Nuclear Power in the Context of Climate Change

Comparing the Cost of Nuclear and Fossil Fuel Power Plants with a Carbon Tax

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Abstract

Concerns about climate change have led many to advocate for future reliance on nuclear power, a constant low-carbon energy source. But nuclear's high capital costs have historically precluded its ability to be cost-competitive with fossil fuel generators. Would nuclear power be cost-competitive if the climate-change damages of carbon emitters are included in the cost of electricity? A new nuclear power plant built at construction costs recently experienced in the United States and Western Europe could be cost-competitive with coal if there is a reasonably sized carbon tax, but to have costs equal to a new natural gas combined-cycle plant would require a minimum carbon tax of $265 per metric ton of CO_2 averaged over the lifetime of the natural gas plant (approximately $196 per metric ton in 2020). At construction costs 55 percent lower than the average costs of recent Western nuclear projects, nuclear could be a viable option for private investors compared to a natural gas combined-cycle plant, but only if there is a moderately sized carbon tax (a minimum of $70 per metric ton averaged over the next 30 years; roughly $51 per metric ton in 2020) and the projected natural gas price is high.

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List of abbreviations

Abbreviation	Definition
CFPP	Carbon Free Power Project
CO_2	Carbon dioxide
DOE	US Department of Energy
EDF	Électricité de France
EIA	US Energy Information Administration
EPC	Engineering, procurement, and construction
FOAK	First-of-a-kind
GW	Gigawatt
IEA	OECD International Energy Agency
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized cost of electricity
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NEA	OECD Nuclear Energy Agency
NOAK	Nth-of-a-kind
NRC	US Nuclear Regulatory Comission
OCC	Overnight construction cost
PSA	Probabalistic Safety Assessment
SCC	Social cost of carbon
SMR	Small modular reactor
TMI	Three Mile Island
UAMPS	Utah Associate Municipal Power Systems
WACC	Weighted average cost of capital

Introduction

Nuclear power offers a low-carbon option for electricity generation. But it is high-cost relative to fossil-fuel generation, particularly combined-cycle natural gas power plants. Over the past three decades, few nuclear power plants have been built in North America and Western Europe, and in countries such as South Korea and Japan, which have seemingly been able to achieve lower-cost nuclear, the construction of new plants has decreased since the 2011 Fukushima Daiichi nuclear accident.

Even with this recent experience, many who worry about climate change continue to pin their hopes on increased use of nuclear electricity. In a special 2018 report, the Intergovernmental Panel on Climate Change included increasing nuclear generation in most of the primary mitigation pathways for limiting global warming to 1.5°C.[1] Within the context of climate change, the benefits of nuclear energy are clear. Nuclear is a low-carbon energy source, and the actual operation of a nuclear power plant has no greenhouse gas emissions.

The history of nuclear construction and recent nuclear projects in the United States, France, and Finland highlight nuclear's downside: its high cost. The operating and fuel costs of nuclear power plants are low relative to fossil fuel generators. But the initial investment costs, exacerbated by frequent delays and cost overruns, are astronomically high.

When averaged and discounted over the lifetime of a power plant, the total costs of nuclear at the current construction costs are substantially higher than both coal and natural gas power plants. A new nuclear power plant built at the construction costs seen at the most recent projects in the United States and Western Europe would have total lifetime costs of 14.4 cents per

[1] Intergovernmental Panel on Climate Change, *Global Warming of 1.5°C: An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty* (2018).

kilowatt-hour (kWh) of electricity produced. Coal has a cost of 7.9 cents per kWh and natural gas has costs of 3.8 to 5.5 per kWh, with the range of costs depending on whether natural gas fuel prices are assumed to follow the US Energy Information Administration's (EIA) *Annual Energy Outlook* 2022 reference case, lowest, or highest projections for future natural gas prices. A 55 percent reduction in the nuclear construction cost would bring nuclear's lifetime costs in line with coal at 7.9 cents per kWh, but would still be significantly more than natural gas generation regardless of the natural gas price.

Though the costs of nuclear are higher than fossil fuels, if the climate-change damages of the latter were included in the cost of electricity, nuclear energy's low-carbon nature might make it cost competitive.[2] A carbon tax that captures the social cost of carbon emissions could make the avoided emissions of nuclear worthwhile even when its high construction costs are considered.

We calculate what carbon tax level would be necessary to induce private investors in the United States to be willing to invest in nuclear power rather than coal or natural gas generation by comparing the lifetime costs of nuclear and fossil fuel generators and determining the carbon tax required to equate them based on the carbon emissions of coal and natural gas. At the lowest assumed nuclear construction costs, the lifetime costs of nuclear and coal are equal so the minimum carbon tax required is $0 per metric ton of CO_2 emissions over the lifetime of the coal plant. At the average construction costs for recent nuclear plants built in the United States and Western Europe, the minimum carbon tax required for nuclear's lifetime costs to equal coal is $79 per metric ton of CO_2 emissions over the lifetime of the coal plant. If the carbon tax grows over time at a 2 percent annual real rate, this corresponds to a tax of approximately $52 in 2020.

[2] Edward Kee, *Market Failure: Market-Based Electricity Is Killing Nuclear Power* (Washington, DC: Nuclear Economics Consulting Group, 2021).

This is in line with widely accepted estimates of the social cost of carbon, suggesting that nuclear energy is competitive with coal if coal carbon emissions are priced.

With carbon priced, nuclear is competitive with natural gas only under unlikely circumstances. If construction costs could be substantially lower than recent nuclear projects in the United States and the assumed future average natural gas price corresponds to EIA's highest projections, the estimated average carbon tax required for the costs of nuclear generation to equal natural gas generation over their respective plant lifetimes is $70 (or approximately $51 in 2020) per metric ton of CO_2. This is in the range of accepted estimates of the social cost of carbon. At the lower assumed natural gas prices, the estimated average tax is slightly outside the range of accepted carbon taxes at more than $107 ($79 in 2020) per metric ton. With nuclear construction costs more in line with the recent construction experience, the carbon tax sufficient for nuclear to compete is more than $265 ($196 in 2020) even at the highest assumed natural gas price.

Thus, unless nuclear construction costs can be substantially reduced, the carbon tax levels recommended by many analysts are too low to induce private investors to build nuclear rather than natural gas generation units. Even at significantly reduced nuclear construction costs, nuclear would still require a high natural gas price to compete with a new natural gas power plant. The history of nuclear construction in the United States does not support hopes that nuclear's high cost will be reduced.

Nuclear power construction costs

Historically, nuclear power's downside has been construction costs and the question of nuclear power's viability largely rests on whether the high construction costs are an intrinsic characteristic or the result of easily reversed design, construction, or regulatory choices. Nuclear power plants are massive, complex structures built to precise standards. They require some of the largest cranes in the world to assemble and comprise huge amounts of piping, valves, cables, concrete, and steel. However, the scale and difficulties of reactor construction are not entirely exceptional. Nuclear plants do require a great deal of material and labor, but other projects, such as chemical plants and coal power plants are also large and complex.[3] And nuclear construction in Asia has had a more positive track record.

The costs of building nuclear reactors are typically quantified as "overnight construction costs" (OCC), estimated as dollars per unit of electrical capacity of the reactor. The overnight cost only considers the engineering, procurement, and construction costs and other owner's costs (including land, site preparation, project management, and commissioning).[4] It excludes the financing costs incurred during the duration of the project. In other words, the overnight cost estimates the cost of construction as if the reactor was built overnight.[5] OCC's benefit is that it allows for an easier direct comparison between construction projects that take different amounts

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[3] See Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018) and Francesco Ganda et al., "Economic Evaluation of Promising Options," US Department of Energy, Fuel Cycle Research and Development, FCRD-FCO-2015-000013, September 30, 2015.

[4] Some studies exclude non-construction, owner's costs from OCC and owner's costs are frequently excluded in OCC estimates from nuclear vendors. Owner's costs can be substantial and add to the total lifetime costs of a power plant. MIT, EIA and IEA/NEA levelized cost estimates explicitly include owner's costs. Following their convention, when possible, owner's costs are included in the OCC numbers described in this paper. See descriptions of OCC in Yangbo Du and John E. Parsons, "Update on the Cost of Nuclear Power," Center for Energy and Environmental Policy Research no. 09-004, May 2009; Sargent and Lundy, L.L.C., "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies," prepared for EIA, February 2020; and International Energy Agency and OECD Nuclear Energy Agency, "Projected Costs of Generating Electricity," 2020.

[5] Jessica R. Lovering, Arthur Yip, and Ted Nordhaus, "Historical Construction Costs of Global Nuclear Power Reactors," *Energy Policy* 91 (April 2016): 371-382.

of time to complete (and between projects with different financial profiles), but this means that overnight costs can be significantly lower than the actual total capital costs.[6] On average, the financing accounts for 46 percent of the total upfront costs of nuclear power.[7]

The importance of financing costs, which will increase as a construction project takes longer to finish, is especially large when considering that nuclear power plants take years to build and are prone to significant construction delays. In a study on electricity construction projects, Benjamin Sovacool, Alex Gilbert, and Daniel Nugent estimate that nuclear reactor projects experienced an average time overrun of 64 percent and an average cost escalation of about 117 percent. The time overruns of reactors were about the same as hydroelectric projects (around 64 percent) but much higher than thermal plants (around 10 percent), which include power plants that burn coal, natural gas, and biomass. And the cost escalation of nuclear plants was much higher than alternatives, for example 71 percent escalation for hydroelectric and 34 percent for thermal plants.[8] In fact, Sovacool, Gilbert, and Nugent estimate that 97 percent of nuclear construction projects in their sample experienced cost overruns.[9]

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[6] Though financing is excluded from the overnight construction cost, the LCOE calculation in this paper includes an estimate of the financing costs during construction. For a more thorough dialogue on the merits of overnight costs see Jonathan Koomey, Nathan E. Hultman, and Arnulf Grubler, "A Reply to 'Historical Construction Costs of Global Nuclear Power Reactors'," *Energy Policy* 102 (March 2017): 640-643; Alexander Gilbert, Benjamin K. Sovacool, Phil Johnstone, and Andy Stirling, "Cost Overruns and Financial Risk in the Construction of Nuclear Power Reactors: A Critical Appraisal," *Energy Policy* 102 (March 2017): 644-649; and Jessica R. Lovering, Ted Nordhaus, and Arthur Yip, "Apples and Oranges: Comparing Nuclear Construction Costs across Nations, Time Periods, and Technologies," *Energy Policy* 102 (March 2017): 650-654.

[7] Jessica R. Lovering, Arthur Yip, and Ted Nordhaus, "Historical Construction Costs of Global Nuclear Power Reactors," *Energy Policy* 91 (April 2016): 371-382. And for an illustration of how financing costs are affected by the cost of capital and construction time, see Lucas W. Davis, "Prospects for U.S. Nuclear Power after Fukushima," Energy Institute at Haas Working Paper no. 218, August 2011.

[8] Benjamin K. Sovacool, Alex Gilbert, and Daniel Nugent, "Risk, Innovation, Electricity Infrastructure and Construction Cost Overruns: Testing Six Hypotheses," *Energy* 74, no. 1 (September 2014): 906-917.

[9] Benjamin K. Sovacool, Daniel Nugent, and Alex Gilbert, "Construction Cost Overruns and Electricity Infrastructure: An Unavoidable Risk?" *The Electricity Journal* 27, no. 4 (May 2014): 112-120.

In sum, nuclear power plants take a long time to build and large cost overruns are almost guaranteed. Whether or not a nuclear project is a viable investment depends on whether construction costs in the US can be reduced. Historically, nuclear costs have not been competitive, and past experience provides little hope that future projects will be able to contain overnight costs.

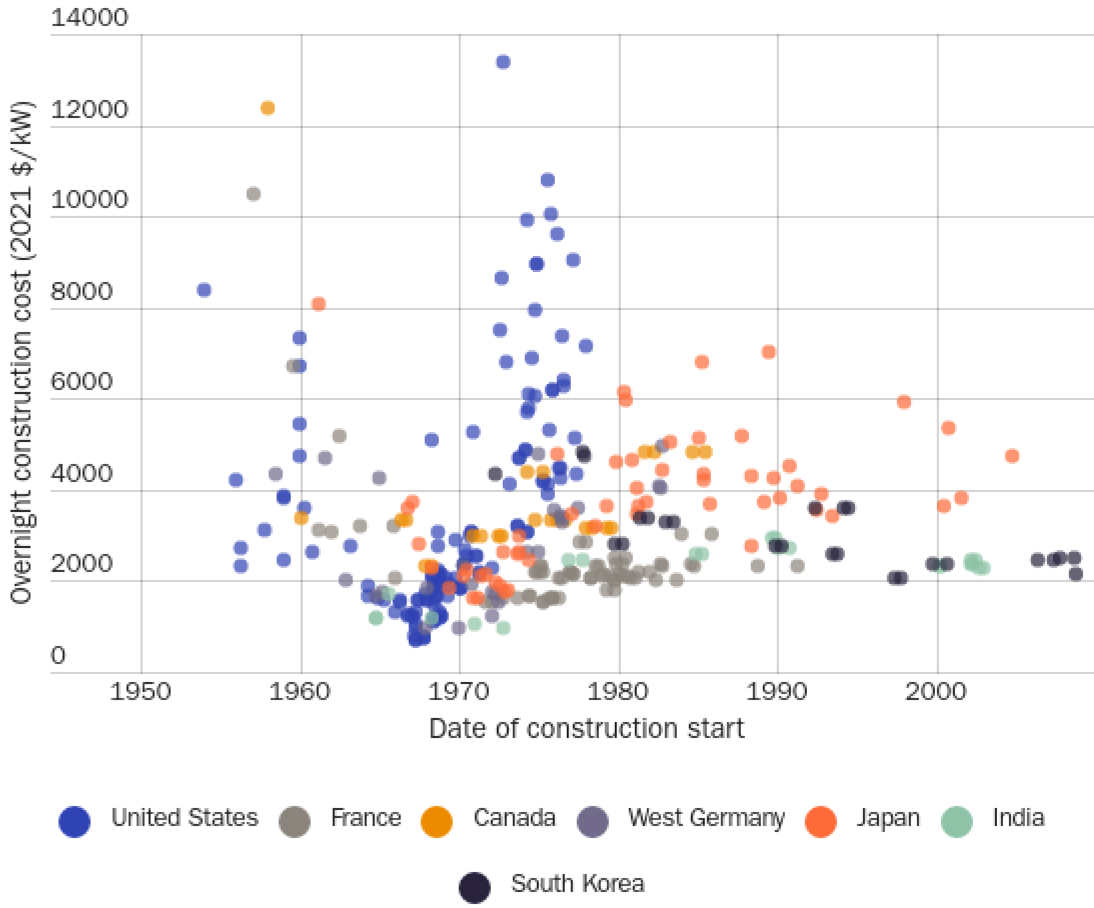
Historical reactor construction costs

Jessica Lovering, Arthur Yip, and Ted Nordhaus provide estimates on historical nuclear power plant overnight costs and give insight on the overall cost trends of reactors built in different countries and eras.[10] In general, as shown in Figure 1, the experience in the West, which includes the United States, France, Canada, and West Germany, is of early small declining cost trends followed by large increasing trends. The experience in Asia, including Japan, India, and South Korea, seems more positive. Their analysis finds that these three countries were able to keep costs level or even maintain slightly decreasing cost trends.

[10] Jessica R. Lovering, Arthur Yip, and Ted Nordhaus, "Historical Construction Costs of Global Nuclear Power Reactors," *Energy Policy* 91 (April 2016): 371-382.

Figure 1

Historical nuclear reactor overnight construction costs



Source: Jessica R. Lovering, Arthur Yip, and Ted Nordhaus, "Historical Construction Costs of Global Nuclear Power Reactors," Figure 12, Energy Policy 91 (April 2016): 371–82.
Note: For comparison purposes, values have been adjusted from 2010$ to 2021$ using the GDP price deflator from BEA.

The cost trends Lovering, Yip, and Nordhaus identify are summarized in Table 1. They classify US reactors into four eras: demonstration reactors that began construction between 1954 and 1968, turnkey reactors started between 1964 and 1967, reactors started between 1967 and 1972 that were completed before the Three Mile Island nuclear accident (TMI), and reactors that were completed post-TMI. The analysis finds that in the first two eras overnight costs declined, but the latter two eras saw significant OCC increases. The 48 pre-TMI reactors had a total OCC increase of 190 percent over the era and the 51 post-TMI reactors had an increase of 50-200 percent.

Table 1

Historic overnight construction cost trends by country and era

Country	Era (defined by time period in which reactors began construction)	Annualized rate of change in OCC* (percent per year)	Total change in OCC by era (percent)
United States	1954–1968, 18 demonstration reactors	–14%	–81%
	1964–1967, 14 turnkey reactors	–13%	–33%
	1967–1972, 48 reactors completed pre-TMI*	+23%	+190%
	1968–1978, 51 reactors completed post-TMI	+5% to +10%	+50% to +200%
France	1957–1966, 7 gas-cooled reactors	–17%	–82%
	1971–1991, 59 light-water reactors	+2% to +4%	+50% to +100%
Canada	1957–1974, 6 reactors	–8%	–77%
	1971–1986, 18 reactors	+4%	+60%
West Germany	1958–1973, 8 reactors	–6%	–63%
	1973–1983, 18 reactors	+12%	+200%
Japan	1960–1971, 11 imported reactors	–15%	–82%
	1970-1980, 13 foreign designs	+8%	+100%
	1980–2007, 30 domestic reactors	–1% to +1%	–17% to +33%
India	1964-1972, 5 imported reactors	–7%	–38%
	1971-1980, 8 domestic reactors	+5%	+150%
	1990–2003, 6 domestic reactors plus 2 imported	–1%	–10%
South Korea	1972–1993, 9 foreign designs	–2%	–25%
	1989–2008, 19 domestic reactors	–1%	–13%

Source: Jessica R. Lovering, Arthur Yip, and Ted Nordhaus, "Historical Construction Costs of Global Nuclear Power Reactors," Table 1, *Energy Policy* 91 (April 2016): 371–82.
Note: *OCC = overnight construction cost; TMI = Three Mile Island.

Experiences in France, Canada, and West Germany are similar, though the scale of cost escalation is smaller.[11] Early reactors started in the 1950s to early 1970s saw construction cost declines over time. But all countries had a later era, from the 1970s into the 1980s when the bulk of their nuclear fleets were built, with large cost increases. The general story in the West is that nuclear construction costs increased as nuclear capacity increased.

This result is the opposite of what would be anticipated for most technologies. As capacity is increased and more construction experience is gained, construction costs are expected to decline as firms learn how to build more efficiently. In the case of nuclear, evidence indicates that there has been a negative "learning effect" in the West.[12] It is difficult to identify the exact causes of the cost increases and negative learning, but it seems that some combination of managerial factors and increasing regulations offset any learning done by individual utilities and construction firms.[13]

Importantly, contrary to some misconceptions the stagnation of the nuclear industry in the United States was not solely a result of increased regulations following TMI. In 1979, unit 2 at Three Mile Island in Pennsylvania experienced a partial meltdown and released a small amount of radioactive material. The actual health impact of TMI was negligible, but the incident brought scrutiny onto the nuclear industry and led to increased safety regulations.[14] Nevertheless, though regulations directly resulting from TMI explain some of the construction cost increases, overnight costs were trending upward before TMI and the nuclear industry was already facing

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[11] There is also reason to believe that the data on OCC for French reactors understate their actual cost. See Jonathan Koomey, Nathan E. Hultman, and Arnulf Grubler, "A Reply to 'Historical Construction Costs of Global Nuclear Power Reactors," *Energy Policy* 102 (March 2017): 640-643.
[12] Arnulf Grubler, "The Costs of the French Nuclear Scale-up: A Case of Negative Learning by Doing," *Energy Policy* 38 (2010): 5174-5188.
[13] Robin Cantor and James Hewlett, "The Economics of Nuclear Power: Further Evidence on Learning, Economies of Scale, and Regulatory Effects," *Resources and Energy* 10 (1988): 315-335.
[14] US Nuclear Regulatory Commission, "Backgrounder on the Three Mile Island Accident."

issues arising from declining growth in electricity demand, high interest rates and costs, and general problems with designing and constructing plants.[15]

Moreover, the expanding nuclear industry of the 1970s was already experiencing growing safety regulation, requiring increases in both the materials and labor needed to build power plants.[16] Econometric analyses from this period estimated that the growth and instability in safety regulations caused a 10-25 percent annual increase in construction costs. [17] One analysis found that regulations accounted for a nearly 70 percent increase in costs from 1967 to 1974, far outweighing any potential learning or improved construction efficiency from building larger reactors.[18] The ramp up of regulatory stringency continued into the 1980s, resulting in increased reactor complexity, demanding higher quality materials and worker qualifications, and causing delays in construction.[19] In the worst cases, regulatory instability compelled extensive reworking mid-construction to meet new higher standards, creating especially large delays and cost overruns.[20]

The scrutiny caused by the Three Mile Island accident and other events in the 1970s might have made increased safety regulation a political necessity.[21] But whether the increased number

[15] Nathan Hultman and Jonathan Koomey, "Three Mile Island: The Driver of US Nuclear Power's Decline?" *Bulletin of the Atomic Scientists* 69, no. 3 (2013): 63-70.
[16] Charles Komanoff, *Power Plant Cost Escalation: Nuclear and Coal Capital Costs, Regulation, and Economics* (New York: Van Nostrand Reinhold Company, 1981); and Jack Devanney, *Why Nuclear Power Has Been a Flop* (Stevenson, WA: CTX Press, 2020), p. 194-195.
[17] Robin Cantor and James Hewlett, "The Economics of Nuclear Power: Further Evidence on Learning, Economies of Scale, and Regulatory Effects," *Resources and Energy* 10 (1988): 315-335.
[18] Soon Paik and William R. Schriver, "The Effect of Increased Regulation on Capital Costs and Manual Labor Requirements of Nuclear Power Plants," *The Engineering Economist* 26, no. 3 (1980): 223-244.
[19] Gordon MacKerron, "Nuclear Costs: Why Do They Keep Rising?" *Energy Policy* 20, no. 7 (July 1992): 641-652; and Electric Power Research Institute, "Advanced Nuclear Technology: Economic-Based Research and Development Roadmap for Nuclear Power Plant Construction," Technical Report, June 2019.
[20] Giovanni Maronati and Bojan Petrovic, "Making Construction Cost Estimate of Nuclear Power Plants Credible: Assessing Impact of Unknown Unknowns," *Nuclear Technology* 207, no. 1 (2021).
[21] Charles Komanoff, "10 Blows that Stopped Nuclear Power," http://www.komanoff.net/nuclear_power/10_blows.php.

and stringency of regulations is necessary from an engineering and economic perspective is not clear-cut. Some regulations are based on actual experience. For example, in 1975 a fire at Browns Ferry Nuclear Plant burned down a cable spreading room that contained cables for several redundant safety systems. The fire prompted the Nuclear Regulatory Commission (NRC) to establish several new fire protection standards, including a requirement that redundant safety systems do not share the same cable spreading rooms.[22]

Are these regulations necessary or excessive? The fire might have encouraged adoption of separate cable spreading rooms for redundant systems as an industry standard without the NRC's intervention. And it is difficult to determine if the regulation is impeding the nuclear industry's ability to find better or more cost-effective alternative methods for ensuring that safety systems are not similarly compromised.

