What is the cost of power: A comparative analysis of the costs to finance, design, construct and operate carbon free baseload power

KUTAKROCK

Summary

Utilities often ask: “what electric power generating facility should we invest in to serve our customers with baseload, dispatchable power and carbon free, carbon neutral and renewable resources.”

In order to assist utilities with understanding the potential costs of available power sources, JLL and Kutak Rock created this paper and model to analyze carbon neutral baseload power sources so as to facilitate an understanding of the Levelized Cost of Electricity (“LCOE”) model as a tool to compare varying energy production technologies. The LCOE of a technology is calculated by taking cost of constructing and operating the asset and dividing it by the asset’s generation over an assumed lifetime. This equates to average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant. We identified key variable inputs that serve as primary drivers of the LCOE calculation including incentives, capital costs, recapitalization, and fixed and variable operations and maintenance (O&M) costs based on fuel consumption, production, and capacity.

What did we find?

Generally, photovoltaic (PV) and wind resources are the least expensive carbon neutral electric power sources. They are not, however, baseload power sources. They provide what is called intermittent (variable) power. To compare the proverbial “apples to apples” we added battery storage to the PV and wind power sources and compared the costs to small modular reactors (“SMR”) assuming it is Nth build SMR versus the first of its kind SMR, or an iteration of an SMR that reached maturation and to a natural gas combined cycle with carbon capture and storage.

We found that with tax incentives and without tax incentives, SMRs are the most cost effective option based on LCOE assuming a 60-year term (which is the estimated useful life – based on licensing – of an SMR). This analysis did not include other potential revenue sources for the electric power generation such as hydrogen production, steam generation, combined heating and cooling and other uses that are being considered for SMRs or additional costs for each power source such as transmission for intermittent resources. Incorporating generation resources into the grid entails additional costs beyond the costs outlined in this LCOE model, such as additional transmission, grid stabilization, and the synchronization of load timing with demand. The model and assumptions we used to reach our conclusion are set forth in Figure 2 seen on page 13 below.

Background

In 2022, carbon free (nuclear and renewable) energy sources accounted for almost 40 percent of the country's electricity generation. The growth in carbon free energy sources has largely come from renewable sources including solar (3.1%) and wind (10.2%) which are intermittent electric power sources and do not supplant the need for reliable baseload generation.

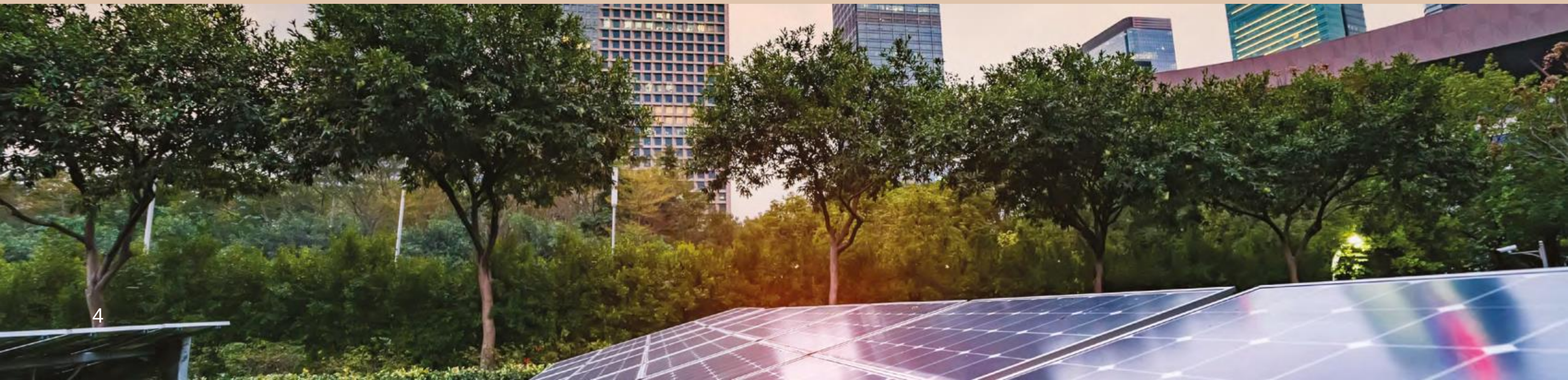
The term "baseload" refers to the minimum amount of electric power delivered or required over a given period of time at a steady rate. Baseload electric power sources are power generation facilities which can consistently generate the electrical power needed to satisfy this minimum demand.

