdrew from the queue than the number of complete or active projects. Figure 10 compares the interconnection costs for five ISOs in the study periods shown.

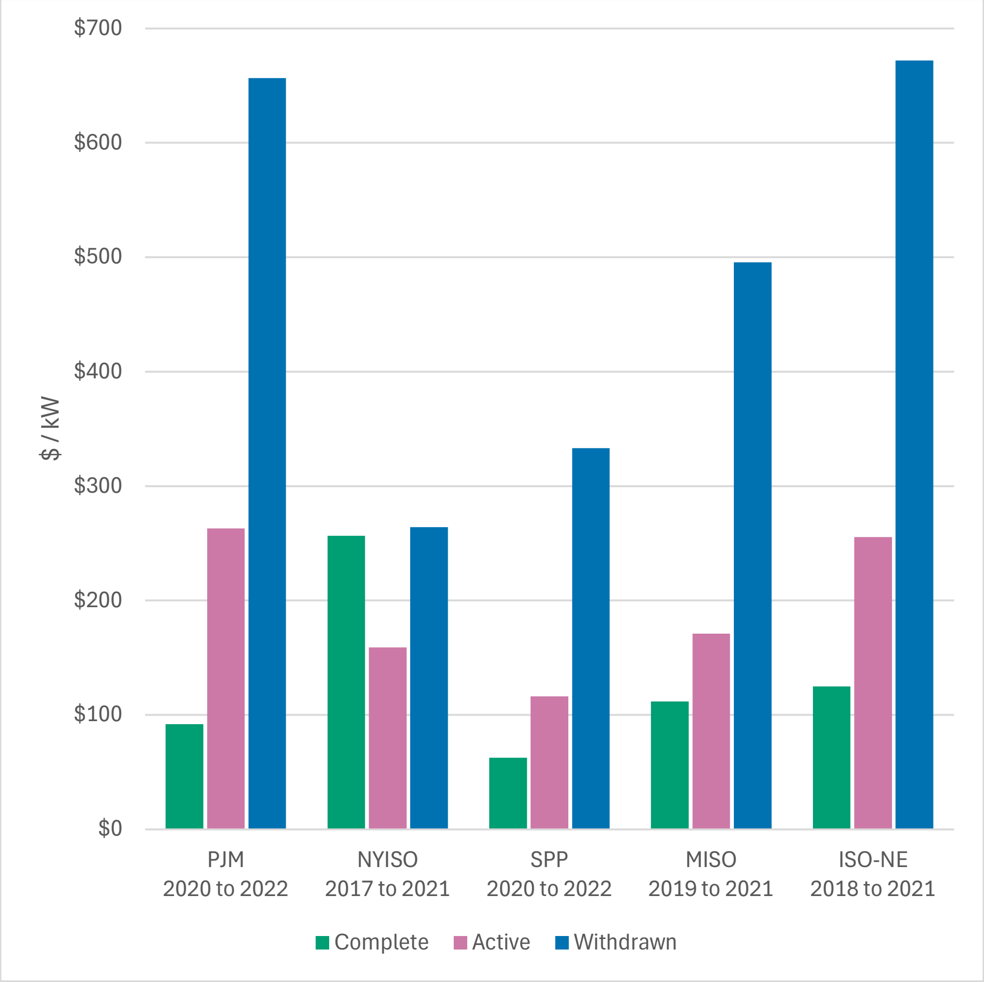

Figure 10. Cost of interconnection for projects completing all interconnection studies along with estimated cost of interconnection for projects still active in the queue and projects that have withdrawn from the queue [104-108]. Costs in $2024.

To determine the value of grid interconnection at U.S. coal power sites, existing interconnection cost data and current plant capacity were used to calculate the expected cost of connecting new generators to the grid at a new site. POI costs for projects that have completed the interconnection queue and for active projects in the queue were averaged to estimate the POI costs for a new project at a new site. Likewise, completed and active network costs were averaged to estimate network costs for new projects. Cost data were not available for the Electric Reliability Council of Texas (ERCOT). To estimate interconnection costs paid by the nuclear power project in ERCOT, SPP and MISO costs are averaged, and the $22.5M allowance provided by ERCOT to new generators is subtracted, splitting the allowance evenly between POI and network costs at $11.25M each.

Cost data were not available for the regulated markets in the southeast, southwest, and northwest. In these vertically integrated markets, it is not uncommon for the same entity to own the generation, transmission, and distribution resources. To estimate the value of interconnection in these areas, the published costs in neighboring ISOs were averaged. For the southeast, PJM and MISO costs were also averaged. For the southwest, SPP costs were used, and for the northwest, SPP and MISO costs were averaged. Figure 11 shows the expected POI and network costs for a 300 MW generator at a new site in each transmission service area.

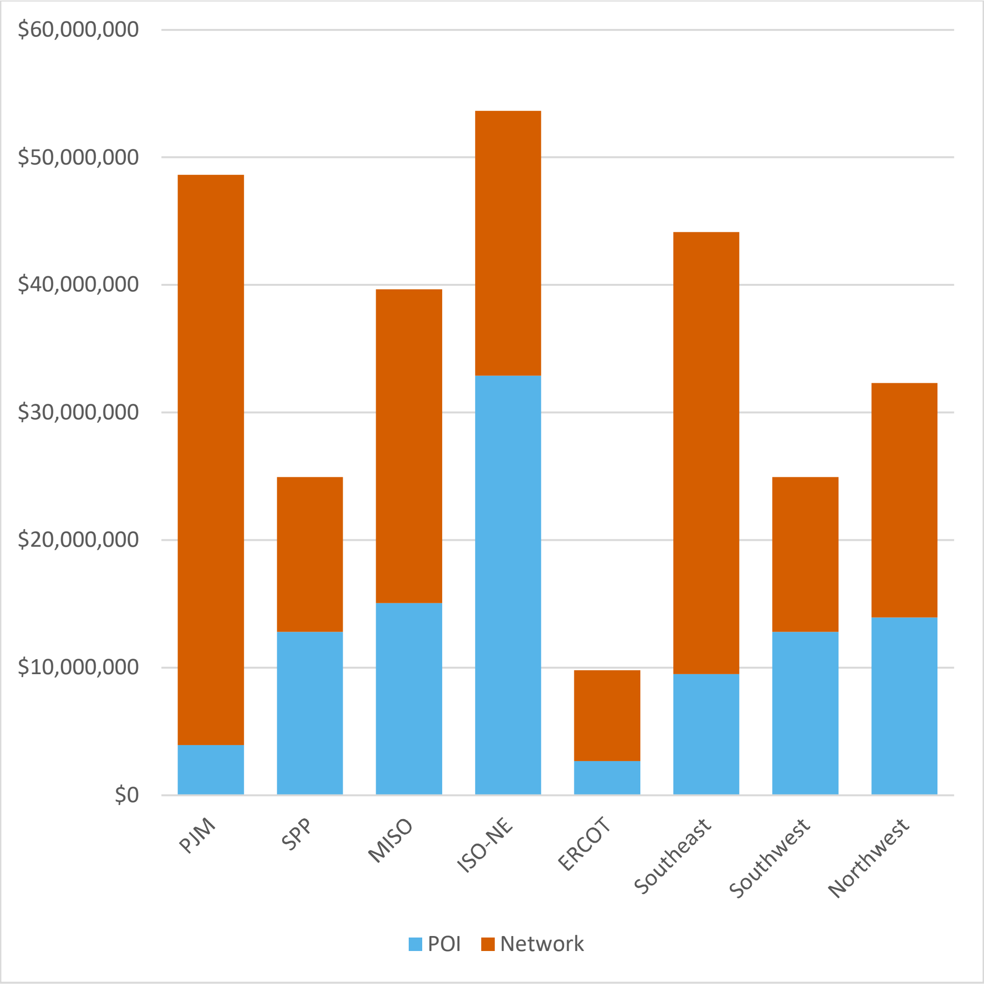

Figure 11. Expected POI and network interconnection costs for a 300 MW generator on a new site, by transmission service area. Expected costs are an average of costs for projects that are complete and projects that are active in the interconnection queue.

In this evaluation it is assumed that the value of the transmission system interconnection at an existing coal power site is equal to the cost of interconnecting the same size project at a new site near the existing coal plant. Hence, the present analysis used this approach to estimate interconnection costs for a new project in the vicinity of the Belews Creek site, which is located in North Carolina at the northern limit of the Southeast transmission area approximately 17 miles from the Virginia border and PJM transmission area. To estimate unpublished interconnection costs in the Southeast the analysis considered published costs in the neighboring PJM and MISO areas [105, 107]. In the PJM area, POI costs for projects completed from 2020 to 2022 averaged \$12/kW and POI costs for projects still active in the interconnection queue during the same period averaged \$13/kW. In MISO, POI costs for projects completed from 2019 to 2021 averaged \$46/kW and POI costs for projects still active in the interconnection queue averaged \$50/kW. When POI costs for completed and active projects in PJM and MISO are averaged, then inflated to \$2024, POI costs for the Southeast transmission area are expected to be \$31.65/kW. Network costs were estimated using this same approach and expected to be \$115.50/kW. A single 300 MW nuclear reactor could expect POI costs of \$9.4M and network costs of \$34.6M for total interconnection costs of \$44.1M.

Belews Creek Station has a plant capacity of 2,160 MW, the largest in the Carolinas [61]. The maximum number of nuclear generators that could be installed and remain within the existing coal plant electrical capacity is seven 300 MW units, for a total capacity of 2,100 MW.

Interconnection costs are reported to benefit from economy of scale for large projects. To account for this, interconnection costs were reduced by 50% when evaluating a site for more than one generator. If seven 300 MW generators were installed at a site nearby the existing Belews Creek Station, they may experience POI costs of \$33.2M and network costs of \$121.3M, for total connection costs of \$154.5M, as illustrated in Figure 12.

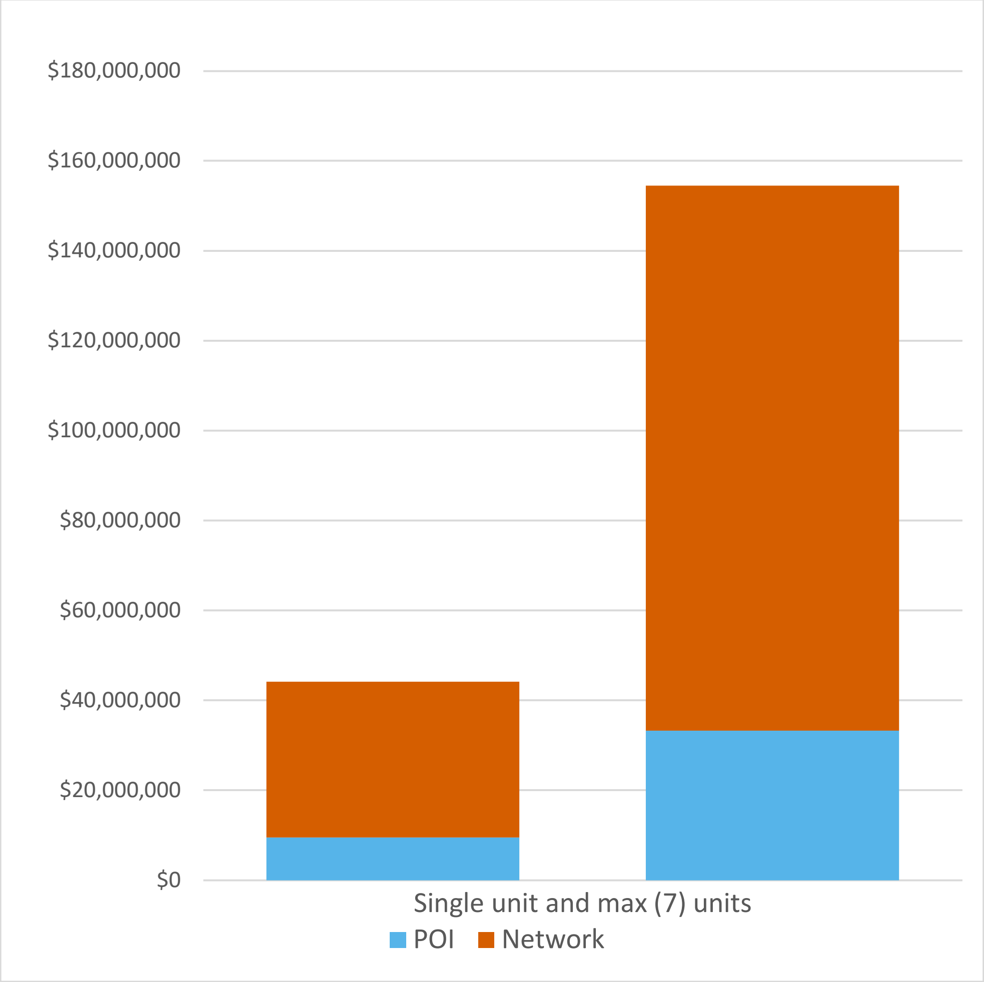

Figure 12. Expected value of existing transmission interconnections at Belews Creek site. Value is based on the expected cost of interconnection at a nearby site away from the existing coal plant. Values shown are for a single 300 MW generator and for seven 300 MW generators totaling the maximum capacity that is less than the existing coal plant capacity.

These methods have now documented the means by which the electrical infrastructure costing analysis is performed on a site-by-site basis, with the example of Belews Creek Station providing the baseline scenario definition.

4.3.1.2.1 Expanding the Analysis to Fleet Scale

To expand the above analysis to a fleet scale, interconnection costs were estimated for new projects in the vicinity of each of the 148 coal power sites using the same method as described for the Belews Creek site, resulting in 148 units interconnected in the single-unit scenario and 526 units connected in the maximum capacity scenario. POI costs for 148 units are estimated to be \$1.7B and network costs are estimated to be \$3.6B for total interconnection costs of \$5.3B. When connection of 526 generators was estimated, the maximum number given current coal plant operating capacity, POI costs are estimated to be \$3.0B and network costs \$7.1B for total interconnection costs of \$10.1B as illustrated in Figure 13.

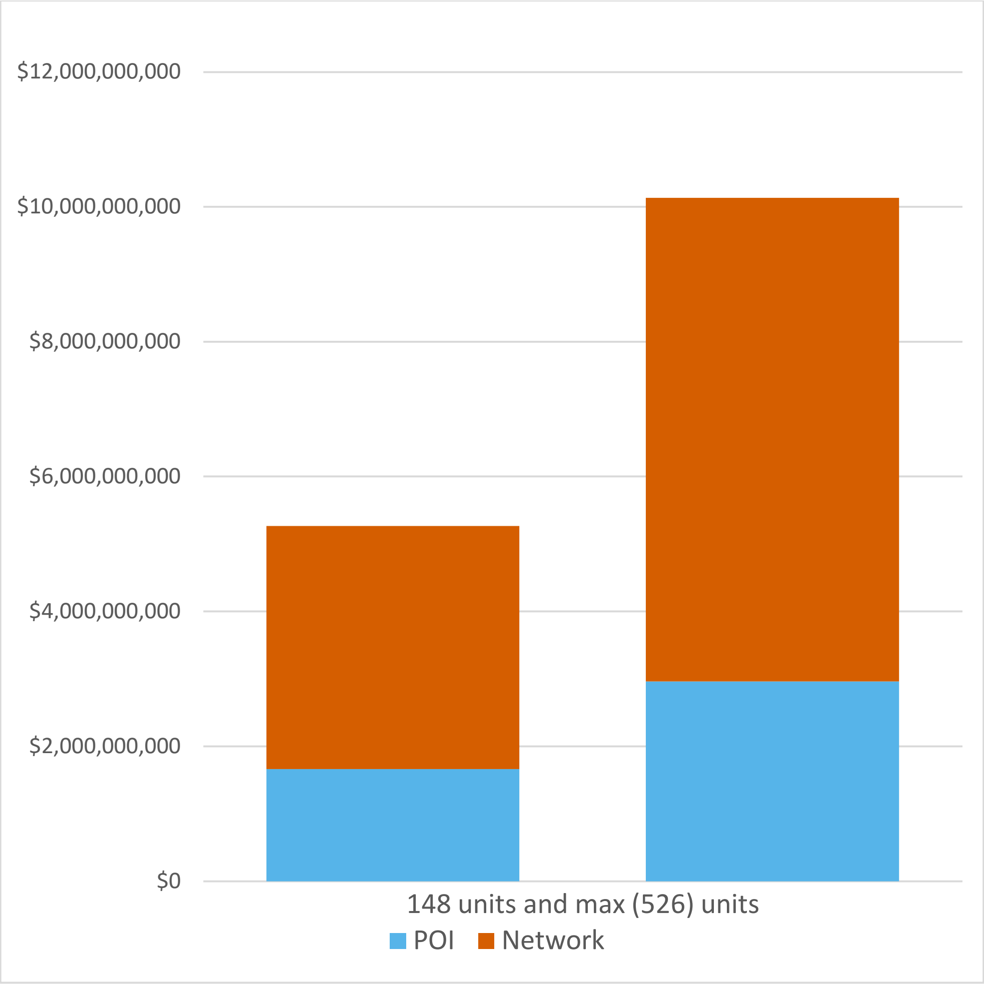

Figure 13. Expected value of existing transmission interconnections across 148 sites in the U.S. coal fleet meeting minimum criteria for further consideration of converting to nuclear power. The first column shows fleet interconnection values when a single nuclear generator is sited at each coal power site. The second column shows fleet interconnection values when the maximum number of generators are installed based on existing coal plant capacity.

4.3.2 Cooling System Results

Cooling system alternatives were investigated for construction of a single, and multiple, 300 MW nuclear power plants at the 148 candidate coal power sites. The process for determining potential savings by constructing at a coal power site compared to a new site are demonstrated for the Belews Creek site. The same process was used at the remaining 147 coal power sites to determine potential value of water availability at sites across the U.S. coal fleet.

4.3.2.1 Belews Creek Site

In this section we first determine annual capital, O&M, and water costs at the Belews Creek site for three cooling methods: once-through cooling, wet recirculating cooling, and dry cooling. Costs are then compared, and savings potential is calculated from continuing to use the current cooling method and existing water source compared to possible alternate methods and water sources at a new site nearby.

Cooling for the two existing 1080 MW coal-powered generators uses once-through cooling technology with water withdrawn from the Belews reservoir. The Belews reservoir was created for this purpose in 1973 by damming Belews Creek. Two intake pumps in Belews reservoir withdraw water at a rate of up to 506,730 gallons per minute each [81]. Water is withdrawn and discharged under permit from the U.S. Environmental Protection Agency's National Pollutant Discharge Elimination System [110]. The main determinants of lake elevation are rainwater and groundwater input [110]. The existing cooling system includes a pump station to pump water from the Dan River into the reservoir in periods of intense drought. Because these pumps have not been operated in ten years [110], they are not included in the analysis below. The following sections describe evaluations for three alternative cooling methods at the Belews Creek site.

4.3.2.1.1 Once-Through Cooling

To evaluate a once-through cooling system this analysis assumes a condenser heat load of 6,550 Btu/kWh [82] for nuclear plants, resulting in a heat duty of 1,965 MMBtu/hr for the 300 MW plant. The condenser range, the temperature difference between the cold water entering the condenser and the hot *water leaving, is assumed to be 20° F. A cooling water flow rate of 600 gpm/MW [82] results in a flow of 180,000 gpm. The design cold water temperature is set at the maximum average monthly intake temperature for the existing Belews Creek cooling system, 84° F experienced during the month of July [92]. A condensing temperature at 108° F results in a terminal temperature difference of 4.4° F, and log mean temperature difference of 11.7° F. The condenser area is calculated using Equation 3, with results shown in*

Table 4.

$$A = \frac{Q}{U * LMTD}, \tag{3}$$

where: A = Condenser area

Q = Heat duty[8]

U = Overall heat transfer coefficient[9]

LMTD = Log mean temperature difference[10]

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[8] Condenser heat load for nuclear power is assumed to be 6.550 Btu/kWh resulting in heat duty for a 300 MW nuclear reactor of 1,965 MMBtu/hr.

[9] An overall heat transfer coefficient of 560 Btu/ft^2-hr-°F is assumed for all cases [82].

[10] Log Mean Temperature Difference assumes cold water entering the condenser at 84°F and exiting at 104°F, and a condensing temperature of 108.4°F.

Table 4. Condenser area calculation for 300 MW nuclear reactor using site conditions at Belews Creek.

Factors:

- *Heat Duty: 1,965 MMBtu/hr*
- *Overall heat transfer coefficient: 560 Btu/hr*
- *Log mean temperature difference: 11.7*

$$Condenser\ Area = 1.965\frac{MMBtu}{hr} * 560\frac{Btu}{hr} * 11.7 = 300{,}536\ ft^2$$

The main circulating water pump power was calculated at 1,463 hp using Equation 2 as shown in Table 5.[11]

Table 5. Pump power calculation for 300 MW nuclear reactor coolant circulating pump for once-through cooling using site conditions at Belews Creek

Factors:

- *Cooling water flow rate: 180,000 gal/min*
- *Differential head: 28'*
- *Specific gravity (water): 1*
- *Pump efficiency: 87%*

$$Pump\ power = \frac{180{,}000\frac{gal}{min} * 28\ ft * 1}{3960 * .87} = 1{,}463\ hp$$

Condenser pricing is a function of condenser area and was estimated using the polynomial in Equation 4 below, originally published in [94] in \$2008.

$$Condenser\ Cost = (3.49519e^{-10}A^2 - 2.09766e^{-4}A + 50.7179) * A \qquad (4)$$

where A = Condenser area

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[11] Differential head includes 2.4' of head equivalent pressure drop across the condenser.

The resultant price was inflated to $2024 leading to an installed cost of $12.0M. Pump cost was estimated at $521/BHP [94] resulting in $773k for the 1,463 hp pump. Piping costs for an intake 1000' from the condenser at the flow above are estimated at $5.82M. Intake and discharge facilities were valued at $4,170/MW resulting in $1.25M [94]. Electrical hookups and controls were estimated at $1.5M. Auxiliary cooling capital costs are included at 5% of main system for an additional $1.07M. The total circulating system capital cost is estimated at $22.47M.