The NRC found that safety related cables at one of the reactor units recently constructed at Vogtle Electric Generating Plant in Georgia did not comply with the cable spreading standard, suggesting that such standards can stop nuclear operators and constructors from repeating past mistakes.[23] But the regulations also initiated a decades long battle between the NRC and nuclear operators, with the operators claiming that the fire protection standards were unnecessary and too expensive.[24]

Some NRC regulations are based on potential accidents with exceedingly low likelihood. For example, because of the September 11 terrorist attacks, in 2009 the NRC imposed a new rule requiring that reactor designs be able to show that reactor containment structures and spent fuel

[22] US Nuclear Regulatory Commission, "The Browns Ferry Nuclear Plant Fire of 1975 Knowledge Management Digest," Office of Nuclear Regulatory Research NUREG/KM-0002, May 2013.
[23] "U.S. NRC Finds Cable Raceway Issues at Georgia Vogtle Nuclear Unit," Reuters, August 27, 2021.
[24] François Lévêque, *The Economics and Uncertainties of Nuclear Power* (Cambridge University Press, 2014).

cooling pools are able to withstand the impact of a large commercial aircraft.[25] The probability of a nuclear plant needing to survive the impact of an airliner is very small, though there are potentially large damages if such a strike does happen and the integrity of the reactor is not maintained. The containment structure of a nuclear reactor is a significant part of the overall cost and building to such a high standard adds a considerable amount to construction costs.

According to some measures, more expensive reactors are in fact safer reactors. Analyzing historical costs in France, economists Lina Escobar Rangel and François Lévêque find that higher costs are correlated with higher reactor safety according to indicators of reactor reliability and accident risk.[26] But they note that their analysis does not tell us the cost-effectiveness of the safety investments. In other words, increased safety increases nuclear costs, but we do not know whether the associated cost increases are worthwhile when considering that a serious nuclear accident is both incredibly unlikely but also potentially very damaging.

Though some portion of cost escalation is the result of regulation, the high overnight costs have also been caused by management problems and design decisions separate from regulatory oversight. The size of nuclear reactors has grown over time. In theory, a larger reactor could benefit from economies of scale. As the electrical capacity of a reactor increases the cost per kilowatt (kW) of capacity could decrease. In practice, longer construction times and more project complexity have resulted in cost increases.[27]

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[25] US Nuclear Regulatory Commission, "Aircraft Impact Assessment," *Code of Federal Regulations,* Title 10, § 50.150.

[26] Lina Escobar Rangel and François Lévêque, "Revisiting the Cost Escalation Curse of Nuclear Power: New Lessons from the French Experience," Mines ParisTech, 2012.

[27] Robin Cantor and James Hewlett, "The Economics of Nuclear Power," Further Evidence on Learning, Economies of Scale, and Regulatory Effects," *Resources and Energy* 10 (1988): 315-335; and Benjamin K. Sovacool, Alex Gilbert, and Daniel Nugent, "Risk, Innovation, Electricity Infrastructure and Construction Cost Overruns: Testing Six Hypotheses," *Energy* 74, no. 1 (September 2014): 906-917.

Nuclear construction has additionally experienced labor management issues. Philip Eash-Gates et al studied the causes of cost increases in the nuclear industry and determined that, while general US construction productivity (as measured by material deployment) has declined since the 1970s, the decline in nuclear construction productivity has been even larger than average. They conclude this is in large part explained by labor management problems:

> Material deployment rates in the construction industry decreased over the period of study, falling about 14 [percent]…. Nevertheless, deployment rates in nuclear construction declined more dramatically, with a precipitous drop between 1979 and 1980 following the Three Mile Island accident. Compared with the construction industry at large, nuclear deployment rates declined five to six times more quickly. This productivity decline was a primary cause of nuclear cost increase. Labor interviews provide insight into some of the causes of declining productivity, pointing to problems experienced in the field. Craft laborers, for example, were unproductive during 75 [percent] of scheduled working hours, primarily due to construction management and workflow issues, including lack of material and tool availability, overcrowded work areas, and scheduling conflicts between crews of different trades.[28]

[28] Philip Eash-Gates et al., "Sources of Cost Overrun in Nuclear Power Plant Construction Call for a New Approach to Engineering Design," *Joule* 4, no. 11 (November 2020): 2360.

The relative shares of nuclear cost escalation attributable to regulation, managerial shortcomings, and low labor productivity are difficult to determine. Eash-Gates et al evaluate cost increases by looking at the containment structure and classify the causes of cost-escalation into three categories: Research and development (R&D), which reflects increased costs caused by fundamental design changes; "process interference, safety" (PIS), which represents the interventions of NRC and other safety personnel; and "worsening despite doing" (WDD), representing decreases in the performance of construction workers. The paper argues that the three categories each account for a quarter to a third of the cost increases, but notes that disentangling the impacts of safety regulations and non-safety related activities is difficult:

> While safety-related considerations likely had an influence on many of the high-level mechanisms studied here, the mechanism most directly related to compliance with regulations is PIS, which contributed approximately 30 [percent] to the observed cost increase between 1976–2017. The mechanism representing R&D activities typically addresses multiple objectives at once, and it is thus more difficult to strictly separate this into safety- and non-safety-related activities, and the same holds for productivity slowdowns reflected in "WDD." However, despite these difficulties, it is relevant to note that direct interference to address safety contributed significantly to cost increases observed (roughly 30 [percent]) but was not the only driver of cost escalation.[29]

[29] Philip Eash-Gates et al., "Sources of Cost Overrun in Nuclear Power Plant Construction Call for a New Approach to Engineering Design," *Joule* 4, no. 11 (November 2020): 2363.

The US cost escalation associated with regulation and ineffective construction management occurred at a time when nuclear construction was booming, implying that any benefits created by a learning effect for individual firms were at their peak but were entirely offset by these other factors. Today, high costs are likely compounded by the fact that the companies building reactors in the United States have either no nuclear construction experience or have not built a reactor in decades. No one should be surprised that recent projects have been defined by construction delays, cost overruns, and bankruptcies.

Recent construction of Western reactor designs

Nuclear construction stagnated in the United States and Europe in the 1980s and 1990s, but the Energy Policy Act of 2005 contained subsidies to restart reactor construction.[30] Nevertheless, nuclear power remained uncompetitive because of its high construction costs and construction delays. A 2009 MIT report on nuclear power asked, "Will construction proceed on schedule and without large cost overruns? The first few U.S. plants will be a critical test for all parties involved."[31] Nine years later, MIT's 2018 report on nuclear power concluded, "Actual experience with the first few new builds…in the United States and Western Europe failed that test spectacularly."[32]

Construction in the West has started with two new reactor designs, the AP1000 designed by Westinghouse built at Vogtle in Georgia (and at V.C. Summer in South Carolina until the project was canceled in 2017) and the EPR designed by Électricité de France (EDF), Areva, and Siemens built at Flamanville in France and Olkiluoto in Finland. In all cases, construction costs

[30] World Nuclear Association, "US Nuclear Power Policy," August 2021.
[31] John M. Deutch et al., *Update of the MIT 2003 Future of Nuclear Power* (MIT, 2009), p. 8.
[32] Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018), p. 35.

of these new designs have exceeded forecast costs and taken much longer than planned. While the reasons for the delays vary by project, the common themes have been issues with construction management, problems with manufacturing plant components and supply chains, and a low level of design completion at the outset of construction.

Table 2

Forecasted and actual construction times and overnight construction costs for recent nuclear reactors built in the United States and Western Europe

			Construction time (years)			OCC (2021 $/kW)		
Reactor	**Design**	**Construction start**	**Forecast**	**Actual**	**Overrun**	**Forecast**	**Actual**	**Overrun**
Vogtle 3&4	AP1000	2013	5	10	100%	5,500	11,050	101%
V.C. Summer 2&3	AP1000	2013	5	N/A	N/A	4,350	N/A	N/A
Olkiluoto 3	EPR	2005	5	17	240%	3,070	8,390	200%
Flamanville 3	EPR	2007	5	17	240%	2,990	8,850	212%

Sources: Authors' calculations. Forecasted construction times and overnight costs based on Jacopo Buongiomo et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018). Nominal projections are adjusted to 2021 dollars using GDP price deflator from BEA. Actual construction times and overnight costs are based on the most recent projections. Estimates for Vogtle are from Georgia Power, "Twenty-Sixth Semi-Annual Vogtle Construction Monitoring Report," Docket No. 29849, February 2022. Georgia Power's share of the project costs is 45.7 percent. Olkiluoto actual OCC is from *The World Nuclear Industry Status Report 2018* (Paris: Mycle Schneider Consulting, 2018). Flamanville actual OCC and construction time are from Benoit Van Overstraeten and Benjamin Mallet, "EDF Announces New Delay and Higher Costs for Flamanville 3 Reactor," *Reuters*, January 12, 2022. Flamanville and Olkiluoto costs are adjusted for inflation using country's GDP deflator and then converted to US dollars using 2021 average exchange rate.

As anticipated, these projects have experienced "first-of-a-kind" (FOAK) costs.[33] The first build of a new type of reactor has costs that will not be incurred by future builds as the technology matures. These include non-recurring costs, such as design, testing, licensing, certification, and supply chain training and qualification costs that will be amortized over the

[33] It is charitable to consider all four AP1000s and both EPR projects as first-of-a-kind projects because only the *first* project can truly be FOAK. This is especially true of the AP1000, since the first four reactors started construction in China in 2009, making the reactors at Vogtle and V.C. Summer the fifth through eighth units of the reactor design to start construction. However, because the projects are being built by different utilities, construction contractors, and utilizing different supply chains, and because the Vogtle and V.C. Summer AP1000s were built nearly simultaneously, they can all in some sense be considered FOAK.

first reactors of a design to be built.[34] Assuming that a series of identical reactors is built by the same construction firms and vendors, after a certain amount of nuclear capacity is constructed new reactors are expected to have "nth-of-a-kind" (NOAK) costs. These are the repeat, inherent costs of building each reactor after the FOAK costs have been fully amortized and the firms involved have learned how to build more efficiently.[35] Estimates for the cost premium experienced by FOAK reactors compared to NOAK range from 15-55 percent.[36]

Even when considering this potential premium, the size of the cost overruns for the early AP1000 and EPR builds belie predictions that these new designs would be more economical than historical reactors. Their experience exemplifies many of the systemic problems facing new nuclear construction and reaffirms concerns that nuclear power plants are large financial risks.

The AP1000 – Vogtle and V.C. Summer

The most recent nuclear projects in the United States were four planned AP1000s at two existing nuclear plants, Virgil C. Summer Nuclear Generating Plant in South Carolina and Vogtle Electric Generating Plant in Georgia. Both plants are in regulated markets, with guaranteed rate-of-return regulated prices ensuring cost recovery. At V.C. Summer, South Carolina Energy and Gas and Santee Cooper, a state-owned electric utility, contracted with Westinghouse to build two new reactors, units 2 and 3 at the plant. In Georgia, a group of four utilities, with Georgia Power Company owning the largest share, contracted with Westinghouse

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[34] OECD Nuclear Energy Agency, "Unlocking Reductions in the Construction Costs of Nuclear: A Practical Guide for Stakeholders," 2020.
[35] Economic Modeling Working Group of the Generation IV International Forum, "Cost Estimating Guidelines for Generation IV Nuclear Energy Systems," September 26, 2007.
[36] See OECD Nuclear Energy Agency, "Reduction of Capital Costs of Nuclear Power Plants," 2000; Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018), p. 35; Robert Rosner, Stephen Goldberg, Joseph S. Hezir, and Edward M. Davis, "Analysis of GW-Scale Overnight Capital Costs," Energy Policy Institute at the University of Chicago, November 2011; and OECD Nuclear Energy Agency, "Nuclear New Build: Insights into Financing and Project Management," 2015.

to build units 3 and 4 at Vogtle. Construction officially began on V.C. Summer unit 2 on March 9, 2013 with the pouring of the base mat concrete and for Vogtle's unit 3 three days later, on March 12, 2013, although considerable site preparation work was done before the official start of construction.

On paper, both projects looked able to address past issues with nuclear construction costs. Like many nuclear projects, the AP1000 benefited from a large amount of federal subsidies. The AP1000 and the reactor it was developed from, the AP600, received hundreds of millions in R&D subsidies as part of the DOE's Advanced Light Water Reactor program.[37] Created in the late 1980s, the program sought to guide development of the next generation of reactors and help them meet the regulatory requirements of the NRC.[38] In 2005, the AP1000 became the first of a new generation of reactor designs to be approved by the NRC.[39]

Being first helped sell the reactor to prospective customers, especially considering a new wave of nuclear subsidies offered on a first-come, first-served basis. Along with federal loan guarantees, the Energy Policy Act of 2005 created a new production tax credit of 1.8 cents per kWh for the first 6,000 MW of nuclear capacity and federal risk insurance of up to $2 billion to offset cost overruns caused by regulatory delays for the first 6 advanced nuclear plants built.[40] Thus, there was an incentive to be among the first new nuclear plants constructed, and at the time the AP1000 was the only advanced reactor design approved.

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[37] Department of Energy, "U.S.-Chinese Agreement Provides Path to Further Expansion of Nuclear Energy in China," December 16, 2006.
[38] J.J. Taylor, K.E. Stahlkopf, and J.C. DeVine, Jr., "Advanced Light-Water Reactor Development in the United States," IAEA Bulletin 3 (1989).
[39] US Nuclear Regulatory Commission, "Issued Design Certification – Advanced Passive 1000 (AP1000)," November 10, 2020.
[40] World Nuclear Association, "US Nuclear Power Policy," August 2021.

Vogtle and V.C. Summer were also the first projects to be certified by a new regulatory licensing process created to address criticisms of NRC licensing procedures. Historically, nuclear plants were licensed under a two-step process that gave permission for a plant to begin construction and then required a separate application for approval to operate the plant later on in construction. This engendered large administrative burdens, more variability in plant design, and regulatory instability.[41] First created in the late 1980s, Part 52 licensing attempts to address these problems by creating a combined construction and operating license (COL). Reactor designs are approved through a separate process, companies then apply for early site permitting, and finally for the COL. As long as the reactor is built according to the approved design and COL, the owner has conditional authority to operate the plant when it is completed. In theory, this would create a more stable regulatory environment and reduce financial risk. It also would encourage reactor standardization, allowing for more learning-by-doing.

The AP1000 additionally includes design features that promised to make it both safer and more economical. Chief among these is its passive safety systems, which use natural air circulation, gravity, and compressed gas to increase safety without the need for operator action or an outside power source. These systems are much simpler than existing reactor safety systems, meaning the AP1000 would be cheaper to build. Westinghouse estimated that it requires 51 percent fewer safety valves, 34 percent fewer pumps, 83 percent less safety piping, and 87 percent less cable than a similar sized conventional reactor.[42] The reactor was also designed to

[41] Stephen G. Burns, "Looking Backward, Moving Forward: Licensing New Reactors in the United States."
[42] T.L. Schulz, "Westinghouse AP1000 Advanced Passive Plant," *Nuclear Engineering and Design* 236 (2006): 1547-1557.

have a much smaller footprint, requiring less than a fifth of the concrete and rebar needed to build existing reactor designs with the same electric capacity.[43]

And the building process sought to limit previous on-site construction delays by relying on modular construction. Pieces of the plant would be constructed in factories off-site, then shipped to the location for assembly. The AP1000 is made up of over 270 modules, which Westinghouse predicted would help reduce the construction schedule, required manpower, and site congestion while allowing for better quality control in the factory. All told, Westinghouse estimated that an AP1000 would take 36 months to build, have a capital cost 20-30 percent lower than other reactors, and would ultimately lead to a cost of 3-3.5 cents per kWh of electricity generated at a twin unit plant.[44]

Furthermore, the contracts between the utilities and Westinghouse and the engineering, procurement, and construction (EPC) firms also seemed to put in place incentives to keep delays and overruns to a minimum. The contracts had "guaranteed substantial completion dates" around three years after construction began, and payments to Westinghouse and construction firms were made on the basis of milestones completed.[45] Failure to deliver the plants on time meant financial damages for the constructors; they also bore responsibility for cost overruns caused by mismanagement.

Based on these aspects of the AP1000's design and the agreements between the utilities and EPC contractors, there were initially optimistic forecasts of the new reactors' costs and construction times. Construction on both projects was planned to start in 2011 and commercial

[43] Paolo Gaio, "AP1000: The PWR Revisited," Presentation at the IAEA International Conference on Opportunities and Challenges for Water Cool Reactors in the 21st Century, October 27, 2009.
[44] T.L. Schulz, "Westinghouse AP1000 Advanced Passive Plant," *Nuclear Engineering and Design* 236 (2006): 1547-1557.
[45] Sonal Patel, "How the Vogtle Nuclear Expansion's Costs Escalated," *Power*, September 24, 2018.

operation for the first reactors was projected to begin in 2016. Vogtle was expected to cost $5,500 per kW, and projections for V.C. Summer were even more optimistic at $4,350 per kW.[46]

However, the projects faced problems, caused both by regulations and by construction management issues, from the beginning. Before construction started, Westinghouse was forced to submit revisions to its design to meet new NRC standards, including that the containment structure be able to withstand an aircraft impact and earthquakes.[47] And in 2012 the NRC determined that rebar installed for the base mat of Vogtle unit 3 did not follow the reactor design, leading to a six-month delay to figure out and get approval for a fix.[48] Thus, official construction, typically measured when concrete for the base mat is poured, did not begin until March 2013 for both Vogtle and V.C. Summer. Throughout construction, the modularization ran into difficulties; the contractors had problems constructing modules and with quality control at their manufacturing facility in Lake Charles, Louisiana.[49]

By 2017, both projects were years behind schedule and billions of dollars over estimated costs. Because of its liability for the two projects, Westinghouse declared bankruptcy, putting the projects in further jeopardy and making their future uncertain. South Carolina Energy and Gas decided to abandon construction at V.C. Summer, while Georgia Power and its partner utilities chose to continue at Vogtle, despite a Georgia Public Service Commission report that the project was no longer economical.[50] The separate outcomes arose from differences in federal loan and Westinghouse's, and its parent Toshiba's, project guarantees. Toshiba owed a guarantee of $3.68

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[46] Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018), p. 220-222. Adjusted to 2021 dollars using GDP price deflator from BEA.
[47] Tom Hals and Emily Flitter, "How Two Cutting Edge U.S. Nuclear Projects Bankrupted Westinghouse," *Reuters*, May 2, 2017.
[48] Rob Pavey, "NRC Says Vogtle Rebar Differs from Approved Design," *The Augusta Chronicle*, April 26, 2012.
[49] Sonal Patel, "How the Vogtle Nuclear Expansion's Costs Escalated," *Power*, September 24, 2018.
[50] Darrell Proctor, "Georgia Regulators: Change Vogtle Economics or Cancel Project," *Power*, December 4, 2017.

billion for the Vogtle project, compared to $2.17 billion for V.C. Summer. At the same time, Vogtle also had Department of Energy guarantees for more than $8 billion in loans borrowed at a below market rate, while V.C. Summer did not.[51] These loan guarantees were intended to reduce Vogtle's financing costs, allowing for a successful project that would help lead to a revival of the US nuclear industry.

Of course, even with the decision to move forward at Vogtle, its litany of construction problems and V.C. Summer's failure have so far delayed any rebirth of nuclear power in the United States. The start of commercial operation at Vogtle 3 and 4 continues to be pushed back, most recently until the end of 2022 for unit 3 and middle of 2023 for unit 4.[52] Project costs have reached more than $28 billion, not including the $3.68 billion paid by Toshiba, and though Georgia Power has so far capped the costs to be recovered from rate-payers it may request rate increases in the future.[53] The most recent projections put the total OCC at Vogtle at over $11,000 dollars per kW, more than double initial forecasts.[54] At V.C. Summer, the project has cost South Carolina rate-payers over $2 billion out of the total costs of over $9 billion for two reactors that were never completed.[55] Despite the seeming promise of the AP1000, early experience has been abysmal.

Like the historical record of reactor construction, determining the underlying causes of the delays and overruns at Vogtle and V.C. Summer is difficult. The effects of regulations and

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[51] Department of Energy, "Secretary Perry Announces Financial Close on Additional Loan Guarantees During Trip to Vogtle Advanced Nuclear Energy Project," March 22, 2019.
[52] Darrell Proctor, "Vogtle Start Dates Pushed Back Again," *Power*, October 23, 2021.
[53] Jeff Amy, "'Outrageous' Price Tag: Plant Vogtle Cost Doubles to $28.5 Billion as Other Owners Balk," *The Augusta Chronicle*, November 4, 2021.
[54] Georgia Power's 45.7 percent share of the total construction costs is outlined in Georgia Power, "Twenty-Sixth Semi-Annual Vogtle Construction Monitoring Report," Docket No. 29849, February 2022.
[55] Avery G. Wilks and Andrew Brown, "3 Years Later: How the Fallout from SC's $9 Billion Nuclear Fiasco Continues," *The Post and Courier*, July 30, 2021.

mismanagement are hard to disentangle, and the utilities, Westinghouse, construction contractors, and NRC all have incentives to place blame on each other. Responsibility is even harder to determine considering that legal liability for the cost overruns, in part, depends on whether the construction delays have been caused by unforeseen regulatory requirements or construction mismanagement. For example, early in construction Westinghouse sued Georgia Power claiming that Georgia Power owed for cost increases caused by changes to the reactor design required by regulators, while Georgia Power claimed that the cost overruns were the consequence of Westinghouse's management deficiencies.[56]

Ultimately, the predicted costs and construction timeline drastically overstated the ability of the innovations of the AP1000 to reduce capital costs through unproven construction techniques, while underestimating the difficulties of achieving the high-quality control standards of nuclear construction. As the 2017 *World Nuclear Industry Status Report* recounted:

> The most significant delays have been due to the 'innovative' design and the challenges created by the untested approach to manufacturing and building reactors. The AP1000 manufacturing method of using prefabricated parts when the supplier was unable to guarantee quality control and compliance with NRC regulations clearly has been costly failure. These have led to major conflicts between contractors and client.[57]

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[56] Anya Litvak, "Westinghouse Clashes with Georgia Power over Nuclear Plant Cost Overruns," *Pittsburgh Post-Gazette*, October 19, 2013.

[57] *The World Nuclear Industry Status Report 2017* (Paris, Mycle Schneider Consulting, 2017).

Whether the high standards are the solely the result of burdensome regulations by the NRC or an inherent characteristic of building a safe nuclear reactor is a difficult engineering question. Recent experience with the EPR built in countries with different regulatory regimes suggests that some of the cost escalation problems go beyond NRC overregulation.

The EPR – Finland and France

Like the AP1000, the EPR has seen construction delays and cost overruns at Olkiluoto, Finland and Flamanville, France. The reactor was developed by EDF, Areva, and Siemens, based on the French N4 and German Konvoi reactor designs. It promised more advanced active and passive safety systems, more efficient use of uranium, and lower capital costs through economies of scale (Areva predicted that the reactor's larger 1600+ MW capacity, compared to 1450 MW for the N4 and 1300-1400 MW for the Konvoi, would offset the cost of the advanced safety systems).[58]

Construction began on Olkiluoto unit 3 in 2005 under a turnkey contract between the Finish utility TVO and Areva and Siemens. The project had an initial predicted cost of €4.2 billion (in 2021 euros, translating to an overnight cost of about $3,070 per kW) and was expected to take 56 months.[59] But it has faced continuous cost escalations and delays caused by quality control issues, including concrete irregularities and deficient welds, and difficulties managing a force of subcontractors speaking different languages. Most recently, fuel loading was delayed because of the discovery of faulty valves that had already gone through quality control checks, leading to

[58] Werner Brettschuh and Dieter Schneider, "Modern Light Water Reactors – EPR and SWR 1000: Present Status and Possibilities of Development and Application," translation of article printed in *ATW: International Journal of Nuclear Power* 46, no. 8/9 (August/September 2001).
[59] Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018), p. 220. Adjusted to 2021 euros using GDP price deflator for Euro area from FRED. Converted to 2021 dollars using average exchange rate for 2021.

investigations into the valves at other EPR projects in France and China.[60] In 2015, Areva went into technical bankruptcy because of the cost overruns and its liabilities at Olkiluoto. The company was saved through restructuring and a bailout from the French government.[61]

Olkiluoto 3 was finally connected to the grid in March 2022, but commercial operation has been again pushed back to late this year.[62] The project is 13 years behind schedule and has cost more than double initial projections.