As load serving utilities contemplate the investments required to replace their aging coal, natural gas and other generation assets, the discussion of what type of power source to purchase is a key consideration. Utilities, on behalf of their customers, analyze the short and long-term cost and reliability of power sources regularly. Regardless of whether the utility is investor owned or municipal owned, these are large investments that take many years to develop and plan, and that can operate for 60 years or more and cost hundreds of millions of dollars. Many utilities are planning to purchase a mixture of both baseload power and intermittent power sources.

Why SMRs?

New nuclear reactors have long been proposed as the solution for addressing the need for 24 hour/7 days a week clean energy. In particular, offer configurations that reduce the scale of upfront investment while at the same time encouraging the development of manufacturing capacity to drive cost reductions. However, with the recent experience of Vogtle 3 and 4, the cost of nuclear energy – and the risk of cost overruns during licensing and construction – remains a key challenge to new nuclear plant deployment. These concerns have been exacerbated in recent years as the construction industry has shifted the risk to the utility related to cost and schedule especially as inflation has significantly increased the cost of new construction. These considerations have heightened the risks associated with a utility's decision to invest in deploying new nuclear reactors.

This paper analyzes options to purchase carbon free energy to assist utilities evaluate, model and compare the cost to finance, design and construct a new nuclear power facility (an SMR), renewable energy facilities that are designed to provide power (24 hour/7 days a week) (such as wind and solar with battery which likely will not meet the need for baseload power as described below), and natural gas combined cycle with carbon capture and storage. Importantly, the analysis considers the current government incentives available and how these incentives create greater parity among the competing options.



Making a decision on the baseload power source

Baseload power plants operate around the clock to support all or part of the minimum load of a system and are essential to the reliable functioning of a utility. The high investment cost and long project lives of baseload power plants present financing challenges for utilities trying to align investment in additional generation with customers' demand for power. Adding to these challenges is the uncertainty introduced by wholesale and retail competition over the past 20 years. Despite the uncertainties, large-scale baseload power plants will need to be developed, designed, and constructed to replace an aging fleet consisting largely of coal and nuclear generation. Given the high investment cost, power plants will rely on long- term debt financing for economic feasibility. Current baseload power plants are coal, large-scale nuclear power, natural gas, and hydro facilities. In each region of the country, utility owners are replacing these baseload facilities with new facilities and are reviewing the options of new baseload facilities (such as SMRs) and comparing the prices with building new coal, natural gas, or large-scale nuclear power facilities or upgrading existing facilities.

Technologies
Nuclear
Solar
Onshore Wind
Solar + BESS
Combined Cycle (with Carbon Sequestration)

The analysis of long-term electric power supply options is needed to adequately address the requirements met by conventional baseload power plants. SMRs have long been considered an ideal candidate for carbon free baseload power. After years of development, SMRs have begun to obtain Nuclear Regulatory Commission ("NRC") regulatory approvals. The U.S. Department of Energy ("DOE") has identified that these small nuclear power plants will "play an important role in addressing the energy security, economic and climate goals of the U.S. if they can be commercially deployed within the next decade." Private industry is leading the development of SMRs, but there is widespread recognition that the risks presented by introducing this new technology in the electric power sector will require public-private risk sharing to achieve commercial deployment. Nuclear construction and licensing in the United States, historically, has been burdened by delays and high costs. However, this experience is based not on SMRs, but on large, traditional light water reactor nuclear power plants.