Annual power cost is based on 8,000 hours per year of operation and an energy cost of $95/MWh resulting in an annual operating power cost of $829,409. Annual maintenance costs of $337,087 were included, calculated at 1.5% of capital costs [82].

Capital costs were annualized over an assumed 30-year cooling system life using a 7% cost of capital. Annualized capital, operating, maintenance, and water costs for the once-through system at the Belews Creek site are shown in Table 6.

Table 6. Estimated annual costs for once-through cooling for a 300 MW nuclear reactor installed at the Belews Creek site.

Site: Belews Creek	
Capital Cost	$22,472,457
Annualized Capital Cost	$1,810,974
Annual Operating Power Cost	$829,409
Maintenance Cost	$337,087
Water Cost	$770,000
Total Annualized Cost	$3,747,470

4.3.2.1.2 Wet Recirculating Cooling

A wet recirculating system was evaluated for a 300 MW nuclear reactor with a 1,965 MMBtu/hr heat duty, the same reactor used in the once-through cooling system evaluation. Capital costs and power requirements for a wet recirculating cooling system with towers for a 600MW nuclear plant in five climate areas are presented in [94]. For the Belews Creek site, climate area 5 was selected, the area most closely matching the Belews Creek conditions. Capital costs in [94] were scaled for heat duty and inflated to $2024. Pump and fan power costs were calculated using electricity cost of $95/MWh and 8,000 hours of annual operation. Maintenance costs were included at 1.5% of capital costs. Annualized costs were evaluated for two cases using minimum and low-medium water costs and median water consumption as was selected for the once-through cooling scenario. Annualized costs for wet recirculating cooling at the Belews Creek site using minimum water costs are shown in Table 7.

Table 7. Estimated annual costs for wet recirculating cooling for a 300 MW nuclear reactor installed at the Belews Creek site.

Site: Belews Creek, existing coal power site	
Capital Cost	$35,805,945
Annualized Capital Cost	$2,885,472
Annual Operating Power Cost	$2,172,080
Maintenance Cost	$537,089
Water Cost	$1,100,000
Total Annualized Cost	$6,694,642

Annualized costs for wet recirculating cooling at a new site using low-medium water costs are shown in Table 8.

. Table 8. Estimated annual costs for wet recirculating cooling for a 300 MW nuclear reactor installed at a new site.

Site: New Site	
Capital Cost	$35,805,945
Annualized Capital Cost	$2,885,472
Annual Operating Power Cost	$2,172,080
Maintenance Cost	$537,089
Water cost	$4,944,972
Total annualized cost	$10,539,613

4.3.2.1.3 Dry Cooling

Cooling costs were evaluated again for the 300 MW nuclear reactor at the Belews Creek site under a scenario using indirect dry cooling technology. Capital costs, power requirements, and generation penalties for a dry cooling system in [94] were scaled for the 300 MW reactor. Operating costs were inflated to $2024 and operating power costs and power penalty costs were calculated using an energy cost of $95/MWh and 8,000 hours of annual operation. Maintenance costs were included at 1.5% of capital costs. Because dry cooling uses relatively little water and consumption at this level may require a higher per-unit price, only the low-medium water cost is considered for this cooling type. Annual costs for indirect dry cooling using low-medium water cost and median water consumption for the Belews Creek site or a new site nearby are shown in Table 9..

Table 9. Estimated annual costs for indirect dry cooling for a 300 MW nuclear reactor installed at a new or existing site.

Site: Belews Creek coal power site or new site nearby	
Capital Cost	$167,091,978
Annualized Capital Cost	$13,465,342
Annual Operating Power Cost	$6,126,959
Annual Penalty Cost	$4,988,237
Maintenance Cost	$2,506,380
Water Cost	$147,172
Total Annualized Cost	$27,234,089

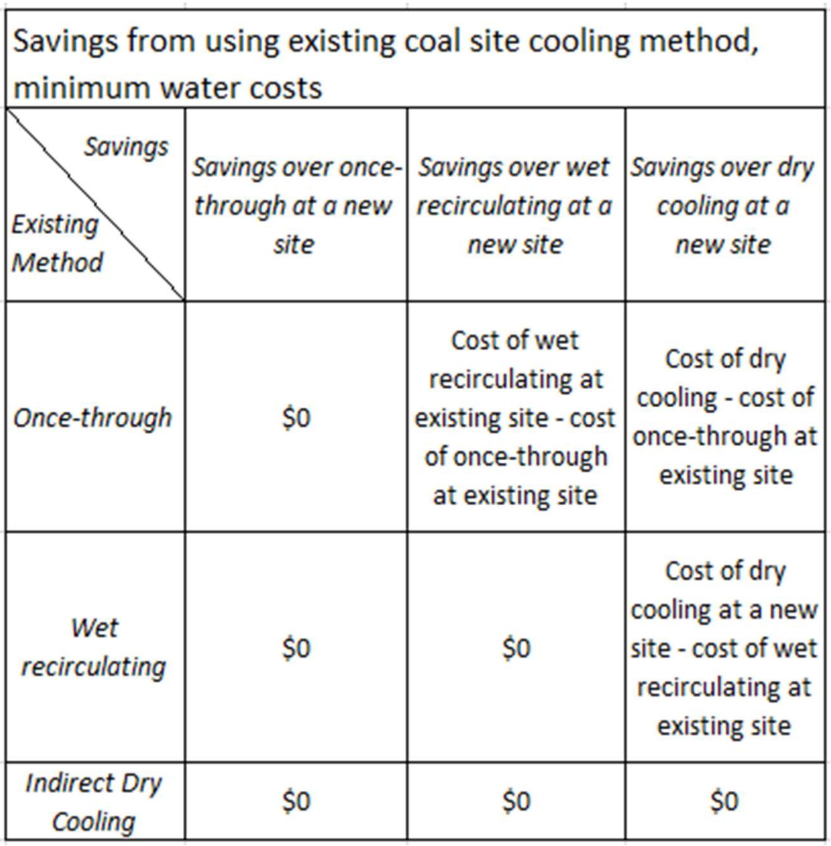
4.3.2.1.4 Cooling System Comparison

The cooling technologies evaluated present different costs and water consumption volumes. Once-through cooling has the lowest capital and operating costs, followed by wet recirculating, then indirect dry cooling. The lowest water costs are achieved using indirect dry cooling, followed by once-through, then wet recirculating cooling. This analysis assumes that existing coal power sites will retain their ability to use the existing water supply source and cooling method in a generator replacement scenario that exchanges the existing coal power plant with a new nuclear power plant. The cooling system types in use at operating coal plants have lower annual costs than cooling system types installed at steam electric generating plants in the most recent ten years evaluated from 2013 to 2022. The cooling water at existing coal plants has a lower cost than those anticipated at new plants based on the water supply sources used for new steam electric generating cooling systems and water costs reported for new permitted and municipal water sources.

4.3.2.1.4.1 Cooling-method savings

Potential savings resulting from water availability at coal power sites can be attributed to two categories: cooling-system savings and water cost savings. Cooling-system savings result from the use of a lower cost cooling solution at the existing site than a new site. To isolate savings resulting from the use of one cooling system type over another, cooling system types are compared using minimum water cost. In this minimum water cost scenario, the cooling method savings of installing once-through cooling at a new site compared to continuing to use once-through cooling at an existing site are $0, since capital, power, and water costs are the same at both sites. The cooling-method savings of continuing to use once-through cooling at an existing site compared to using wet recirculating cooling at a new site are the annual cost of wet recirculating cooling minus the annual cost of once-through cooling when both sites are evaluated with minimum water cost. The rubric for determining potential cooling-method savings resulting from the continued use of the existing cooling method is shown in Table 10.

Table 10. Potential cost savings from continued use of the existing cooling method at coal plants in a conversion to nuclear power when compared to alternate cooling methods. Water prices are set to minimum in all scenarios.



Savings from using existing coal site cooling method, minimum water costs

Savings / Existing Method	*Savings over once-through at a new site*	*Savings over wet recirculating at a new site*	*Savings over dry cooling at a new site*
Once-through	$0	Cost of wet recirculating at existing site - cost of once-through at existing site	Cost of dry cooling - cost of once-through at existing site
Wet recirculating	$0	$0	Cost of dry cooling at a new site - cost of wet recirculating at existing site
Indirect Dry Cooling	$0	$0	$0

Costs for the different cooling solutions at the Belews Creek site were evaluated. The analysis assumes the continued use of the existing once-through cooling method and cooling water source for a 300 MW nuclear reactor at the Belews Creek site, then evaluates the cost savings compared to wet recirculating cooling and indirect dry cooling installed at a new site while keeping both sites at minimum water cost. Cost savings are evaluated from continued use of the existing cooling method over a composite “expected cooling method” composed of 61% wet recirculating cooling and 39% dry cooling; the distribution of new cooling system types for steam electric plants installed from 2013 to 2022 when no new once-through cooling installations are assumed. The equation for expected annual savings is shown in Equation 5.

$$EAS = (.61 * WRS) + (.39 * DCS), \tag{5}$$

where EAS = Expected Annual Savings

WRS = Wet Recirculating Savings

DCS = Dry Cooling Savings

Error! Reference source not found. shows potential annual savings by cooling system type at the Belews Creek site when water costs are minimum, assuming continued use of existing cooling method once-through cooling when installing a single 300 MW nuclear reactor.

Table 11. Potential annual savings by cooling system type at the Belews Creek site when water costs are minimum, assuming continued use of existing cooling method (once-through cooling) when installing a single 300 MW nuclear reactor

Site: Belews Creek, single unit, minimum water cost			
Annual savings over once-through cooling	Annual savings over wet recirculating	Annual savings over dry cooling	Expected annual savings
$0	$2,947,172	$23,486,619	$10,957,556

Next, the case is considered where the maximum cooling capacity of the existing coal plant is replaced with multiple 300 MW nuclear reactors. The cooling capacity of the existing site is calculated using the nameplate rating of the generator units and a 5,000 Btu/kWh condenser heat load for the coal-fired units. The number of 300 MW nuclear units that could be installed is then determined assuming a 6,500 Btu/kWh condenser heat load [82], rounding down to the maximum number of generation units. The two Belews Creek coal-fired units have a combined generator nameplate capacity of 2,160MW, resulting in a condenser heat load of 10,800 MMBtu/hr. Each 300 MW nuclear generator has a condenser heat load of 1,950 MMBtu/hr. The maximum number of 300 MW nuclear generators that could be installed, with a total condenser heat load less than 10,800 MMBtu/hr, is 5 generators[12].**Error! Reference source not found.** shows the potential annual cooling-method savings of continued use of once-through cooling at the Belews Creek site when replacing existing generation with five 300 MW nuclear reactors.

Table 12. Potential annual savings of continued use of once-through cooling at the Belews Creek site when replacing existing generation with five 300 MW nuclear reactors

Site: Belews Creek, multiple units, minimum water cost			
Annual savings over once-through cooling	Annual savings over wet recirculating	Annual savings over dry cooling	Expected annual savings
$0	$14,735,858	$117,433,094	$54,787,780

4.3.2.1.4.2 Water Cost Savings

To understand the potential savings from water cost at existing coal power sites compared to anticipated water costs at new sites, a scenario is evaluated where water costs at new sites are the low-medium rate described above and water at existing sites remains at the minimum cost. Annual cooling system costs are compared for a nuclear generator installed at an existing coal power site using the existing cooling method and the existing water source, with a nuclear generator installed at a new site using alternate cooling methods and the composite expected cooling method described previously using the anticipated water cost for the new site. This analysis examines this scenario for a single unit, and for the maximum number of units at the site using the rubric in Table

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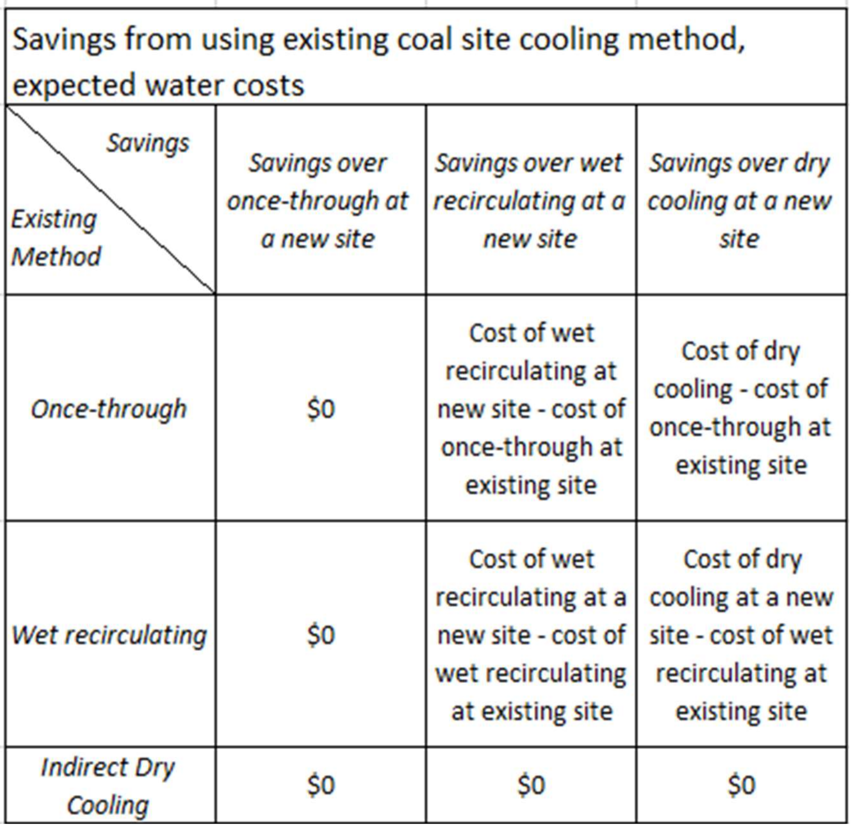
[12] While the electrical capacity of coal stations can potentially be replaced with identical capacity nuclear generators, the higher condenser heat load of nuclear reactors compared to coal stations may limit the number of generators that can be installed within existing cooling capacity to a smaller number than could be installed when considering the electrical capacity of the grid interconnection alone.

13. The results include both the cooling-method savings and savings from lower-cost water at the existing site.

Table 13. Potential cost savings from continued use of the existing cooling method at coal plants in a conversion to nuclear power when compared to alternate cooling methods at new sites with anticipated water costs



Savings from using existing coal site cooling method, expected water costs			
Savings *Existing Method*	*Savings over once-through at a new site*	*Savings over wet recirculating at a new site*	*Savings over dry cooling at a new site*
Once-through	$0	Cost of wet recirculating at new site - cost of once-through at existing site	Cost of dry cooling - cost of once-through at existing site
Wet recirculating	$0	Cost of wet recirculating at a new site - cost of wet recirculating at existing site	Cost of dry cooling at a new site - cost of wet recirculating at existing site
Indirect Dry Cooling	$0	$0	$0

The potential for cooling and water savings at the Belews Creek site were evaluated when a single and multiple 300 MW nuclear reactors replace the existing coal power plant using the existing cooling system type and water source at minimum cost, compared to the same nuclear reactors installed at a new site using alternate cooling system types and the higher low-medium water cost anticipated. Results for the single and multiple unit scenarios are shown in Table 14.

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Table 14. Potential annual savings by cooling system type at the Belews Creek site assuming continued use of existing cooling method once-through cooling and cooling water source when installing a single and multiple (5) 300 MW nuclear reactors compared to alternate cooling methods installed at a new site with anticipated water costs

Site: Belews Creek, single unit, anticipated water cost				
	Annual savings over once-through cooling	Annual savings over wet recirculating	Annual savings over dry cooling	Expected annual savings
Single Unit	$0	$6,792,143	$23,486,619	$13,302,989
Multiple Units	$0	$33,960,716	$117,433,094	$66,514,943

In Figure 14 the potential annual savings are illustrated for a single 300 MW nuclear generator installed at the Belews Creek site compared to a new site. Cooling method savings and the total savings considering the higher water costs anticipated at a new site are shown. In the case of dry cooling, new and existing sites are assumed to have the same water price resulting in identical potential savings.

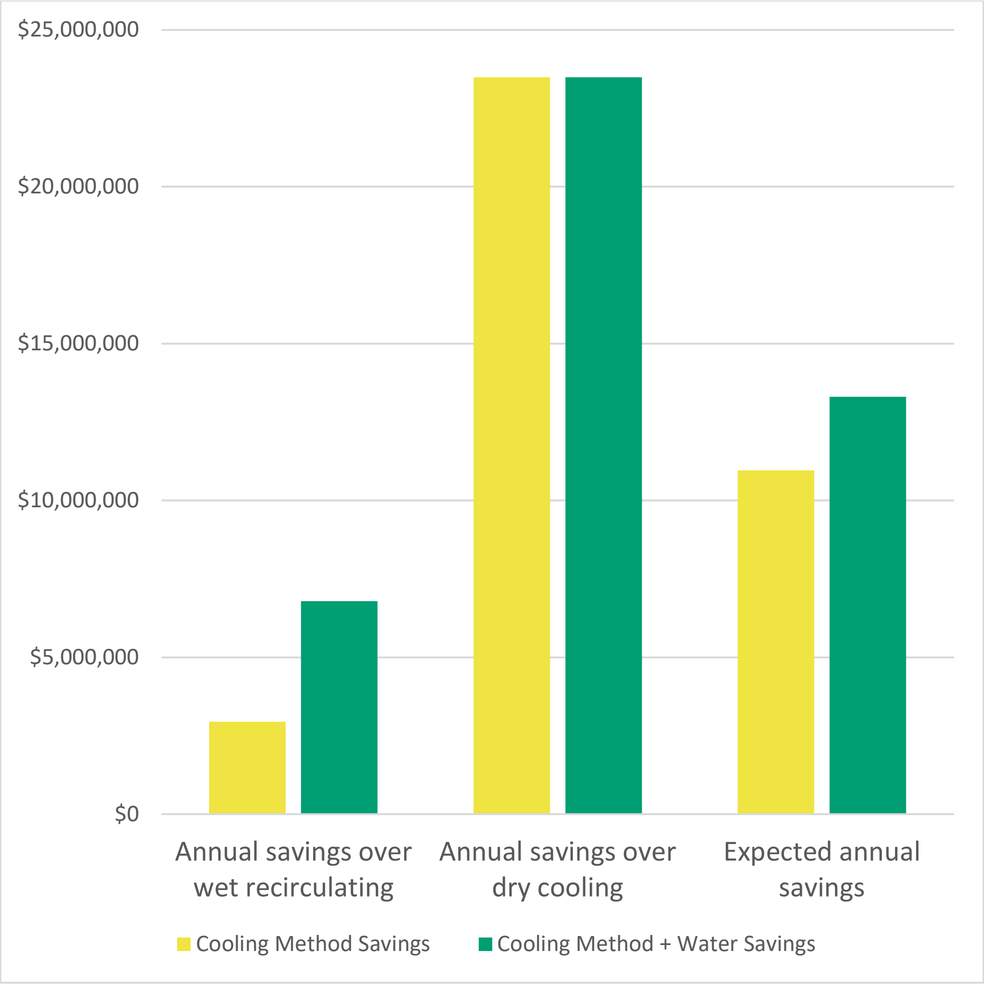

Figure 14. Potential annual savings for a single 300 MW nuclear generator installed at the Belews Creek site compared to a new site. Shown are the cooling method savings, savings from using the existing cooling method compared to more expensive cooling methods, and the total savings when considering the cooling method and the higher water costs anticipated at a new site.

These methods have described the evaluation for the costs and benefits associated with cooling method and cooling water costs that is performed on a site-by-site basis, with the example of Belews Creek Station providing the baseline scenario definition.

4.3.2.2 U.S. Coal Fleet

Using the same approach described for the coal power site at Belews Creek, the 148 coal-to-nuclear candidate plants in the U.S. coal fleet were then evaluated for similar cost savings. As with the Belews Creek example, the analysis assumes the nuclear reactors replacing coal plants on the same site will use the same cooling method and cooling water source. Potential savings were evaluated by comparing the existing cooling method and water source with alternate cooling methods and water sources at a new site nearby.

4.3.2.2.1 Cooling-method savings

To determine cooling method savings potential across the fleet of U.S. coal power sites annual cooling costs were established for each cooling method in each of the five climate areas. **Error! Reference source not found.** shows annual cooling costs for a single 300 MW nuclear reactor developed using methods described above.

Table 15. Expected annual cooling system costs for each cooling method in each climate area for a 300 MW nuclear reactor using anticipated water costs (minimum water cost at existing sites and low-medium water cost at new sites) adapted from [79, 82].

	Hot, arid	Hot, humid	Arid, extreme	Moderate, cool	Moderate, humid
Once-through, existing site	$3,747,470	$3,747,470	$3,747,470	$3,747,470	$3,747,470
Wet recirculating, existing site	$6,748,016	$6,748,058	$6,418,397	$6,450,793	$6,694,642
Wet recirculating, new site	$10,592,988	$10,593,030	$10,263,368	$10,295,765	$10,539,613
Dry cooling, all sites	$38,118,029	$28,180,165	$23,111,571	$22,932,206	$27,234,089

The U.S. coal fleet was evaluated for potential annual cooling-method savings resulting from the use of existing cooling methods compared to alternate cooling methods for a case where a single 300 MW nuclear generator is installed at each coal power site, as well as a case where the maximum number of generators based on existing coal plant cooling capacity are installed, using the rubric described in Table 10. Potential cooling-method savings for both cases are shown in Table 16..

Table 16. Potential annual cooling-method savings across the fleet of U.S. coal power sites from installing 300 MW nuclear reactors using the existing cooling method compared to alternate cooling methods. Costs calculated with minimum water costs at all sites to isolate potential cooling-method savings. Cases shown for a single unit at each site, and the maximum number of units per site based on existing coal plant cooling capacity.

	Annual savings over wet recirculating	Annual savings over dry cooling	Expected annual savings
Single unit	\$137,601,202	\$3,258,203,101	\$1,354,635,943
Maximum units	\$384,983,562	\$8,671,009,838	\$3,616,533,809

4.3.2.2.2 Water Cost Savings

It might be expected that the water costs at new generation sites would be higher than the water costs at existing generation sites, because many of the existing water sources and water rights contracts are less expensive than the cost of new water sources and contracts. To estimate potential savings at existing sites resulting from higher water costs at new sites along with the cooling-method savings described above, this analysis evaluates existing sites assuming the minimum water cost and new sites with low-medium water cost, using annual cooling system costs shown in Table 15.