Meanwhile, construction at Flamanville unit 3 continues. Led by EDF, a French state-owned utility with extensive experience building nuclear plants, construction began in 2007 and was expected to last 5 years. The reactor was initially estimated to cost €4.1 billion (in 2021 euros, about $2,990 per kW).[63] Like Olkiluoto, Flamanville has had problems with concrete and welds failing to meet technical specifications. And the project faced further quality control issues when it was discovered that steel components from Creusot Forge were weakened by high carbon concentrations. An investigation discovered that the forge may have been falsifying manufacturing documents for 40 years, leading to the shutdown of 12 reactors in France in the winter of 2016-2017.[64]

Fuel loading was recently again pushed back to the second quarter of 2023 because of further problems with faulty welds. Current projections put the total cost of the reactor at €12.7 billion and in the best case the project has been delayed 12 years.[65]

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[60] Energy Intelligence Group, “EDF to Inspect for Faulty Pressurizer Valves at EPRs,” June 4, 2020.
[61] Geert De Clercq, “France Ready to Save Nuclear Group Areva Whoever Wins Presidency,” *Reuters*, January 4, 2017.
[62] American Nuclear Society, “Olkiluto-3 Start Pushed to End of Year,” Nuclear Newswire, June 20, 2022.
[63] Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018), p. 221. Adjusted to 2021 euros using GDP price deflator for Euro area from FRED. Converted to 2021 dollars using average exchange rate for 2021.
[64] Geert De Clercq, “Areva Factory Ill-Equipped to Make Nuclear Parts – French Watchdog,” *Reuters*, March 16, 2017.
[65] Benoit Van Overstraeten and Benjamin Mallet, "EDF Announces New Delay and Higher Costs for Flamanville 3 Reactor," Reuters, January 12, 2022.

The most recent EPR project to start construction is a joint venture between EDF and the Chinese state-owned China General Nuclear Power Group (CGN) to construct two EPRs at Hinkley Point C (HPC) in the United Kingdom. The project, which has been in discussion since 2008, did not officially begin construction until 2018. Original projections estimated that, in total, the two reactors would cost £19 billion (in 2021 pounds, about $26.2 billion) and construction would be completed in 2025.[66] These numbers translate to a seven-year construction time at an overnight cost of about $8,000 per kW—much more pessimistic than previous EPR predictions, but still likely too low. The contract has a strike price, an inflation-adjusted guaranteed price of £92.50 per MWh for the first 35 years of the plant's operational life, significantly higher than the UK's wholesale electricity price.[67] Already, HPC has experienced cost-overruns and delays. Commercial operation has been pushed back to at least 2026 and project costs have risen to roughly £25–26 billion (in 2021 pounds, about $34.5–36 billion).[68]

So far, despite optimistic predictions on the EPR's and AP1000's ability to contain capital costs, early construction experience has shown that these new designs have been unable to solve the historical problems of nuclear construction cost escalation. All of these projects are in countries with limited recent experience constructing reactors, implying that lack of construction experience could explain some of the high cost. Recent EPR and AP1000 builds in China, however, support the fact that the high costs of these recent designs are at least partly inherent.

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[66] Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018), p. 221. Adjusted to 2021 pounds using pound sterling deflator from FRED. Converted to 2021 dollars using 2021 average exchange rate.
[67] Holly Watt, "Hinkley Point: The 'Dreadful Deal' Behind the World's Most Expensive Power Plant," *The Guardian*, December 21, 2017.
[68] EDF, "Hinkley Point C Project Update (1)," January 27, 2021. Adjusted to 2021 pounds using pound sterling deflator from FRED and converted to 2021 dollars using 2021 average exchange rate.

Western reactors recently built in China

Over the past couple of decades, China has been aggressively pursuing increased nuclear power and has extensive recent experience building reactors. This put it in the best position to build the AP1000 and EPR according to optimistic cost and schedule predictions. However, efforts building both designs have exhibited outcomes similar to the projects in the United States and Europe, though not to the same scale. Thus, the problems with these reactors goes beyond country-specific issues with nuclear experience, construction productivity, or regulation.

China started building four AP1000s at two sites in 2009. The projects experienced similar construction and manufacturing issues as in the United States, including quality control problems with reactor coolant pumps. At one site, Sanmen, the reactors began commercial operation in 2018, four years behind schedule, at a cost of over $8 billion, more than double initial projections.[69] As a result of these issues, China has decided against the AP1000 for future nuclear projects.[70]

Chinese experience with the EPR has been similar. Construction officially began on the first of two EPRs at the Taishan Nuclear Power Plant in 2009 and was planned to take 46 months.[71] The plant finally began commercial operation in 2018, five years behind schedule and 40 percent over the original cost estimate.[72] The delays in China, like in Finland and France, were caused by quality control issues and safety concerns.

Even in China, which, like South Korea and Japan, has had much recent experience with nuclear construction and has a track record of keeping costs low, imported advanced Western

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[69] Peter Fairley, "China's Nuclear Hiatus May Be Coming to an End," *Technology Review*, February 1, 2019; and *The World Nuclear Industry Status Report 2018* (Paris, Mycle Schneider Consulting, 2018).
[70] Echo Xie, "China Ditches US Nuclear Technology in Favour of Home-Grown Alternative," *South China Morning Post*, September 14, 2020.
[71] David Dalton, "Ceremony Marks Official Start of Taishan Construction," nucnet.org, December 21, 2009.
[72] *The World Nuclear Industry Status Report 2017* (Paris: Mycle Schneider Consulting, 2017).

reactor designs have had numerous quality control issues and safety problems. An important question for the future viability of nuclear power in the West is, assuming that design-specific problems can be fixed, whether lessons on nuclear construction from Asia be effectively transplanted and implemented.

Reactor construction in Asia

Despite China's recent experience with the EPR and AP1000, one of the primary advantages of historic nuclear construction in Asia has been that, as relative latecomers, countries like Japan, South Korea, and China have had the opportunity to import proven designs from pioneers like the US, UK, Canada, France, and the USSR. This has allowed them to avoid some of the first-of-a-kind issues inherent to new designs and to take advantage of experienced international nuclear vendors and mature supply chains.

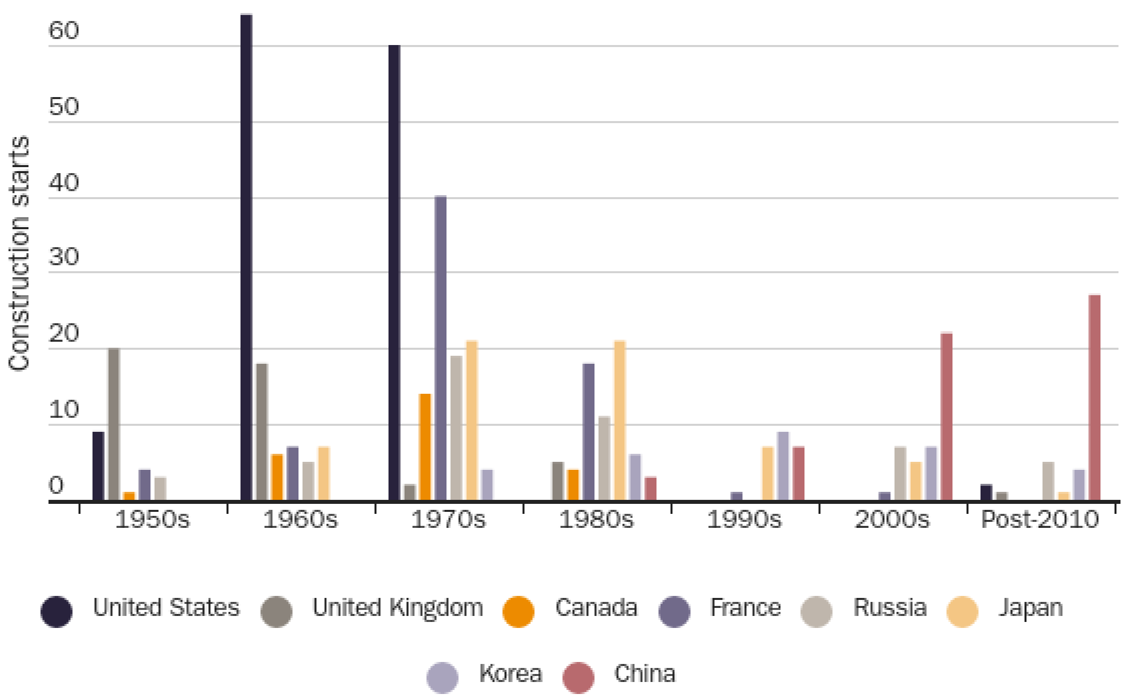
As shown in Figure 2, reactor construction began in Japan and Korea in the 1960s to 1970s with imported designs. While construction stagnated in the West in the 1980s and 90s, they developed domestic designs based on the imported reactors, and through the 2000s were able to contain overnight costs and keep construction schedules short. Likewise, China began building imported reactors in the 1980s, and in the past decade has begun localizing its reactor designs as it has actively sought to increase its use of nuclear energy.

Unlike the West, available evidence from Asia suggests that Japan, South Korea, and China have managed to keep costs contained. Recent reactors built in Japan have had overnight costs of around $4,000 per kW, and the analysis by Lovering, Yip, and Nordhaus finds that from the

1980s to 2000s Japan was able to keep costs level.[73] South Korea and China have managed to keep costs even lower, with overnight costs averaging around $2,800 per kW for recent units, though data from these countries should be interpreted cautiously.[74]

Figure 2

Nuclear reactor construction starts for select countries by decade



Source: IAEA, Country Nuclear Power Profiles.

Note: Excludes canceled and suspended reactors.

[73] See Jessica R. Lovering, Arthur Yip, and Ted Nordhaus, "Historical Construction Costs of Global Nuclear Power Reactors," *Energy Policy* 91 (April 2016): 371-382; and Yangbo Du and John E. Parsons, "Update on the Cost of Nuclear Power," Center for Energy and Environmental Policy Research no. 09-004, May 2009.

[74] Average costs for China are calculated from Francesco Ganda et al., "Economic Evaluation of Promising Options," US Department of Energy, Fuel Cycle Research and Development, FCRD-FCO-2015-000013, September 30, 2015; and South Korean costs are from Korea Electric Power Corporation (KEPCO) financial statements. Questions about Chinese and Korean data transparency are mentioned in Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018), pp. 34-35. Specifically regarding South Korean costs, Koomey et al note that the data comes from South Korea's nuclear utility and has not been independently audited. See Jonathan Koomey, Nathan E. Hultman, and Arnulf Grubler, "A Reply to 'Historical Construction Costs of Global Nuclear Power Reactors," *Energy Policy* 102 (March 2017): 640-643.

The most cited reasons for successful nuclear construction in Asia are top-down country-wide nuclear programs—leading to standardization and a greater ability to realize learning effects—and lower labor costs. MIT's 2018 study on nuclear power estimates that French nuclear construction labor rates are 60-80 percent, South Korean labor rates are 50-60 percent, and Chinese labor rates are less than 20 percent of the US nuclear construction labor rate.[75] The difference in labor costs also applies to the construction of alternative generators, including coal and natural gas. And yet, in South Korea and China, the overnight costs of nuclear reactors are still roughly 2–3 times higher than a coal power plant and 3–4 times higher than a natural gas plant.[76]

Crucially, the labor cost differences include both the direct costs of construction laborers and the labor component of "indirect services costs," which includes engineering and project management. A recent Energy Technologies Institute study on the cost drivers of nuclear construction estimates that much of the cost differences between reactors constructed in the West and reactors constructed in the rest of the world can be explained by higher proportional direct labor and indirect services costs in the West.[77] Labor makes up about 40 percent of the direct costs and 80 percent of the indirect costs, suggesting that a large portion of the difference is a result of the wage differences of both construction laborers and engineers.

While high direct construction labor rates are a problem that go well beyond the scope of nuclear construction, the indirect services costs can theoretically be reduced by better project management. The indirect services costs "are driven by (in)efficiencies in design completion and

[75] Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018).
[76] Comparison to ultra-supercritical coal and combined-cycle natural gas power plants in OECD International Energy Agency and Nuclear Energy Agency, "Projected Costs of Generating Electricity," 2020.
[77] Eric Ingersoll, Kirsty Gogan, John Herter, and Andrew Foss, "The ETI Nuclear Cost Drivers Project: Full Technical Report," Energy Technologies Institute, September 2020.

the need to resolve quality and regulatory issues, which often entail extensive engagements with regulators and suppliers, additional design engineering work, onsite rework, and delays."[78] Thus, a major factor is design completion, and one of the primary criticisms of the AP1000 and EPR has been that underdeveloped designs have created delays. Starting with more complete and mature designs, or even depending more on proven already-built designs instead of looking to create major innovations could help reduce the need for engineering costs. It is also possible that the difference in required indirect services is caused more by different regulatory regimes, which is an issue that is more difficult to address on a project-by-project basis.

The supposed main lesson from Asia is the importance of a nation-wide government led nuclear program. In theory, this allows for better cooperation between utilities and regulators and more design standardization to take better advantage of learning-by-doing. In South Korea, for example, nuclear development became a government priority in the 1950s, and the growth of the nuclear industry and localization of reactor designs was a part of the nation's overall economic plan.[79] Recent nuclear development in China has similarly been part of a government plan to shift away from coal.

Evidence does indicate that design standardization helps keep costs down. Michel Berthélemy and Lina Escobar Rangel analyze reactor costs in the United States and France and find that standardization helps shorten construction times and keep costs low.[80] They also find that, as a result of moving away from standardized designs, reactor innovation actually increases construction costs. This is confirmed by anecdotal evidence from South Korea, where nuclear

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[78] Eric Ingersoll, Kirsty Gogan, and Giorgio Locatelli, "Managing Drivers of Cost in the Construction of Nuclear Plants," *The Bridge* 50, no. 3 (Fall 2020).
[79] Sungyeol Choi, et al, "Fourteen Lessons Learned from the Successful Nuclear Power Program of the Republic of Korea," *Energy Policy* 37 (2009): 5494-5508.
[80] Michel Berthélemy and Lina Escobar Rangel, "Nuclear Reactors' Construction Costs: The Role of Lead-Time, Standardization and Technological Progress," Mines ParisTech Working Paper 14-ME-01, October 9, 2013.

designs have evolved only incrementally, while remaining largely standardized and allowing costs to be reduced over time.[81]

Some argue that the balkanization of US electricity markets does not allow for the same type of standardization.[82] It is true that the US faces a more variable patchwork of state-level regulatory regimes and utilities, but the reactors built in the US have almost all come from only four reactor vendors (Westinghouse, General Electric, Combustion Engineering, and Babcock & Wilcox) implying that there are some opportunities for standardization even if the utilities and operators are different. Berthélemy and Rangel also note that growing NRC safety regulations following Three Mile Island required nuclear vendors to change reactor designs to comply with new and changing rules, suggesting that regulatory stability plays a large role in the ability to standardize.

Reactor construction in Japan, South Korea, and China has faltered as a result of safety concerns following the 2011 Fukushima Daiichi nuclear accident. In Japan, all nuclear plants were shutdown following the accident. Currently, only about a third of the reactors have been restarted, construction on two new reactors has essentially stopped, and there are no plans to build new plants.[83] South Korea decided to phase-out nuclear power following Fukushima and a scandal involving falsified safety documents for reactor parts. Plans for future construction were canceled, though recently elected President Yoon Suk-yeol has reversed the phase-out.[84] In

[81] Michael Shellenberger, "If Innovation Makes Everything Cheaper, Why Does It Make Nuclear Power More Expensive?" *Forbes*, June 21, 2018.
[82] Brad Plumer, "Why America Abandoned Nuclear Power (And What We Can Learn from South Korea)," Vox, February 29, 2016.
[83] Tsuyoshi Inajima and Shoko Oda, "Nuclear Power's Growing Fan Base in Japan Faces a Reality Check," Bloomberg, April 5, 2022; *The World Nuclear Industry Status Report 2021* (Paris: Mycle Schneider Consulting, 2021); and Aljazeera, "Japan's Kishida Pledges to Restart Idled Nuclear Power Plants," May 27, 2022.
[84] Joyce Lee, "South Korea's Nuclear Power at Inflection Point as Advocate Wins Presidency," *Reuters*, March 11, 2020.

China, construction has continued but they have not achieved their nuclear goals. China had targeted 58 gigawatts (GW) of operating nuclear power with an additional 30 GW under construction by 2020, but only managed to have 47.5 GW operating with less than 16 GW under construction. And the Chinese government has reportedly recently shifted their focus more to renewables.[85]

Despite these uncertainties about its future, the story of nuclear power in Asia over the past several decades has been one of general success. This is exemplified by the ongoing construction of four South Korean reactors in the UAE at Barakah. The first unit began commercial operation in March 2021 after nearly 9 years of construction at an estimated cost of about $6,230 per kW.[86] Current estimates for the cost of the fourth unit are $2,630 per kW, for an average cost across the four units of around $4,230 per kW. If these estimates are accurate and the projected costs are achieved it implies that at least some of the construction lessons in Asia can be transplanted elsewhere, though these lessons are still subject to differences in labor rates and regulation in the United States and Europe. But the competitiveness of nuclear power, even at a construction cost similar to Barakah, depends also on the relative costs of alternatives.

[85] *The World Nuclear Industry Status Report 2021* (Paris: Mycle Schneider Consulting, 2021).

[86] These costs are from Eric Ingersoll, Kirsty Gogan, John Herter, and Andrew Foss, "The ETI Nuclear Cost Drivers Project: Full Technical Report," Energy Technologies Institute, September 2020, p. 86. They have been adjusted from 2009 $ to 2021 $ using GDP price deflator from BEA. The dollar year is not explicitly reported in the source, but it is based on the total $20.4 billion contract between the UAE and South Korea awarded in 2009. These costs are not overnight construction costs because they include financing costs and the costs of some additional services agreed on in the nuclear tender (such as training and the first two fuel loads). Excluding the additional costs would mean the OCC of Barakah is lower, but projected costs have also increased since the original agreement was made, and the project has taken longer than the initially forecasted 5 years. Without more detailed current cost projections we cannot estimate the net effect on the Barakah OCC. Michel Berthélemy and François Lévêque, “Korea Nuclear Exports: Why Did the Koreans Win the UAE Tender? Will Korea Achieve Its Goal of Exporting 80 Nuclear Reactors by 2030?” MINES ParisTech Working Paper 2011-04, April 2010; and Nuclear Intelligence Weekly, “Kepco Takes 18% of Barakah,” October 19, 2016.

Levelized costs of nuclear power and alternative baseload generators

The primary tool used to compare the costs of different electricity generating technologies is the levelized cost of electricity (LCOE). It models the cash flows of a plant over its construction period and operational lifetime and determines the average price of electricity (in cents per kWh of electricity generated) required for the plant to breakeven when accounting for investment costs, operational costs, and a market return to investors.

The LCOE allows for comparisons between different generating technologies with differing cost profiles. For example, nuclear has high initial investment costs but low operating costs, whereas natural gas generators are relatively cheap to build but have larger operating costs, especially if the price of gas is high. The LCOE makes it possible to compare the overall costs of technologies with different types of costs incurred at different points in time. Our LCOE calculations only include nuclear, coal, and natural gas because the mismatch between the timing of the output of renewable generators and electricity demand needs (as expressed by wholesale pricing) means it is inappropriate to use LCOE to compare conventional sources to renewable sources like wind and solar.[87]

It is important to note that this analysis focuses on the average costs of power plants in the United States. Along with construction costs, differences in labor costs between countries also affect O&M costs, meaning comparisons between nuclear and fossil fuel power plants elsewhere may have different results.

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[87] The LCOE is a constant price required for a plant to breakeven, though in reality wholesale electricity prices vary depending on electricity demanded at different times of the day and year. The ability of renewable sources to produce electricity relies on the availability of wind and solar energy and, to the extent that their hourly output does not align with times of high electricity prices, renewable sources are at an economic disadvantage compared to conventional sources. The levelized cost does not include the dynamics of variable wholesale prices, so the LCOE of renewables understates their true cost. See Paul Joskow, "Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies," *American Economic Review* 101, no. 3 (May 2011): 238-241.

Furthermore, while Asian countries have managed to keep nuclear construction costs lower, the cost and benefit consideration of nuclear power is also different because of the fuel prices of the alternatives. In particular, as a result of the fragmentation of world natural gas markets, the prices of natural gas between the United States, Europe, and Asia vary greatly. For example, from 2001–2021 the median annual U.S. natural gas price was $4.97 per MMBtu in 2021 dollars, compared to $9.29 per MMBtu in Europe and $11.40 per MMBtu for imported liquified natural gas in Japan.[88] These prices do not include the costs of transportation and delivery to power plants, but they illustrate the different price levels by region. Therefore, the cost-benefit analysis in Asia may favor nuclear because of both lower nuclear construction costs and higher relative costs of alternatives.

At the same time, the cost of natural gas power in the US is lower because of much more natural gas extraction. More integration of global natural gas markets and increased natural gas extraction in the rest of the world would further decrease the cost of natural gas, though regulations on fracking in Europe mean this is unlikely to happen.[89]

Key variables

The LCOE calculations consider three types of new build power plants in the United States: a nuclear reactor, a coal power plant, and a combined-cycle natural gas plant. Combined-cycle natural gas plants generate electricity both through a combustion turbine and by using the waste heat from combustion to create steam that is then converted to electricity by steam turbines. This

[88] World Bank Commodity Price Data, Annual Prices, 1960 to Present, Real 2010 US Dollars. Converted to 2021 dollars using GDP price deflator from BEA.
[89] Aurélien Saussay, "Can the US Shale Revolution Be Duplicated in Continental Europe? An Economic Analysis of European Shale Gas Resources," *Energy Economics* 69 (2018): 295–306.

increases their output per unit of fuel used relative to simple natural gas turbines that only generate electricity from combustion.

All the plants are baseload generators, meaning they will operate nearly constantly to meet the minimum amount of electricity demanded by the electrical grid, and are modeled as having a capacity of 1000 MW and a capacity factor (the ratio of electricity actually produced by a power plant to the theoretical maximum amount of electrical output if it ran continuously) of 85 percent.[90] The construction times and operating lifetimes correspond to the assumptions made by the OECD International Energy Agency (IEA) and Nuclear Energy Agency's (NEA) 2020 LCOE estimates.[91] The nuclear plant is constructed over a 7-year period and then operates for 60 years. This construction time is understated when compared to recent builds in Europe and the United States.[92] The operating life represents a 40-year NRC operating license plus one 20-year renewal.[93] Coal and natural gas plants are expected to take 4 and 3 years to build and operate for 40 and 30 years, respectively.

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[90] The choice of a 1000MW capacity for all generators is inconsequential because the levelized cost is estimated per unit of electricity produced and the capacity is therefore divided out of the calculations. 1000 MW is chosen to roughly illustrate the size of a power plant, but any effects of size on cost (e.g., economies of scale) are included in the relevant inputs in the LCOE model, which are in terms of dollars per unit of capacity. Because the LCOE is an analysis of lifetime cash flows, the capacity factor used represents the average lifetime capacity factor. An 85 percent capacity factor is lower than recent average *yearly* capacity factors of the U.S. nuclear fleet (more than 90 percent). But 85 percent is higher than the *lifetime* capacity factor of U.S. nuclear reactors, and it is unlikely that a newly built reactor will immediately reach a capacity factor of 90 percent. See Paul Joskow and John Parsons, "The Economic Future of Nuclear Power," *Daedalus* 138, no. 4 (2009): 45-59; and Yangbo Du and John E. Parsons, "Capacity Factor Risk at Nuclear Power Plants," Center for Energy and Environmental Policy Research no. 10-016, November 2016.