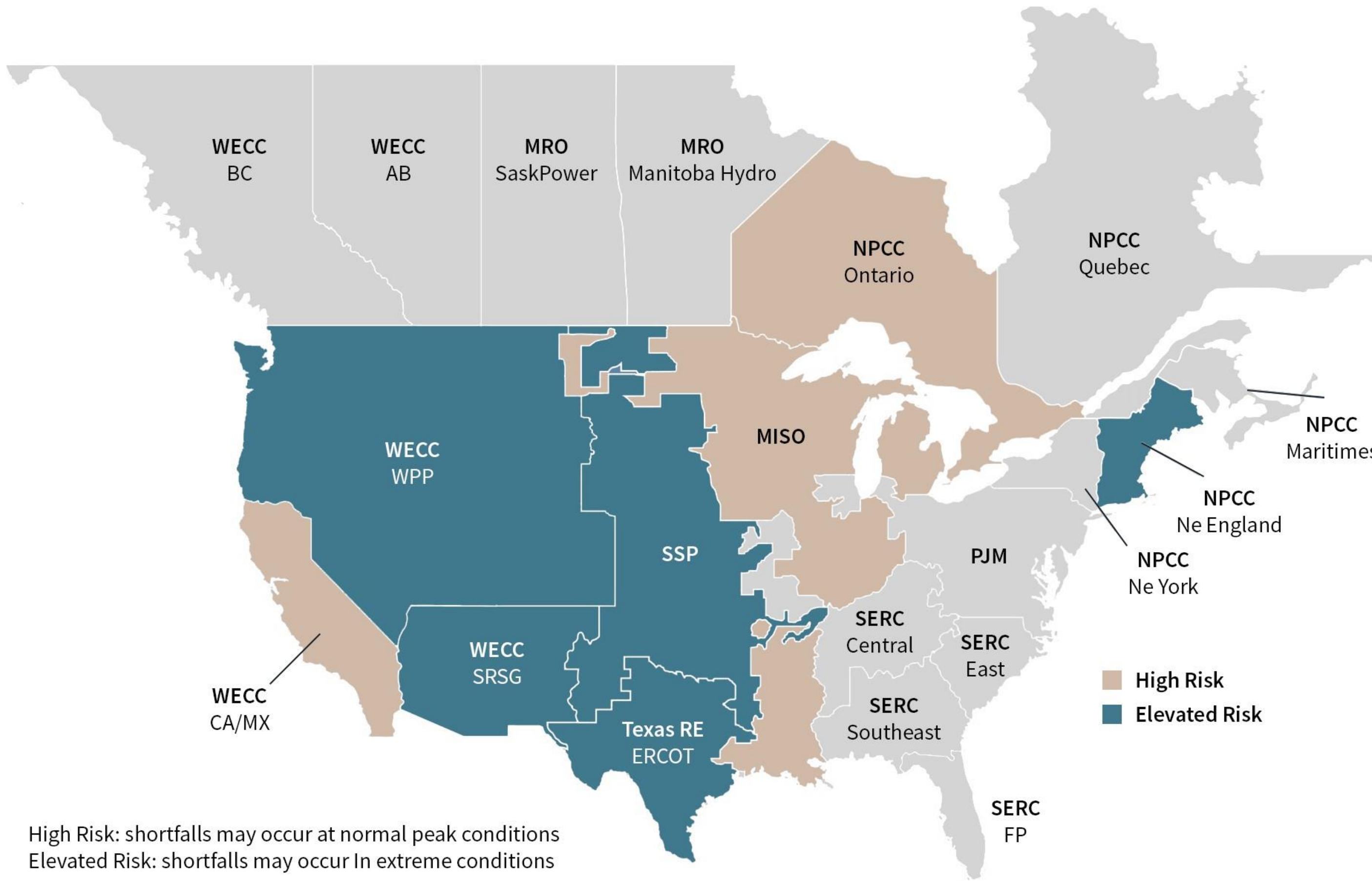
Comparing carbon free alternatives for baseload power presents several challenges given the nascent stage of commercial deployment. For example, the cost of SMRs is burdened by the uncertainty and costs associated with a first-of-a-kind deployment while the technology for solar or wind projects with battery storage also requires development to serve as true baseload capacity.

The analysis that follows reviews the cost of an SMR, assuming that the SMR is not a first-of-a-kind project that needs to be licensed for the first time by the NRC, but instead is part of an ongoing process of licensing new nuclear projects (also sometimes referred to as the “Nth” project). Comparing an SMR, assuming that the NRC licensing process and timing has been more clearly defined, with a renewable energy option that also requires a battery or other tool to support 24/7 power for several days at a time, will serve to inform the analysis of generation alternatives by placing the choices in comparable, “apples to apples” terms.