A case where a single 300 MW nuclear generator is installed at each coal power site is again considered along with a case where the maximum number of generators based on existing coal plant cooling capacity are installed. Total potential savings resulting from the combined cooling-method and water costs for both cases are shown in Table 17.

Table 17. Potential savings from installing 300 MW nuclear reactors using the existing cooling method at coal power sites compared to wet recirculating and indirect dry cooling methods at new sites and using anticipated water costs (minimum water cost at existing sites and low-medium water cost at new sites) from Table 15 at all sites. Potential savings include cooling-method savings and water cost savings. Cases are shown for construction of a single unit at each site, as well as the maximum number of units per site, based on existing coal plant cooling capacity.

	Annual savings over wet recirculating	Annual savings over dry cooling	Expected annual savings
Single unit	$687,432,136	$3,258,203,101	$1,690,032,812
Maximum units	$1,846,072,757	$8,671,009,838	$4,507,798,219

Potential savings available from installing a single 300 MW nuclear reactor and the maximum number of reactors at 148 sites in the U.S. coal fleet compared to new sites, considering both cooling-method and water cost savings, are shown in Figure 15.

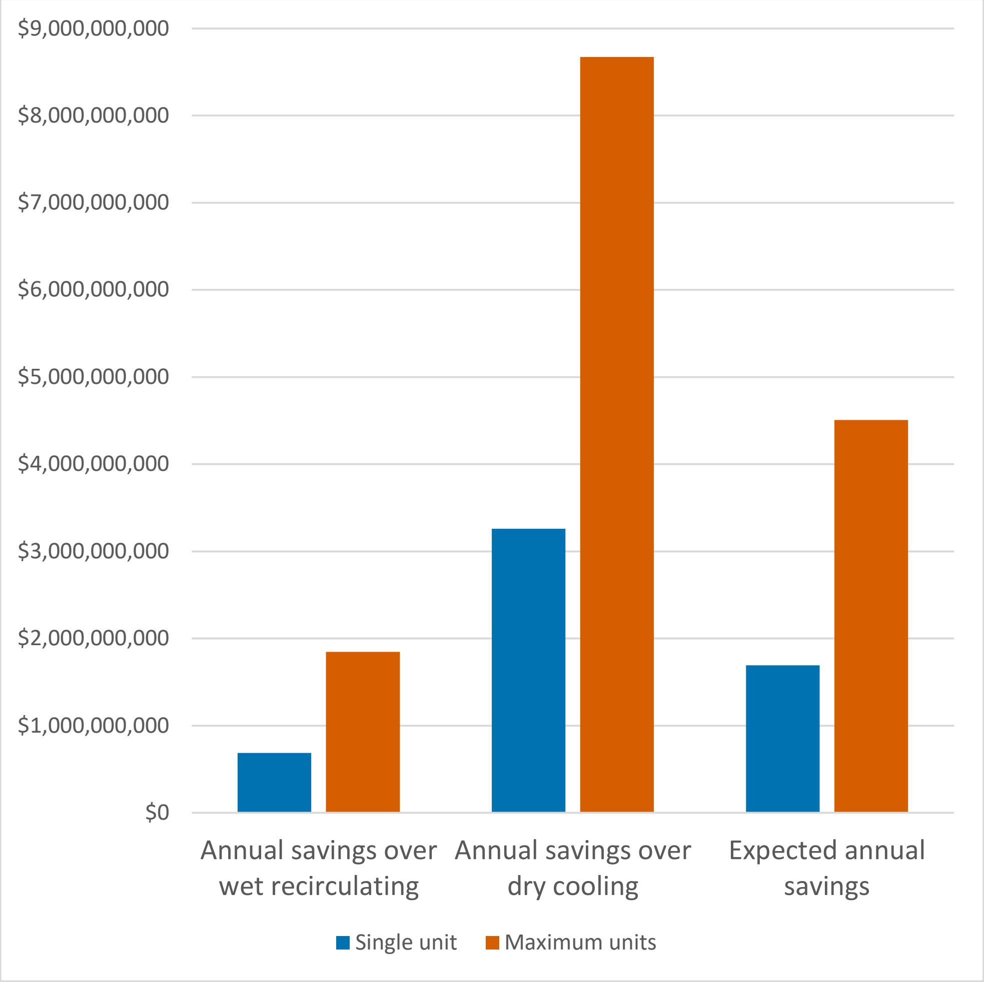

Figure 15. Potential savings available from installing a single 300 MW nuclear reactor per site, as well as the maximum number of 300 MW reactors, considering savings resulting from continued use of the current cooling method compared to alternate cooling methods, wet recirculating and dry cooling, as well as an expected composite cooling method consisting of 61% wet recirculating and 39% dry cooling, where proportions are consistent with recent installations. Potential savings also include water cost savings anticipated from using the existing cooling water supply at coal power sites compared to water acquired from water right purchase or lease, or municipal water source at a new site for the fleet of U.S. coal plants.

4.3.2.3 Summation of Relative Costs Savings Available from Electrical and Cooling Infrastructure Reuse

This paper attempts to determine relative potential cost savings from constructing a 300 MW nuclear power plant at an existing coal power site compared to a new site. To date, no low enriched uranium reactors with reasonable NRC interaction including the Holtec SMR300, the Westinghouse AP300, or NuScale Power VOYGR, or even the GE-Hitachi BWRX300 considered herein, have been constructed. Recent papers [95, 111] and U.S. Government web-based resource [112] have offered expectations for the capital and operating costs of a small nuclear reactor. In these artifacts, costs are based on a scenario where the design has been constructed multiple times and first-of-a-kind costs are realized by others, but full-scale fleet implementation has not yet been reached. In the present study capital and operation and maintenance (O&M) cost estimates in [95, 111, 112] are normalized for a 300 MW reactor at 90% capacity factor inflating to \$2024 using a 4.7% construction inflation rate, and annualized capital costs with a 7% cost of capital over 30 years. Summing variable and fixed O&M costs and annualized capital expenses result in total annual costs of \$244.1M in [112], \$272.4M in [111], and \$332.6M in [95]. Annualized O&M and capital costs are shown in Figure 16.

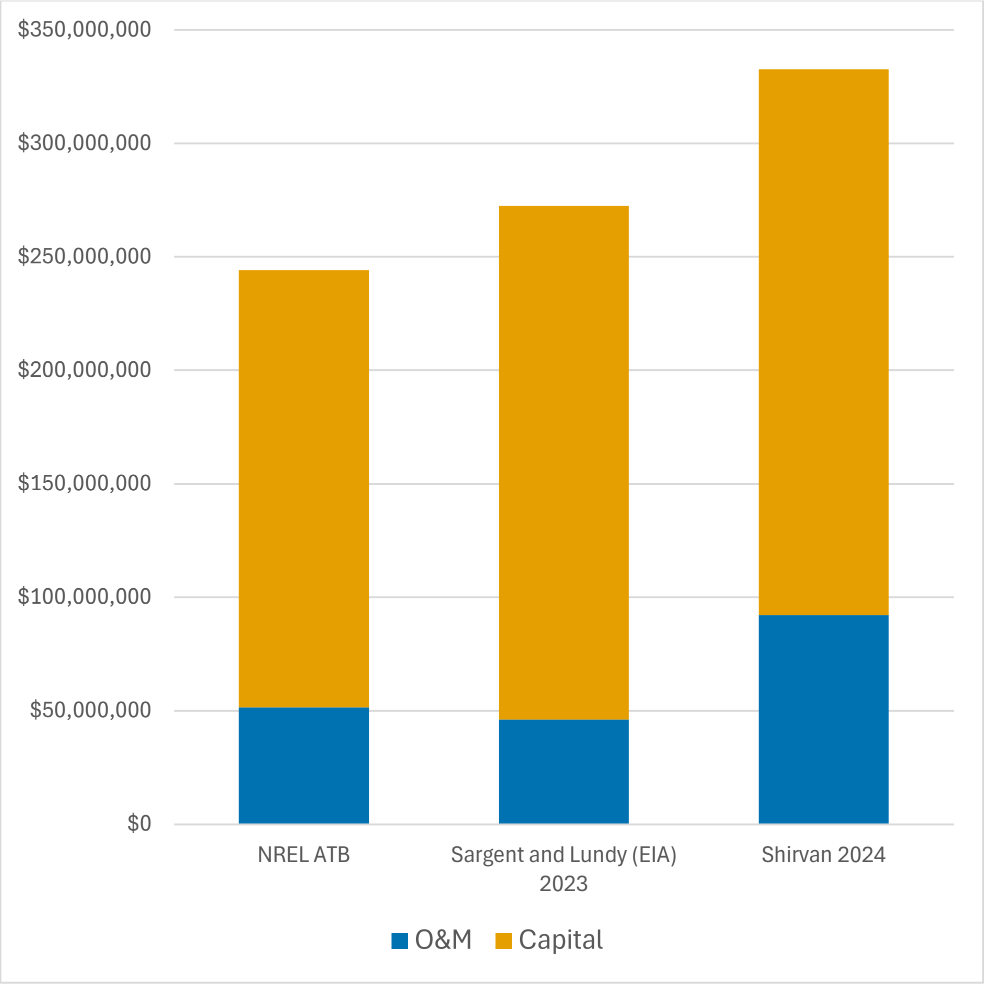

Figure 16. Expected annual O&M and capital costs for a 300 MW nuclear reactor as estimated in [95, 111, 112].

Expected annual costs and savings of constructing a nuclear reactor at a coal power site rather than a new site were evaluated with respect to the total estimated project cost at a new site to determine the relative savings of water and transmission connection availability. Cost savings described above were compared with total project estimates from [111], the intermediate total project cost estimate of those reported in [95, 111, 112]. The baseline cost is assumed to use wet recirculating cooling at a new site in the SMR cost estimates. Alternate cooling-method costs and savings for a scenario where a nuclear reactor is constructed at an existing coal power site were evaluated to determine the percentage of the annual combined capital and O&M costs for the plant they represent. The range representing the minimum and maximum by climate type for these relative savings is shown in Table 18.

Savings from existing interconnections at coal power plants relative to total plant costs were also evaluated. The one-time interconnection fee was compared to the capital cost of the plant, calculating a range of savings representing the lowest and highest cost transmission service areas. Projects in the SPP area can expect a .9% savings based on the existing interconnection while plants in ISO-NE can expect up to 1.9% savings when installing a single 300 MW nuclear reactor, as shown in Table 18.

Table 18. Costs and savings of alternate cooling technologies and existing electrical interconnection relative to total plant cost when assuming a baseline of wet recirculating cooling at a new site.

Annual savings using once-through cooling at an existing coal site	2.4 % - 2.5%
Annual savings using wet recirculating at an existing coal site	1.4%
Additional annual cost of using dry cooling	6.1% - 10.1%
Initial capital cost savings from using existing electrical interconnection	0.9 - 1.9%

4.4 Conclusions

As the ageing U.S. coal power fleet nears retirement, little is certain about the role these sites will play in a clean energy transition. While other researchers have investigated the possibility of reusing coal power plant operating components in a conversion to nuclear power, this analysis specifically considers the value of access to cooling water and the utility corridor.[13] In most locations, both are positioned near the existing coal plant on the same site. Previously, little was understood about the value these elements represent for individual sites, or the broader U.S. coal

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[13] For the purposes of the present study, reuse of other site infrastructure is disregarded.

power fleet, when converting to nuclear power. This analysis determines that the value of cooling water and grid interconnection availability at existing coal power sites is significant. If retiring coal capacity is to be replaced with clean energy sources like nuclear power, attention should be given to existing coal power sites due to the value of cooling water and grid interconnection availability.

To measure the value of the availability of cooling water, three alternate cooling technologies were evaluated at an existing coal power site and compared with the same alternatives at a new site nearby. Use of the existing cooling method and water source when installing a single 300 MW nuclear reactor can save \$6.8M - \$23.5M depending on the cooling method chosen at the new site, with expected savings of \$13.3M. Expected savings across the fleet are valued at \$1.7B - \$4.5B annually, depending on the number of reactors installed. Potential savings result from lower capital and operating costs for cooling systems in use at existing coal power sites, usually once-through cooling or wet recirculating cooling, compared to a more expensive cooling method like dry cooling. The use of a higher-cost cooling method due to water scarcity, water costs, environmental regulation or other reasons is expected for many new generation sites based on the type of recent cooling systems installed.

To estimate the value of the existing grid connection at coal power sites, the cost to connect the same generator to the grid at a new site was evaluated. The transmission service area was determined for the 148 coal plants considered. Point of interconnection and network costs were estimated based on cost information from completed and proposed projects. The value of existing electrical grid connections for the 300 MW reactor can range from \$25M to \$53.6M, depending on geographic location, with existing grid connections across the fleet valued from \$5.3B – \$10.1B depending on the number of reactors installed. Potential savings from reusing grid interconnections at existing coal sites can be considered alongside the increasing difficulty of installing new electrical transmission lines in some areas, including those with dense populations. Reuse of an existing grid interconnection can also reduce project risk by avoiding entrance to the transmission organization's interconnection queue.

These findings suggest existing electrical grid connections and cooling water availability represent considerable value that should be considered, along with other factors, by entities considering siting alternatives for small nuclear reactor installation.

CHAPTER 5: COMMITTED EMISSIONS REDUCTIONS AVAILABLE FROM REPLACEMENT OF COAL-FIRED POWER PLANTS WITH NUCLEAR PLANTS[14]

5.1 Introduction

The power sector is the largest emitter of greenhouse gas globally [113]. In the United States (U.S.) electric power accounts for 25% of greenhouse gas emissions [114]. Within the power sector, coal fired power plants represent the biggest source of emissions, accounting for 53% of emissions from power generation in 2022 [115].

Action is required to meet ambitious decarbonization goals like those in the Paris Climate Agreement and the set of aligned federal, state and local policies. Modelling studies indicate these goals can largely be achieved through the reduction of burning of fossil fuels and a reliance on rapid electrification of all economic sectors [3, 116]. The three primary energy sources accounting for over 97% of global electricity generation are fossil fuels, renewable sources, and nuclear energy. Coal consumption accounts for 37% of electricity generation globally [117] and 20% in the U.S. [118]. Reducing this leading emitter in electricity generation features prominently in emissions reduction models [3, 116] under climate stabilization scenarios.

Decarbonizing electricity generation faces many challenges including a projected increase in demand. Even with increased efficiency, energy demand globally is projected to increase markedly over this century [18, 19]. Globally, electricity consumption is predicted to increase to 60,000

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[14] This section has been published in its entirety in *Environmental Research: Energy* as J. E. Pope, T. Coburn, and T. H. Bradley, "Committed emissions reductions available from replacement of coal-fired power plants with nuclear plants," *Environmental Research: Energy,* 2024. An earlier version with the same title was presented in May 2024 in Washington, DC, as a poster at the 2024 Battelle Symposium on Innovations in Climate Research.

TWh in 2050, a 158% increase from 2020 [5]. In the U.S. electricity consumption is forecasted to increase 22% from 2022 to 2050, largely attributable to economic growth and increasing electrification in end-use sectors [33]. Considering a projected decrease in the use of fossil fuels for electricity generation and increase in electrical consumption, fossil fuel plant capacity must be replaced, and worldwide generation increased.

In the U.S., none of the capacity lost to retiring coal plants is projected to be replaced by new coal plants [33]. In other parts of the world new coal plants are still being built. Between 2000 and 2023 global coal capacity increased by over 1.5 million MW [61]. According to U.S. Energy Information Administration (EIA) models, some U.S. coal capacity replacement is anticipated to come from converting coal plants to a natural gas burning technology, or by the construction of new gas- or diesel-fired plants. Most capacity replacement is projected in the form of additional variable renewable generation (mainly solar), and diurnal energy storage [33]. Shearer et al. [119] show that while conversion of coal plants to natural gas can reduce annual emissions, committed emissions increase because of the emissions that result from burning natural gas for energy production, plus the increased years of operation of the plant resulting from the conversion.

Alternatives such as nuclear could, and should, be considered as part of a clean energy system [31]. For example, replacement of coal power generation with nuclear power such as that produced by small modular reactors (SMRs) could reduce overall emissions while maintaining firm, dispatchable capacity, since no CO_2 is emitted when electricity is generated using nuclear energy. Roadmap models for meeting Paris climate goals from the International Energy Agency (IEA) and Intergovernmental Panel on Climate Change (IPCC) show global nuclear capacity doubling or tripling by 2050 [3, 116]. In December 2023 the U.S. signed a declaration with more than 20 other countries to triple global nuclear energy capacity by 2050, recognizing the key role of nuclear energy in reaching net zero [120].

The past few years have seen several papers discussing the possibility of converting existing coal plants to nuclear plants in the U.S., Poland, and China [24, 30, 38-41]. The extent to which emissions would be impacted by coal-to-nuclear conversion remains relatively unknown. This paper evaluates the potential for emissions reductions resulting from converting coal plants to nuclear in the U.S. and India, the countries with the world's second and third largest installed coal-fired generating capacity.

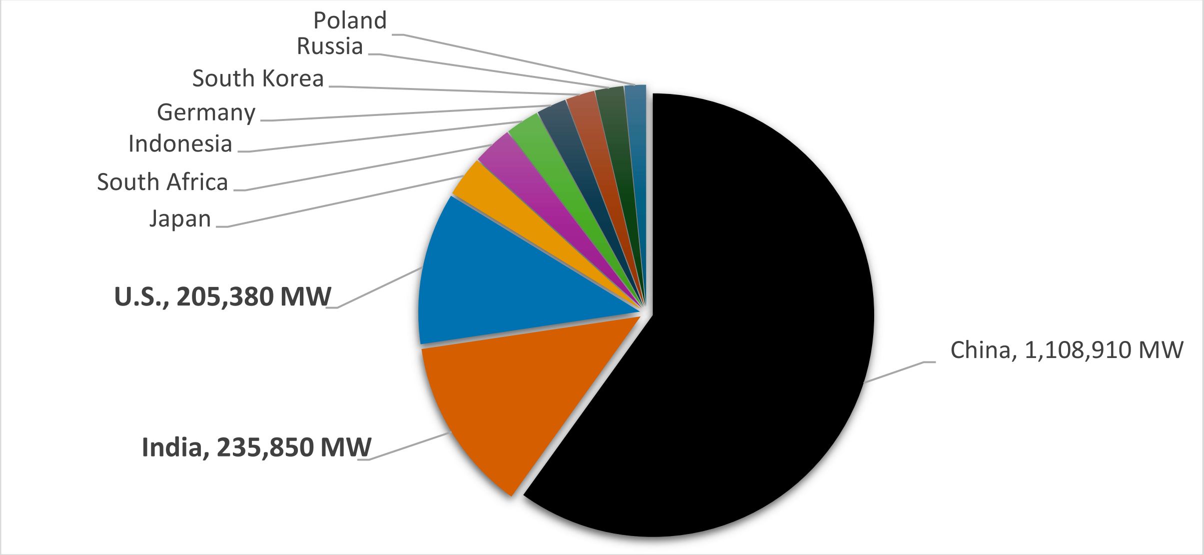

Figure 17. Relative illustration of installed capacity of coal power plants in 2023 for top global producers

These countries present an interesting comparison due to their size, each having about four times as much coal power capacity as Japan (which has the next-largest national capacity), but much smaller than China, which has an installed capacity about five times that of India or the U.S., as illustrated in Figure 17 [61]. While these two countries have a similar installed coal capacity, within 15% of each other, the age of their existing fleets is very different. The average start year for a coal unit in the U.S. is 1979, compared to 2006 in India (calculated from [61]). Both the U.S. and India currently have nuclear power programs. The U.S. operates 94 nuclear power reactors, while India operates 20 power reactors with an additional seven under construction [87]. Both countries have set aggressive decarbonization goals. India plans to reduce carbon emissions 50% and achieve 500 GW fossil fuel free generating capacity by 2030 and aims to reach net zero by 2070 [121]. The U.S. has announced a goal of 65% emissions reductions by 2030 and net zero by 2050 [122].

This paper considers potential timelines for coal plant conversions to nuclear and calculates the resulting emissions to better understand the contribution a fleet-scale nuclear conversion campaign could make to each nation's decarbonization goals.

5.2 Methods

To calculate emissions, a model was created including all operating coal power plants in the U.S., and those operating or nearing construction completion, with planned start year by 2026 in India. No new coal-fired power plants are under construction in the U.S. Annual and committed emissions for each coal generating unit were calculated at all plants for the remaining life of the unit, and with varying plant life assumptions. Conversion of coal power plants to nuclear plants was then analyzed. A baseline project conversion schedule was used to develop fleet conversion schedules considering assumed supply chain constraints. Remaining committed emissions were calculated for each unit based on the plant conversion schedule and compared to a base case where units continued to burn coal and operate until retirement.

5.2.1 Committed Emissions Defined

The concept of "committed emissions" in the context of energy and transportation infrastructure was introduced by Davis et al. [123] and later expanded in [124]. Committed emissions are the emissions expected from fossil fuel-burning infrastructure assuming expected lifetimes and utilization rates [119]. As a plant operates, committed emissions can be separated into two types: committed emissions realized and committed emissions remaining, the sum of which makes up the plant's total committed emissions. Stated another way, on the day a plant is to begin operation, all the emissions expected over the plant's lifetime are committed emissions; and since the plant has not yet emitted any CO_2, all the committed emissions are remaining.

After the first year of operation, the emissions from the first year are now committed emissions realized (actual emissions), and when subtracted from the total committed emissions of the plant, the result is committed emissions remaining. Calculating committed emissions is especially valuable when comparing generation technologies having different levels of emissions, such as coal and natural gas, but is also useful in the nuclear conversion case where remaining emissions fall to zero. The simple approach used here neglects to reflect operational considerations that vary by unit and by year; notably the possibility of a higher capacity factor in early years followed by a reduced capacity factor as the unit ages, along with more required maintenance and reduced efficiency with age. Still, applying averages across the life of the unit allows for reasonable emissions approximations and comparison. An example diagram of committed emissions for the single-unit Seward Power Plant that began operation in 2004 in Pennsylvania, assuming the plant operates for 55 years, is shown in Figure 18 below. This plant was selected because the simplicity of a single unit provides an uncomplicated illustration of the concept. A similar diagram could be produced for any plant.