[91] OECD International Energy Agency and Nuclear Energy Agency, "Projected Costs of Generating Electricity," 2020.

[92] 7 years is also lower than the average construction period of 7.7 years for pressurized water reactors built between 1976 and 2009. See Pedro Carajilescov and João M. L. Moreira, "Construction Time of PWRs," International Nuclear Atlantic Conference, 2011.

[93] The lifetime of nuclear plants is capped by the NRC license. Currently, a few plants have received approval for a second 20-year renewal, which will bring their total operational life to 80 years. And DOE research suggests that there is no technical limit to a reactor's lifetime. However, because of discounting the benefit of extending the operational life quickly diminishes and beyond sixty years there is a relatively small decrease in the cost. For example, in these LCOE calculations, doubling a reactor's life from 30 years to 60 years had a roughly 9 percent

The calculations modeling the cash flows, as well as additional assumptions and input parameters of the LCOE, are outlined in the appendix. Here we describe the variables that have a significant impact on the LCOE estimates: nuclear overnight costs, the discount rate, and fuel costs.

Nuclear overnight costs

The overnight costs used are based on the historic and recent construction costs of nuclear reactors, as described above. The estimates use three levels of OCC for nuclear, a high, middle, and low projected overnight cost for building future reactors.

The high OCC is $9,000 per kW. This is in line with recent costs at Olkiluoto and Flamanville and is substantially lower than the most recent reactors under construction in the United States at Vogtle.[94]

The middle OCC is $6,700 per kW. This would represent the NOAK cost of building a nuclear reactor if it is assumed that the high case $9,000 per kW includes a large FOAK premium of around 35 percent. Reactor costs in the US have escalated over time and any potential FOAK premium has previously been outweighed by growing costs from increased regulation, poor construction management, or the decision to build different, bigger, and more complex reactor designs. While it has historically not been the case, the mid-range OCC

decrease in the LCOE while doubling from 60 years to 120 years had a 1 percent decrease. For research on technical limits on the life of a reactor see Light Water Reactor Sustainability, Idaho National Labs, https://lwrs.inl.gov/SitePages/Home.aspx; and see DOE Office of Nuclear Energy, "What's the Lifespan for a Nuclear Reactor? Much Longer Than You Might Think," April 16, 2020.

[94] $9,000 per kW is close to the average of the costs from Vogtle, Flamanville, and Olkiluoto ($9,430). It therefore represents the average cost of recent reactors built in the West, but, insofar as US costs would be expected to be higher than construction costs in France or Finland, it could understate future OCC for a new reactor in the United States.

optimistically considers a scenario in which future US reactors are able to contain and reduce construction costs by a significant amount.

The low OCC is $4,000 per kW, representing a cost that is in the range of the recent construction at Barakah in the UAE. In this scenario, lessons from Asia on effective construction management along with significant reductions in the amount and stringency of safety regulations would allow US nuclear constructors to achieve costs significantly lower than those seen at Vogtle, Olkiluoto, and Flamanville. Alternatively, $4,000 per kW could represent costs of a new generation of reactor technologies that manage to elude the drivers of cost escalation experienced by the current and previous generations of reactors.

As Table 3 shows, OCC assumptions in noteworthy LCOE estimates have been steadily increasing since the early 2000s. Estimates of nuclear OCC before recent construction experience in the West were around $2,000 per kW in nominal dollars. The higher forecasted OCCs of projects like Vogtle and V.C. Summer led to updated cost estimates, such as a doubling of costs from $2,000 per kW to $4,000 per kW between MIT's 2003 study on nuclear power and its 2009 update. These forecasted costs proved significantly lower than actual construction costs. More recent LCOEs have used costs over $6,000 per kW.

Such OCCs are still optimistic when considering the cost overruns at Vogtle, Olkiluoto, and Flamanville and the fact that the most recent EPR project at Hinkley Point C shows no signs that costs will be contained. However, the range of OCC of $4,000–9,000 per kW allows for easy comparison of the estimates here to previous LCOEs and exploration of nuclear power's competitiveness even under the most charitable assumptions.

Table 3

Comparison of overnight construction costs assumptions to recent construction and previous levelized cost estimates

Source	$ year	Nuclear ($/kW)	Coal ($/kW)	Natural gas ($/kW)
This paper				
High	*2021*	*9,000*		
Middle	*2021*	*6,700*	*4,100*	*1,100*
Low	*2021*	*4,000*		
Average recent OCC* in the United States and Europe	2021	9,430		
MIT 2003	2002	2,000	1,300	500
University of Chicago 2004	2003	1,200–1,800	1,200	590
IEA/NEA 2005	2005	1,894	1,160	609
CBO 2008	2006	2,358	1,499	685
CRS 2008	2006	3,900	2,500	1,200
MIT 2009	2007	4,000	2,300	850
IEA/NEA 2010	2010	3,382	2,108	969
University of Chicago 2011	2010	4,210		
IEA/NEA 2015	2015	4,100	2,496	1,143
MIT 2018	2017	4,100–6,900	3,515	948
IEA/NEA 2020	2020	4,250	4,157	952
Lazard 2021	2021	6,100–10,025	2,375–4,925	650–1,175
EIA AEO 2022	2021	7,030	4,074	1,062

Source: See text for a discussion of recent average OCC. Stephen Ansolabehere et al., *The Future of Nuclear Power: An Interdisciplinary MIT Study* (MIT, 2003); George S. Tolley et al., "The Economic Future of Nuclear Power," University of Chicago, August 2004; Congressional Budget Office, "Nuclear Power's Role in Generating Electricity," May 2008; Stan Kaplan, "Power Plants: Characteristics and Costs," Congressional Research Service, November 13, 2008; John M. Deutch et al., *Update of the MIT 2003 Future of Nuclear Power* (MIT, 2009); Robert Rosner, Stephen Goldberg, Joseph S. Hezir, and Edward M. Davis, "Analysis of GW-Scale Overnight Capital Costs," Energy Policy Institute at the University of Chicago, November 2011; Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018); Lazard, "Lazard's Levelized Cost of Energy Analysis—Version 15.0," October 2021; EIA, "Cost and Performance Characteristics of New Generating Technologies," *Annual Energy Outlook 2022* (EIA, 2022); and International Energy Agency and OECD Nuclear Energy Agency "Projected Costs of Generating Electricty," 2005–2020.

Note: MIT coal OCC is for Integrated Coal Gasification Combined Cycle, not ultra-supercritical coal as used in this paper *OCC = overnight construction cost.

Discount rate

The LCOE estimates, and in particularly the estimates for nuclear, are highly sensitive to the choice of discount rate. The costs of the plant over time are converted to a present value using a discount rate representing the time value of money (i.e., a dollar today is worth more than a dollar tomorrow). A high discount rate weights money today much more than money in the future whereas a low discount rate more evenly values present and future dollars.

For nuclear, which is characterized by large upfront costs and low future operating costs, a high discount rate means that the large construction costs are valued more highly than the future benefit of lower operating costs. On the other hand, a high discount rate comparatively benefits the estimates for natural gas because the low upfront costs are highly valued, whereas the large future operating costs are not worth as much.

Other LCOEs typically use the weighted average cost of capital (WACC) as the discount rate. The WACC is calculated from assumed debt-to-equity ratios and costs of debt and equity. Some studies incorporate a higher risk premium for nuclear, reflecting uncertainties surrounding the capital costs and regulation of nuclear compared to fossil fuel generators. The MIT 2009 study, for example, uses pre-tax, nominal effective discount rates of 11.5 percent for nuclear and 9.6 percent for fossil fuels (corresponding to inflation-adjusted pre-tax effective rates of 8.3 percent and 6.4 percent, respectively).[95]

This LCOE instead uses the discount rate as the opportunity cost of capital, the expected rate of return on the capital invested in the power plant if instead it was invested in other public

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[95] The MIT study includes taxes, so the after-tax nominal WACCs used are 10 percent for nuclear and 7.8 percent for fossil fuels. The study separately assumes an inflation rate of 3 percent. Yangbo Du and John E. Parsons, “Update on the Cost of Nuclear Power,” Center for Energy and Environmental Policy Research no. 09-004, May 2009. And for more detailed examination of discount rates, WACC and risk see OECD International Energy Agency and Nuclear Energy Agency, “Projected Costs of Generating Electricity,” 2015; and William D. D’haeseleer, “Synthesis on the Economics of Nuclear Energy,” European Commission, DG Energy, November 27, 2013.

investments in the U.S. The rate used is 7 percent, which is approximately the pre-tax real annualized average rate of return of the S&P 500 from 1972 to 2021.[96] This is in line with other estimates of LCOE. For example, four recent studies used costs of capital of 6.2 to 7.9 percent.[97] For comparison, the results when using costs of capital of 3 and 10 percent are also reported and the estimates' sensitivity to the rate is illustrated in figures.

Those readers who are familiar with the economics of climate studies may conclude that our discount rate is too high. Such studies use a so-called "social discount" rate that reflects an ethical preference about the value of consumption for present versus future generations in their calculations of an optimal carbon tax. We are not calculating an optimal carbon tax and we take no position on what it's value should be. Instead, we are asking a simpler, more focused question: what carbon tax price would be necessary to induce private investors to be willing to invest in nuclear power.

Fuel costs

While the most important input for capital intensive nuclear plants is the construction costs, the most important for natural gas is the fuel price. The capital costs of nuclear plants account for 60 to 80 percent of their LCOE whereas fuel costs account for more than 50 percent of the natural gas LCOE.

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[96] The real annualized average rate of return of the S&P 500 is calculated from Robert Shiller, "U.S. Stock Markets 1871-Present and CAPE Ratio," http://www.econ.yale.edu/~shiller/data.htm.

[97] See Jacopo Buongiorno et al., The Future of Nuclear Energy in a Carbon-Constrained World (MIT, 2018); Lazard, "Lazard's Levelized Cost of Energy Analysis—Version 15.0," October 2021; EIA, "Cost and Performance Characteristics of New Generating Technologies," Annual Energy Outlook 2022 (EIA, 2022); and International Energy Agency and OECD Nuclear Energy Agency "Projected Costs of Generating Electricity," 2020. Nuclear OCC for EIA from EIA, "Cost and Performance Characteristics of New Generating Technologies," *Annual Energy Outlook* 2022 (EIA, 2022). MIT, EIA, and Lazard include taxes in their calculations, meaning their discount rates are *after-tax* WACCs and are not directly comparable to the *pre-tax* cost of capital used here. Inclusion of taxes in the LCOE decreases the effective discount rate but increases the pre-discounted costs. When using our methodology with taxes these effects roughly canceled each other out and the net results were similar to our reported LCOE estimates.

Because of this reliance on fuel cost, the natural gas LCOE is highly sensitive to the natural gas price. This LCOE uses a range of natural gas prices based on the Energy Information Administration's projections of the price of natural gas delivered to the electric power sector in the *Annual Energy Outlook* 2022. The prices used are the average estimated fuel prices, in dollars per million Btu (MMBtu), from 2021 to 2050 for three EIA scenarios, the high oil and gas supply, reference, and low oil and gas supply cases. The low-end fuel price is $3.10 per MMBtu, the middle price is $3.80 per MMBtu, and the high price is $5.80 per MMBtu.[98]

While natural gas volatility is not modeled by the LCOE calculations, these prices represent the *average* annual natural gas price over the 30-year operational life of the plant. For comparison, between 1997 and 2021, the average annual delivered natural gas price was about $5.80, while the maximum annual price was $11.20 and the minimum was $2.50, in 2021 dollars per MMBtu.[99]

The coal price, $1.90 per MMBtu, is the average projected price from EIA's reference case.[100] Because the coal LCOE is less sensitive to fuel price, and because coal power plants typically buy coal under longer term contracts so the delivered coal prices are less volatile, only one coal price is used. Between 2008 and 2020, the average annual delivered coal price was about $2.50, the maximum price was $2.85 and the minimum was $2.00, in 2021 dollars per MMBtu.[101]

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[98] Authors' calculations using average heat content of natural gas of 1.034 MMBtu/Mcf and high oil and gas supply side case, reference case, and low oil and gas supply side case from EIA, "Table 13: Natural Gas Supply, Disposition, and Prices," in *Annual Energy Outlook 2022* (EIA, 2022).
[99] Authors' calculations using average heat content of natural gas of 1.034 MMBtu/Mcf from EIA, "U.S. Natural Gas Electric Power Price," Annual, 1997-2021.
[100] Authors' calculations from EIA, "Table 15: Coal Supply, Disposition, and Prices," in *Annual Energy Outlook 2022* (EIA, 2022).
[101] Authors' calculations from EIA, "Coal Shipments to the Electric Power Sector: Price," 2008-2020. Coal prices converted from $/short ton to $/MMBtu using average yearly heat content in Btu/lb for coal shipments to the power sector from EIA, "Coal Shipments to the Electric Power Sector: Heat Content," 2008-2020.

Like coal, uranium is typically bought under longer term contracts and prices are therefore more stable. Nuclear fuel must be enriched before it can be used by a nuclear power plant. Other LCOEs calculate the nuclear fuel price from the price of natural uranium and the costs involved in the conversion, enrichment, and fabrication processes.[102] In order to simplify the analysis and because of the small impact of the nuclear fuel cost on the nuclear LCOE, this estimate uses historic nuclear fuel prices from EIA to forecast an average annual nuclear fuel price.

The price chosen is $0.60 per MMBtu. To model the best case for nuclear power, this price is closer to the minimum annual price from 1970 to 2020 of $0.58 than to the average $0.94 or the maximum of $1.54, in 2021 dollars per MMBtu.[103] While the chosen fuel price is on the low end, it is in line with the 2020 OECD International Energy Agency and Nuclear Energy Agency's estimate of the cost of the front-end (excluding back-end costs like fuel removal, storage, and disposal) of the fuel cycle. The IEA/NEA LCOE estimates project a front-end nuclear fuel cost of 0.7 cents per kWh, while this LCOE projects a cost of about 0.6 cents per kWh.[104]

Levelized cost estimates

Using the inputs outlined above and in the appendix, the LCOE calculations find that, in general, nuclear is not competitive with natural gas or coal in the United States.

Table 4 reports the levelized costs of all three technologies using the cost of capital of 7 percent as a discount rate. Coal has a levelized cost of 7.9 cents per kWh and natural gas at low, middle, and high projected fuel prices has levelized costs of 3.8, 4.2, and 5.5 cents per kWh, respectively. Nuclear at an overnight cost of $4,000 per kW has an LCOE of 7.9 cents per kWh,

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[102] For a detailed look at this process see Appendix 4 of Stephen Ansolabehere et al., *The Future of Nuclear Power: An Interdisciplinary MIT Study* (MIT, 2003).
[103] Authors' calculations from EIA, "Nuclear Fuel Average Price, Electric Power Sector, United States," 1970-2020.
[104] OECD International Energy Agency and Nuclear Energy Agency, "Projected Costs of Generating Electricity," 2020.

and is competitive with coal, while the higher OCCs of $6,700 and $9,000 per kW have much higher respective levelized costs of 11.4 and 14.4 cents per kWh.

Table 4
Levelized cost estimates (cents/kWh) broken down by type of cost

	Capital (including decomissioning)	Non-fuel O&M*	Fuel	Total
Nuclear				
Low OCC* (4,000 $/kW)	5.3	2.0	0.6	7.9
	67%	25%	8%	100%
Middle OCC (6,700 $/kW)	8.8	2.0	0.6	11.4
	77%	17%	5%	100%
High OCC (9,000 $/kW)	11.9	2.0	0.6	14.4
	82%	14%	4%	100%
Coal				
	5.2	1.0	1.6	7.9
	66%	13%	21%	100%
Natural gas				
Low fuel price (3.10 $/MMBtu)	1.5	0.4	2.0	3.8
	38%	10%	52%	100%
Middle fuel price (3.80 $/MMBtu)	1.5	0.4	2.4	4.2
	34%	9%	57%	100%
High fuel price (5.80 $/MMBtu)	1.5	0.4	3.7	5.5
	26%	7%	67%	100%

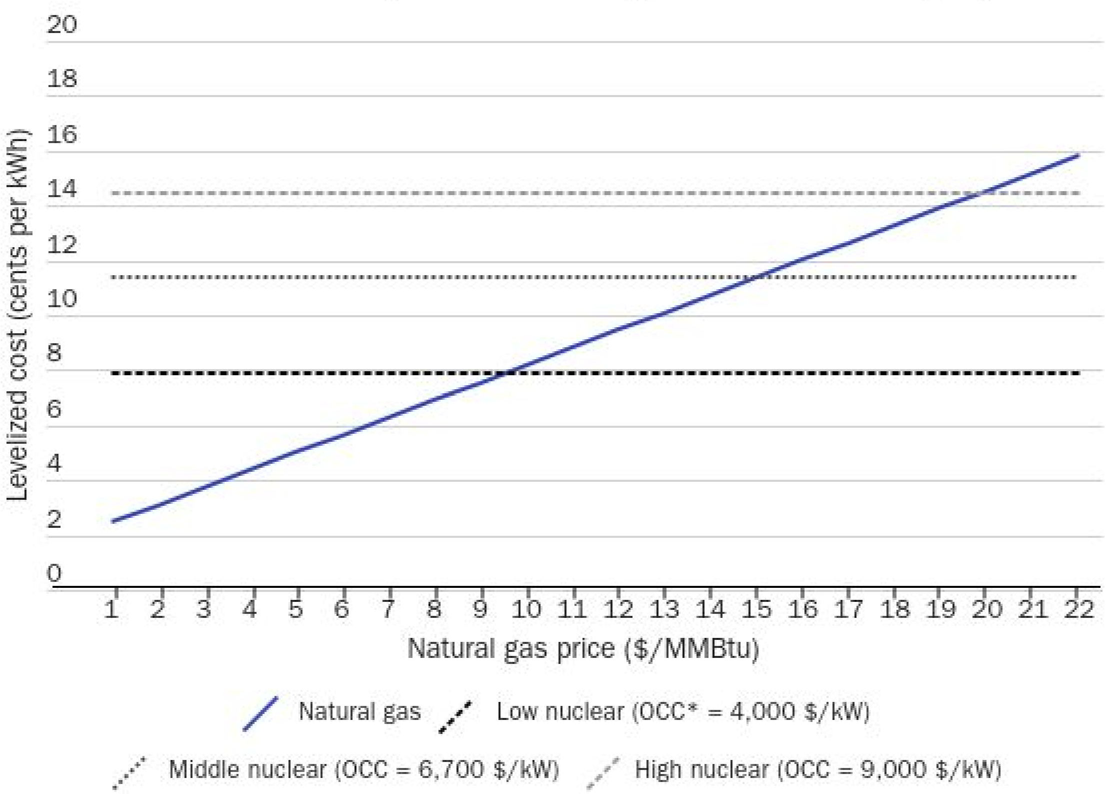
Source: Authors' calculations.
Note: Estimates calculated using 7 percent cost of capital; *OCC = overnight construction cost; O&M = operations and maintenance.

The breakdowns of the total levelized cost by type of cost highlight the relative importance of capital costs to nuclear and fuel price to natural gas. The operating costs (the O&M plus the fuel costs) of nuclear are lower than natural gas and even with coal. But the levelized capital costs are significantly higher, except when compared to coal at the lowest nuclear OCC.

The average annual natural gas price would need to be significantly higher than the highest level used in these calculations ($5.80 per MMBtu) for the LCOE of natural gas to be on par with nuclear. As illustrated in Figure 3, all else equal, the levelized cost of natural gas would equal that of nuclear at a 4,000 $/kW OCC if the average natural gas price were about 9.50 $/MMBtu, at an OCC of 6,700 $/kW if the gas price were 15.10 $/MMBtu, and at an OCC of 9,000 $/kW if the gas price were 19.80 $/MMBtu.

Figure 3

Levelized costs of nuclear compared with natural gas at different natural gas prices



Source: Authors' calculations using 7 percent cost of capital; *OCC = overnight construction cost.

As shown in Table 5, the LCOEs are sensitive to the opportunity cost of capital. At the higher cost of capital of 10 percent, nuclear has a substantially higher LCOE than natural gas regardless of the level of OCC or natural gas price. Even at a low OCC, nuclear's levelized cost is higher than coal.

Table 5

Levelized cost estimates (cents/kWh) at 3, 7, and 10 percent costs of capital

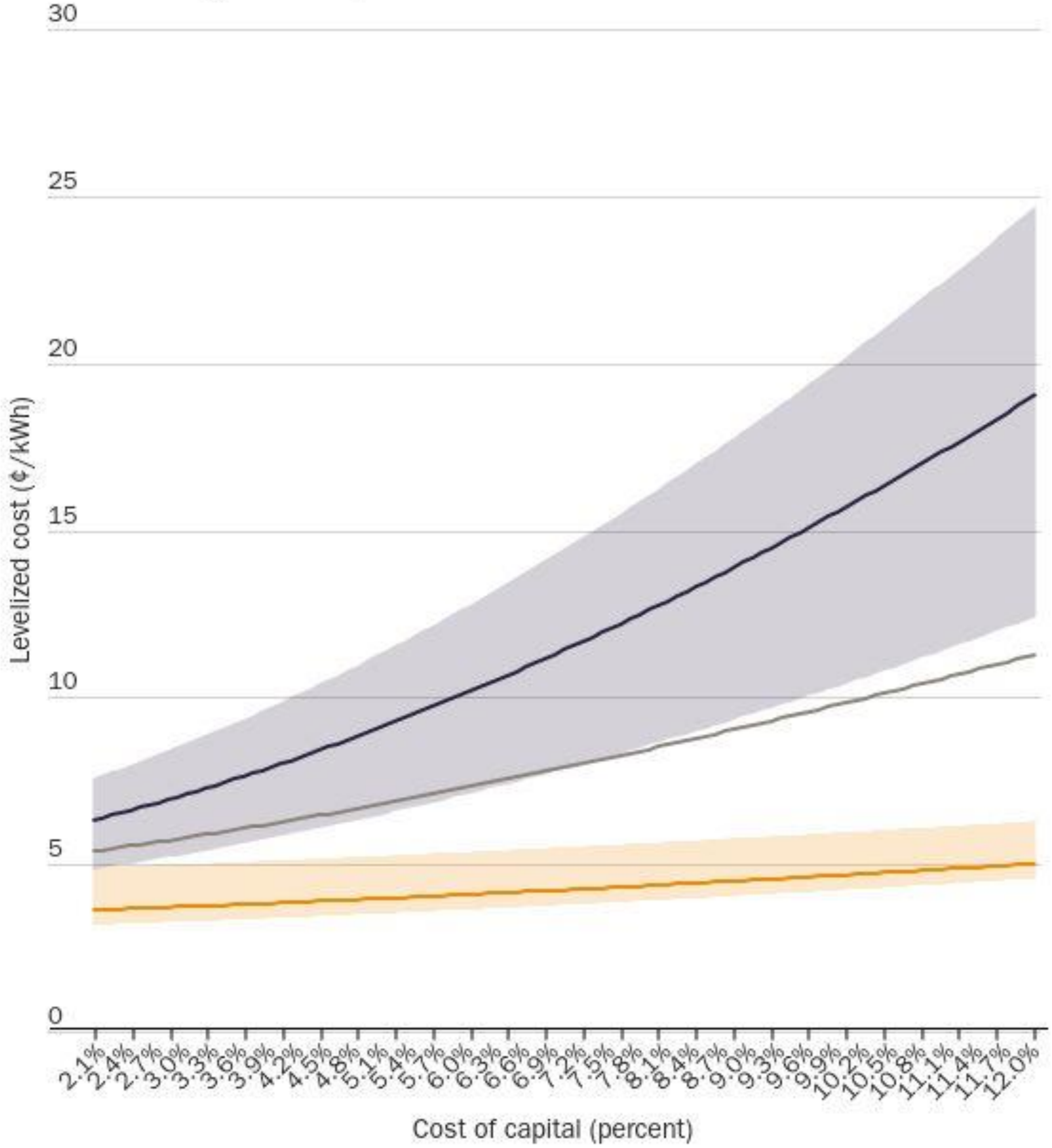
	Cost of capital		
	3%	**7%**	**10%**
Nuclear			
Low OCC* (4,000 $/kW)	5.3	7.9	10.4
Middle OCC (6,700 $/kW)	7.1	11.4	15.7
High OCC (9,000 $/kW)	8.6	14.4	20.2
Coal			
	5.8	7.9	9.8
Natural gas			
Low fuel price (3.10 $/MMBtu)	3.3	3.8	4.2
Middle fuel price (3.80 $/MMBtu)	3.7	4.2	4.7
High fuel price (5.80 $/MMBtu)	5.0	5.5	6.0

Source: Authors' calculations; *OCC = overnight construction cost.