Power sector competitive landscape

The comparison of alternative sources of power generation is complicated by trends impacting the power sector. While the proliferation of renewables in some regions has resulted in excess capacity during certain hours of the day, additional baseload resources remain a critical need. Today, there are regions around the country that face potential supply shortfalls in the near term. The North American Electric Reliability Corporation's ("NERC") Long Term Reliability Assessment released in December 2022 concluded that several independent system operators ("ISOs") in the United States face high or elevated risks of resource shortfalls over the next five years. Figure 1 highlights the ISOs at high and elevated risk.

Figure 1: Potential electricity supply shortfalls 2023-2027



NERC attributes the supply challenges to the frequency of extreme weather events that need to be considered in resource adequacy planning and on planned retirements of generating assets. In total, over 88 GW of generating capacity is confirmed for retirement over the next ten years and much of this capacity comes from traditional baseload generation sources.

Long-term power resource planning challenges

As utilities around the country look to supplement their sources of supply through new generation assets, they are having to navigate a highly dynamic environment brought about by the country's energy transition as well as other trends that make long-term power resource planning a daunting challenge. In addition to extreme weather events and plant retirements these trends include:

1. **Electrification**
The transition to transportation and building electrification as well as the increased power needs of the grid will require additional investment in generating assets by load serving utilities to accommodate steadily rising electricity demand to power electric vehicles, heat pumps, data centers, industrial electrification and hydrogen electrolysis.

2. **Intermittent resources**
The growing presence of renewables in the generation mix requires additional planning to ensure sufficient resources. The variability of wind and solar mean the utilities need to plan around seasonal and hourly variations as well as extended periods of resource inadequacy due to weather events.

3. **Inflation**
The high inflationary environment in the post Pandemic period has affected new plant construction across the power sector, increasing cost estimates and introducing uncertainty into the planning of large capital investments. This trend is exacerbated by supply chain disruptions and rising interest rates and while it should impact all new plant construction, it hits large capital projects – like baseload power – particularly hard given the scale of investment.

4. **Grid limitations**
Much of the country's grid infrastructure is antiquated. Seventy percent of the grid's transmission lines and power transformers are over 25 years old and there is insufficient transmission capacity (especially transmission that facilitates transfer of power across regions). This means that there will continue to be a need for power generation that is proximate to load centers.

In comparing alternatives, it is important to note that the above trends are being experienced across the power sector, including renewable sources. Not only does this impact plant economics, but the attendant uncertainty introduces risks that need to be considered by project developers. Supplementary costs, which vary depending on the project and the electric grid system, associated with types of renewable generation technologies looking to achieve the same baseload, predictable power that SMRs can provide tend to be comparatively lower for small modular reactors (SMRs).

Analysis of carbon free power alternatives

The options for developing new carbon free power sources are varied, requiring normalizing the economic analysis to account for differing features of each option under consideration. Key factors that drive power plant economics include:

1 **Nameplate or rated capacity**
Refers to maximum amount of power a technology can deliver an instantaneous basis.

2 **Capacity factor**
This refers to the actual energy output of a system over a year compared to the theoretical maximum if the plant were operating at 100% of its nameplate capacity over a year. A plant's capacity factor is expressed as a percentage of its nameplate or rated capacity.

3 **Overnight capital cost**
This refers to the cost of building the project without including the costs of financing, inflation, or other factors that may increase the total cost over time.

4 **Operation cost**
Refers to the costs associated with the operations and maintenance of the technologies. It is expressed as a $/ kW for the fixed costs and $/MWh for the variable costs.

5 **Fuel costs**
Refers to the fuel costs to account for the energy needed to power certain technologies.

6 **Recapitalization**
Refers to the replacements of assets which that do not have a useful life over the full 60 year analysis period.

7 **Cost of capital**
Refers to the rate at which to discount future cash flows to today to compare projects on a Net Present Value Basis based on the company's cost of borrowing money as well as the return required by investors.