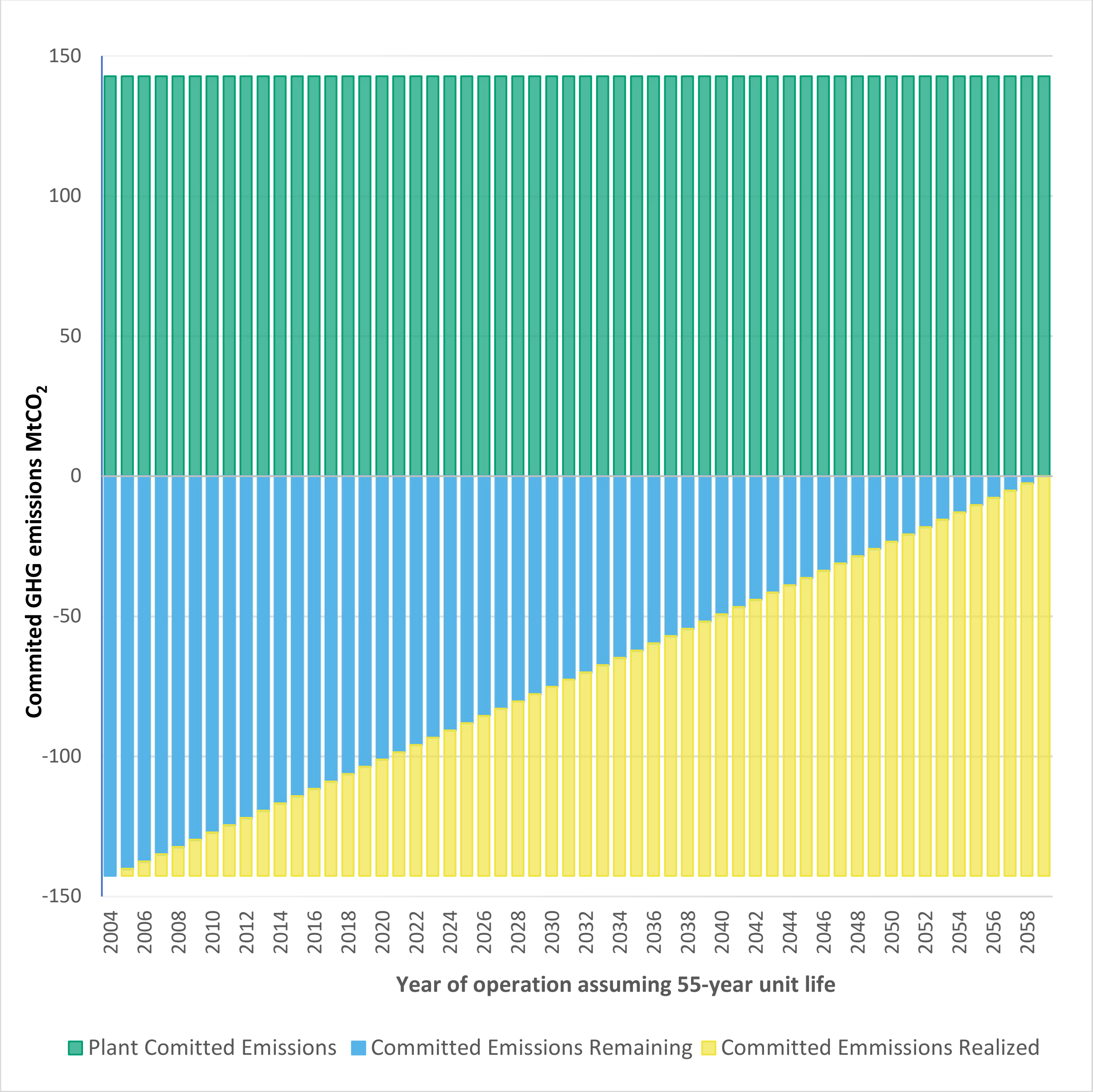

Figure 18. Committed emissions for the single unit at Seward Power Plant, Indiana County, Pennsylvania. This figure illustrates the relationship between committed emissions, the future emissions expected when a plant is built, and its components: committed emissions realized and remaining. As the plant operates, emissions can be separated into committed emissions realized and committed emissions remaining, the sum of which makes up the plant's total committed emissions.

5.2.2 Calculating Committed Emissions Remaining

To calculate committed emissions remaining for a single coal power unit this analysis considers unit capacity based on nameplate rating, heat rate based on the combustion technology used, emission factor based on coal type, capacity factor based on global average by fuel type, and remaining plant lifetime using publicly available data [61] or the plant conversion schedule, as shown in Equation 6 below.

$$CER = PC * HR * EF * CF * RPL \tag{6}$$

where CER = Committed emissions remaining[15]

PC = Plant capacity

HR = Heat rate

EF = Emissions factor

CF = Capacity factor

RPL = Remaining plant life

An example calculation using Equation 6 for a single unit, the Comanche Power Station Unit 3 in Pueblo, CO is given in Table 19.

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[15] Plant capacity is the sum of unit nameplate capacities. Heat rate is based on the type of combustion technology, with performance penalties for older and smaller units as calculated by [61]. Emission factor is based on the type of coal using 2006 IPPC Guidelines for National Greenhouse Inventories as reported in [61]. Capacity factor is standardized for all units in this study, using a global average of 53% based on IEA's 2022 World Energy Outlook as reported in [61].

Table 19. Committed emissions remaining at Commanche Power Station, Unit 3, Pueblo, Colorado[16]

Factors:

- *Capacity: 856.8 MW*
- *Heat rate: 9,250 Btu/kWh*
- *Emission factor: 96,100 kg CO_2/TJ*
- *Capacity factor: 53%*
- *Remaining plant life: 6 years*

$$Committed\ emissions\ remaining$$

$$= 856.8\ MW * 9{,}250\frac{Btu}{kWh} * 96{,}100\frac{kg\ CO_2}{TJ} * 53\% * 6\ years$$

$$= 22.4\ Mt\ C0_2$$

5.2.3 Other Considerations

5.2.3.1 Lifecycle Emissions

Combustion during generation is not the only source of emissions attributed to power production. For example, the process of coal mining releases trapped methane gas from fracturing seams and surrounding rock. Methane is the second largest greenhouse gas contributor to climate change after CO_2 [125]. Despite its short lifespan, methane traps 29.8 times more heat in the atmosphere than CO_2 when averaged over 100 years [126]. Mining uranium, the naturally occurring raw material processed and enriched to make nuclear fuel, results in virtually zero methane emissions [127]. Energy is needed for both coal and uranium mining in the form of heat from diesel or propane, as well as electricity from diesel generators or the grid [128]. Emissions from these and other energy sources are included in the lifecycle emissions of nuclear and coal

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[16] Conversion factors not shown include: 8,760 hours = 1 year, 1,000 kW = 1 MW, 1 tonne = 1000 kg, $1.0550559e^{-9}$ TJ = 1 Btu.

power plants, which considers, when applicable, all stages of the power production process, including mining and milling, conversion, enrichment, fuel fabrication, plant construction, operation, decommissioning, spent fuel management, and final waste disposal. Greenhouse gas (GHG) emissions of global nuclear power using the life cycle assessment approach averages 6.1 g CO_2e/kWh [128] while coal contributes 1,001 g CO_2e/kWh [129]. Together with wind, nuclear power has the lowest lifecycle emissions compared to other generation sources including hydropower, solar, geothermal, and natural gas [3]. Lifecycle analysis comparing coal, nuclear, and other sources of power has been performed by others [130, 131] and is not the goal of the present research. Committed emissions calculations shown here include only the CO_2 emissions from ongoing combustion, of which nuclear has none [132].

5.2.3.2 Nuclear Conversion Timeline

To calculate potential reductions in committed emissions from converting operating coal power plants to nuclear plants, a timeline was established for the conversion of a single plant, and assumptions were made about the commercial supply chain and regulatory approval constraints on a broad implementation. The timeline for conversion of a single plant to nuclear used in this analysis assumes the complete replacement of the coal power generation equipment, likely on a different part of the existing site. This conversion would replace the steam system, turbines, and generator, but could retain the electric grid and cooling water connections existing at coal power plant sites. The timeline tasks include performance of a feasibility study, license application development, license application review, technology evaluation, design and procurement, site preparation, construction, and commissioning. It is assumed the timeline accounts for the replacement of coal power generators with an SMR like the GE-Hitachi BWRX-300, which is currently undergoing pre-application review by the U.S. Nuclear Regulatory Commission [133], or the NuScale VOYGR [134], undergoing design approval review. The 10-year project timeline assumed for converting a coal plant to nuclear is shown in Figure 19. This timeline was developed by adapting input from existing proposed timelines from similar projects and industry organizations as well as vendor information [84, 135-139]. The timeline does not include demolition or decontamination of the existing equipment or site.

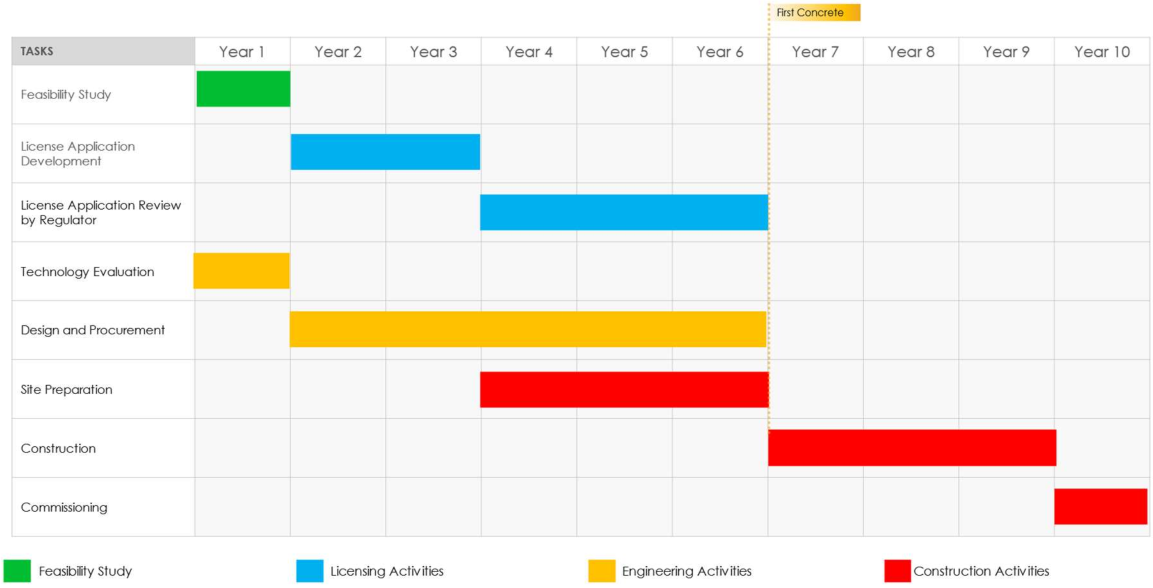

Figure 19. Conversion timeline showing possible durations and sequencing of tasks necessary to license, build, and commission an SMR at a coal power site.

5.2.3.3 Supply Chain

Supply chains for material and labor may limit the number of conversions that could be accomplished each year. For large nuclear power plants only a limited number of facilities worldwide have the large forges needed to produce reactor pressure vessels for traditional large nuclear power plants [140], but it is assumed small reactors could utilize a broader manufacturing base. Other components like valves, pumps, turbines, etc. may experience supply chain constraints, especially in the short term during a scenario where demand suddenly increases. The assumption for this study is that industry could support the conversion of 10 coal power plants nationally per year. Considering the assumptions above, this study examines a proposed scenario where the first 10 converted nuclear power plants begin commercial operation in the year 2034, 10 years after conversion projects commence in 2024, with 10 additional conversions being completed each consecutive year.

5.2.3.4 Capacity and Generation

Individual coal plant capacity may not need to be fully replaced by nuclear power. A plant's capacity is the amount of energy it can produce in a specified time period, usually measured in MW. Electricity generation is the amount of power the plant produces over time, usually measured in MWh. Plant capacity factor is defined as the actual electricity production divided by the maximum possible electricity output of a power plant, over a period of time [141] (see Equation 7).

$$CF = A/B \tag{7}$$

where CF = Capacity factor

A = Actual electricity generated

B = Maximum possible electricity generation

An example capacity factor calculation based on Equation 7 is shown in Table 20. Given a scenario where a power plant with a capacity of 1,000 MW produces 660,000 MWh of electricity in a 30-day period, the capacity factor is the electricity produced divided by the total electricity that could have been produced if the plant ran continuously for the same 30 days at nameplate rating.

Table 20. Example capacity factor calculation

$$\boxed{CF = \frac{660{,}000\ MWh}{(30\ days) * \left(24 \frac{hours}{day}\right) * (1000\ MW)} = .917 = 91.7\%}$$

Capacity factors vary for different plants and different fuel types and are influenced by market forces. The average capacity factor for nuclear power in 2021 was 92.7% in the U.S. [60] and 82.3% globally [142]. The 2021 average capacity factor for U.S. coal plants was 49% in the U.S. [52] and 53% globally [61].

The power system composition in the U.S. has changed in recent decades from one made almost entirely of dispatchable energy sources, defined as those which can be turned on and off at every point in time both to supply energy and network reliability services [143], to a system with considerable amounts of intermittent or variable renewable energy sources. In 2022 renewables accounted for 21% of U.S. power generation [144]. New electrical capacity additions are dominated by renewables with solar expected to account for more than half of 2023 capacity additions [145]. To be reliable, an energy system must maintain an adequate supply of dispatchable power on the grid to deliver power during peak periods, even when variable power is not available. Replacing coal capacity with nuclear has the potential to replace one dispatchable power source with another. Because the nuclear capacity factor is higher than that for coal, less nuclear plant capacity could be required to replace the existing coal generation in a scenario where nuclear is used to provide base load. Alternatively, nuclear could be used to coordinate with fluctuations of variable renewable sources like solar in a load following application [146]. The decision on how much capacity to install will depend on grid demand, composition, and economic considerations. For the purpose of calculating emissions, this study considers only the scenario where existing coal plant electrical generation (but not necessarily capacity) is replaced by nuclear generation.

5.2.3.5 Plants for Conversion

The number of plants available to convert and the order in which to convert them is also considered. In 2024 it is projected that 205 coal plants will be in operation in the U.S. and 859 in India (calculated from [61]). The number of plants in the U.S. is expected to decline by about half by 2034, considering planned retirements and plants reaching their end of life, but continue to grow in India (calculated from [61]). Units at some plants in the U.S. have announced a planned retirement year and the base case for this study assumes those units will cease operation in the year planned. An alternative case is considered where units do not retire on the announced date and operate for the full assumed lifetime of that scenario. For plants that do not have an announced retirement date, a unit life assumption is made. The most common age of recently retired coal units in the U.S. is 50-60 years, with an average age at retirement of 52 years [147], while the historic global average is 46 years [148]. Some plants operate much longer. For example, the Shawnee Fossil Plant in West Paducah, Kentucky has nine units all built between 1953 and 1955 that are still in operation [61]. To facilitate comparison between the fleets in the U.S. and India, a 50-year unit lifetime (two years less than the recent U.S. average and four years more than the historic global average) is used for most emissions calculations. In the U.S., the fleet is evaluated again with an assumed 55-year lifetime to compare the effect of operating those plants longer.

Plants eligible for conversion were studied by Hansen [39], who evaluated operational U.S. coal plants considering the following inputs: population, earthquake potential, faults, protected land, slope, landslide potential, and the presence of wetlands and open water, floodplains, and hazardous facilities. His research determined that 80% of coal plants in operation at the time of the study were amenable to further consideration for siting an SMR. Examination of the DOE datasets reveal that population density was the most influential discriminator and the only factor that resulted in an existing plant not being considered for further SMR site evaluation.

In the present study, the plants expected to be in operation at the time of a possible conversion to nuclear were evaluated for nearby population (U.S. only) and existing plant capacity. To be considered for conversion a plant was required to meet three criteria (an "amenable" plant):

- Expected to be operational in 2034[17]
- Population, where more than 50% of the area in a four-mile radius around the existing plant does not have a population density greater than 500 people per square mile (population data not available for India).[18]
- Plant capacity greater than 200 MW[19]

Only one unit in a plant was needed to remain operational to consider a plant for conversion. When calculating emissions for plants that are older than the lifetime assumption but still operating, five more years of operation are assumed. Amenable plants were ordered for conversion

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[17] Calculated using Global Energy Monitor's Coal Plant Tracker database considering start year, planned retirement year, and unit lifetime assumption.

[18] The population density metric is introduced in Hansen [15]. Datasets from this report were used to determine suitability for further consideration to nuclear conversion of the plant sites in the present study.

[19] Nuclear solutions perceived as having a possibility to come to market in the timelines proposed in this paper begin at approximately 300 MW with one exception. Decarbonization potential and existing infrastructure value, when paired with larger generation solutions, make existing plants under 200 MW capacity unlikely candidates for conversion.

based on descending capacity and 10 plants are assumed to be converted per year. In practice, the decision on the order to convert would involve many factors relying heavily on financial considerations. The Electric Power Research Institute (EPRI) [56] discusses advantages of converting operational plants compared to retired plants due to possible degradation of infrastructure and loss of permits, rights, and potential staff after a coal plant retires. To maximize the potential for success of a broad implementation of nuclear conversions only plants currently in operation were chosen to begin a nuclear conversion project.

Comparing U.S. operating units against the criteria above using different unit lifetime assumptions yields a range of results from 38 plants when assuming 40-year unit lifetime, to 81 plants when assuming a 60-year unit lifetime, as illustrated in Figure 20. Announced retirement dates displaced natural retirement based on unit lifetimes when determining the number of amenable plants.

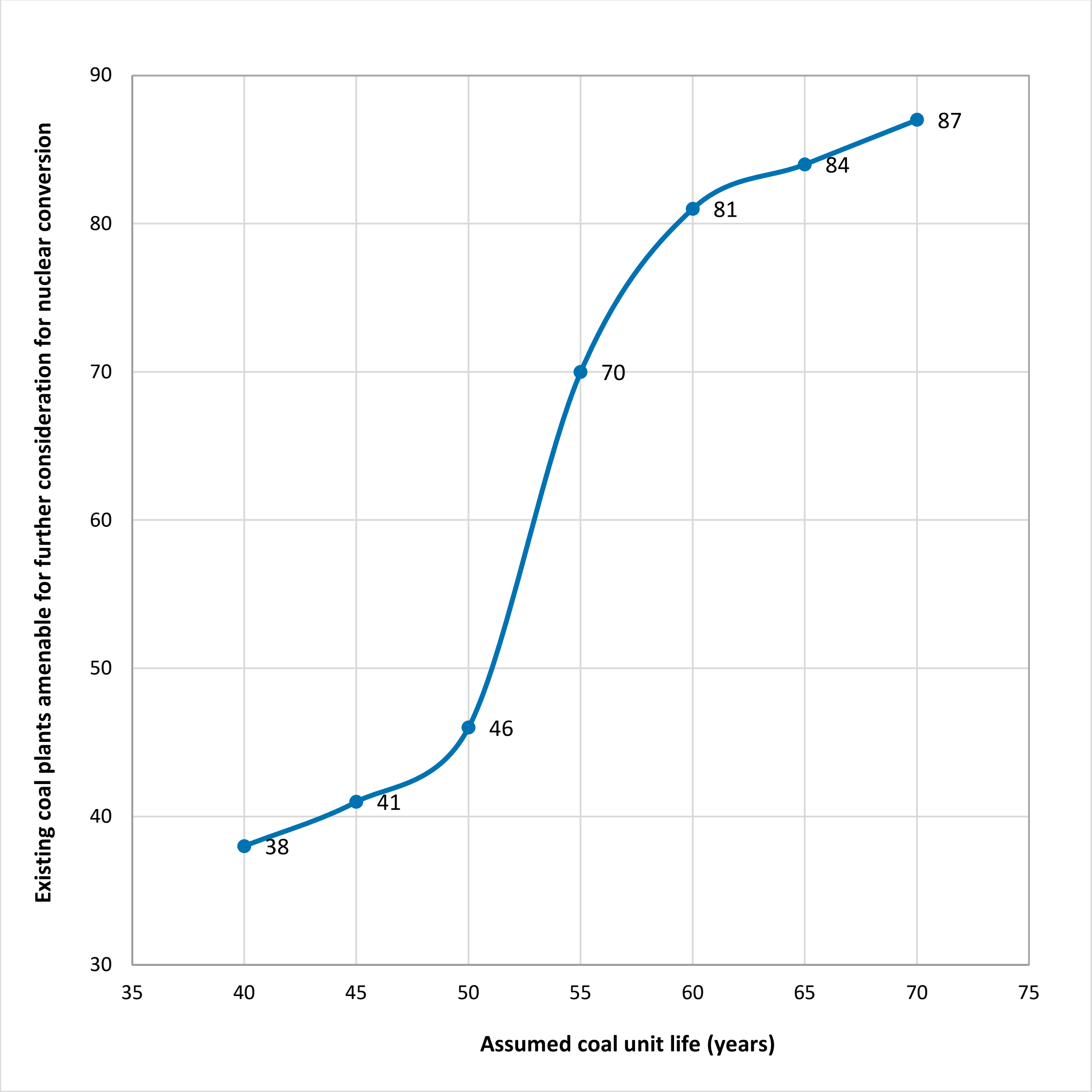


Figure 20. U.S. Coal-fired power plants amenable for further consideration for conversion to nuclear power considering a range of unit lifetime scenarios and announced planned retirements. Plants amenable for further consideration have at least one unit still operational in 2034, meet area population density criteria, and have a capacity of at least 200 MW.