When the opportunity cost of capital is 3 percent, the levelized cost of nuclear at an OCC of $4,000 per kW is lower than that of coal. However, at the middle and high nuclear OCC, the nuclear LCOE estimates are larger than those for coal. And natural gas is still more competitive regardless of nuclear OCC or natural gas price.

At the chosen baseline cost of capital of 7 percent, the low end nuclear is equal to coal. The cost of natural gas is significantly lower than nuclear, regardless of fuel price.

Figure 4
Levelized costs by cost of capital



Source: Authors' calculations. Shaded area for nuclear represents levelized costs of nuclear between the low and high OCC and for natural gas represents costs between low and high natural gas prices.

The importance of the opportunity cost of capital on the technology-specific ranges of LCOE estimates is further illustrated by Figure 4. The lines show how the LCOEs of each technology change according to cost of capital. For nuclear, the solid line is the LCOE at the middle OCC and for natural gas it is the LCOE at the middle fuel price. The shaded areas represent the range of low OCC to high OCC for nuclear and the range of low fuel price to high fuel price for natural gas. At higher opportunity costs of capital the cost of nuclear is higher than coal and significantly higher than natural gas regardless of fuel price and nuclear OCC. At lower costs of capital the comparisons between the technologies are more dependent on the levels of natural gas price and nuclear OCC.

While the figure shows that nuclear' s competitiveness with coal is dependent on the opportunity cost of capital, based on the OCCs and natural gas prices used in the estimates, nuclear is only competitive with natural gas at the very low end. Only in an unrealistic best-case scenario for nuclear, at a very low opportunity cost of capital when it has a low OCC and the average annual natural gas price is high, does it come close to competing with natural gas without government intervention.

Comparison to previous levelized cost estimates

The levelized cost estimates here for all three technologies fall within a range of recent estimates from the US EIA's 2022 *Annual Energy Outlook*, investment banking firm Lazard, the OECD International Energy Agency and Nuclear Energy Agency, and MIT, as shown in Table 6. Most of the notable differences in the estimates can be explained by different assumptions for three of the most important variables: cost of capital, nuclear overnight cost, and natural gas price. Otherwise, variability is largely caused by different performance assumptions (e.g., capacity factor and power plant efficiency) and methodologies.

The similar results affirm that nuclear is widely accepted as more costly than natural gas combined cycle. The relative cost difference, however, depends largely on a few key variables.

Table 6

Comparison of levelized costs to LCOE estimates in recent studies (cents/kWh)

	This paper						
	Low	**Middle**	**High**	**EIA AEO 2022**	**Lazard 2021**	**IEA/NEA 2020**	**MIT 2018**
Nuclear (total)	**7.9**	**11.4**	**14.4**	**8.8**	**13.0–20.4**	**7.1**	**9.7**
Capital	5.3	8.8	11.9	6.1	10.3–17.3	5.0	
Non-fuel O&M	2.0	2.0	2.0	1.9	1.9–2.2	1.2	
Fuel	0.6	0.6	0.6	0.8	0.9	0.9	
Coal (total)		**7.9**		**8.3**	**6.5–15.2**	**9.3**	**7.7**
Capital		5.2		5.2	4.5–11.5	4.7	
Non-fuel O&M		1.0		1.0	0.8–1.9	3.0	
Fuel		1.6		1.9	1.3–1.8	1.7	
Natural gas (total)	**3.8**	**4.2**	**5.5**	**4.0**	**4.5–7.4**	**3.5**	**6.4**
Capital	1.5	1.5	1.5	0.9	1.8–4.2	1.1	
Non-fuel O&M	0.4	0.4	0.4	0.4	0.5–0.9	0.5	
Fuel	2.0	2.4	3.7	2.6	2.1–2.4	1.8	
Cost of capital	7.0%	7.0%	7.0%	6.2%	7.7%	7.0%	7.9%
Nuclear OCC ($/kW)	4,000	6,700	9,000	7,030	6,100–10,025	4,250	5,500
Natural gas price ($/MMBtu)	3.10	3.80	5.80	4.05	3.45	3.20	7.52

Sources: Jacopo Buongiorno et al., *The Future of Nuclear Energy in a Carbon-Constrained World* (MIT, 2018); Lazard, "Lazard's Levelized Cost of Energy Analysis—Version 15.0," October 2021; EIA, "Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022," March 2022; and International Energy Agency and OECD Nuclear Energy Agency "Projected Costs of Generating Electricty," 2020. Nuclear OCC for EIA from EIA, "Cost and Performance Characteristics of New Generating Technologies," *Annual Energy Outlook 2022* (EIA, 2022).

Note: This paper excludes back-end costs of the nuclear fuel cycle (storage and disposal of nuclear waste) while the other sources include it in overall nuclear fuel cost. EIA, Lazard, and MIT costs of capital are after-tax weighted average cost of capital. EIA reports variable O&M and fuel cost together as variable costs. They have been separated and recategorized into non-fuel O&M and fuel cost to match other sources using EIA's inputs for fixed and variable O&M. EIA natural gas price is calculated from the fuel cost and using EIA assumption for natural gas combined cycle heat rate. EIA total includes separate transmission cost. IEA/NEA estimates are for United States and exclude carbon pricing. MIT coal estimates are for Integrated Coal Gasification Combined Cycle, not ultra-supercritical coal as used in this paper.

Carbon taxes necessary for nuclear to compete with fossil fuels

What level of carbon tax would make the levelized costs of nuclear equivalent to those of natural gas and coal? Or, put alternatively, at what estimated social cost of carbon (SCC) would the avoided carbon emissions of nuclear power be worth its high costs?

Carbon emissions create costs that are not borne by the carbon emitter.[105] A tax on carbon emissions incentivizes producers and consumers to take such costs into account. The carbon tax should be set equal to the SCC. In practice, the SCC is difficult to determine, and a review of the literature on the SCC found that estimates range from -$13.36 to $2,386.91 per metric ton of CO_2.[106]

The Interagency Working Group on the Social Cost of Greenhouse Gases for the U.S. federal government estimates that the SCC in 2020 ranges from of $14 to $76 per metric ton (in 2020 dollars) of CO_2, depending on the choice of social discount rate (from 2.5 to 5 percent).[107] The middle value (with a middle social discount rate of 3 percent) is $51 per metric ton. It projects a carbon tax of $32 to $116 per metric ton, with a middle value of $85, in 2050. The average over the thirty years is thus $22 to $96 with a middle value of $68 per metric ton, and the average growth rate for these estimates is roughly 2 percent per year.

A 2020 survey found that 400 experts across 40 countries had an average recommendation of a carbon tax of $50 per metric ton in 2020 and of $224 per metric ton in 2050. However, the median (less sensitive to extreme values) recommendation was of $40 per metric ton in 2020 and

[105] The theory behind and difficulties of setting an appropriate carbon tax are summarized by Jeffrey Miron and Pedro Braga Soares, "What Should Policymakers Do about Climate Change?" Cato Institute Briefing Paper no. 130, November 30, 2021.

[106] Pei Wang, Xiangzheng Deng, Huimin Zhou, and Shangkun Yu, "Estimates of the Social Cost of Carbon: A Review Based on Meta-Analysis," *Journal of Cleaner Production* 209 (2019): 1494–1507.

[107] Interagency Working Group on Social Cost of Greenhouse Gases, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990," February 2021.

$100 in 2050.[108] Thus according to the survey, the mean carbon tax over the thirty years should be around $70 per metric ton.

Hence, the range of appropriate carbon taxes according to the U.S. government and a climate expert survey is roughly $15 to $75 per metric ton in 2020, and an average carbon tax over the next thirty years of between $20 to $100 per metric ton, depending on the social discount rate used. These correspond to a generally accepted middle value, at a middle social discount rate, of around $50 in 2020, and a thirty-year average of around $70 per metric ton.

To determine the carbon tax sufficient for nuclear levelized costs to be attractive to a private investor, the LCOEs of nuclear and fossil fuel technologies are compared, and the tax necessary to make up the difference based on the carbon dioxide emissions factors of coal and natural gas is calculated.[109]

Table 7 contains the carbon taxes estimates at different fuel prices and nuclear OCCs when using the baseline cost of capital of 7 percent. The carbon tax reported is the average tax per ton of carbon emitted that would equate nuclear, coal and natural gas generation levelized costs over the lifetime of the fossil fuel plant (30 years for natural gas and 40 years for coal). The values in parentheses in Table 7 reflect the approximate carbon tax in 2020 if the real annual escalation rate of the tax is roughly the same as in the Interagency Working Group's technical guidance (2 percent per year).[110]

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[108] Moritz A. Drupp, Frikk Nesje, and Robert C. Schmidt, "Pricing Carbon," CESifo Working Paper no. 9608, March 2022.
[109] This calculation is outlined in the appendix.
[110] This approximation is outlined in the appendix. Escalation rate from the Interagency Working Group estimates based on authors' calculations of the average growth rate from 2020 to 2050 for carbon taxes at 5, 3, and 2.5 percent discount rates. Interagency Working Group on Social Cost of Greenhouse Gases, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990," February 2021.

Table 7

Carbon taxes that equate levelized costs of fossil fuel and nuclear generation (2021 $/metric ton of CO_2 emissions)

Average tax over fossil fuel plant lifetime (approximate tax in 2020)

	Nuclear		
	Low OCC* (4,000 $/kW)	Middle OCC (6,700 $/kW)	High OCC (9,000 $/kW)
Coal			
	0 (0)	43 (28)	79 (52)
Natural gas			
Low fuel price (3.10 $/MMBtu)	121 (89)	226 (167)	316 (234)
Middle fuel price (3.80 $/MMBtu)	107 (79)	213 (157)	303 (224)
High fuel price (5.80 $/MMBtu)	70 (51)	175 (129)	265 (196)

Source: Authors' calculations.

Note: Estimates calculated using 7 percent cost of capital. Estimates in parentheses represent approximate carbon taxes in 2020 if tax grows at real annual rate of 2 percent; *OCC = overnight construction cost.

The levelized cost of nuclear at a low OCC is equal to the LCOE of coal so the carbon tax required to make the levelized costs equal is zero. At middle and high nuclear OCCs, the carbon tax sufficient to make it competitive with coal is $43 (approximately $28 in 2020) and $79 ($52 in 2020) per metric ton. These estimates are in range with widely accepted estimates of the social cost of carbon. This implies that nuclear at an OCC of $6,700 per kW or even at the higher OCC of $9,000 per kW is likely worth building to avoid the carbon emitted by a new coal power plant.

The carbon tax that equates nuclear's levelized cost to natural gas ranges from $70–316 (approximately $51–234 in 2020) per metric ton of CO_2, depending on the natural gas price and nuclear OCC. In the best-case scenario for nuclear—when it has a low OCC and the average annual natural gas price is high—the carbon tax is $70 ($51) per metric ton, which is in the range of carbon taxes recommended by the U.S. Interagency Working Group and a survey of experts. At the lower natural gas prices, the estimated tax required is slightly outside the recommended range: more than $107 ($79) per metric ton.

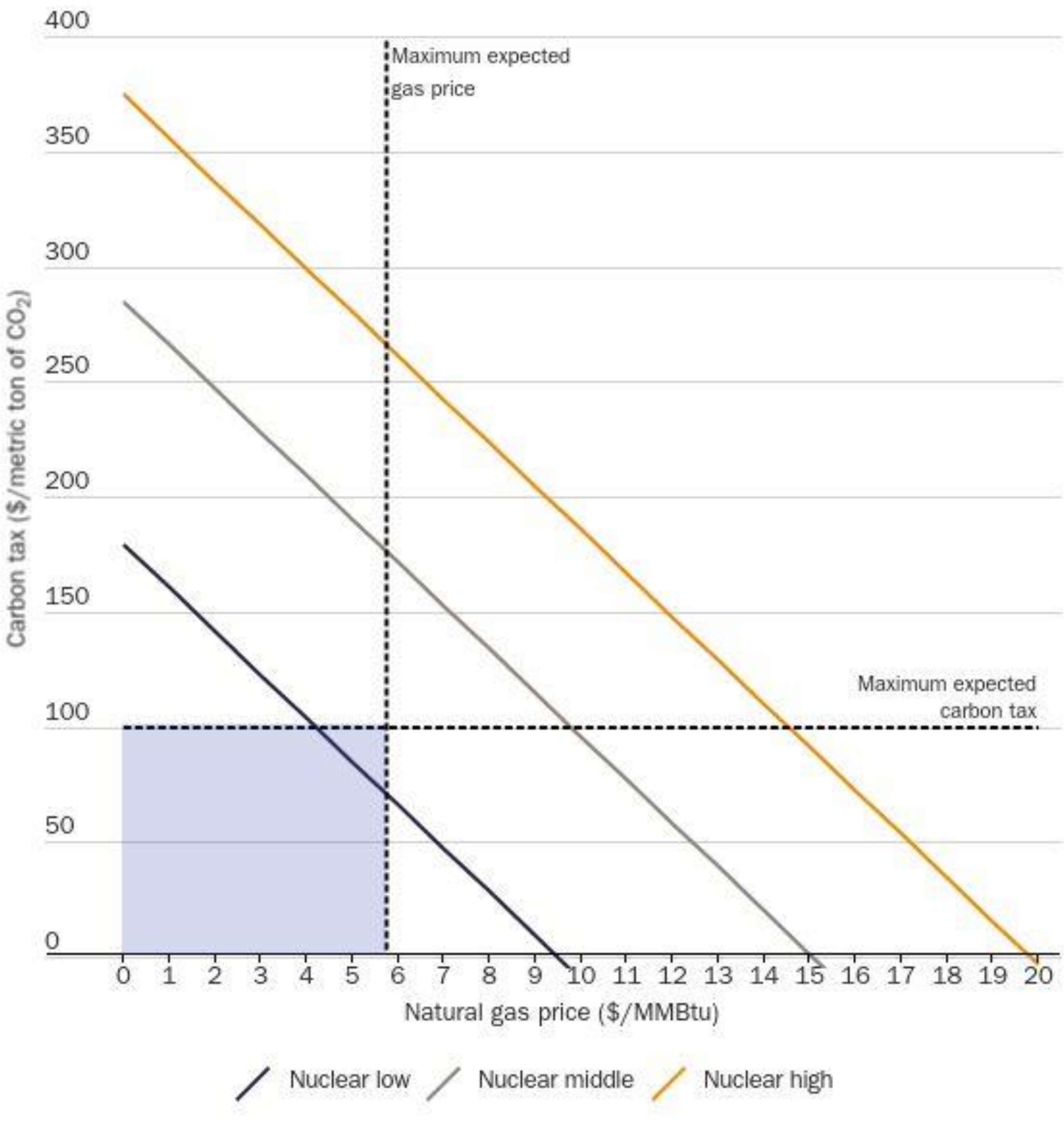
As the nuclear OCC increases, the estimated tax required for it to compete with natural gas quickly grows. At the middle OCC, the carbon tax would need to be at least $175 ($129 in 2020) per metric ton; at the high OCC it would need to be larger than $265 ($196) per metric ton. This indicates that, unless nuclear construction costs can be significantly reduced, the high capital costs of nuclear power are not worth the avoided emissions of natural gas.

Overall, these results suggest that private investors would consider nuclear to be a viable generation source under a specific set of circumstances; namely, if nuclear has a low OCC and the average natural gas price is high or the carbon tax is slightly higher than widely accepted estimates. Figure 5 plots the carbon tax necessary for the levelized cost of nuclear to equal natural gas at different natural gas prices and at the assumed nuclear OCCs. The dashed lines are the upper level of carbon taxes recommended by experts ($100 per metric ton) and the maximum projected average natural gas price over the next thirty years ($5.80 per MMBtu). Assuming that these are the upper limits of the expected carbon taxes and natural gas prices, the shaded area reflects the range of possible future carbon tax and natural gas prices.

The overlap of the solid line with the shaded area represents the window of feasible conditions under which nuclear has costs equal to natural gas. The higher OCC levels are well above the shaded area, indicating that the circumstances at which nuclear built at these construction costs is cost-competitive with natural gas are beyond expected carbon tax levels and natural gas prices. The $4,000 per kW OCC does intersect with the shaded area, but the overlap is small, illustrating the narrow set of likely conditions required for nuclear even at this low OCC to be cost-competitive.

Figure 5

Carbon taxes that equate levelized costs of nuclear and natural gas by natural gas price



Source: Authors' calculations at 7 percent cost of capital.

The boundaries of the shaded area chosen here are not meant to be actual projections of future carbon taxes or natural gas prices, and if these expected levels are higher or lower the window for nuclear to be competitive will grow or shrink. Instead, they illustrate that, all else equal, even assuming that construction costs can be reduced the appeal of nuclear compared to natural gas is dependent on the projected carbon taxes and gas prices being just right. As economist Lucas Davis explains in his 2012 paper on the prospects for nuclear power,

> The chairman of one of the largest U.S. nuclear companies recently said that his company would not break ground on a new nuclear plant until the price of natural gas was more than double today's level and carbon emissions cost $25 per ton…. This comment summarizes the current economics of nuclear power pretty well. Yes, there is a certain confluence of factors that could make nuclear power a viable economic option. Otherwise, a nuclear power renaissance seems unlikely.[111]

The results here reaffirm this conclusion. From an investor's perspective, nuclear's viability depends on a couple of highly uncertain variables, and the further risk of construction costs substantially larger than $4,000 per kW makes it less appealing.

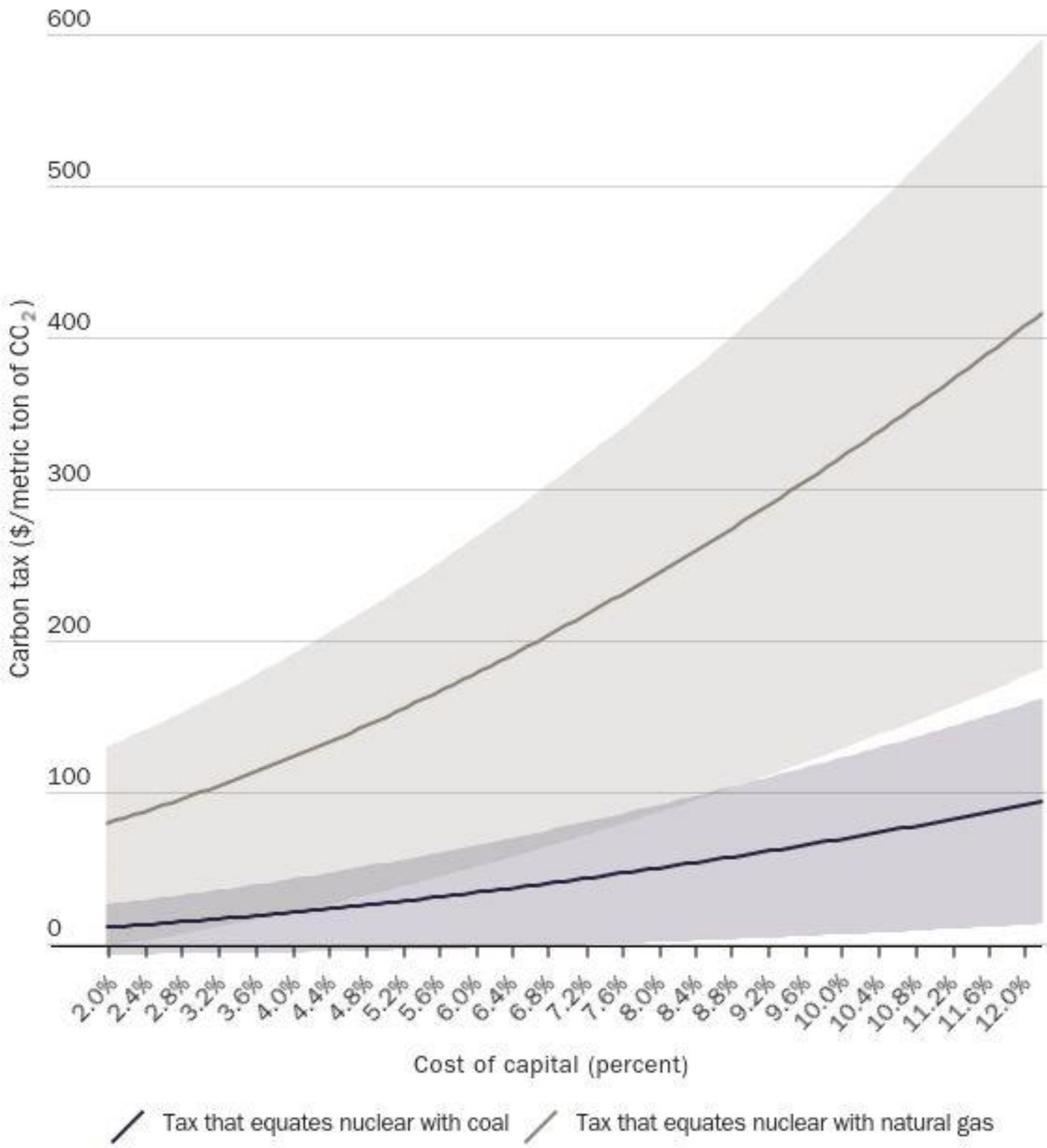
Because of the LCOE's sensitivity to cost of capital, the estimated carbon taxes are also largely affected by the assumed cost of capital. Figure 6 demonstrates this sensitivity. The solid lines represent the carbon taxes needed to equalize the costs of nuclear at the mid-range OCC with the levelized costs of fossil fuels (and natural gas at the mid-range fuel price). The shaded areas represent the range of the highest to lowest estimated carbon taxes. For coal, the upper bound of the shaded area represents a high nuclear OCC and the lower bound represents a low OCC. For natural gas, the upper bound represents the worst-case scenario for nuclear (where nuclear has a high OCC and natural gas has the low real fuel price) and the lower bound

[111] Lucas W. Davis, "Prospects for Nuclear Power," *Journal of Economic Perspectives* 26, no. 1 (Winter 2012): 49–66.

represents the best-case for nuclear (where it has a low OCC and natural gas has the high fuel price). The wide band around the estimated mid-range natural gas carbon tax illustrates the effects of the chosen inputs.

Figure 6

Carbon taxes that equate nuclear levelized costs with coal and natural gas by cost of capital



Source: Authors' calculations. Shaded areas represent the minimum and maximum carbon tax estimates based on nuclear OCC and, for natural gas, natural gas price.

With history as a guide, US nuclear construction costs are unlikely to achieve an OCC of 4,000 $/kW and the middle range OCC of 6,700 $/kW is still substantially lower than the costs of recent reactors built in the West. This suggests that the social cost of carbon that would induce private investors to consider nuclear power is on the higher end of these estimates. Of course, a carbon tax this high would also incentivize construction of other low-carbon alternatives, including renewable energy and storage technologies, changing the economic valuation of nuclear power.