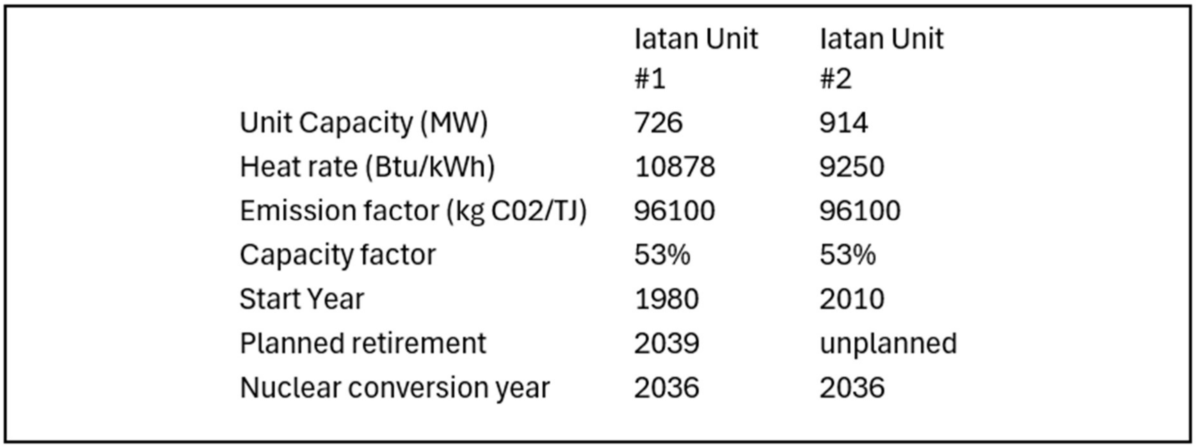
Four cases were examined for U.S. plants: (1) a base case where no nuclear conversions are performed and units retire at the announced date or end of assumed unit life, (2) an alternate base case where announced retirement dates are disregarded and units retire at the end of assumed unit life, (3) a conversion case where 46 coal plants are converted to nuclear, corresponding to an assumed coal unit life of 50 years, and (4) a second conversion case where 70 coal plants are converted to nuclear, corresponding to an assumed coal unit life of 55 years.

In India, many more plants were amenable for further consideration for conversion to nuclear because of the younger age of the plants. For India, a base case with no conversions was examined, along with conversion cases of 46, 75, and 150 plants, all assuming a 50-year unit life.

5.2.4 Single Plant Example

To illustrate the method used, the process for calculating emissions for a single plant is described below. Plant emissions are the sum of unit emissions at the plant. Fleet emissions are the sum of all plant emissions in the national fleet. The example uses the Iatan Generating Station in Weston, Missouri, with inputs specified in Table 21. The unit lifetime assumption is 55 years, and in the conversion case, the plant is assumed to complete a conversion to nuclear in 2036. This plant was chosen as an example because it includes several elements exhibited alone or in combination at many U.S. coal plants, including two units of different capacity constructed in different eras, one with a planned retirement and the other unplanned.

Table 21. Input data from Iatan Generating Station, Weston, Missouri



	Iatan Unit #1	Iatan Unit #2
Unit Capacity (MW)	726	914
Heat rate (Btu/kWh)	10878	9250
Emission factor (kg C02/TJ)	96100	96100
Capacity factor	53%	53%
Start Year	1980	2010
Planned retirement	2039	unplanned
Nuclear conversion year	2036	2036

In the base case, Iatan Unit #1 retires in 2039, the announced retirement year, and Unit #2 operates for 55 years, retiring in 2065. In the conversion case both units are converted in 2036. Annual emissions for the life of the plant in both cases are shown in Figure 21, where, in the base case, plant annual emissions fall in 2039 as Unit 1 retires, then continue at the Unit 2 level until retirement in 2065. In the conversion case, annual emissions fall to 0 in 2036 when nuclear conversion is complete.

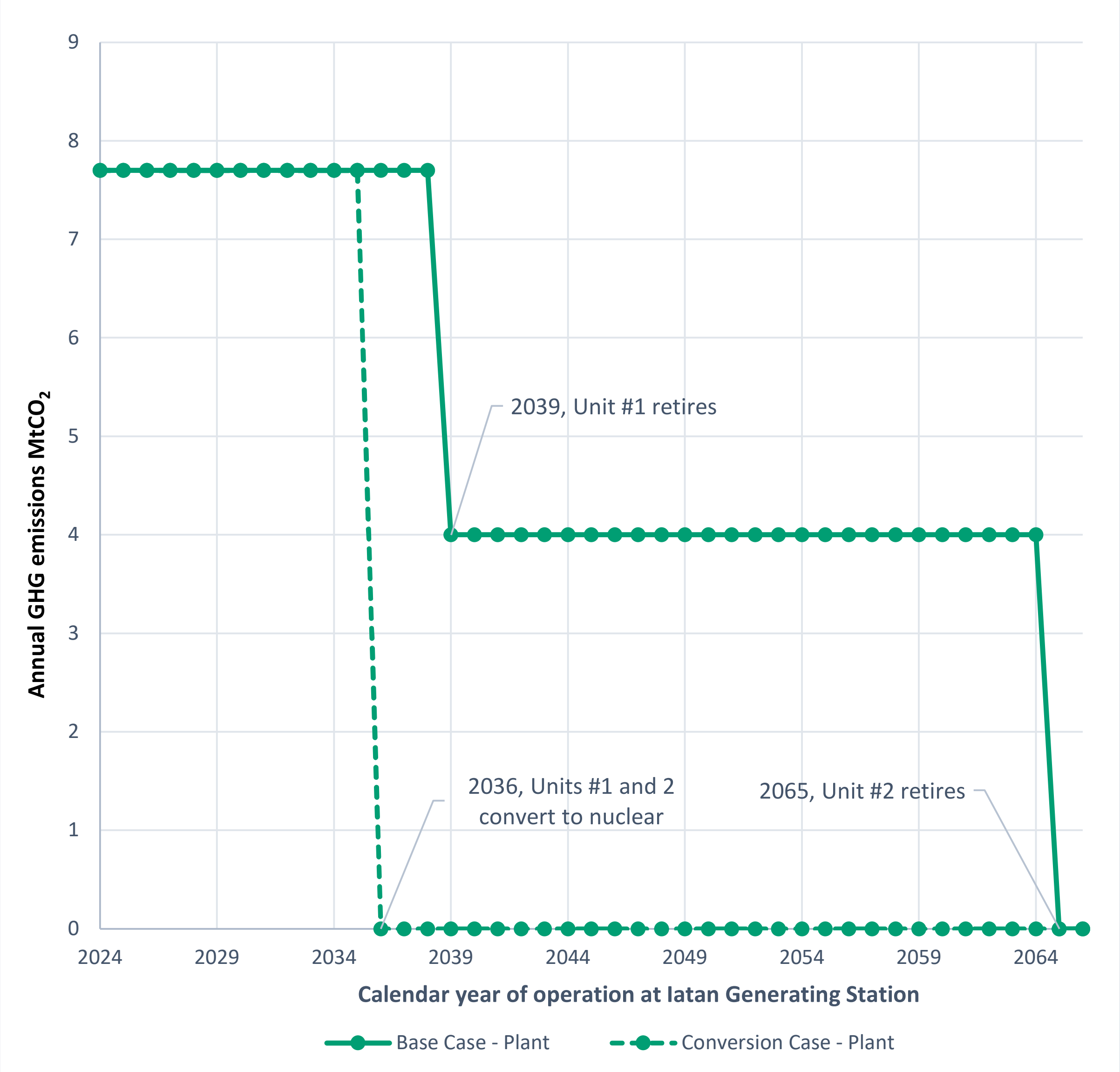


Figure 21. Annual emissions, Iatan Generating Station, Weston, Missouri, 2024-2066 for base and conversion case scenarios. The base case shows the effect on emissions of the planned retirement of unit #1 in 2039 and continued operation of unit #2 for an assumed 55-year life. In the conversion case both coal units are converted to nuclear power in 2036, avoiding 29 years of coal plant emissions.

Committed emissions remaining in 2024 were calculated for (1) a base case where units operate without conversion across the range of lifetime assumptions or the exact retirement date when announced, (2) a second case where announced retirements are disregarded, and (3) a conversion case where both units are converted to nuclear in 2036.

Resulting plant committed emissions remaining over a range of lifetime assumptions is shown in Figure 22. Data points for the base case considering retirements and the conversion case are called out for 55-year unit life. The same data points are called out again inFigure 24, where remaining committed emissions are plotted from 2024 through 2050, highlighting the potential committed emissions reduction at this plant. Also, observable is the effect of planned retirement. Because the owner has announced plans to retire Unit #1 in 2039, after 59 years of operation, committed emissions plots for the base case and the case disregarding planned retirement cross over at this point.

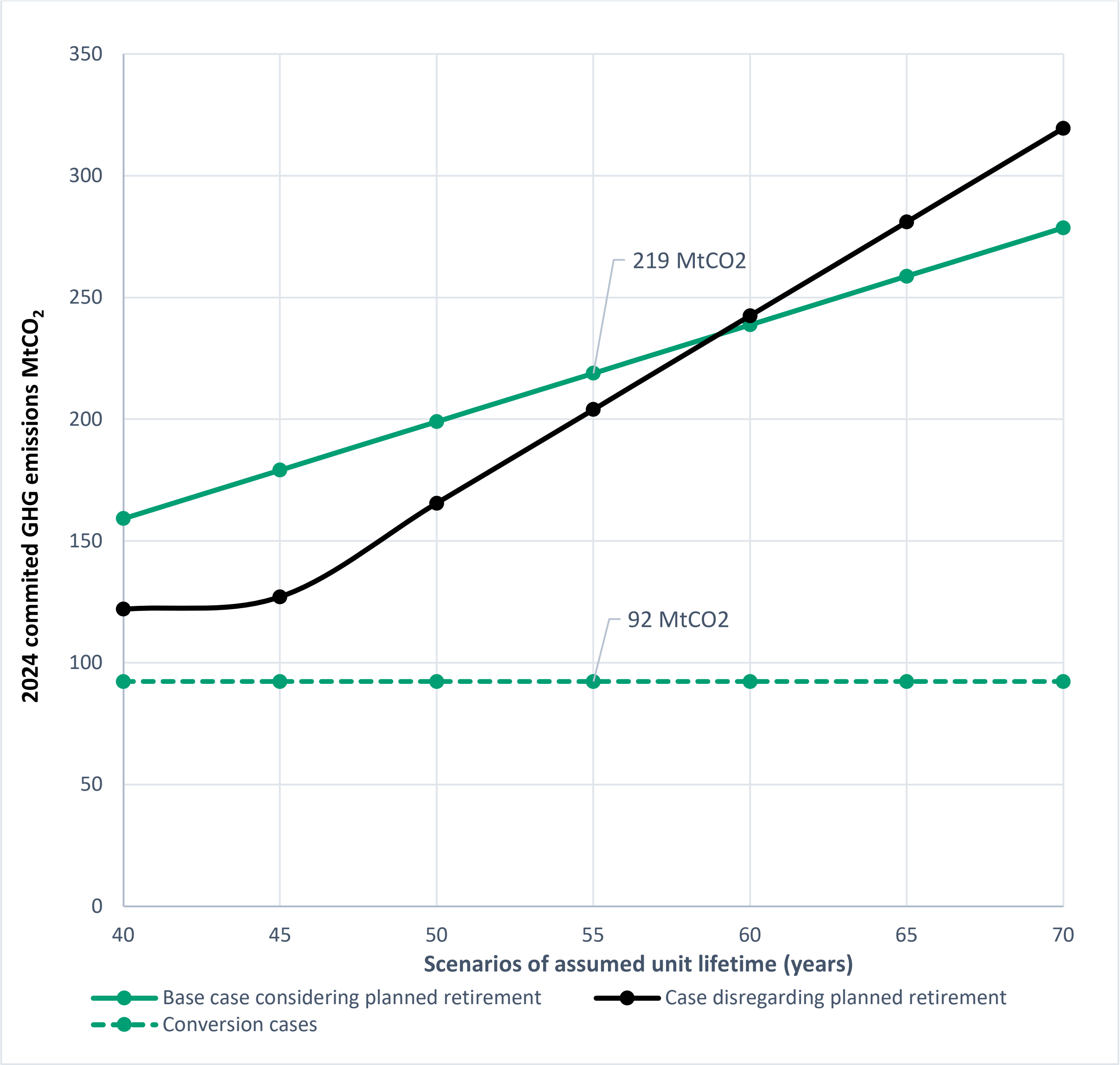


Figure 22. Committed emissions remaining in 2024 over a range of unit lifetime scenarios, Iatan Generating Station, Weston, Missouri. This figure for a single plant with two units illustrates the expectation for emissions to increase as the plant lifetime increases for a base case where coal units operate for an assumed lifetime while considering announced planned retirements, and another case where planned retirement is disregarded, and units operate until the end of the assumed lifetime for each scenario. Because Unit #1 has an announced retirement date in 2039, after 59 years of operation, the two coal-only cases cross at this point. A third case shows emissions remaining when both units are converted to nuclear power in 2036.

Committed emissions remaining for each unit were calculated using the remaining years of operation and the plant input data presented in Table 3. Committed emissions by unit for the Iatan plant are shown in Figure 23, where the differing impacts of converting Unit 1 and Unit 2 are seen. While the units have a similar capacity, converting Unit #1 results in an 11 Mt CO_2 reduction of remaining committed emissions; but, converting the newer Unit #2 results in a 115 Mt CO_2 reduction, which is more than ten times the impact.

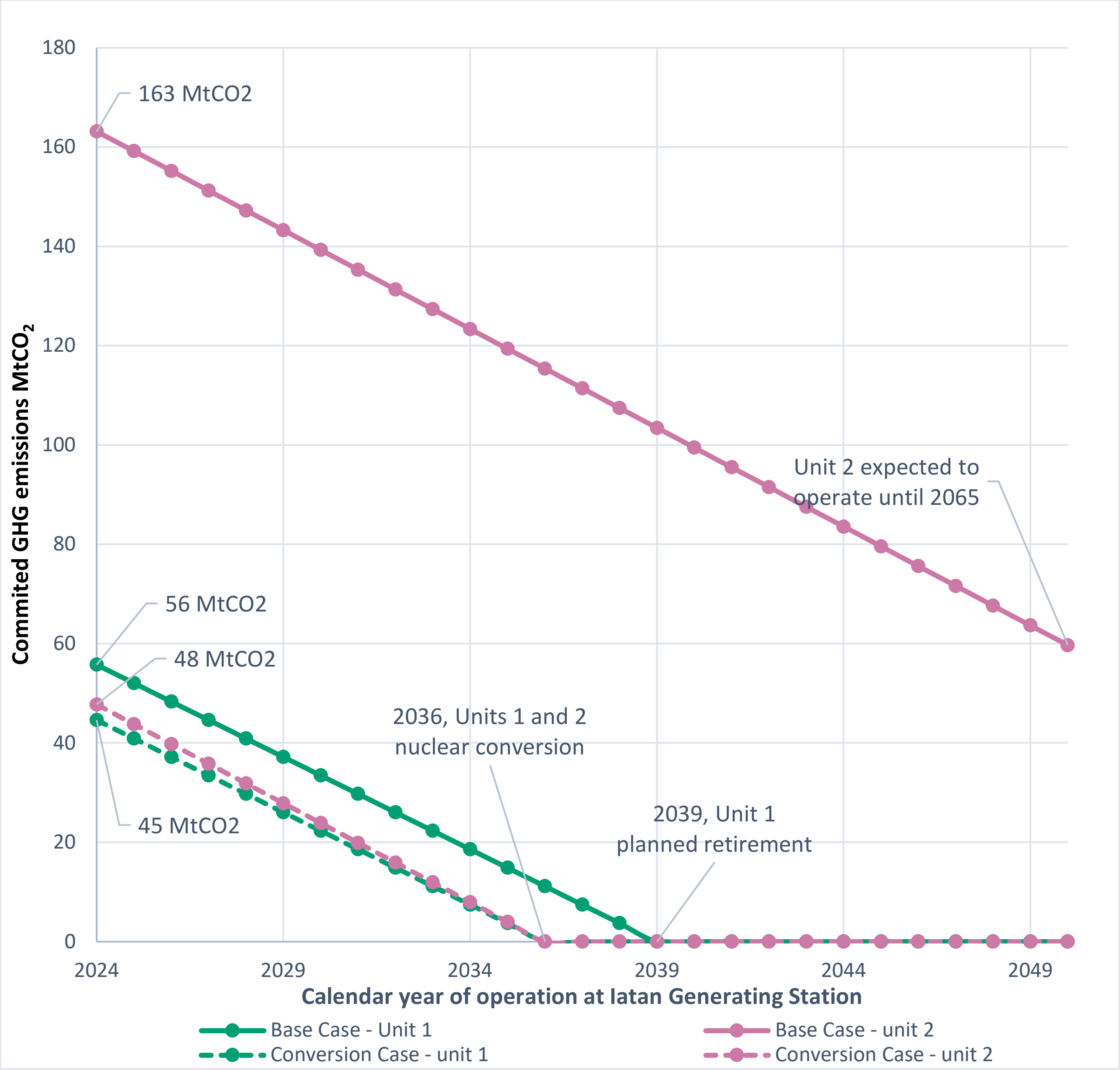


Figure 23. Committed emissions remaining, by unit, 2024-2050, Iatan Generating Station, Weston, Missouri. This figure illustrates the difference in remaining committed emissions between the new Unit #2 constructed in 2010 and the older Unit #1 constructed in 1980 and planned for retirement in 2039 when compared to a nuclear conversion case where both plants are converted in 2036.

Unit emissions were summed to determine plant emissions. Committed emissions remaining for the combined Iatan Generating Station base and conversion cases are shown in

Figure 24.

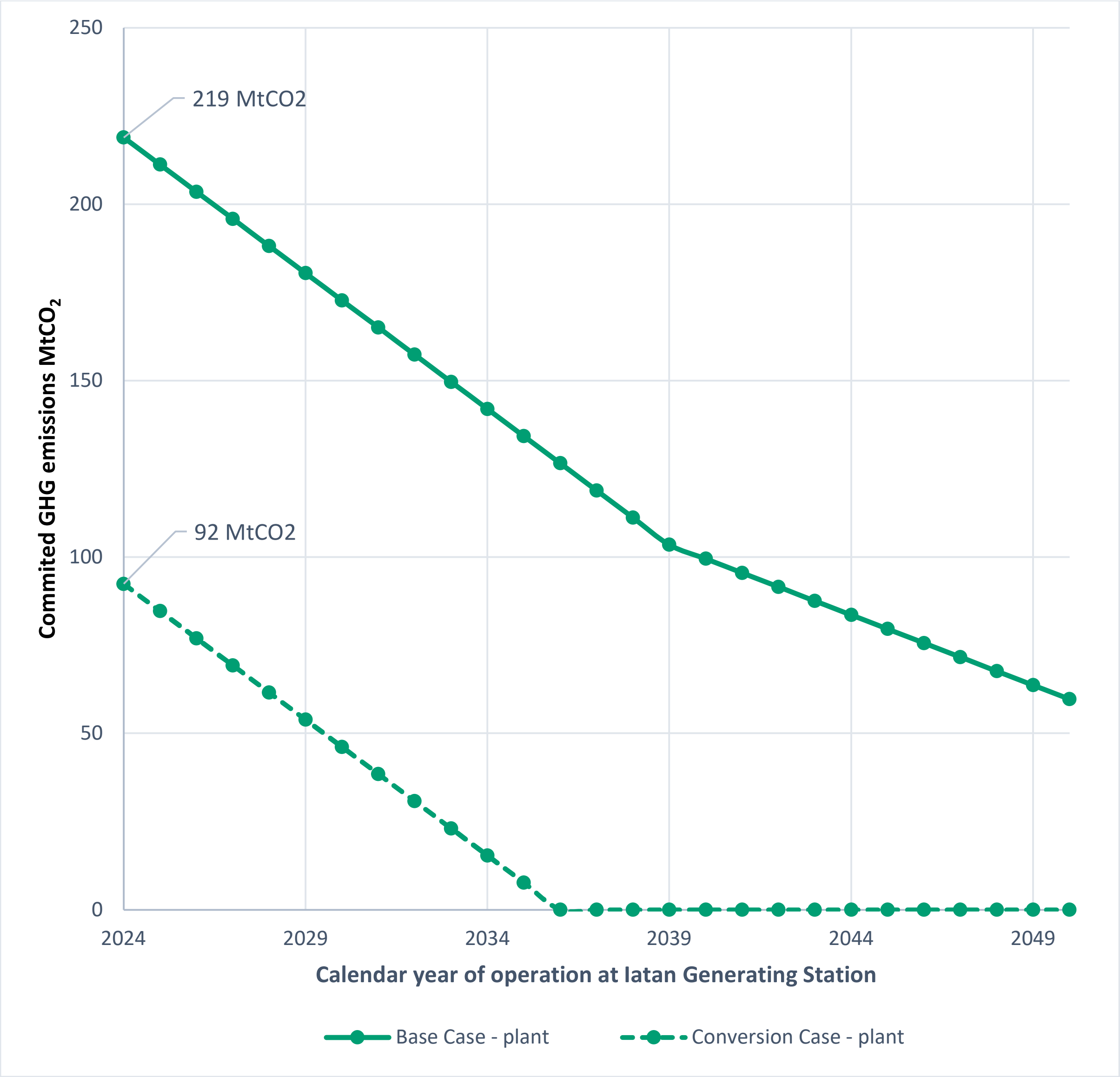


Figure 24. Committed emissions remaining, whole plant, 2024-2050, Iatan Generating Station, Weston, Missouri. This figure shows committed emissions by year of operation for a base case where units operate until the end of an assumed 55-year unit life or until an announced retirement date, and a conversion case where both units are converted to nuclear power in 2036. Whole plant emissions are the sum of individual unit emissions at the plant.

Results from this single-plant example reveal that converting the Iatan Generating Station to nuclear power in the year 2036 could reduce committed emissions remaining in 2024 by 127 Mt $C0_2$, representing a reduction of 58% at this site. This method was used for each for each coal unit and plant in the U.S. and India to arrive at the fleet results discussed below.

5.3 Results

An analysis of the 427 coal-fired power plants operating in the U.S. in 2023 shows annual emissions continuing to decline as a result of plant retirements. New U.S. coal plant construction ceased in 2014 with the Spiritwood Industrial Park plant in Jamestown North Carolina [61], and no new coal plants are planned [33]. Because the average age of U.S. coal power units operating in 2024 is 45 years (calculated from [61]), and the average age of recent retirements is 52 years [147], a decline in the number of operating plants in coming years can be expected. Figure 25 shows estimated U.S. annual emissions beginning in 2024 for a base case, where plants operate until the end of an assumed 50-year unit lifetime, and a conversion case, where 46 plants are converted to nuclear. The first nuclear conversions come online in 2034 at the end of a 10-year project beginning in 2024, and conversions continue to 2038 when 46 plants have been converted.

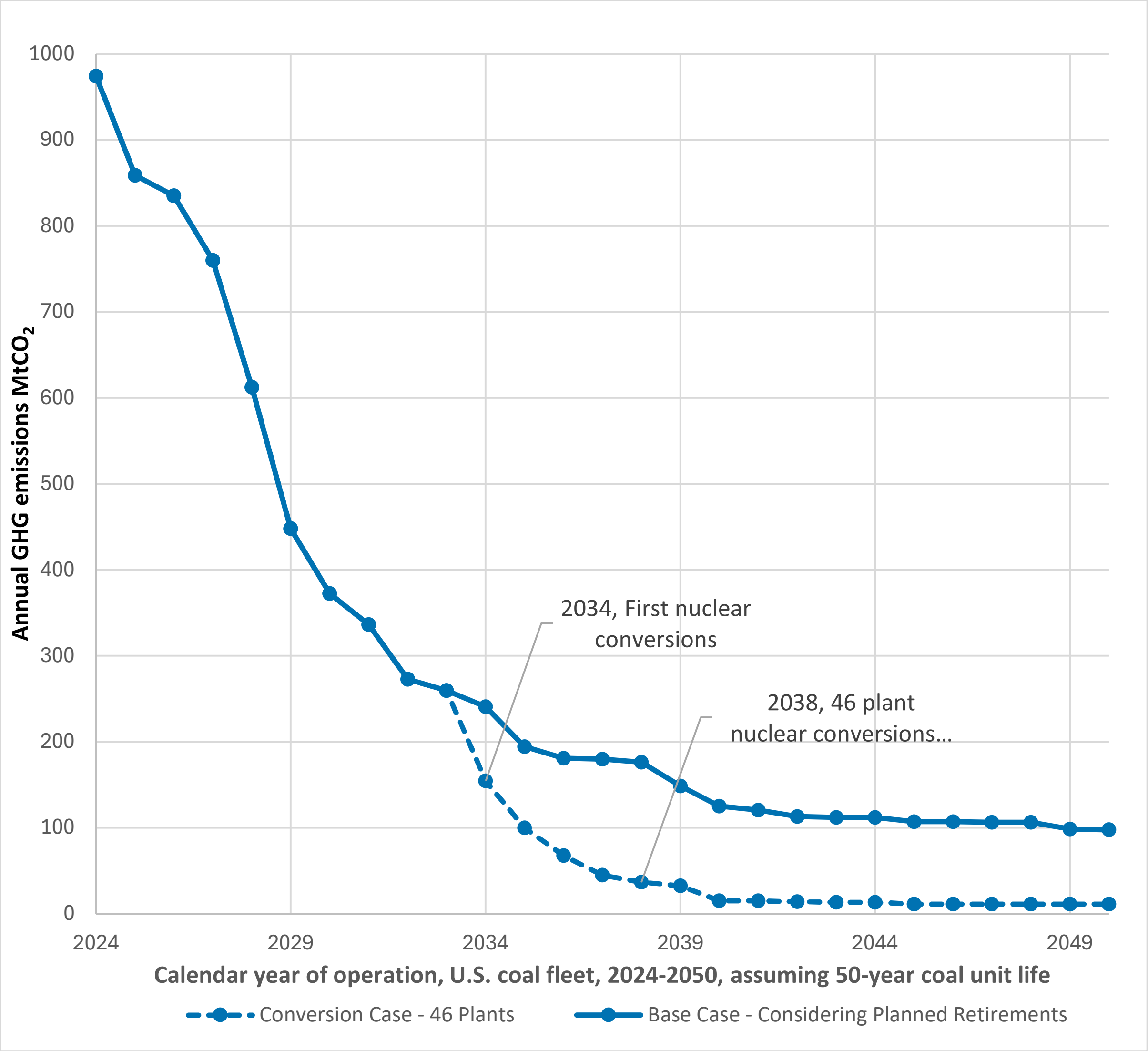


Figure 25. Annual emissions, 2024-2050, U.S. coal fleet. Annual emissions are shown for a base case where coal units operate until the end of an assumed 50-year unit life or until an announced retirement date, and a conversion case where 46 plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year beginning in 2024.

In the conversion case, annual emissions remain unchanged from the base case until 2034 when the first nuclear conversion is completed. Annual emissions are reduced by 22% from the base case in 2034 and continue to fall in the years that plants are converted. When conversions are completed in 2038, annual emissions are reduced by 79%. The 2038 annual emissions reduction is estimated at 139.4 $MtCO_2$.

As in the case of the single plant example, committed emissions remaining in 2024 were calculated for (1) a base case where units operate without conversion across the range of lifetime assumptions or the exact retirement date when announced, (2) a second case where announced retirements are disregarded, and (3) a conversion case where 46 coal plants were converted to nuclear plants. Remaining committed emissions were calculated using a range of unit lifetimes from 30 to 70 years and plotted in Figure 26. Assuming a 50-year unit life, the conversion of 46 coal plants to nuclear reduces 2024 committed emissions remaining by 2,463 $MtCO_2$, or 28% compared to a base case where coal units continue to operate until the planned retirement year when announced, or unit life assumption. Disregarding planned retirements and operating all units to 50 years increases remaining committed emissions by 1,240 $MtCO_2$, or 14% compared to the base case.

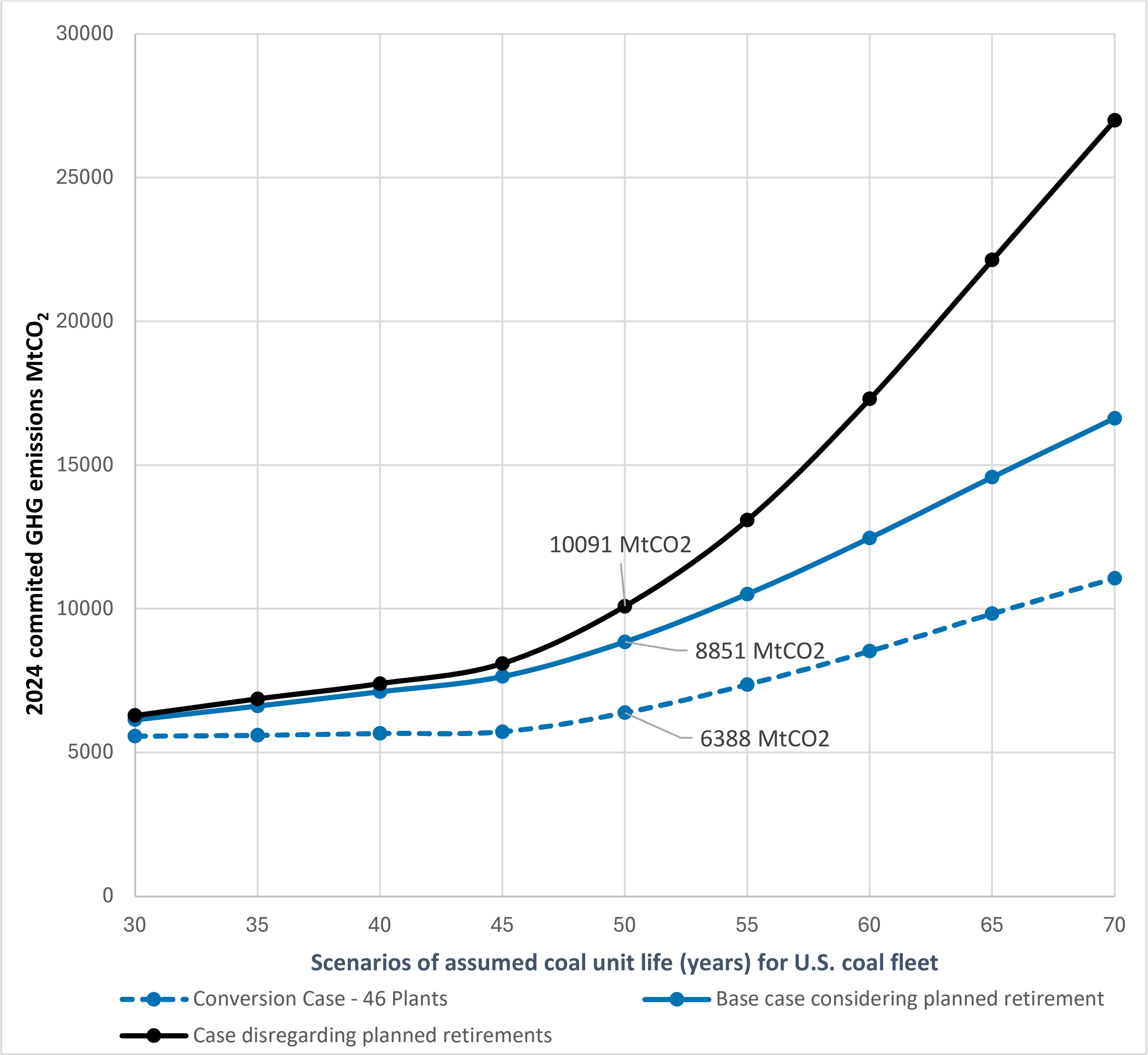


Figure 26. Committed emissions in 2024 over a range of unit lifetime assumptions, U.S. coal fleet. This figure shows U.S. fleet emissions from multiple unit-life scenarios for a base case where coal units operate for an assumed lifetime while considering announced planned retirements, and another case where planned retirement is disregarded, and all units operate until the end of the assumed lifetime for that scenario. A third case shows committed emissions remaining in 2024 when 46 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year beginning in 2024.

Figure 27 plots the U.S. coal fleet committed emissions remaining through 2050, assuming a 50-year unit life, and shows the rate of change in these emissions. The 2,463 MtCO$_2$ difference in committed emission remaining in the base and conversion cases called out in Figure 10 is again shown in Figure 11 for 2024. Results for subsequent years produce a more negative slope through 2038 (the year conversions are completed) in the conversion case, indicating a more rapid reduction in remaining emissions compared to the base case.

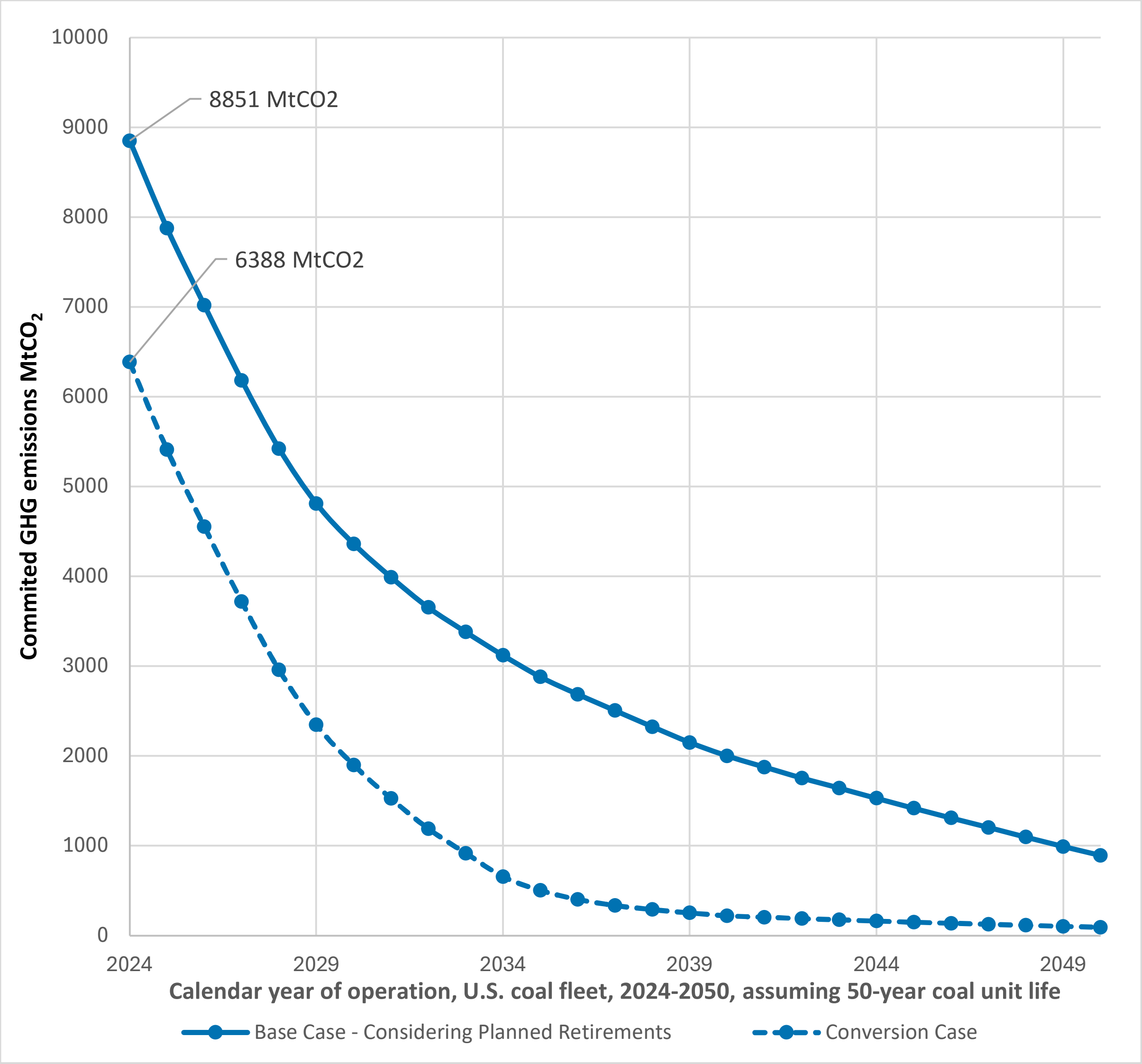


Figure 27. Committed emissions remaining, U.S. fleet for a base case where units operate until the end of an assumed 50-year unit life or until an announced retirement date, and a conversion case where when 46 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year beginning in 2024.

5.3.1 Extending U.S. Coal Unit Life to 55 Years

The U.S. coal fleet was further modelled assuming a 55-year unit life to evaluate the effect of five years additional operation compared to the 50-year case. In the 55-year case 24 additional plants are amenable for further consideration for conversion to nuclear using the criteria described above. In the 55-year unit life conversion case, all 70 plants deemed amenable for further consideration are converted to nuclear.

Extending unit life to 55 years increases annual emissions compared to the 50-year unit life base case scenario. Annual emissions in 2034, the year the first nuclear conversion plants come online, are 47%, or 112 $MtC0_2$, larger in the 55-year base case.

In the conversion cases, emissions reductions from the base cases in 2034 are approximately the same for the 50- and 55-year unit life scenarios, or about 115 $MtCO_2$.

By 2040, all coal-to-nuclear conversions have been completed in the 50- and 55-year unit life scenarios. Conversion of 70 coal plants to nuclear in the 55-year unit life scenario results in approximately the same annual emissions as converting 46 plants in the 50-year unit life scenario from 2040 onward, as shown in Figure 28.

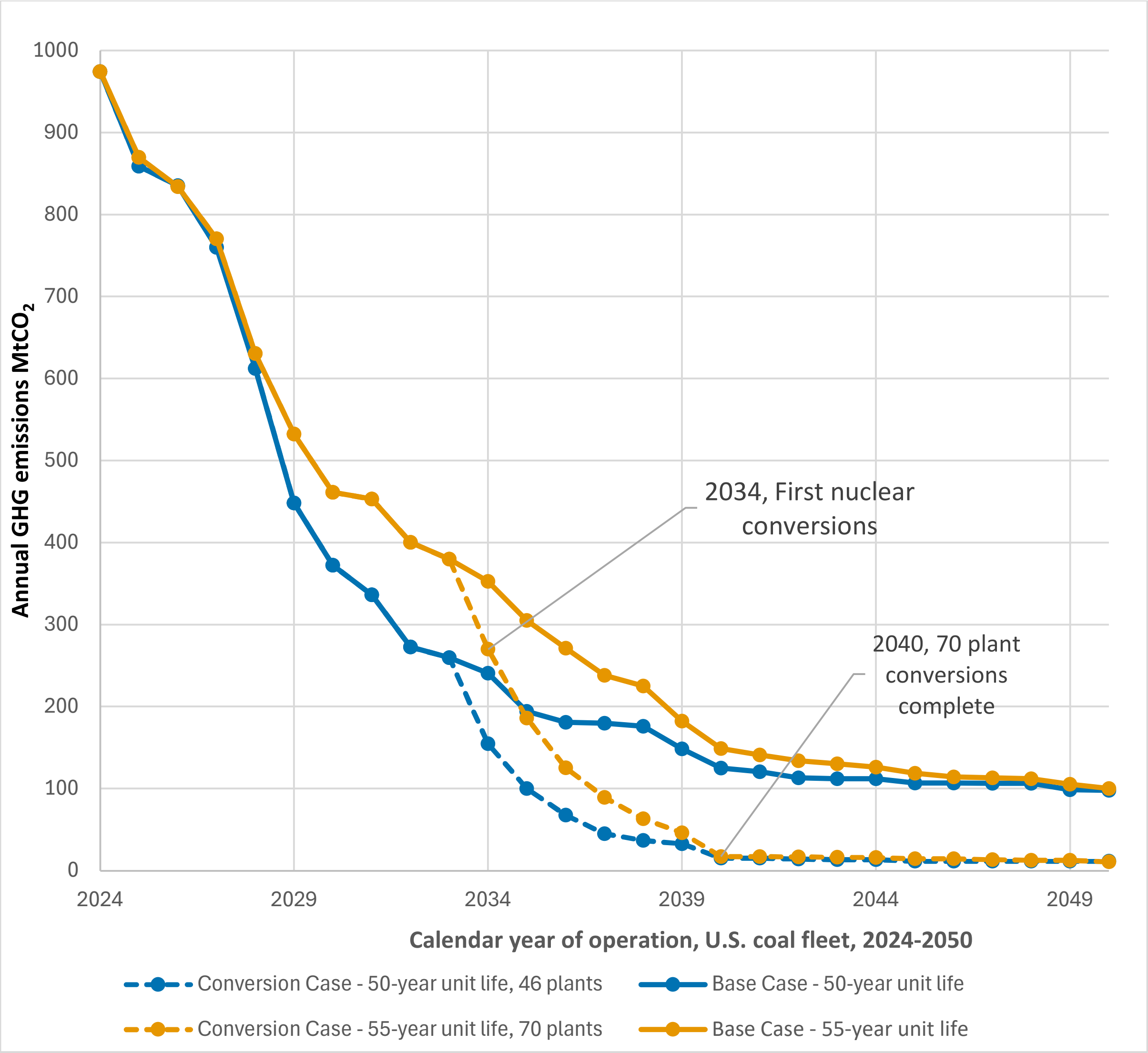


Figure 28. Annual emissions 2024-2050, 55-year unit life versus 50-year unit life, U.S. fleet. For both the 55- and 50-year scenarios a base case is shown where units operate until the end of either an assumed 55- or 50-year unit life or until an announced retirement date. In the 55-year conversion case, 70 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year beginning in 2024. In the 50-year conversion case 46 plants are converted using the same timeline. The number of plants converted corresponds to the number of plants amenable for further conversion consideration based on the unit lifetime and selection criteria described in Section 2.3.5.

Remaining committed emissions were again modelled through 2050 with a 55-year unit life and plotted in Figure 29, along with results from the 50-year unit life scenario for comparison.

Remaining committed emissions in 2024 were reduced by 3,135 $MtCO_2$ or 30% from the base case, when converting 70 plants in the 55-year unit life scenario. When compared to unit lifetimes of 50-years and 46 plant conversions to nuclear, increasing unit life to 55 years increased committed emissions remaining in 2024 by 1,663 $MtCO_2$, or 19% in the base case, and 992 $MtCO_2$, or 16% in the conversion case.