Additional cost and benefit considerations

Our estimates indicate that nuclear power is competitive with natural gas only under the most charitable conditions, but are there additional considerations that shift the cost benefit calculus more in nuclear power's favor? Factors like generation flexibility and natural gas price volatility are unlikely to favor nuclear. Exclusion of the health impacts of conventional air pollution understates the costs of fossil fuels, while exclusion of nuclear liability and the handling of spent nuclear fuel understate the costs of nuclear power. And a consideration of the emissions of construction and on-going non-combustion emissions of the fuel supply chains of the generating technologies could favor either nuclear or fossil fuels, depending on what estimates of the life-cycle emissions are used.

A full accounting of the costs and benefits of these factors is outside the scope of the LCOE calculations and many of them have substantial uncertainties that make them difficult to easily consider. However, a review of the available evidence can help provide a sense of the relative magnitudes of these factors and whether they are likely to bias the analysis in the direction of nuclear or fossil fuels.

Generation flexibility

The technical characteristics of electricity grids require flexible electrical output from some generators to ensure that the supply of electricity equals demand at all times.[112] Electricity demand varies in a fairly predictable daily cycle: lowest at night, much higher during the day, peaking in late afternoon, and decreasing in the evening. The economics of generators following demand are not captured by levelized cost comparisons.

In the United States, nuclear plants function as baseload generators, meaning they operate nearly continuously at maximum capacity to serve the minimum amount of electricity demanded at all times.[113] Nuclear reactors are feasibly able to vary output, but they face technical limitations that do not apply to fossil fuel combustion turbines, including natural gas combined-cycle plants.[114] Most importantly, nuclear's large capital and low operating costs are ideally suited to continuous operation at capacity.

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[112] Varying output to match changes in demand is called "load following". Flexible generation also allows power plants to help regulate the electrical frequency of the power grid ("frequency control"). Load following and frequency control requirements are described in Jason S. Johnston, "Renewable Power and the Reliability and Cost of Electricity," University of Virginia Law School, Law and Economics Paper Series no. 2022-05, May 2022.

[113] One exception in the US is the Columbia Generating Station, a nuclear plant in Washington. Because of the large amount of hydroelectric power in the Pacific Northwest, the plant changes output based on anticipated weather, river flow, and demand conditions. The changes are typically planned days in advance and the plant is not able to respond to needs for flexible operation in real time. Nuclear Economics Consulting Group, "Nuclear Flexibility," NECG Commentary #12, September 24, 2015.

[114] IAEA, "Non-baseload Operation in Nuclear Power Plants: Load Following and Frequency Control Modes of Flexible Operation," IAEA Nuclear Energy Series no. NP-T-3.23, 2018; and Alexey Lokhov, "Technical and Economic Aspects of Load Following with Nuclear Power Plants," OECD Nuclear Energy Agency, 2011. Large scale coal plants also face limitations on their ability to operate flexibly, though recently in the United States they have been used for load following and frequency control. See Phillip Graeter and Seth Schwartz, "Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices," National Association of Regulatory Utility Commissioners, January 2020.

Flexible generation is sometimes cited as a benefit of nuclear power.[115] But, in practice, the only places where nuclear plants have been extensively used for flexible generation are countries with energy mixes that necessitate reliance on nuclear for these purposes. For example, countries with a high percentage of nuclear power (e.g., France where 70 percent of electricity is provided by nuclear plants) or a large amount of solar or wind energy, which is not technically capable of varying output (e.g., Germany where over 40 percent of electricity is generated by renewable sources), need nuclear plants to vary their output to follow electricity demand and maintain grid reliability, despite the economic downsides.[116]

The technical feasibility of flexible nuclear means on a power-grid-level it could provide a benefit that is not offered by renewable sources. But natural gas combined cycle plants can vary output more cost effectively. If the levelized costs of nuclear and natural gas combined cycle are similar, the benefit of flexibility would favor natural gas over nuclear power.

Natural gas price volatility

Natural gas prices are more volatile than coal or enriched uranium. Does this make nuclear power more or less attractive? Fabian Roques, David Newberry, and William Nuttall use Monte Carlo simulations of investment returns for natural gas, coal, and nuclear power plants to find the best portfolio mixes for private investors in liberalized electricity markets.[117] They conclude that when natural gas and electricity prices are highly correlated, as is the case in much of Europe and the United States, portfolios with mostly combined cycle natural gas generators are more

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[115] Edward Kee, *Market Failure: Market-Based Electricity Is Killing Nuclear Power* (Washington, DC: Nuclear Economics Consulting Group, 2021).
[116] IAEA, "Non-baseload Operation in Nuclear Power Plants: Load Following and Frequency Control Modes of Flexible Operation," IAEA Nuclear Energy Series no. NP-T-3.23, 2018
[117] Fabien Roques, David M. Newberry, and William J. Nuttall, "Fuel Mix Diversification Incentives in Liberalized Electricity Markets: A Mean-Variance Portfolio Theory Approach," *Energy Economics* 30 (2008): 1831-1849.

favorable. In other words, though natural gas prices are volatile, because natural gas generators typically set the marginal price of electricity, the *returns* of natural gas are not as volatile. And, by increasing the correlation between prices, building additional natural gas power plants in fact reduces the volatility of returns more than relying nuclear or coal technologies whose fuel prices are more stable.

Conventional air pollutants

Along with greenhouse gases, fossil fuel generators emit conventional air pollutants that create damages separate from climate change. Including these additional externalities could provide a comparative benefit to the assessment of nuclear costs. In particular, conventional pollutants, like particulate matter, may have significant adverse health effects, though the science on their actual impact is not settled.[118]

Coal power is generally much dirtier than natural gas and the burning of coal creates most of the conventional pollution emitted by the power industry. In fact, shifting away from coal and towards natural gas combined cycle power plants has led to a substantial decrease in the amount of conventional air pollution emitted by the electric power sector.[119]

Estimates of the marginal damages of conventional pollutants face uncertainties over the health impacts of particulate matter, the value of a statistical life, and different marginal effects by year and location of the pollution source. However, putting these questions aside, models of air pollution damages and estimated power plant emissions can be used to approximate the relative costs of air pollution for coal and natural gas. The largest health effects are caused by

[118] Peter Van Doren, "The Fight over Particulate Matter," Cato at Liberty, April 22, 2019.
[119] Peter Tschofen, Inês L. Azevedo, and Nicholas Z. Muller, "Fine Particulate Matter Damages and Value Added in the US Economy," *Proceedings of the National Academy of Sciences* 116, no. 40 (2019): 19857–19862.

fine particulate matter and two of its precursor gases, sulfur dioxide and nitrogen oxides. Estimates of the marginal damages of fine particulate matter, sulfur dioxide, and nitrogen oxides are about $98,000, $45,000, and $16,000 per metric ton, respectively.[120] Using data on emissions by coal and natural gas combined cycle power plants, this translates to a cost of roughly 6 cents per kWh for coal and of 0.3 cents per kWh for natural gas.[121]

If the assumptions on the health impacts of conventional pollutants are correct, then inclusion of these damages would considerably increase the cost of coal power (by roughly 75 percent for the estimated LCOE of 7.9 cents per kWh) but only marginally increase the cost of natural gas (by 5 percent for the high natural gas price LCOE estimate of 5.5 cents per kWh).

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[120] Authors' calculations from Stephen P. Holland, Erin T. Mansur, Nicholas Z. Muller, and Andrew J. Yates, "Decompositions and Policy Consequences of an Extraordinary Decline in Air Pollution from Electricity Generation," *American Economic Journal: Economic Policy* 12, no. 4 (2020): 244–274. Estimates for marginal damages in 2017 in 2014 $/lb are converted to 2021 $/metric ton using conversion of 1 metric ton = 2,205 lbs. and GDP price deflator from BEA.

[121] Estimated cost per unit of electricity is the sum of the costs of the individual pollutants, calculated using emissions factors (EF, in g/kWh) and marginal damages (MD, in $/metric ton divided by 10,000 to convert to cents/g):

$$EC = EF \times \frac{MD}{10{,}000}$$

The emissions factors used are 0.942 grams of sulfur oxides (SO_x) , 0.708 grams of nitrogen oxides (NO_x), and 0.06 grams of fine particulate matter ($PM_{2.5}$) per kWh for coal steam turbines and 0.007 grams of SO_x, 0.05 grams of NO_x, and 0.017 grams of $PM_{2.5}$ per kWh for natural gas combined cycle from Longwen Ou and Hao Cai, "Update of Emission Factors of Greenhouse Gases and Criteria Air Pollutants, and Generation Efficiencies of the U.S. Electricity Generation Sector," Energy Systems Division, Argonne National Laboratory, August 2020, Table 6. These estimates likely overstate the emissions of the coal and natural gas combined-cycle plants envisioned in this paper. The estimates are for the entire electric generation sector in 2017, meaning that the thermal efficiency and emissions controls may be lower than those of a brand-new power plant. Furthermore, as outlined on p. 18 in Ou and Cai, the emissions factor for $PM_{2.5}$ from natural gas combined cycle is more than 10 times previous estimates (0.001 grams per kWh) because of a change in methodology. Using the previous estimate of 0.001 grams of $PM_{2.5}$ per kWh would revise the costs of conventional pollutants for natural gas combined cycle down to 0.1 cents per kWh.

Nuclear accident liability

High profile nuclear accidents like Chernobyl, Fukushima, and Three Mile Island have increased the visibility of the accident risks of nuclear power. While the most deadly and costly energy related disaster was a series of dam failures in China in 1975 that caused the deaths of over 170,000 people, the second deadliest is Chernobyl, which caused the deaths of around 4,000 people. And nuclear accidents are especially expensive. A review of energy related accidents from 1907 through 2007 found that nuclear incidents accounted for around 40 percent of all property damages included in the study.[122]

In the United States, nuclear power plants' liability for accidents is capped. For those who believe in private markets, a careful consideration of the costs of nuclear accidents and their assumption by taxpayers is an important addition to the levelized costs assessment.

Nuclear liabilities are capped under a two-layered system created by the Price Anderson Act. The first layer is that nuclear power plants must be covered by the maximum amount of private insurance available ($450 million as of 2017).[123] The average annual site premium (depending on number of reactors at a site) is only about $1.3 million.[124] In the case of an accident exceeding $450 million in damages, a secondary layer of nuclear industry self-insurance would come into effect. Every US reactor would be required to cover a share of the excess damages up to a maximum of around $130 million per reactor. If the accident exceeded both layers of insurance

[122] The costs include "destruction of property, emergency response, environmental remediation, evacuation, lost product, fines, and court claims." Benjamin K. Sovacool, "The Costs of Failure: A Preliminary Assessment of Major Energy Accidents, 1907-2007," *Energy Policy* 36 (2008): 1802-1820.

[123] The amount of insurance required by the act is periodically increased according to the maximum amount offered by American Nuclear Insurers (ANI). Most recently, in 2017 ANI increased the amount available to $450 million, prompting the NRC to correspondingly increase the amount required. Nuclear Regulatory Commission, "Increase in the Maximum Amount of Primary Nuclear Liability Insurance," *Federal Register* 81 (December 30, 2016): 96347-96349.

[124] Nuclear Regulatory Commission, "Backgrounder on Nuclear Insurance and Disaster Relief," April 2022.

(total coverage of around $13.5 billion), additional payments would need to be approved by Congress and would likely be covered by the nuclear industry or the federal government.

Estimating a reactor's liability without a cap is difficult because both the probability of a nuclear accident and the potential level of damage are uncertain. Within the nuclear industry, reactor safety is estimated using probabilistic safety assessments (PSAs) that rely on simulations and event trees to evaluate the potential for failure in different systems. PSAs are mainly used to identify problems with reactor designs, although they also can be used to estimate the overall probability of a nuclear accident. Areva's PSA for the EPR under construction at Hinkley Point estimated a one in one million chance of a nuclear accident per year.[125]

Nuclear safety is also evaluated from the observed frequency of reactor accidents. The most basic estimates simply use the number of nuclear incidents divided by the total number of years reactors have operated. Nuclear accidents are rare. During the more than 18,000 reactor-years of worldwide experience there have only been 12 core meltdowns.[126] But reactors are not identical. They differ both in design and location and have different levels of safety regulation and operator compliance. The causes of one accident may not apply to another. And lessons learned from nuclear accidents lead to changes in reactor designs and safety regulations, meaning that the likelihood of the same type of event causing additional accidents is lower as nuclear operators and engineers learn from past experiences. If learning exists, the observed frequency of nuclear accidents overstates future nuclear accident probabilities. But if future accidents are

[125] Romain Bizet and François Lévêque, "Ambiguity Aversion and the Expected Cost of Rare Energy Disasters: An Application to Nuclear Power Accidents," Interdisciplinary Institute of Innovation Working Paper no. 16-CER-01, April 2016.
[126] Romain Bizet and François Lévêque, "Ambiguity Aversion and the Expected Cost of Rare Energy Disasters: An Application to Nuclear Power Accidents," Interdisciplinary Institute of Innovation Working Paper no. 16-CER-01, April 2016. Total reactor years surpassed 18,000 in 2019. Marta M. Gospodarczy and Marianne Nari Fisher, "IAEA Releases 2019 Data on Nuclear Power Plants Operating Experience," International Atomic Energy Agency, June 25, 2020.

unrelated to past ones the frequency will not improve. Putting these issues aside, the observed frequency of nuclear accidents suggests a reactor has a roughly one in one thousand chance of a nuclear accident per year—one thousand times more than the probability estimated by the EPR PSA.

What are the damages per nuclear accident? Estimates for a large-scale accident range from less than $100 billion to over $5 trillion.[127] The wide range results from the types of costs included (e.g., only assessing direct costs versus including broader macroeconomic consequences), the locations and boundaries of the studies (e.g., focusing on a reactor in a densely populated area, or excluding health affects across national borders), and the statistical methods employed.

Nuclear accidents don't always develop into a major nuclear disaster. Most have been core damage accidents (e.g., Three Mile Island), in which the reactor core is uncovered and heats to the point that there is oxidation and fuel damage. There is little to no radioactive material released, but these events can still cost several billions caused by evacuations, decontamination and cleanup, and damage to the reactor itself. In some cases (Chernobyl and Fukushima), a core damage accident results in a large radioactive material release outside the containment vessel. The core damage incident at Three Mile Island caused damages of around $3 billion; the large release accidents at Chernobyl and Fukushima cost hundreds of billions.[128]

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[127] Romain Bizet and François Lévêque, "The Economic Assessment of the Cost of Nuclear Accidents," chapter in Joonhong Ahn, Franck Guarnieri, and Kazuo Furuta, eds., *Resilience: A New Paradigm of Nuclear Safety* (Springer, 2017).

[128] In 2021 dollars. Benjamin K. Sovacool, "The Costs of Failure: A Preliminary Assessment of Major Energy Accidents, 1907-2007," *Energy Policy* 36 (2008): 1802-1820; IAEA, "The Human Consequences of the Chernobyl Nuclear Accident: A Strategy for Recovery," February 6, 2002; and *The World Nuclear Industry Status Report 2021* (Paris: Mycle Schneider Consulting, 2021).

Romain Bizet and François Lévêque estimate the magnitude of nuclear liability.[129] They use a worst-case probability of a core damage accident of 10^{-3} per reactor year based on the observed frequency and a best-case probability of 10^{-6} per reactor year based on PSAs for the EPR reactor. In both cases, there is a 1 in 10 chance that core damage turns into a large-release accident (i.e., the probability of a large-release is 10^{-4} in the worst case and 10^{-7} in the best case). The estimated costs are around $3 billion for a core damage accident and around $200 billion for a large release.[130]

In the *worst case*, this suggests an annual risk of $22.7 million per reactor, which translates to a cost of about 0.3 cents per kWh.[131] Given our low-end estimate of the levelized cost of nuclear at 7.9 cents per kWh, including this liability would represent a 4 percent increase in costs to 8.2 cents per kWh.

There are higher estimates of the cost of a large-release accident. The $200 billion used is in line with the Japanese government official estimate of the total costs of the Fukushima accident, including the costs of decommissioning, decontamination, and compensation to victims and the local communities. But an independent assessment found that the damages may actually range from $320 to $760 billion when the costs of the final disposition of radioactive waste and water

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[129] Romain Bizet and François Lévêque, "Ambiguity Aversion and the Expected Cost of Rare Energy Disasters: An Application to Nuclear Power Accidents," Interdisciplinary Institute of Innovation Working Paper no. 16-CER-01, April 2016.

[130] Adjusted to 2021 dollars from Romain Bizet and François Lévêque, "Ambiguity Aversion and the Expected Cost of Rare Energy Disasters: An Application to Nuclear Power Accidents," Interdisciplinary Institute of Innovation Working Paper no. 16-CER-01, April 2016.

[131] Per Bizet and Lévêque, the expected cost (in $/MWh) is:

$$EC = \frac{(p_{CDA} - p_{LRA}) \times D_{CDA} + p_{LRA} \times D_{LRA}}{Q}$$

where p_{LRA} and p_{CDA} are the probabilities of a large-release accident and core damage accident, respectively; D_{LRA} and D_{CDA} are the expected damages; and Q is the yearly amount of electricity produced. For these estimates, Q is calculated using a 1000 MW reactor with an 85 percent capacity factor. As described in the LCOE calculations, the yearly output is: $Q = 1{,}000MW \times 0.85 \times 8{,}766 \frac{Hours}{Year} = 7{,}451{,}100\ MWh$. To convert to cents per kWh divide the expected cost by 10.

purification are considered, or 0.5 to 1 cent per kWh using the worst-case probability (a core damage accident rate of 1 per 1000 reactor years).[132] Using Bizet and Lévêque's best-case probability (a core damage accident rate of 1 per million reactor years using simulations and events trees), even if a large-release accident had an expected cost of $760 billion the liability would be only about 0.001 cents per kWh.

This analysis limits the maximum level of expected damages to an accident on the scale of Fukushima or Chernobyl. It is possible, however, that previous events understate the potential magnitude of a nuclear accident. For example, many nuclear reactors are in much more densely populated areas, suggesting that the cost of evacuations, decontamination, and compensation to victims could be much higher than previous nuclear accidents. Considering this, other analyses find that there is a risk of extreme events that precludes private insurance for nuclear accidents.[133] In other words, the possible accident severity is so high that private insurance for such an accident could not be financed. This would imply that, without a cap on nuclear liabilities and thus a government guarantee to cover accident costs beyond the cap, the liability costs of nuclear power would be too high for it to be feasible. It would also mean that the LCOE ignores a sizable negative externality of nuclear power that, if included, might substantially tip the analysis in favor of coal and natural gas.

Currently, the two layers of the Price Anderson Act provide coverage of up to roughly $13.5 billion. This would cover an accident the size of TMI but would be well below the hundreds of billions in damages potentially caused by a large-release accident. In that case, the federal

[132] *The World Nuclear Industry Status Report 2021* (Paris: Mycle Schneider Consulting, 2021).
[133] See Marius Hofert and Mario V. Wüthrich, "Statistical Review of Nuclear Power Accidents," *Asia-Pacific Journal of Risk and Insurance* 7, no. 1 (2013); and Spencer Wheatley, Benjamin Sovacool, and Didier Sornette, "Of Disasters and Dragon Kings: A Statistical Analysis of Nuclear Power Incidents and Accidents," *Risk Analysis* 37, no. 1 (January 2017): 99–115.

government would most likely cover the damages, meaning there is an additional cost to nuclear that the LCOE does not consider.

Nuclear waste

The LCOE calculations also exclude the costs of the long-term storage of nuclear waste. Because of its radioactivity, and the long time for which it remains radioactive, spent nuclear fuel incurs costs when it is removed from the reactor, stored, and eventually disposed of. The high energy content of nuclear fuel means very little is required to generate a large amount of electricity, so only a small amount of nuclear waste is actually produced. An OECD NEA study on the economics of the nuclear fuel cycle projects that the levelized waste (back-end) costs are around a third of the front-end fuel costs, and only a few percentage points of the overall estimated LCOE.[134]

Spent nuclear fuel in the US has been made a statutory responsibility of the federal government. Until recently, nuclear power plants were required to pay a fee of 0.1 cents per kWh of electricity produced to the Nuclear Waste Fund. The Fund was intended to pay for a permanent spent nuclear fuel repository at Yucca Mountain in Nevada. Because of local opposition, the Yucca Mountain repository has not been constructed and nuclear operators eventually sued the Department of Energy because it was collecting the waste fee despite not meeting its obligations to handle the waste. As a result, the waste fee has been suspended until the federal government's obligations are fulfilled or an alternative plan is enacted.[135]

Currently, though, because nuclear waste is the federal government's responsibility it has been forced to pay for the storage of existing spent nuclear fuel. Most of this fuel is stored on-

[134] OECD Nuclear Energy Agency, "The Economics of the Back End of the Nuclear Fuel Cycle," 2019.
[135] World Nuclear News, "Zero Day for US Nuclear Waste Fee," May 16, 2014.

site at reactors in spent fuel pools and dry-cask storage. As of September 2020, the federal government had paid nuclear operators almost $9 billion out of a total liability of over $30 billion.[136] Hence, US nuclear power plants are currently being subsidized for the interim storage of their spent nuclear fuel.

If the 0.1 cent per kWh fee were still collected from US reactors, it would increase the levelized costs of a nuclear reactor by only about 1 percent at a levelized cost of 7.9 cents per kWh. This amount is in line with other estimates of waste costs. For example, unlike the United States, plans for the construction of a geologic spent fuel repository in Sweden are moving forward. The repository is owned by the country's nuclear industry and paid for by Sweden's waste management fund. In order to pay for both waste disposal and future decommissioning costs, the Swedish government charges a fee of around 0.04 kronor (the equivalent of about 0.4 cents) per kWh.[137] After removing the decommissioning costs, the waste fee is around 0.2 cents per kWh, or roughly 2.5 percent of a levelized cost of 7.9 cents per kWh.[138]

Though the costs of waste are not currently borne by US nuclear operators and they are a relatively small part of the total LCOE, because they are excluded the analysis is marginally biased in favor of nuclear power plants.

[136] GAO, "Commercial Spent Nuclear Fuel: Congressional Action Needed to Break Impasse and Develop a Permanent Disposal Solution," September 2021.
[137] The fee varies depending on the amount of electricity produced. Swedish National Debt Office, "The Government Has Decided on Nuclear Waste Fees for 2022-2023 in Accordance with the Debt Office's Proposal," January 31, 2022.
[138] The LCOE estimates include a decommissioning cost of $800 million. When divided by the lifetime output of the nuclear reactor, decommissioning would cost about 0.2 cents per kWh.

Life-cycle emissions

Though nuclear power plants emit no greenhouse gases during the actual generation of electricity, there are greenhouse gases emitted during construction, mining and processing of uranium, and storage and disposal of spent nuclear fuel. Likewise, for coal and natural gas power plants the construction of the plants and extraction of fuels create life-cycle emissions beyond just the burning of the fossil fuels themselves. The combustion of fossil fuels generally dwarfs the emissions created by the additional phases of the life-cycle, but the emissions during these stages could bolster or undermine nuclear's benefit of avoided emissions.

The primary emissions of nuclear are the on-going non-combustion emissions of mining and enriching uranium. While nuclear plants can consist of tens of thousands of tons of steel and hundreds of thousands of tons of concrete, both materials that are carbon intensive to manufacture, the actual per unit of electricity carbon emissions created during the construction of a nuclear plant is relatively low. This is because these are one-time emissions that, when divided over the electricity produced during the long lifetime of a nuclear plant, are small compared to the on-going emissions of the uranium supply chain. Similarly, the largest non-combustion emissions of natural gas and coal are the emissions created by their fuel supply chains. This may be large for natural gas in particular because of methane leakage during extraction and processing.[139]

Estimates of total life-cycle emissions of a power plant, particularly for nuclear, vary widely because of sensitivity to key assumptions.[140] For nuclear, for example, some studies assume that

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[139] Timothy J. Skone et al., "Life Cycle Analysis of Natural Gas Extraction and Power Generation," U.S. Department of Energy National energy Technology Laboratory, August 30, 2016.