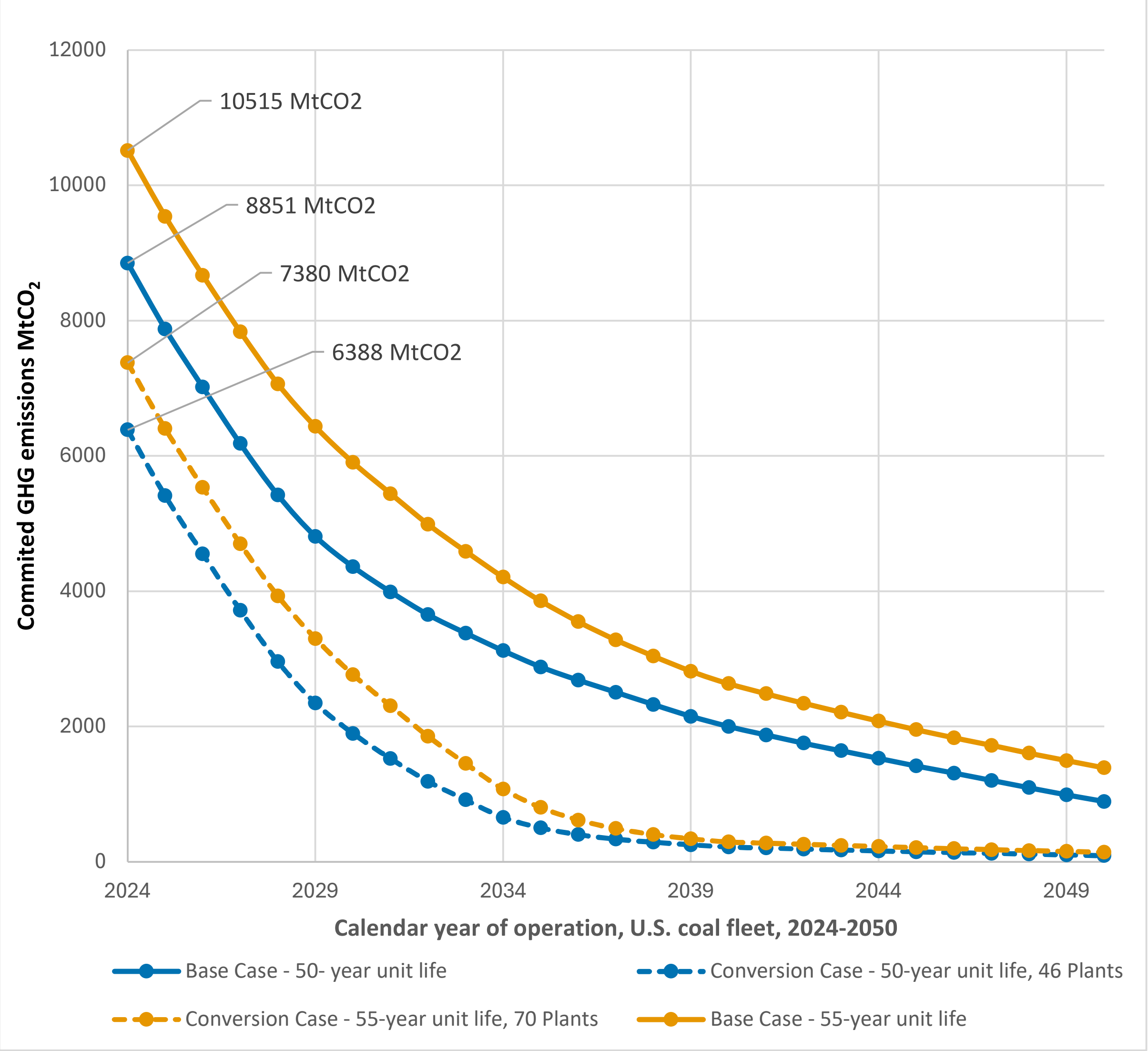


Figure 29. Committed emissions remaining 2024-2050, 55-year unit life versus 50-year unit life, U.S. fleet. For both the 55- and 50-year scenarios a base case is shown where units operate until the end of either an assumed 55- or 50-year unit life or until an announced retirement date. In the 55-year conversion case, 70 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year beginning in 2024. In the 50-year conversion case 46 plants are converted using the same timeline. The number of plants converted corresponds to the number of plants amenable for further conversion consideration based on the unit lifetime and selection criteria described in section 2.3.5.

5.3.2 Comparison with India

Despite a similar coal generation capacity between India and the U.S., the age of India's fleet is much younger. Twenty-nine percent of India's units operating in 2024 are 10 years old or less, compared to less than one percent in the U.S. (calculated from [61]). Units under 25 years old make up 75% of the Indian fleet compared to just 13% in the U.S. The average unit age in 2024 is plotted against the assumed unit lifetime of 50 years for both countries in Figure 30.

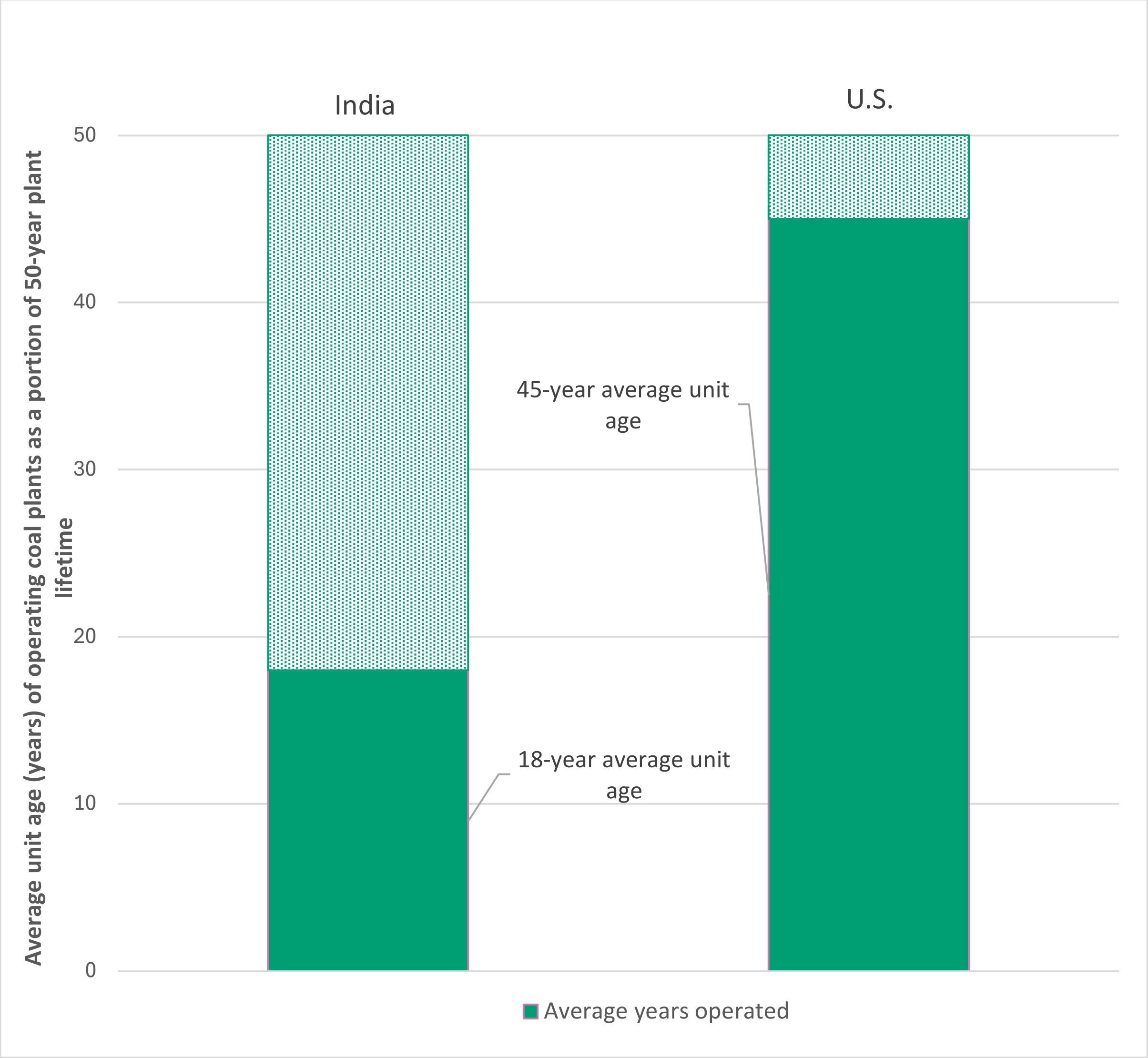


Figure 30. Average age of existing coal units as a percentage of assumed 50-year life, U.S. versus India.

Annual emissions in India were modelled for a base case where coal units operate until the end of an assumed 50-year life, then compared with a 46-plant conversion case, as was done in the U.S. model. The lower ages of India's coal units compared to those in the U.S. contributed to annual emissions in the base case falling year-over-year at a lower rate, since less retirements are expected. In the conversion case, annual emissions are reduced by 14% from the base case in 2034 and continue to add additional reductions until 46 plants are converted in 2038 when annual emissions are reduced by 31%. 2038 annual emission reduction is estimated at 337 $MtCO_2$. This represents a larger reduction than in the U.S. model, due primarily to the larger capacity of India's largest plants in the 46-plant conversion case. Unlike the U.S. case, where no more plants are amenable for conversion consideration after 46 conversions, India has 199 plants meeting capacity and age criteria [61]. Additional conversion cases analysed with 75 and 150 plants result in 61% and 88% annual emissions reductions from the base case. Results are displayed in Figure 31 below, which includes U.S. results for comparison.

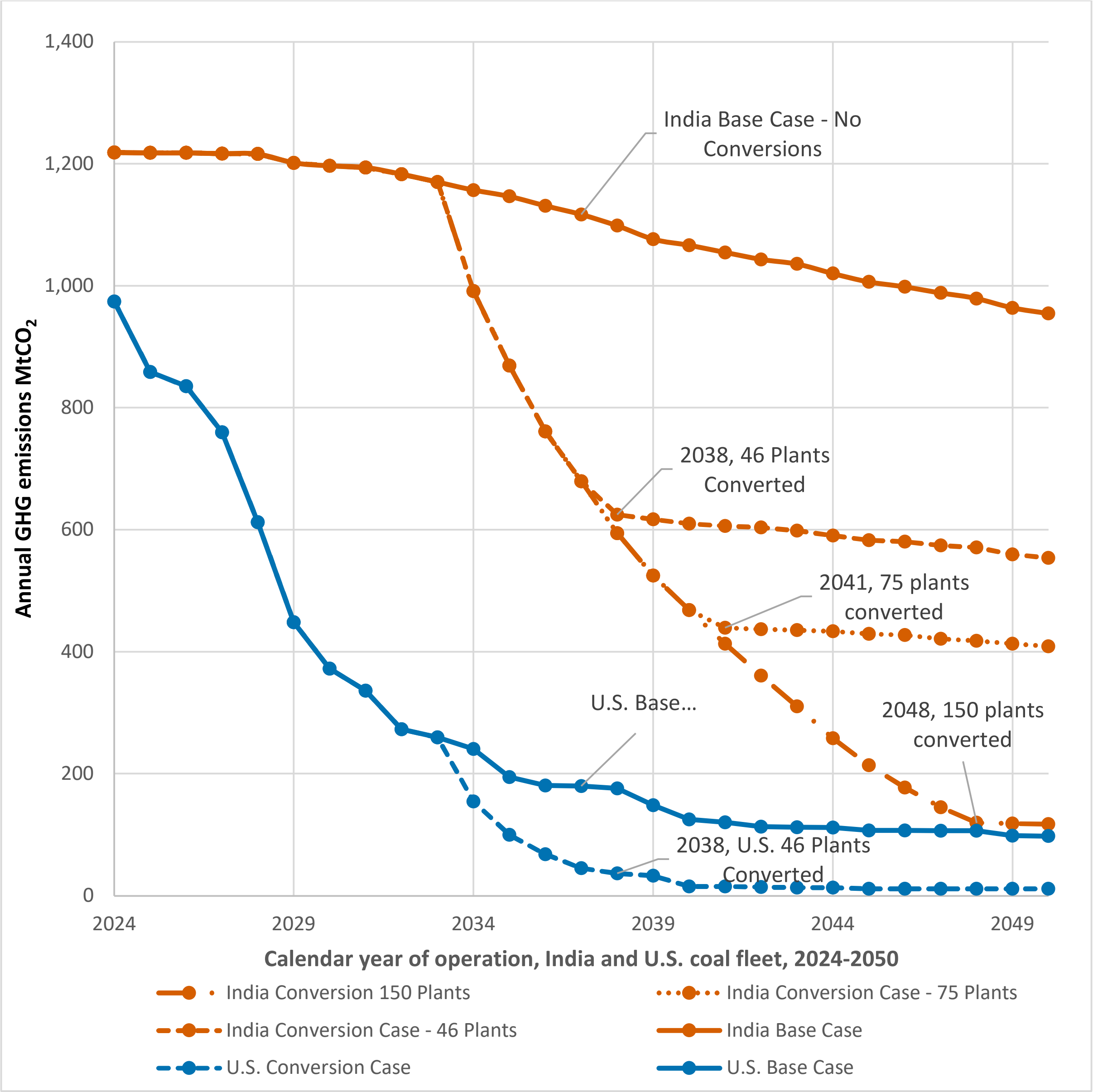


Figure 31. Annual emissions 2024-2050 assuming 50-year unit life, U.S. versus India. In this figure base cases are considered for both U.S. and India where coal units operate until the end of an assumed 50-year unit life or until an announced retirement date. In the U.S. conversion case 46 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year beginning in 2024. For India, three conversion cases are shown representing the conversion from coal to nuclear power at 46, 75, and 150 plants following the same timeline.

Committed emissions were modelled for a base case and three conversion cases, over a 30–70-year range of unit lifetime assumptions. Committed emissions remaining in 2024 for the 46, 75, and 150 plant conversion cases were reduced from the base case by 29%, 39%, and 52% respectively. Simply put, the more plants converted, the greater the decrease in emissions from the base case. Likewise, extending unit life results in increased emissions. The percentage of emissions reduced from the base in conversion cases continues to increase as unit life increases in all cases. Committed emissions remaining in the Indian fleet are plotted over a range of lifetime assumptions in Figure 32.

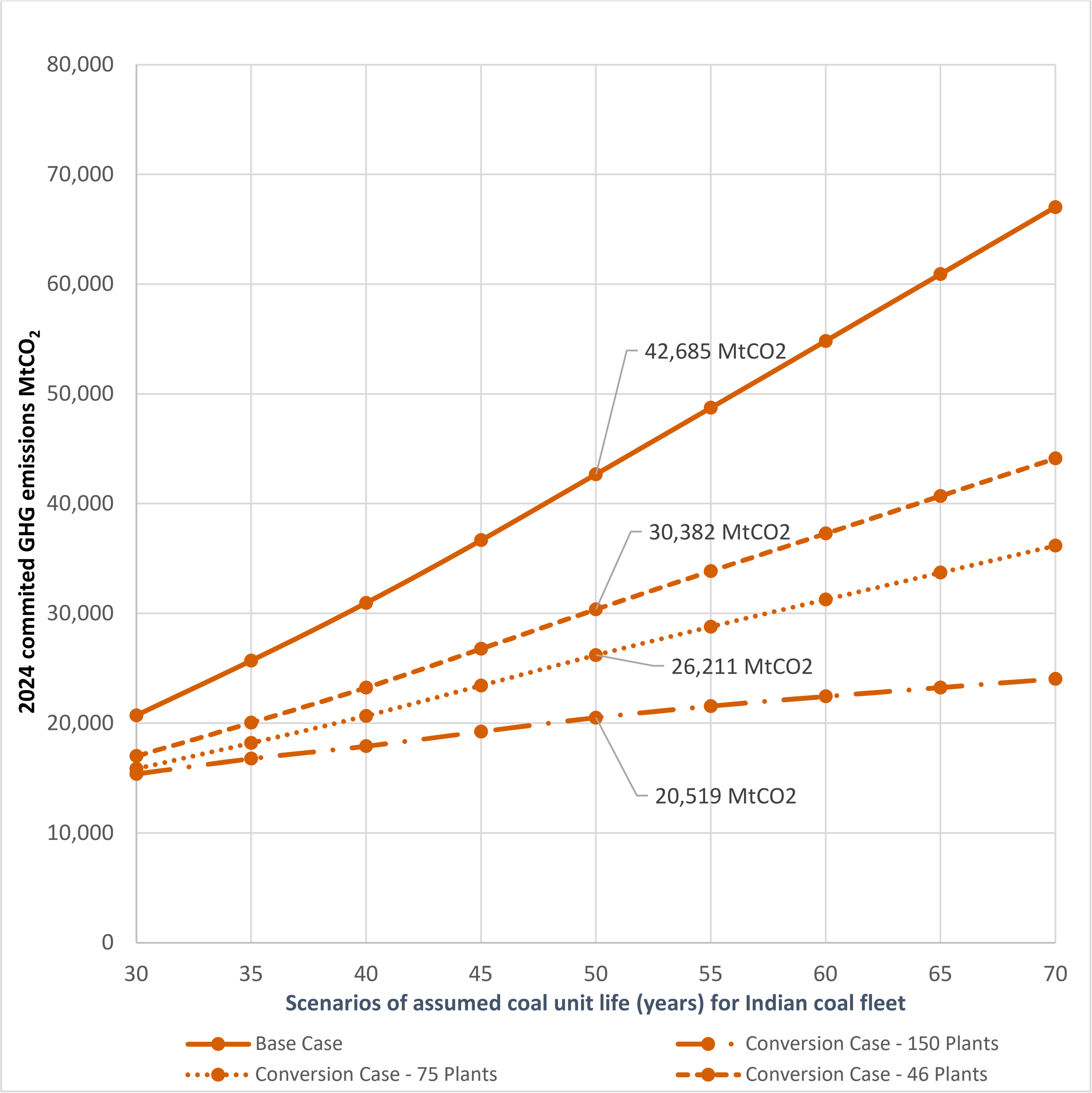


Figure 32. 2024 committed emissions remaining over a range of unit lifetime assumptions, India fleet. This figure shows the results from multiple unit-life scenarios for a base case where coal units operate until the end of the assumed lifetime for that scenario, and for conversion cases where 46, 75, and 150 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year beginning in 2024.

The committed emissions remaining in 2024 assuming a 50-year unit life in Figure 32 are plotted from 2024 to 2050 in Figure 33. Committed emissions remaining in the U.S. over the same period are included in this figure for comparison. Base case committed emissions remaining in the U.S. are 33,834 $MTCO_2$ less than in India, or 21% of India's emissions. In the 46-plant conversion cases, U.S. remaining emissions are 23,994 $MtCO_2$ less than in India, again 21% of the India's emissions. Figure 34 charts committed emissions remaining in 2024, assuming a 50-year plant life, in India and the U.S.

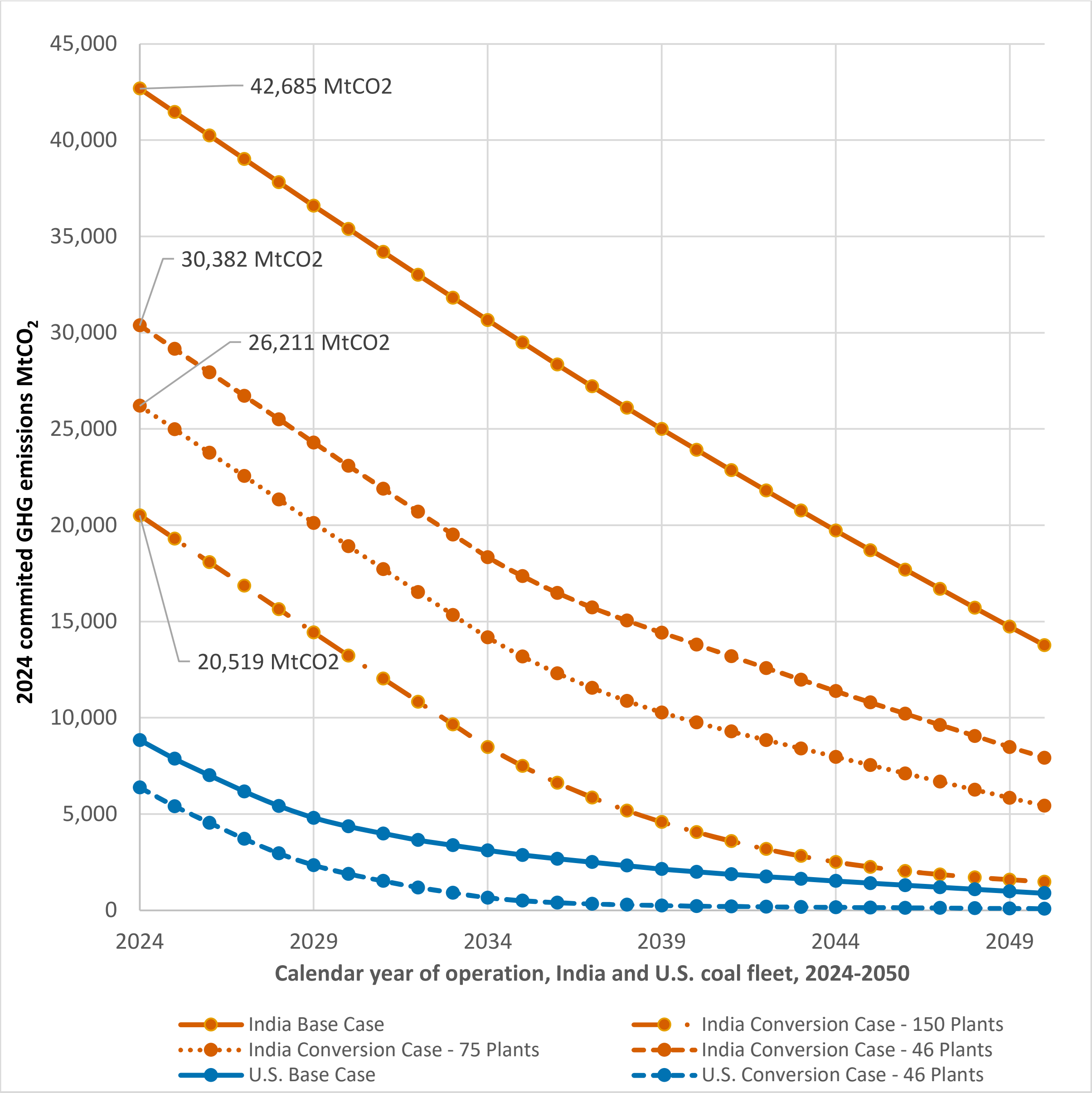


Figure 33. Committed emissions remaining, U.S. versus India, 2024-2050. In the base cases units operate until the end of an assumed 50-year unit life or until an announced retirement date. In the conversion cases, 46, 75, and 150 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year in each country beginning in 2024.

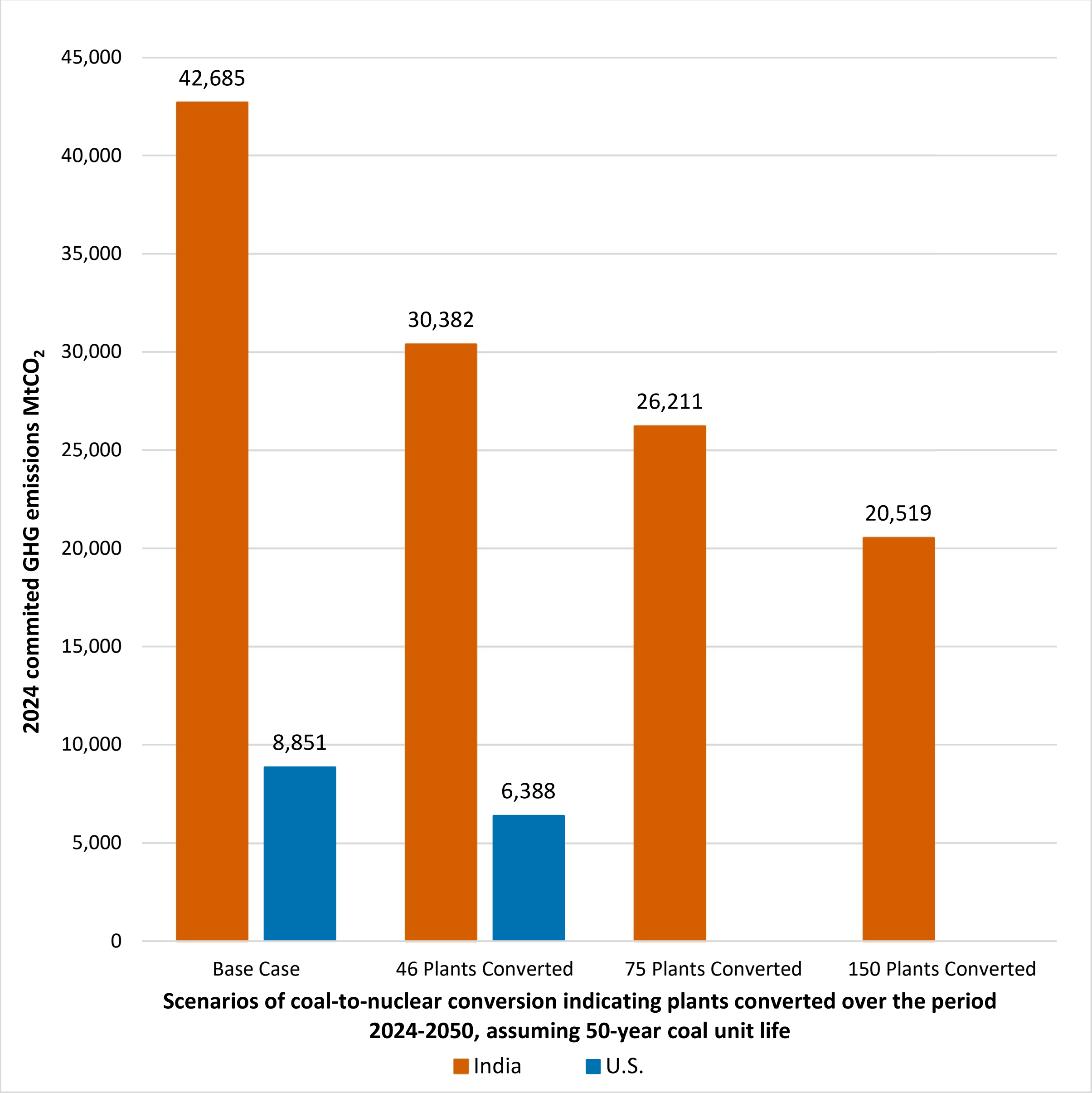


Figure 34. 2024 Committed emissions remaining 2024, U.S. versus India. In the base cases units operate until the end of an assumed 50-year unit life or until an announced retirement date. In the conversion cases, 46, 75, and 150 coal plants are converted to nuclear power at the end of a 10-year conversion project where ten plant conversion projects are started per year in each country beginning in 2024.

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5.4 Discussion and Conclusion

This work considers potential timelines for coal plant conversions to nuclear in the U.S. and India and calculates the resulting emissions to better understand the contribution fleet-scale nuclear conversion campaigns could make to decarbonization goals.

Results demonstrate that while, at present, the U.S. and India have similar installed coal generation capacity and annual emissions, committed emissions remaining in India are approximately five times greater than in the U.S., both for the base case and the 46-plant conversion case. Conversion of 46 plants in India has the potential to reduce remaining committed emissions by 29%. Similarly, conversion of 46 plants in the U.S. will reduce remaining committed emissions by 28%. While the percentage reductions are similar, the potential reduction in India is 12,303 $MTCO_2$, compared to 2,464 $MTCO_2$ in the U.S., or the potential to avoid five times as many emissions in India. Stated another way, a reduction of 12,303 $MTCO_2$ by converting 46 plants in India provides the same impact as stopping all coal power production in India for a decade, or all coal power production in the world (including China whose annual coal power emissions are more than all other countries combined), for 1.2 years (calculated from [61]).

The potential for an extended conversion campaign also differs between the two countries. As mentioned previously, the 46 plants converted in the U.S. model represent all the plants amenable for further conversion consideration assuming a 50-year unit lifetime. In the Indian model, 46 plants represent only 23% of those amenable for conversion consideration, due to the comparatively younger age of India's coal power plant fleet. As more plants are converted in the Indian model, remaining committed emissions continue to decline, offering the potential for a 22,166 $MTCO_2$, or 52%, reduction from the base case after 150 plants are converted.

It can be concluded from this research that converting coal power plants to nuclear plants can offer emissions reductions, but national impact relies heavily on fleet composition. Although older fleets have the potential to offer annual reductions resulting from retirement along with conversions, younger fleets offer greater potential for conversions to reduce committed emissions. Committed emissions are a better indicator of the impact that conversion of coal plants to nuclear energy can make, because they consider the lifetime of the plant.

While nuclear conversions can offer system benefits that result from replacing one dispatchable generation source with another, even aggressive rates of coal-to-nuclear conversions in the U.S. will be a minor contributor to decarbonization. On the other hand, in India, aggressive rates of coal-to-nuclear conversions could be a major contributor to decarbonization.

This study expands on work performed by Hansen [39] where local emissions in coal power plant communities are predicted to experience sizable annual emissions reductions when converting to nuclear power. The findings by Hansen and this work are not contradictory, as the annual impact at the local level can be significant while still making a minimal impact on national committed emissions reduction, especially in the case of an older plant. Local communities may experience benefits from discontinuing coal plant operation beyond decarbonization. Adults living near coal power plants were significantly more likely to suffer from respiratory, gingiva, and skin symptoms than a comparison population in a recent study [53], and air pollution associated with coal plant emissions is associated with increased levels of mortality [54]. Future work could include investigation of emissions reductions available under varying regulatory requirements prompting earlier coal plant closures or increasing the likelihood of extending plant lifetimes. Work could also explore how varying public perception of the impact of emissions on climate change affects national decarbonization policy and goals. Further, additional studies could also investigate decarbonization opportunity under varying climate change scenarios such as Representative Concentration Pathways and Shared Socioeconomic Pathways as described by the IPCC [149].

The limited decarbonization potential from nuclear conversions in countries with mature fleets that have already discontinued new coal power projects should not dissuade decision makers from considering existing coal plants for conversion to nuclear. As trends and models, including those detailed here, illustrate, the capacity lost from retiring coal plants will be replaced and generation increased to meet increasing demand. Nuclear power can fulfil the need for dispatchable power in a reliable electricity system by integrating with other clean energy sources.

CHAPTER 6: ADDRESSING RESEARCH QUESTIONS

6.1 Addressing Research Question 1

Having concluded this research, I am prepared to address research question 1. This question seeks to quantify the value of electrical grid connection and cooling water availability at coal power plant sites when replacing existing coal plants with small nuclear reactors. To evaluate the fleet of U.S. coal power sites I investigated each U.S. coal power plant individually, comparing to various scenarios defining the construction of a new nuclear power plant onsite.

The value of the interconnection at the existing coal power site is calculated as the cost avoided by not needing to pay for a new grid interconnection. Each existing coal power site determined to be amenable for consideration for siting a nuclear reactor was evaluated for potential interconnection savings in a case where a single 300 MW reactor was installed on the site, and another case where the site's electrical capacity was replaced with nuclear reactors. Across the U.S. coal power fleet, the potential value of existing electrical grid connections is $5.3B when a single reactor is installed at each site and exceeds $10B when existing coal plant electrical capacity is replaced, representing 1.3% of the capital cost for the plant.

The value of cooling water availability at existing coal power plant sites is assumed to be the savings from using the existing water supply and cooling method at a coal power plant site compared to a new site nearby. Savings were evaluated by combining the additional cost of water anticipated at new sites with costs from using more expensive cooling methods also expected at new sites. U.S. coal power plant sites were again evaluated for scenarios where a single reactor was installed and a scenario where the cooling capacity of the existing plant was replaced with nuclear reactors. Because reactor cooling includes capital and operating costs, savings were evaluated annually. The value of water availability at the Belews Creek Station site, used as an example when a single reactor was installed, is \$13.2M annually, and \$66.5M when the existing plant’s full cooling capacity is utilized. Across the U.S. fleet the annual value of cooling water availability at existing sites is \$1.7B for a single reactor per site, and \$4.5B for the maximum number of reactors, representing 4.2% of the annual cost of the plant (including capital, operating, and maintenance costs).

This research demonstrates that existing coal power plant sites can provide value to nuclear reactor projects though the existing electrical grid connection and availability of lower cost cooling water and cooling methods. Of the two infrastructure elements investigated at existing plant sites, cooling water represented the larger value when compared to the electrical interconnection.

6.2 Addressing Research Question 2

Upon concluding the research described in Chapters 4 and 5, I am prepared to address research question 2, which involves evaluation of schedule efficiencies resulting from construction of a nuclear reactor on a coal power site. To do so, the project timeline shown in Figure 19 was developed, drawing from project schedules and published information from vendors and generating utilities considering new small nuclear development [84, 135-139]. A project scenario is considered where an operating coal plant is replaced with a nuclear reactor on a different part of the coal power site. The timeline in Figure 19 can be used for the construction of a small nuclear reactor at a coal power site when using the described conversion scenario, or at a different greenfield or brownfield site, as described in the second research question. In Chapter 4 the value of electrical grid connection in different transmission service areas is investigated. In addition to the estimated cost of grid interconnection for a 300 MW nuclear reactor, the estimated wait time in the interconnection queue was determined using recent completed and active project data published in [76, 104-108]. Durations from interconnection request to commercial operation vary depending on the region and size of project. Projects with capacity over 200 MW experienced a median duration of 55 months when evaluated across a range of ISOs and non-ISO balancing areas, with durations up to 80 months excluding outliers [76].

While not investigated in detail, it is assumed that the wait time to connect to municipal water supplies like those described in [99] and water right purchase or auction like those described in [82] will not be longer than the electrical grid interconnection queue. With a 10-year project timeline, there is adequate time to schedule grid interconnection and water supply wait time in parallel with other project activities without delaying the project. The second research question asks if there are cost savings available from a reduced timeline resulting from the existing water and grid connection availability. While the electrical grid connection and cooling water availability at existing coal power sites represents significant value as demonstrated in Chapter 4, no reduction in project timeline is available from the availability of these infrastructure elements, as they may be replicated at another site within the overall duration allotted to the nuclear project.

6.3 Addressing Research Question 3

Having concluded the research described in this chapter, I am equipped to address research question 3. This question seeks to quantify committed emissions that will be avoided by replacing coal plants with nuclear reactors. Having identified a subset of operating coal power plants amenable to conversion to nuclear power as described in Task 1, I developed a timeline for a single plant conversion, then a timeline to convert all U.S. plants considering current operating years, announced retirement, and assumed supply chain capacity for national conversions per year as part of Task 5. I then created a model considering individual unit capacity, fuel heat rate, emission factor, and capacity factor, and the conversion timeline described above as described in Tasks 3 and 4. I then modelled committed emissions remaining and annual emissions for each U.S. plant under various scenarios including different assumed unit lifetimes and considering or disregarding announced planned unit retirements for a case where no plants were converted to nuclear and another where plants were converted following the timeline created to complete tasks 6 and 7. The results showed limited committed emissions reductions available from replacing coal plants with nuclear reactors, largely due to the age of the coal plants, 45 years on average, most of which are scheduled to retire soon. To understand how the possibility for committed emissions reduction in a relatively old coal fleet like that in the U.S. compares with a fleet with similar installed capacity but different unit age characteristics I created a similar model for coal plants in India where the average age of coal units is 18 years. Results of this analysis showed the opportunity for emissions reductions from replacing coal plants with nuclear reactors in the younger fleet were five times greater after converting 46 plants, the smallest plant conversion scenario. The younger fleet showed increased reductions as more plants were converted for up to 150 plants, the largest plant conversion scenario modelled. In Task 7 I analyzed the possible contribution nuclear conversions could have to national decarbonization goals.

These findings are summarized by asserting that converting coal power plants to nuclear plants can offer emissions reductions, but national impact relies heavily on fleet composition. Although older fleets have the potential to offer annual reductions resulting from retirement along with conversions, younger fleets offer greater potential for conversions to reduce committed emissions. Committed emissions are a better indicator of the impact that conversion of coal plants to nuclear energy can make, because they consider the lifetime of the plant. While nuclear conversions can offer system benefits that result from replacing one dispatchable generation source with another, even aggressive rates of coal-to-nuclear conversions in the U.S. will be a minor contributor to electricity sector decarbonization. On the other hand, in India, aggressive rates of coal-to-nuclear conversions could be a major contributor to decarbonization of its electricity sector.

CHAPTER 7: CONCLUSIONS, CONTRIBUTIONS, AND FUTURE WORK

This research aimed to investigate cost savings and decarbonization potential from constructing small nuclear reactors at existing coal plants. Cost savings potential focused on the availability of existing electric grid connections and cooling water sources and methods. Other infrastructure elements remain to be considered in future work. Decarbonization potential considered committed emissions reductions available from replacing coal plants with nuclear reactors.

7.1 Conclusions

Electricity generated by retiring coal power plants must be replaced and national capacity increased to meet projected U.S. electricity demand. Alternatives to fossil fuel, including nuclear power, are included in electricity sector decarbonization roadmaps. Recent projects have been proposed to install small nuclear reactors on the site of existing coal power plants. Replacing coal plants with nuclear reactors presents a zero-emission alternative with higher reliability. The methodology described here has significant potential for enhancing evaluations of individual or group installations of small nuclear reactors when replacing coal plants at existing coal power sites. This research has demonstrated how these processes can be used to evaluate potential savings from water costs and the ability to continue to use an existing cooling method when compared to anticipated higher water costs and the use of more expensive cooling methods at new sites. It has also demonstrated that, when combined with savings from using existing grid connections at coal power plant sites, nuclear projects can expect cost efficiencies that may make these sites preferable to a new site nearby. The fact remains that nuclear power projects are expensive. Cooling water and interconnection costs, along with other considerations (like community support, local workforce, transportation infrastructure, land availability, and others), are factors that should be considered when deciding where to site a small nuclear reactor, after the decision to install nuclear has already been made, but cost savings from one site to another may not be significant enough to influence decisions on generation technology or the decision whether or not to pursue a new generator project. The decision whether to install a new generation source, and the type of generation technology to pursue, is often made with the benefit of energy system modelling. Energy system models evaluate scenarios for capacity expansion that consider financial, technical, regulatory, and policy variables based on design and operation constraints including other generators in the system and hourly electricity supply and demand predictions. To determine if nuclear power is the optimal solution to replace retiring coal generation capacity and meet projected capacity requirements, electrical systems containing coal power sites must be evaluated using energy system models to understand how a new generation technology will integrate with renewable energy sources and other system generators and loads. The anticipated savings from siting a small nuclear reactor at a coal power site that are discovered in this work should be included when programming cost parameters into an energy system model to increase the accuracy of revenue predictions when a suitable coal power conversion site exists.

In addition to researching the impact of existing coal power sites on new nuclear project costs, this work also sought to determine the decarbonization potential from a nationwide coal to nuclear conversion campaign. This work calculates emissions reductions available from converting coal-fired power plants to nuclear plants in both the U.S. and India, the countries having the world’s largest coal-fired power generation capacity outside of China. Various scenarios are used to model potential timelines for coal to nuclear conversions, then determine resulting emissions to help us better understand the impact that a fleet-scale nuclear conversion campaign could have on each nation's decarbonization goals. Results indicate that, while the U.S. and India presently have similar installed coal generation capacity and annual emissions, India's remaining committed emissions are approximately five times greater than those of the U.S. for both a base case and a 46-plant conversion case. It can be concluded that converting coal-fired power plants to nuclear plants can offer emissions reductions, but that the national impact relies heavily on fleet composition. Although older fleets have the potential to offer annual emissions reductions from retirements and conversions, converting younger fleets can have a much greater impact on committed emissions, which is a better indicator of the potential of coal-to-nuclear conversion in global decarbonization. While nuclear conversions can offer system benefits that result from replacing one dispatchable generation source with another, even aggressive rates of coal-to-nuclear conversions in the U.S. will be a minor contributor to electricity sector decarbonization. On the other hand, in India, aggressive rates of coal-to-nuclear conversions could be a major contributor to decarbonization of its electricity sector.

7.2 Research Contributions

This dissertation aims to inform the pre-feasibility process for organizations considering the construction of small nuclear reactors, those considering siting alternatives for a small nuclear reactor, and policy makers balancing economic and environmental considerations of providing reliable electricity for sustained growth while decarbonizing the electric power sector. The research activities presented within this dissertation provide the following contributions:

(1) The development of a model to estimate the value of water availability at existing coal power sites, including the ability to be more precise with water cost and cooling method data for a comparison site, or make assumptions based on historic

water costs and cooling method information. The output of this model indicates potential cost savings available at specific sites that can be used as inputs to an energy system model, and pre-feasibility and feasibility studies. Previously no such examination of the value of cooling water availability at coal power sites has been published.

(2) The further development of a representative timeline for a coal-plant to small nuclear reactor project including a potentially long-lead item in some areas: the electrical grid interconnection.

(3) Identification and quantification of the decrease in electrical generation capacity expected in near-term resulting from retiring coal power plants along with a possible dispatchable replacement alternative in the form of the coal-to-nuclear conversion of these plants. No timeline-inclusive assessment of coal-to-nuclear conversions for the entirety of the U.S. and Indian fleet to quantify committed emissions savings has been published.

(4) The development of a model to evaluate committed and annual emissions reductions expected from replacing coal power plants with nuclear reactors that considers SMR project timelines, supply chain constraints, and individual unit parameters. These models identify that the coal-to-nuclear conversions will play an insignificant role in reducing U.S. committed emissions because of the high rate of coal plant retirements under the analyzed scenario. In contrast, the coal-to-nuclear conversion concept can realize significant decarbonization benefits in the developing world, where the coal fleet is further from planned retirement.

Together, these research contributions describe an overall enhancement to the understanding of how existing power plant sites utilizing fossil fuels like coal can contribute to a clean energy transition through reduced costs for alternative technology projects, and reduced timelines for decarbonization in some instances.

7.3 Future Work

7.3.1 Locational Marginal Price of Electricity

In some areas, wholesale electricity markets rely on locational marginal pricing of electricity to improve the dispatch of resources resulting in cost savings from reduced congestion. Locational marginal prices (LMPs) vary widely at different geographic locations in a transmission network, and at different times of the day and year because of system demand. Coal power plants reside in the existing transmission network, providing a dispatchable source of electricity. The planned retirement of most U.S. coal plants in the coming decades will result in a change in the nation's energy generation source profile, as retiring coal plants will not be replaced with new coal power. Existing coal power sites offer value when considering conversion of the site to a new generation technology because of the infrastructure at the site discussed in this dissertation. In addition to the value of the physical grid interconnection previously described, existing coal sites, through their transmission access, have the continued opportunity to sell electricity on the grid at a price determined by the physical location of the plant. This physical location determines the logical location of the generation node in the transmission operator's LMP pricing system.

To date, no research has been done to determine the value of the physical location of coal power sites in a regional transmission system. Future work could use historical nodal pricing data to develop a generation profile for existing coal power plants and determine how prices at nodes associated with these plants compare with generation node prices across the transmission system, potentially indicating a more favorable geographic location on the grid from a revenue perspective.

7.3.2 Energy Storage

An additional possible opportunity for coal sites is energy storage. Energy storage allows generator owners to either purchase or generate electricity during periods of low demand and sell it during periods of high demand when prices are higher. One nuclear technology, Terra Power's Natrium, includes energy storage as part of its design submitted to the U.S. NRC [57]. The profitability of energy storage relies on node prices that vary adequately to justify the capital expense and efficiency losses associated with storage. Future work will explore if nodes at existing coal power sites offer suitable economic conditions for installing an energy storage device as part of a proposed coal-to-nuclear transition.

7.3.3 Coal Contamination

While existing coal power sites bring opportunities in the form of potential cost savings, they also present challenges. Coal ash contains radioactive elements, uranium, thorium, and others [150]. Research has shown the "Stack Shadow" (~0.6 mi) around the stack has the highest levels of uranium and thorium [151]. Coal dust containing these elements pollutes treetops, buildings, and the soil surrounding the coal plant. When wind blows, this contamination could drift into the nuclear operating zone for years. Coal ash and dust is mixed into existing soils surrounding the plant, which could be introduced into the operating site on workers, equipment, etc. While the presence of radiation should not affect the plant functionally, rigorous radiation monitoring could affect plant operations if contamination is introduced from an operating stack or from local environmental contamination. Coal plants in the U.S. are regulated by the Environmental Protection Agency while a nuclear plant will be regulated by the Nuclear Regulatory Commission. Requirements for monitoring (air, surface, personnel, etc.), and reporting is different between the two. Future work will have to address legacy contamination issues, including questions like:

1) How will radiation from coal ash deposited during the nuclear project construction affect plant operations after start-up when detected with air monitoring sensors, swipes, surveys, etc.?
2) How will environmental radiation resulting from years of ash deposits from the operating coal plant affect nuclear plant operations due to lingering ash in vegetation, soils, buildings, equipment, etc. when detecting radiation while testing for contamination resulting from nuclear power production?

7.3.4 Energy System Modelling

The decision whether to install a new generation source, and the type of generation technology to pursue, is often made with the benefit of energy system modelling. Energy system models evaluate scenarios for capacity expansion that consider financial, technical, regulatory, and policy variables based on design and operation constraints, including other generators in the system and hourly electricity supply and demand predictions. To determine if nuclear power is the optimal solution to replace retiring coal generation capacity and meet projected capacity requirements, electrical systems containing coal power sites must be evaluated using energy system models to understand how a new generation technology will integrate with renewable energy sources and other system generators and loads. Future work could evaluate the energy systems that include coal power plants to determine if nuclear replacement provides the best solution based on different scenarios, including varying costs for nuclear, government incentives, and environmental requirements limiting greenhouse gas emissions.

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