[140] Jef Beerten, Erik Laes, Gaston Meskens, and William D'haeseleer, "Greenhouse Gas Emissions in the Nuclear Life Cycle: A Balanced Appraisal," *Energy Policy* 37, no. 12 (December 2009); and Benjamin K. Sovacool, "Valuing the Greenhouse Gas Emissions from Nuclear Power: A Critical Survey," *Energy Policy* 36 (2008): 2940–2953.

as nuclear capacity increases nuclear plants will be forced to rely on lower quality uranium. This would require more energy for mining and enriching and mean that as capacity grows life-cycle emissions will actually increase. Additionally, the assumed existing energy mix of the system considered in the estimates affects the projected life-cycle emissions of a new power plant. If we assume that a new nuclear plant is being built in a system that largely relies on coal power then the emissions created by the energy used will be much higher than a system that already relies mainly on nuclear power.

A review of studies on nuclear life-cycle emissions harmonized performance assumptions, such as the operational life and capacity factor, and found a median of 17 and a range of 3.7–110 grams of CO_2 equivalent emission per kWh of electricity produced.[141] Similar harmonization for coal finds a median of 790 and range of 730 to 1,010 grams of CO_2 per kWh and for natural gas finds a median of 450 and range of 330 to 690 grams of CO_2 per kWh.[142] While these estimated life-cycle emissions have been harmonized across a review of studies, they have not been harmonized to match the performance assumptions made in this paper. Therefore, they should be only cautiously compared to the *combustion only* emissions used in our carbon tax estimates, 827 and 337 grams of CO_2 per kWh for coal and natural gas, respectively.[143]

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[141] Ethan S. Warner and Garvin A. Heath, "Life Cycle Greenhouse Gas Emissions of Nuclear Electricity Generation," *Journal of Industrial Ecology* 16, no. 1 (April 2012): S73–S92.

[142] Values for supercritical coal from Michael Whitaker, Garvin A. Heath, Patrick O'Donoughue, and Martin Vorum, "Life Cycle Greenhouse Gas Emissions of Coal-Fired Electricity Generation Systematic Review and Harmonization," *Journal of Industrial Ecology* 16, no. S1 (2012): S53–S72; and natural gas combined cycle from Patrick R. O'Donoughue, Garvin A. Heath, Stacey L. Dolan, and Martin Vorum, "Life Cycle Greenhouse Gas Emissions of Electricity Generated from Conventionally Produced Natural Gas," *Journal of Industrial Ecology* 18, no. 1 (February 2014): 125–144.

[143] As outlined in the appendix, the per unit of electricity carbon intensity is:

$$\frac{I_{Carbon} \times HR}{1{,}000{,}000} \times 1{,}000$$

Where I_{Carbon} is the technology specific carbon dioxide intensity (52.91 kg-CO_2/MMBtu for natural gas and 95.74 kg-CO_2/MMBtu for coal) and HR is the heat rate (6,370 for natural gas and 8,638 for coal) and multiplied by 1,000 to convert from metric tons/MWh to g/kWh.

This large variability in estimates means that the carbon tax required for parity between nuclear and fossil fuel generators could be larger or smaller depending on the assumptions made when assessing the life-cycle emissions. Nevertheless, because the majority of fossil fuel emissions are a result of combustion and, when ignoring large outliers, the estimated life-cycle emissions of nuclear are relatively small, it is unlikely that including total life-cycle emissions would have a large impact on the magnitude of carbon taxes estimated.

Nuclear power subsidies

Throughout its history, nuclear power has received substantial government support. In many countries, nuclear has been constructed by government-owned utilities or as part of top-down government led and funded efforts to expand the use of nuclear power. In the United States, nuclear power plants have been built in government-regulated electricity markets guaranteeing cost recovery for utilities. Support for recent US nuclear projects includes favorable loan guarantees, electricity production tax credits, and research and development subsidies.

The LCOE calculations explicitly exclude some of the government subsidies available to a new nuclear power plant by using a private cost of capital and disregarding production tax credits. However, because the assumed overnight construction costs are derived from OCCs of reactor designs that have received substantial government R&D support, the effects of these government subsidies are included in the LCOE estimates.

It is not possible to determine what the cost of building a reactor would be without government funding, particularly considering that US nuclear support has been extensive. Between 1948 and 2018, nuclear received 48 percent of federal energy R&D funding, compared to 24 percent for fossil fuels and 13 percent for renewables.[144] The AP1000 was developed with DOE R&D support.

To the extent that some of these subsidies are motivated by nuclear power's low-carbon nature, they represent an implicit carbon price. Their inclusion in the LCOE calculations means the carbon tax levels we estimate understate the SCC that would make nuclear's avoided emissions worth the high capital costs. The true SCC would include both the carbon tax necessary to make the LCOE of fossil fuels equal to that of nuclear and the value of the subsidies needed to reduce nuclear's OCC to its current level.

Some economists argue that an optimal policy to address climate change should include both R&D subsidies to clean technologies and a carbon tax.[145] The R&D subsidies would be used to redirect technological innovation from dirty to clean sectors, thereby incentivizing the development of clean technology. And once such technology exists, the carbon tax would encourage its use. The claim is that the overall costs of the transition to a clean energy future would be lower with the combination of early subsidies and later carbon tax than with only a carbon tax. The supportive evidence comes from data on the responsiveness of patents to R&D expenditures.

Considering nuclear's long history of direct and indirect subsidies, this research would not seem applicable to the cost effectiveness of nuclear power.[146] In fact, nuclear energy illustrates the downside of targeted R&D subsidies. Federal research programs to achieve specific

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[144] Corrie E. Clark, "Renewable Energy R&D Funding History: A Comparison with Funding for Nuclear Energy, Fossil Energy, Energy efficiency, and Electrical Systems R&D," Congressional Research Service, June 18, 2018.
[145] See Daron Acemoglu, Philippe Aghion, Leonardo Bursztyn, and David Hemous, "The Environment and Directed Technical Change," *American Economic Review* 102, no. 1 (2012): 131–166; and Daron Acemoglu, Ufuk Akcigit, Douglas Hanley, and William Kerr, "Transition to Clean Technology," *Journal of Political Economy* 124, no. 1 (2016): 52–105.
[146] Taxpayers for Common Sense, "Understanding Nuclear Subsidies: Why Shoveling More Handouts Won't Revive the Industry or Solve Our Energy Problems," February 2021.

commercial outcomes have a history of failure.[147] Seventy years of federal research support has been unable to reduce nuclear costs to a level where it is competitive with fossil fuels.

Some part of the high cost of nuclear is a result of stringent regulations, though the net effect of the regulations and subsidies on nuclear costs is not known. Because the OCCs used in the LCOE are lower than they would be without the R&D subsidies, the calculations understate nuclear's costs and therefore also underestimate the carbon tax needed for nuclear's costs to equal those of fossil fuels.

Advances in nuclear technology and opportunities for cost reductions

Historic nuclear cost estimates have been too low.[148] Will future reactor designs be different?

Many argue the future of cost-effective nuclear power is small modular reactors (SMRs): reactors with an electrical capacity less than 300 MW (compared to 1117 MW for the AP1000 and around 1600 MW for the EPR).[149] SMR designs use modules manufactured in factories and shipped to the site and assembled. The economic success of SMRs will depend on cost reductions from manufacturing standardized components offsetting diseconomies of scale from their smaller size. If only the economies of scale of reactor size are considered, SMRs would have lower total capital costs but a higher per unit of capacity overnight cost.

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[147] Linda R. Cohen and Roger G. Noll, *The Technology Pork Barrel* (Washington: The Brookings Institution, 1991).
[148] Nathan E. Hultman and Jonathan G. Koomey, "The Risk of Surprise in Energy Technology Costs," *Environmental Research Letters* 2 (2007); and Nathan E. Hultman, Jonathan G. Koomey, and Daniel M. Kammen, "What History Can Teach Us about the Future Costs of U.S. Nuclear Power," *Environmental Science & Technology*, April 1, 2007.
[149] In this paper, SMR refers to "small modular reactors," though some of the sources cited use SMR to refer to "small and medium-sized reactors."

SMRs take advantage of efficiencies elsewhere. For example, by building multiple smaller reactors at one location, SMRs can spread the siting costs, such as land acquisition and connection to the electric grid, across multiple units. Factory manufacturing is also cheaper than on-site fabrication, and by building much of the plant in a factory, SMRs can better take advantage of standardization and replication than large reactors that are typically built entirely on site. SMRs also typically rely on simpler designs that are, in theory, less expensive to build. Together, these economies of mass production suggest that, despite the loss of economies of scale, the overnight cost of SMRs could be on par with those of large reactors.[150]

The factory construction of SMRs also might allow them to be built more quickly than conventional sized reactors. Shorter construction time and lower total capital costs imply that SMRs could have lower financial risks, and may therefore be more palatable to investors. Building the power plant in separate modules could require less upfront capital and allow completed modules to begin producing electricity while other modules are still under construction. This would help to smooth the cash flows of the power plant, also limiting risk for investors.[151]

SMR advocates claim cost reductions will arise from learning through large-scale deployment. Consider a comparison between a generic NOAK large reactor and a power plant made up of SMR modules. The large reactor has a capacity of 1000 MW (1 gigawatt (GW)) and an OCC of $6,700 per kW, as envisioned in our LCOE estimates. The SMR plant is made up of

[150] M.D. Carelli et al., "Economic Features of Integral, Modular, Small-to-Medium Size Reactors," *Progress in Nuclear Energy* 52 (2010): 403-414. Other analyses find that SMRs would still require substantial on-site labor, meaning the diseconomies of scale would still lead to higher OCCs than conventional sized reactors. W.R. Stewart and K. Shirvan, "Capital Cost Estimation for Advanced Nuclear Power Plants," *Renewable and Sustainable Energy Reviews* 115 (March 2022).

[151] See Lauren M. Boldon and Piyush Sabharwall, "Small Modular Reactor: First-of-a-Kind (FOAK) and Nth-of-a-Kind (NOAK) Economic Analysis," Idaho National Laboratory, 2014.

10 modules with 100 MW capacity each, for a total capacity equal to the large reactor at 1 GW. The total capital cost of the large reactor is $6.7 billion but, because of diseconomies of scale of the smaller reactor size, the cost of each SMR is not simply 10 percent of the large reactor ($670 million) but $1.6 billion.[152] Thus, the per unit of electricity OCC of the first individual SMR module would be $16,072 per kW, an increase of around 140 percent.

Advantages, such as co-siting, factory fabrication, and modularization, are claimed to reduce construction costs of the SMR by about 35 percent.[153] The extra costs of building a FOAK reactor might conservatively increase the OCC by 20 percent.[154] After these adjustments, the FOAK OCC of the SMR reactor is $12,536 per kW, about 90 percent higher than the large reactor overnight cost.

However, as more SMR modules are built and learning occurs, the SMR LCOE might reach parity with the large reactor, after which subsequent SMR power plants should have costs lower than the NOAK conventionally sized plant. Estimates of SMR's cost declines from learning can range from 5 to 10 percent for every doubling of SMR capacity.

The learning rate increases with the number of reactors built per year and the portion of capital expenditures that occur in the factory.[155] An assessment of SMRs for the UK government

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[152] The estimated cost difference for reactors of different sizes is calculated using:

$$Cost_{small} = Cost_{large} \times \left(\frac{Size_{small}}{Size_{large}}\right)^{a}$$

where $Cost$ is the total overnight capital cost, $Size$ is the capacity, and a is a scaling factor. The scaling factor used is 0.62, as discussed in M.D. Carelli et al., "Economic Features of Integral, Modular, Small-to-Medium Size Reactors," *Progress in Nuclear Energy* 52 (2010): 403-414.

[153] Rounded up from estimates of 32 percent capex savings described by Tony Roulstone et al., "Small Modular Reactors: Can Building Nuclear Power Become More Cost-Effective," EY, March 2016.

[154] The extra costs of a first-of-a-kind build could be as much as 15–55 percent. Lauren M. Boldon and Piyush Sabharwall, "Small Modular Reactor: First-of-a-Kind (FOAK) and Nth-of-a-Kind (NOAK) Economic Analysis," Idaho National Laboratory, 2014.

[155] An alternative conception of learning rates is based on technological maturity. A complex structure like a nuclear reactor has a mix of mature and immature technologies with different learning rates. Using this framework, the overall average learning rate of an SMR could be estimated at around 4.5 percent, as in Lauren M. Boldon and

estimated that building more than 10 reactors per year with 60 percent of the capital expenditures occurring in the factory would achieve a high learning rate of 10 percent, building more than 10 reactors per year with 45 percent of the expenditures in the factory would mean a learning rate of 8 percent, building around 5 reactors per year with 45 percent of expenditures in the factory would have a learning rate of 7 percent, and building fewer than 1 reactor per year with 45 percent of the expenditures in the factory would mean a slower learning rate of 5 percent.[156]

Comparing the levelized costs of the large reactor to a 10 module SMR plant shows that, at first, the SMR plant is not competitive even if the learning rate is applied immediately to the 10 units as they are built. The LCOE of the large reactor, using the inputs outlined in the estimates above and the appendix, is 11.4 cents per kWh. The LCOE of the first 10-module SMR power plant at a capacity factor of 95 percent (to reflect the fact that an SMR theoretically will have less downtime compared to a conventional reactor) and a shorter construction time of 4 years, is estimated to be 14.6, 14.1, 13.8, and 13.4 cents per kWh at learning rates of 5, 7, 8, and 10 percent, respectively.[157] As subsequent plants are built, the LCOE estimates might decline until they are lower than the costs of the large reactor

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Piyush Sabharwall, "Small Modular Reactor: First-of-a-Kind (FOAK) and Nth-of-a-Kind (NOAK) Economic Analysis," Idaho National Laboratory, 2014.

[156] Atkins Limited, "SMR Techno-Economic Assessment: Project 1: Comprehensive Analysis and Assessment," Report for the UK Department of Energy and Climate Change, July 21, 2016.

[157] The LCOEs are calculated by applying the learning curve to the overnight costs of the SMRs. The average OCC for each iteration of the 10-module SMR power plant is then calculated and the LCOE is estimated using the total power plant capacity of 1000 MW, a capacity factor of 95 percent, construction time of 4 years, and the remaining inputs for the light-water reactor described in the appendix (including a 7 percent cost of capital).
The learning curve is calculated using the equation:

$$OCC_n = OCC_{FOAK} \times n^b$$

where OCC_n is the overnight cost of each unit n after the first unit; OCC_{FOAK} is the initial, first-of-a-kind OCC (i.e., the overnight cost of the first unit, $n = 1$); and b is a function of the learning rate (LR):

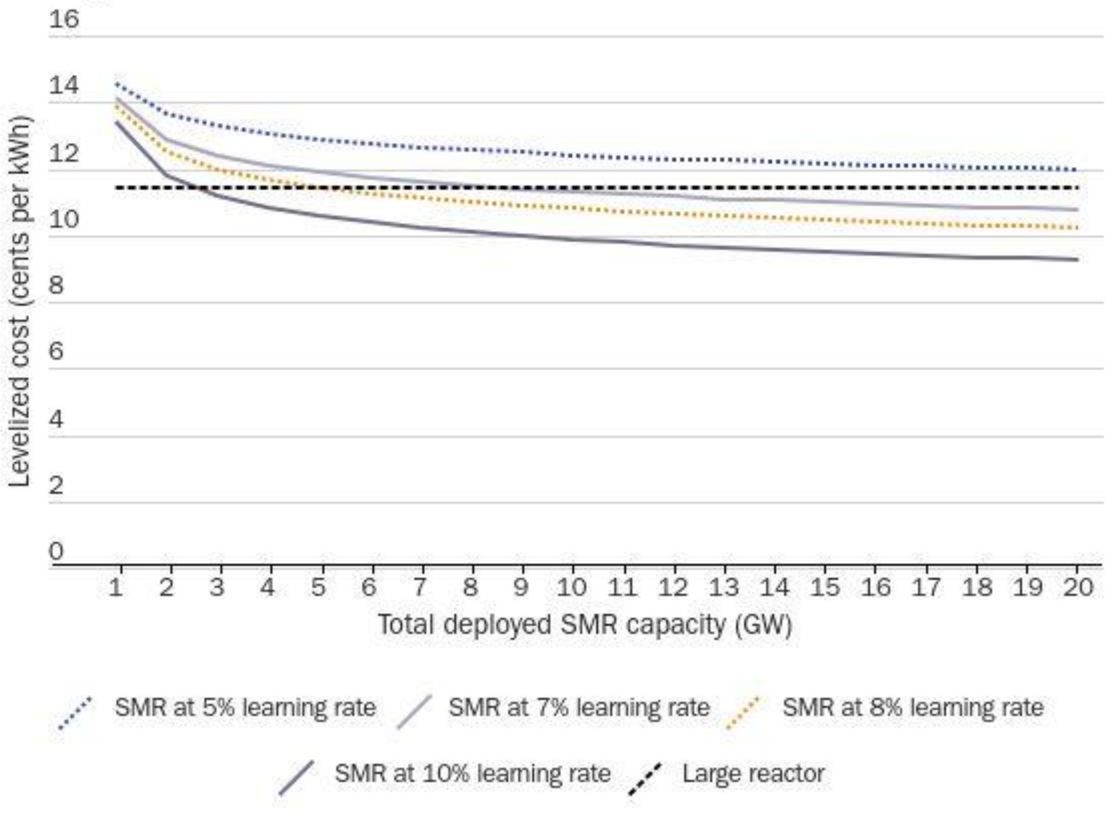
$$b = \ln{(1 - LR)}/\ln{(2)}.$$

The learning function is further described in EIA, "Assumptions to the Annual Energy Outlook 2022: Electricity Market Module," March 2022; and Lauren M. Boldon and Piyush Sabharwall, "Small Modular Reactor: First-of-a-Kind (FOAK) and Nth-of-a-Kind (NOAK) Economic Analysis," Idaho National Laboratory, 2014.

As shown in Figure 7, the effects of learning are large for the first several plants but abate over subsequent units. The colored lines represent the levelized costs of the 10-module, 1 GW SMR power plants as deployment of SMRs increases at learning rates of 5, 7, 8, and 10 percent. The black dashed line is the estimated LCOE of the large reactor (11.4 cents per kWh). At a learning rate of 10 percent, the LCOE of the SMR plant would be less than the cost of the large reactor once 3 GW of capacity (or 30 reactors) were built. At 8, 7, and 5 percent learning rates, the SMR would cost less after 6 GW (60 reactors), 9 GW (90 reactors), and 53 GW (530 reactors) were deployed, respectively.

Figure 7

Small modular reactor levelized costs compared with a large reactor by estimated learning rate



Source: Authors' calculations.

Hence, the amount of capacity required for SMRs to take advantage of their increased learning effects is sensitive to the forecasted learning rate. For context, the US currently has 93 reactors with about 95.5 GW of capacity.[158] This means that, under these rough assumptions, at the higher learning rates of 7 to 10 percent, the equivalent of 3–9 percent of total US nuclear capacity would have to be deployed for the benefits of SMRs to start paying off. At a learning rate of 5 percent, more than 55 percent of current US capacity would be needed.

Because the estimated learning rate is itself based on manufacturing speed, the importance of the ability to mass produce is compounded. A high learning rate requires a lot of manufacturing capacity which means that the benefits of learning will be quickly realized. Conversely, a low level of manufacturing capacity means a low learning rate and a much longer timeline for the benefits to payoff. At a 10 or 8 percent learning rate, with at least 10 reactors produced per year, it would take 3 to 6 years to manufacture the number of reactors required for the benefits to be realized, plus the time needed to deploy the manufactured reactors to actually realize the benefits. At a 7 percent learning rate, with 5 reactors produced each year, it would take 18 years to manufacture the necessary number of reactors, and at a 5 percent learning rate, with less than 1 reactor produced a year, the amount of capacity required to reach the costs of the generic large reactor would take at least 530 years to manufacture.

These back-of-the-envelope calculations illustrate the importance of the learning and manufacturing rates, though there are other factors that would greatly affect the ability of SMRs to achieve cost parity. For example, the LCOEs of SMRs are also sensitive to the initial overnight cost. A higher FOAK OCC for SMRs would mean that much more capacity would be needed for the learning effect to bring the LCOE in line with large reactors, whereas more savings from co-siting and modularization or a lower impact from lost economies of scale, and therefore a lower FOAK OCC, would mean less capacity is needed. Other than varying the

[158] Net summer capacity from Energy Information Administration, *Monthly Energy Review*, Table 8.1, March 2022.

capital costs, capacity factor, and construction time, the LCOE estimates keep all other assumptions consistent between the large reactor and SMR. Smaller reactors may have higher relative fuel costs because of the smaller core size and operations and maintenance costs because of diseconomies of scale.[159]

The cost reductions from SMRs are highly dependent on mass production benefits. Less generous assumptions suggest that thousands of reactors need to be built before SMRs could reach costs equal to large reactors.[160] Currently, the factories and supply chains necessary to build at least 10 reactors per year are not in place and do not look to be on the horizon. For the time being, learning rates of 10 and 8 percent would be difficult to achieve. Experience with modular construction with the AP1000s at Vogtle and V.C. Summer is certainly not supportive.

Current small modular reactor projects in the United States

To date, development of SMRs in the United States has been difficult. The ideas behind SMRs are not new, and many of the leading projects have been under development for years. Even with significant federal investment, some of the most prominent US nuclear companies have struggled to bring an SMR to market.

For example, Babcock & Wilcox, one of the US's most storied reactor designers, began development of the mPower SMR in 2009. In 2012, the DOE announced a 5-year cost sharing agreement for the mPower, which was being designed along with Bechtel, a large construction firm, and the Tennessee Valley Authority.[161] In 2017, Babcock & Wilcox canceled the project

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[159] Mario D. Carelli et al., "Competitiveness of Small-Medium, New Generation Reactors: A Comparative Study on Capital and O&M Costs," Proceedings of the 16th International Conference on Nuclear Engineering, May 11-15, 2008.

[160] Alexander Glaser, M.V. Ramana, Ali Ahmad, and Robert Socolow, "Small Modular Reactors: A Window on Nuclear Energy," An Energy Technology Distillate from the Andlinger Center for Energy and the Environment at Princeton University, June 2015.

[161] World Nuclear Association, "Small Nuclear Power Reactors," December 2021.

because it was unable to secure sufficient funding, despite receiving $111 million from the DOE.[162] Westinghouse similarly decided to slow development of its own SMR design in 2014 after the DOE made cost-sharing agreements with its competitors and because they were unable to find customers.[163] More recently, after a DOE award of $12.9 million in 2019, Westinghouse decided to move forward with development of a separate 25 MW "micro-reactor."[164]

The most mature SMR design in the US is being developed by NuScale. The reactor has a capacity of 77 MW and can be built in configurations of up to 12 modules, for a total gross capacity of 924 MW. Development began in the early 2000s with DOE funded research at Idaho National Lab. NuScale was founded in 2007, applied for design certification to the NRC in 2016, and finally became the first SMR design be certificated in 2020.[165]

During this time, NuScale's projected overnight cost, and levelized costs, have declined. In 2015, company presentations estimated an FOAK OCC of about $5,000 per kW.[166] This corresponded to an FOAK LCOE of 10.1 cents and a NOAK LCOE of 9 cents per kWh at a discount rate of 6.5 percent. At municipal financing (i.e., a lower discount rate of 3.5 percent), NuScale projected an LCOE of 7.2 cents per kWh.

More recently, after uprating the reactors' capacity from 50 MW to 60 MW and then to 77 MW, NuScale projects an NOAK OCC of $3,600 per kW, LCOE of 4 to 6.5 cents per kWh (depending on the "financial profile of the customer," suggesting different discount rates), and

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[162] Rod Adams, "Bechtel and BWXT Quietly Terminate mPower Reactor Project," Forbes, March 13, 2017.
[163] Anya Litvak, "Westinghouse Backs off Small Nuclear Plants," *Pittsburgh Post-Gazette*, February 1, 2014.
[164] Sonal Patel, "Bagging DOE Support, Westinghouse Eyes Demonstration for Nuclear Micro-reactor by 2022," *Power*, March 28, 2019.
[165] NuScale, "History of NuScale Power," https://www.nuscalepower.com/About-Us/History.
[166] Jay Surina and Micke McGough, "The NuScale Value Proposition," February 18, 2015, https://web.archive.org/web/20160328211326/http://www.nuscalepower.com/pdf/nuscale-value-proposition.pdf. This OCC likely excludes owner's costs, such as land, project management, site preparation, and commissioning. This means it is low relative to other OCCs cited in this paper that do include these costs.

construction time of 36 months.[167] Despite the lost economies of scale, NuScale projects that benefits of co-siting, factory construction, and modularization allow it to achieve overnight costs nearly 70 percent less than the current costs at Vogtle.

The first planned NuScale power plant is the Carbon Free Power Project (CFPP) at Idaho National Labs. The CFPP would be owned by the Utah Associate Municipal Power Systems (UAMPS), a consortium of over 50 municipal utilities across Western states. The project is funded by a subscription model where individual municipalities chose to subscribe for a certain amount of capacity and owe capital costs based on that percentage of the overall plant capacity. UAMPS and NuScale have managed to secure a significant amount of DOE funding, including a nearly $1.4 billion cost-sharing agreement over 10 years.[168]

UAMPS has the option to terminate the project at various points along its development before the start of construction.[169] As new more accurate cost estimates are periodically made, the project undergoes an economic competitive test. The new cost estimates are used to calculate the expected levelized costs of the power plant and are compared to a targeted levelized cost of 5.5 cents per kWh, representing the cost of the primary alternative option, a natural gas power plant. Currently, UAMPS believes that—when the DOE cost sharing, production tax credits, and

[167] NuScale, "NuScale's Affordable SMR Technology for All," *NUCLEAS* (Spring 2020); and NuScale, "A Cost Competitive Nuclear Power Solution." It is not clear exactly what the OCC of $3,600 per kW quoted here includes, but based on past NuScale OCC estimates it most likely only includes the direct and indirect engineering, procurement, and construction costs, and excludes owner's costs, such as land, project management, site preparation, and commissioning. If so, the NuScale OCC here is low relative to other OCCs in this paper that do include owner's costs. See costs included in this estimate of NuScale OCC, Geoffrey A. Black, Fatih Aydogan, and Cassandra L. Koerner, "Economic Viability of Light Water Small Modular Reactors: General Methodology and Vendor Data," *Renewable and Sustainable Energy Reviews* 103 (2019): 248–258. Owner's cost could be as much as 15–20 percent of the quoted overnight cost, meaning the full NuScale OCC estimate comparable to other OCC estimates in this paper could be $4,140–4,320 per kW. See William D. D'haeseleer, "Synthesis on the Economics of Nuclear Energy," European Commission, DG Energy, November 27, 2013, p. 38.
[168] NuScale, "The Carbon Free Power Project."
[169] NuScale and UAMPS, "Development Cost Reimbursement Agreement," November 2020, http://ieefa.org/wp-content/uploads/2022/02/Development-Cost-Reimbursement-Agreement-Execution-Copy-20201014.pdf.

favorable loan guarantees are included and at a low discount rate of around 3.5–4 percent—the project will have an LCOE below the 5.5 cents per kWh target, thereby passing the economic competitive test.

The full details of the model used to assess the LCOE are not publicly available, so it is difficult to compare the LCOEs with and without the subsidies. Other sources indicate that the value of the DOE cost sharing agreement is about 1.5 to 3 cents per kWh, depending on discount rate.[170] The project would also receive a nuclear production tax credit of 1.8 cents per kWh for the first 8 years of operation, up to a maximum of $125,000 per MW of capacity.[171] Levelized over a 40-year plant life, this would amount to about 0.5 cents per kWh.[172]

Insofar as the justification for the DOE cost sharing and production tax credits is solely to avoid carbon emissions, taken together the subsidies represent an implicit carbon price of around $60 to $105 over the UAMPS estimated LCOE of 5.5 cents per kWh for natural gas.[173] If the actual cost of a natural gas plant is in fact lower, or the true LCOE of the CFPP ends up being higher, the implicit carbon price would be larger.

The CFPP project is moving forward, though the total expected costs (the project costs beyond the estimated OCC) have increased over time.[174] However, because of difficulties getting municipalities to subscribe, and some towns choosing to drop out even with the DOE cost

[170] Mark R. Weimar et al., "Techno-economic Assessment for Generation III+ Small Modular Reactor Deployments in the Pacific Northwest," Pacific Northwest National Laboratory, April 2021, p. 59.
[171] Nuclear Energy Institute, "The Nuclear Production Tax Credit."
[172] The levelized tax credit is calculated using the net capacity of the CFPP of 685 MW (as a plant configuration of 12 modules with 60 MW gross capacity each), a capacity factor of 95 percent, a plant life of 40 years, and a discount rate of 3.75 percent to match assumptions believed to be made for UAMPS' LCOE estimates. With the $125,000 per MW cap, the tax credit amounts to 1.5 cents per kWh for the first 8 years of the operation life. Discounted and averaged over the lifetime electrical production of the plant, the subsidy is 0.5 cents per kWh.
[173] Calculated using the combined benefit of the cost sharing agreement and tax credit of 2 to 3.5 cents per kWh and the carbon intensity of natural gas as described in the appendix.
[174] Sonal Patel, "Commerical NuScale SMR in Sight as UAMPS Secures $1.4B for Plant," *Power,* October 22, 2020.

sharing, UAMPS has scaled the CFPP down to 6 modules for a lower total gross capacity of 462 MW.[175] The project partners plan to submit a construction and operating license application to the NRC in 2024 with the first module currently expected to begin generating power in 2029.[176]

Of course, because of the possibility of cost surprises, the success of the CFPP cannot be assessed until much later in its development and construction. With over 20 years of development time at this point, the NuScale SMR still faces some of the most difficult obstacles for nuclear projects: construction management and regulatory instability during construction. As the most advanced SMR design, and with the issues at Vogtle and V.C. Summer, hopes for the future of the US nuclear industry rest largely on NuScale's ability to avoid these historical drivers of cost escalation.

NRC licensing reform

While the benefits of SMRs and advanced reactor designs have yet to be proven, impediments to the ability to develop and test new designs and nuclear concepts should be removed. One primary impediment is the NRC licensing process, which can take years and cost hundreds of millions. For example, NuScale's recent design certification took 5 years and cost the company more than half a billion dollars (it should be noted that NuScale has also received nearly $450 million in DOE R&D grants).[177]

The problem with current NRC licensing procedures is that they are prescriptive and based on conventional reactor designs. Requirements do not necessarily apply to SMRs or advanced

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[175] Hal Bernton, "This Next-Generation Nuclear Power Plant Is Pitched for Washington State. Can It 'Change the World'?" *Seattle Times*, November 8, 2021.
[176] Sonal Patel, "Nuclear Field Activities Completed for Idaho NuScale SMR Project," *Power*, February 3, 2022.
[177] Thomas A. Bergman, "Lessons-Learned from the Design Certification Review of the NuScale Power, LLC Small Modular Reactor," Letter to Margaret M. Doane, NRC Executive Director of Operations, February 190, 2021; and Taxpayers for Common Sense, "Doubling Down: Taxpayers' Losing Bet on NuScale and Small Modular Reactors," December 2021.

reactors.[178] The process also requires extensive data and evidence, and the act of collecting such data can be time consuming and difficult. For example, NRC site permitting requires five years of weather data for the location under review. If five years of data is not already available, the process of licensing must be delayed until it is collected. An alternative option would be to rely instead on the probability and magnitude of an extreme weather event.[179]

In general, reform to NRC licensing procedures could institute a "risk-informed performance-based" regulatory framework. As Adam Stein from The Breakthrough Institute explains,

> This means that clear, objective, and measurable performance criteria should be defined that are scaled to the level of risk. For example, a performance criterion could be that the power plant should be able to withstand an earthquake without damage to safety systems. To be risk-informed the design should be able to meet that performance criterion based on the likelihood and magnitude of an earthquake in that location.
>
> The existing licensing frameworks are prescriptive, meaning that they contain specific requirements that the NRC mandated when licensing the existing large light water reactors. In our earthquake example, the requirements might prescribe specific

[178] Adam Stein and Sola Talabi, "Lessons from NuScale's Design Certification Process," The Breakthrough Institute, November 2, 2021.
[179] Jaime Livingston, "NRC Must Adopt Simpler Safety Metrics for Proposed Nuclear Power Plants," The Breakthrough Institute, October 27, 2021.

> methods that a design must use for earthquake protection, such as seismic dampers or backup cooling pumps in case one fails.[180]

The new framework would allow more flexibility in reactor designs, reducing the licensing burden on nuclear designs with major differences from traditional reactors.

The Nuclear Energy Innovation and Modernization Act of 2019 required the NRC to modify licensing to make it more technology inclusive. So far, NRC has begun the rulemaking process, but it will take several years before any changes are instituted. And there have been concerns from some pro-nuclear organizations that the new procedures will not be successful in providing more flexibility.[181]

Regulatory licensing reform is by itself no guarantee that innovation will help make nuclear energy competitive. But government-imposed obstacles to nuclear competitiveness should be removed.

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[180] Adam Stein, "FAQ on Advanced Nuclear Reactor Licensing," The Breakthrough Institute, July 7, 2021.
[181] Joint letter to the NRC, "Joint NGO Comments on Preliminary Proposed Rule Language, 'Risk-Informed, Technology-Inclusive Regulatory Framework for Advanced Reactors,'" The Breakthrough Institute, ClearPath, Good Energy Collective, Nuclear Innovation Alliance, and Third Way, July 23, 2021.

Conclusion

From its inception, nuclear power's promise of clean and abundant energy has been appealing. In the context of climate change, this appeal has grown and, for many, the need to increase reliance on nuclear, a constant low-carbon source of energy, has become more urgent. But nuclear power plants are very costly.

At current cost levels, nuclear power is not worth the value of its avoided emissions. At overnight costs of $6,700 and $9,000 per kW, much less the astronomical costs experienced by the United States' most recent nuclear projects, the social cost of carbon would need to be well above the levels recommended by the U.S. government and academic experts to make nuclear capital costs worthwhile.

The exact reasons behind nuclear's high costs are not entirely clear. Whether large costs are a requirement of safe nuclear reactors, or a consequence of overregulation or mismanagement depends largely on whether one is pro- or anti-nuclear. It is apparent that nuclear power plants frequently experience substantial delays and cost overruns caused by a variety of factors, including problems involving managing labor forces, supply chains, and quality control. The reason for these problems is a mix of the high level of regulation, design choices, and mismanagement.

However, assuming that these problems can be addressed, the intrinsic construction cost of an acceptably safe reactor would need to be substantially lower than current levels for nuclear to be an appealing option for private investors. Even if overnight construction costs were only $4,000 per kW, a decrease of 55 percent compared to this study's high OCC of $9,000 per kW and of nearly 65 percent compared to the costs at Vogtle, nuclear power's levelized cost would equal natural gas only if the natural gas price is high or there is a carbon tax higher than the levels recommended by the U.S. government and academic experts.

This does not suggest that it is impossible to build a cost-effective nuclear reactor. In fact, removing prescriptive regulations and impediments to licensing is worthwhile to ensure that nuclear costs are not unjustifiably high and to allow nuclear's viability to hinge on its ability to contain costs through better project management and innovation. But nuclear power's history, and the large amount of federal support it has received, exemplify the downsides of targeted R&D spending programs. After seventy years and billions of dollars in federal subsidies, nuclear would still require a specific set of circumstances—either a high natural gas price or additional government intervention through an excessive carbon tax—to be cost competitive with natural gas.[182]

Whether a large enough reduction in capital costs for future nuclear to be feasible is possible remains to be seen. But, to date, a remarkably diverse set of countries, companies, and contractors have been unable to achieve it.

[182] Taxpayers for Common Sense, "Understanding Nuclear Subsidies: Why Shoveling More Handouts Won't Revive the Industry or Solve Our Energy Problems," February 2021.

Appendix: Levelized Cost of Electricity

The levelized cost of electricity (LCOE) calculation used in this paper was developed from methodology used in a 2003 MIT report on nuclear power and its 2009 update and International Energy Agency and OECD Nuclear Energy Agency reports on the projected costs of electricity generation.[183] The LCOE models the cash flow of a power plant over its construction period (CP) and operational lifetime (T) and calculates a real electricity price at which the plant will breakeven. During the construction period (starting in year $t = -CP$) the costs are the upfront capital costs according to the estimated overnight night cost and the interest incurred during construction. Once plant operation starts (in year $t = 0$), the plant incurs operations costs and earns revenues. The investment will breakeven when the discounted lifetime costs of the plant equal the discounted lifetime revenues.

The sums of the revenues (R) and costs (C) for each year (t) are set equal:

$$\sum_{t=0}^{T-1} R_t \times (1+r)^{-t} = \sum_{t=-CP}^{T-1} C_t \times (1+r)^{-t}$$

where $(1+r)^{-t}$ is the discount factor. The revenues of the plant each year are:

$$R_t = p \times Q$$

[183] The MIT methodology is outlined in Yangbo Du and John E. Parsons, "Update on the Cost of Nuclear Power," Center for Energy and Environmental Policy Research no. 09-004, May 2009; and the most recent IEA/NEA report is OECD International Energy Agency and Nuclear Energy Agency, "Projected Costs of Generating Electricity," 2020. This paper also incorporates insights from George S. Tolley et al., "The Economic Future of Nuclear Power," University of Chicago, August 2004; François Lévêque, The Economics and Uncertainties of Nuclear Power (Cambridge University Press, 2014); William D. D'haeseleer, "Synthesis on the Economics of Nuclear Energy," European Commission, DG Energy, November 27, 2013; and Geoffrey Rothwell, *Economics of Nuclear Power* (Routledge, 2016).

where p is the real price of electricity in dollars per megawatt hour (MWh) and Q is the quantity of electricity produced each year in MWh. It is the product of the plant capacity (L), capacity factor (Φ), and number of hours in a year:

$$Q = L \times \Phi \times 8{,}766$$

The yearly cost is the sum of capital costs (including decommissioning costs), operations and maintenance, fuel, and (if included) a carbon price:

$$C_t = C_{t,Capital} + C_{t,OM} + C_{t,Fuel} + C_{t,Carbon}$$

When the total revenue equals total cost, and because the price is a constant, the LCOE (which is equivalent to the price) in \$/MWh is:[184]

$$LCOE = p = \frac{\sum_{t=-CP}^{T-1} (C_{t,Capital} + C_{t,OM} + C_{t,Fuel} + C_{t,Carbon}) \times (1+r)^{-t}}{\sum_{t=0}^{T-1} Q \times (1+r)^{-t}}$$

LCOE variables

The generators assessed are a light water nuclear reactor with a 60-year operating life, ultra-supercritical coal with a 40-year life, and combined-cycle multi shaft gas turbine with a 30-year life. The input parameters for each plant are reported in table A.1.[185] The inputs used reflect average estimates across the United States, but the levelized costs estimated would vary by region in so far as fuel, construction, labor, and other costs are different. The levelized costs would also be different if the focus of this study were expanded beyond the United States. This is

[184] The calculations here are in dollars per MWh but the numbers reported in the text are in cents per kWh. To convert to cents per kWh, divide the amount in dollars per MWh by 10.

[185] The technology specific values for fixed and variable O&M, heat rate, and coal and natural gas OCC are from the values for ultra-supercritical coal, combined-cycle multi-shaft natural gas, and light water nuclear reactor in Table 1 of EIA, "Cost and Performance Characteristics of New Generating Technologies," *Annual Energy Outlook 2022* (EIA, 2022). Sources for the other inputs are discussed in the text.

especially true in other countries, like Japan and South Korea, with higher natural gas prices where the relative costs of the generating technologies would be different.

Each of the generators is modeled with a net capacity of 1000 MW and a capacity factor of 85 percent. Fuel prices are discussed in the text and the fixed and variable O&M are from EIA's *Annual Energy Outlook* 2022. The heat rate, a measure of a power plants thermal efficiency (i.e., the amount of energy a plant converts to electricity), is from the EIA in Btu per kWh.

Table A.1

Characteristics of nuclear, coal, and natural gas power plants in the LCOE calculations

Variable (notation)	Units	Nuclear	Coal	Natural gas
Operational life (T)	Years	60	40	30
Construction period (CP)	Years	7	4	3
Capacity (L)	MW	1,000	1,000	1,000
Capacity factor (Φ)	%	85	85	85
Heat rate (HR)	Btu/kWh	10,443	8,638	6,370
Overnight cost (OCC)	$/kW	4,000; 6,700; 9,000	4,100	1,100
Incremental capital (C_{Incr})	$/kW-year	40, 67, 90	47.15	13.2
Fixed O&M (C_{OMf})	$/kW-year	127.35	42.49	12.77
Variable O&M (C_{OMv})	$/MWh	2.48	4.71	1.96
Fuel cost (C_{Fuel})	$/MMBtu	0.60	1.90	3.10, 3.80, 5.80
Decommissioning	Million $	800	-	-
Carbon dioxide intensity (I_{Carbon})	kg-CO_2/MMBtu	-	95.74	52.91

Source: Sources in text.

Discount rates

As discussed in the text, the baseline discount rate used in this analysis is 7 percent, representing the opportunity cost of capital. This is approximately the pre-tax inflation adjusted average annualized return of the S&P500 from 1972 to 2021.[186] Results for discount rates of 3 percent and 10 percent are also shown.

Capital costs

The total capital investment costs (TCIC) include the overnight construction cost and costs of financing the project. The choices for overnight construction costs (OCC) for nuclear are discussed in the text. OCC for coal and natural gas are taken from the *Annual Energy Outlook* 2022. The overnight costs are distributed according to a uniform schedule for each year of construction. The construction periods are 7 years for nuclear, 4 for coal, and 3 for CCGT. The outlays for each year of construction are determined based on the fraction of OCC spent each year (F_t):[187]

$$C_{t,Construction} = F_t \times OCC \times L \times 1{,}000$$

The TCIC is the yearly construction costs considering the opportunity cost of capital:

$$TCIC = \sum_{t=-CP}^{-1} C_{t,Construction} \times (1 + r)^{-t}$$

Following the MIT methodology, incremental capital costs, representing further capital investments over the plant's life, are modeled as yearly expenditures. The incremental costs (C_{Incr}) each year are a constant proportion (P_{Incr}) of the OCC and are the same as in the MIT studies: 1 percent for nuclear, 1.15 percent for coal, and 1.2 percent for natural gas. For each year, they are calculated as:

$$C_{t,Incr} = P_{Incr} \times OCC \times L \times 1{,}000$$

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[186] The real annualized average rate of return of the S&P 500 is calculated from Robert Shiller, "U.S. Stock Markets 1871-Present and CAPE Ratio," http://www.econ.yale.edu/~shiller/data.htm.
[187] In this equation and in other equations, except when otherwise noted, the value is multiplied by 1,000 to convert from $/kW to $/MW.

The total capital costs each year are:

$$C_{t,Capital} = C_{t,Construction} + C_{t,Incr}$$

Decommissioning costs are included for nuclear, but because of the discount rate and the long period before the costs are incurred the actual impact of the decommissioning is small. A 2016 OECD Nuclear Energy Agency study estimated that US nuclear plants have decommissioning costs of $544–821 million in 2013 dollars.[188] Other LCOEs typically use a decommissioning cost of 15 percent for nuclear. This LCOE uses a $800 million decommissioning cost (800 $/kW), which is 9 percent of an OCC of 9,000 $/kW, 12 percent of 6,700 $/kW, and 20 percent of 4,000 $/kW. The decommissioning cost is added to the final year of the nuclear plant's incremental capital costs.

The different components of the capital cost are not incurred every year. For the construction period the capital costs are simply the yearly construction costs including the interest. Once completed, the capital costs are just the incremental capital costs until the final year when the decommissioning costs are added in.

Non-fuel operations and maintenance

Once in operation, the plant incurs operations and maintenance costs. Data on the O&M costs are taken from the *Annual Energy Outlook* 2022, which are based on a study prepared for EIA by engineering firm Sargent and Lundy.[189] Fixed O&M (C_{OMf}) are yearly costs that do not vary with electricity generated while variable O&M (C_{OMv}) are generation-based costs excluding the

[188] OECD Nuclear Energy Agency, "Costs of Decommissioning Nuclear Power Plants," 2016.
[189] Sargent and Lundy, L.L.C., "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies," prepared for EIA, February 2020.

fuel costs. Fixed O&M is measured in dollars per year for each kW of capacity and variable O&M is in dollars per MWh. The yearly O&M costs are:

$$C_{t,OM} = \left(C_{OMf} \times L \times 1{,}000\right) + \left(C_{OMv} \times Q\right)$$

Fuel

See the text for a full explanation of fuel cost choices. The yearly total fuel cost is the price of fuel (C_{Fuel}), multiplied by the quantity of electricity produced and the heat rate:[190]

$$C_{t,Fuel} = C_{Fuel} \times \frac{HR}{1{,}000} \times Q$$

Carbon pricing

The cost of carbon emissions depends on the carbon tax (τ_{Carbon}, in dollars per metric ton of carbon dioxide emitted), the carbon dioxide intensity of the technology (I_{Carbon}, in kilograms of carbon dioxide per MMBtu and divided by 1,000 to convert to metric tons per MMBtu), the heat rate, and the amount of electricity produced:

$$C_{t,Carbon} = \tau_{Carbon} \times \frac{I_{Carbon}}{1{,}000} \times \frac{HR}{1{,}000} \times Q$$

The technology specific carbon intensities of 52.91 kg-CO_2/MMBtu for natural gas and 95.74 kg-CO_2/MMBtu for coal are taken from EIA.[191]

Because the carbon tax and carbon intensity are constant over the lifetime of the plant, the carbon price can be simplified out of the equation for LCOE:

$$LCOE = \frac{\sum_{t=-CP}^{T-1}\left(C_{t,Capital} + C_{t,OM} + C_{t,Fuel}\right) \times (1+r)^{-t}}{\sum_{t=0}^{T} Q \times (1+r)^{-t}} + \left(\tau_{Carbon} \times \frac{I_{Carbon} \times HR}{1{,}000{,}000}\right)$$

[190] The heat rate is in Btu/kWh. To match other units, it is converted to MMBtu/MWh:

$$HR \times \frac{1{,}000\ kWh}{1\ MWh} \times \frac{1\ MMBtu}{1{,}000{,}000\ Btu} = \frac{HR}{1{,}000} MMBtu/MWh$$

[191] EIA, "Carbon Dioxide Emissions Coefficients," November 18, 2021.

Therefore, the carbon tax sufficient to make the levelized costs of natural gas and nuclear equal is the carbon tax that makes the LCOE of natural gas with no carbon tax equal to the LCOE of nuclear (with both LCOEs in \$/MWh) considering the carbon intensity of natural gas:

$$\tau_{Carbon,Gas} = \frac{LCOE_{Nuc} - LCOE_{Gas\ no\ tax}}{\left(\frac{I_{Carbon,Gas} \times HR_{Gas}}{1{,}000{,}000}\right)}$$

Because this is a static estimate of the carbon tax needed for the cost of nuclear to equal the cost of the fossil fuel generators, it can be viewed as an average carbon tax over the lifetime of the fossil fuel plant. If carbon taxes grow over time, the carbon tax in the first year of operation can be approximated using an estimated real escalation rate of the tax (e):

$$\tau_{0,Carbon} = \frac{\tau_{Carbon} \times T}{\sum_{t=0}^{T-1}(1+e)^t}$$