Variable

ITC

Overnight cost

PTC

Cost of capacity

Capacity factor

Fuel cost escalation

The discussion around alternative sources of carbon free power often focuses on cost per unit of capacity which can be misleading when comparing technologies with different capacity factors. For example, upfront capital investment in renewables sources is comparatively low relative to new nuclear sources, but so too are the capacity factors (which drives up the delivered power cost on a per unit basis). Similarly, the timing and tenor of cashflow investments and returns vary significantly from one technology to another.

To compare the economic merit of alternative carbon free technologies that can provide baseload, dispatchable power to the grid, the analysis employed a LCOE approach to support meaningful comparisons. LCOE measures the lifetime costs of a power plant and divides these costs by the plant's energy production. LCOE facilitates comparisons of technologies and considers all costs associated with generating electricity, including capital expenditures, operating expenses, fuel costs, decommissioning, and cost of capital. It is expressed as the cost per unit of electricity generated, usually in dollars per megawatt-hour (MWh). The LCOE is calculated by taking the net present value of the costs of the project over the project lifetime and dividing it by the net present value of the generation of the project over the project lifetime. While LCOE facilitates comparisons of economics, it carries several drawbacks, the most significant of which is that different sources of power serve different roles in delivering reliable and resilient power to retail, commercial and industrial loads. The LCOE of a technology ignores the value of dispatchability for energy sources to match grid demand compared to some technologies that are dependent on external factors such as the availability wind or sunlight.

SMR technology can provide load serving utilities and the grid a generation technology that can provide baseload, dispatchable, reliable, and clean power. To support the economic analysis of comparable alternatives, four different technologies (or combinations of technologies) were identified for comparison. An analysis of solar and wind on a standalone basis was also included to facilitate mapping renewable LCOE results to carbon free baseload power results. Each of the selected technologies and technology combinations is described below.

LCOE Formula

$$\frac{\text{NPV of total costs}}{\text{NPV of total electrical production}}$$

Cost drivers	Production drivers	Financial drivers
Capital costs	Capacity factor	WACC
O&M	Degradation	
Recapltalizatlon		
Fuel costs		

1

Solar PV

The first technology that was compared to Nuclear SMR technology is Fixed Tilt Solar Photovoltaic (PV). PV is a renewable, intermittent energy source that will generate electricity during the daytime. While PV does not compare from a firm baseload perspective, PV is a carbon free technology.

2

Solar PV with Battery Energy Storage

PV and battery energy storage to system (BESS) technology generally replicates a project that can provide baseload power carbon free electricity to discharge energy when PV fails to generate electricity. The BESS is sized based on the average solar production for each hour of the year and charged using excess generation and discharged during times of low or no energy generation to recreate a flat baseload energy source. The analysis does not assume a BESS minimum state of charge nor BESS charge or discharge inefficiencies, as well as any annual costs associated with the augmentation of the BESS, other than the recapitalization of the BESS asset at the end of the useful life. The team estimated that a six-hour battery with a battery capacity that can capture the excess energy is necessary to recreate a flat baseload energy source based on the average hourly load profile. However, the necessary battery sizing will vary depending on the solar technology and the capacity factor of the array which will be location dependent (and must also address the seasonal variations that occur with solar and may cause the battery sizing to be impacted in practice).

3

Onshore Wind

Onshore wind is a renewable, intermittent energy source that generates its electricity during the times of the day when wind is available. Wind also is not a firm baseload electric power source. Wind energy’s production profile differs slightly from the production profile of PV. It is highly dependent on wind availability, and there may be extended periods where wind turbines do not generate power due to low wind conditions. Nonetheless, in regions with stable wind flow patterns, wind projects can generate power for more extended periods than PV projects.

4

Natural Gas Combined Cycle with Carbon Capture and Storage

Natural gas combined cycle with carbon capture and storage is another technology that was compared against SMRs as it is the most suitable technology for replicating a baseload, dispatchable, and reliable generation source. The natural gas combined cycle power plant is a well-established technology that is currently serving the grid on a commercial scale. Although carbon capture/storage technology is relatively new and its true costs and impacts are not yet fully understood, it bears remarkable similarities to the SMR Nuclear technology, with the technology capable of producing baseload, dispatchable, reliable power that can be described as carbon free electricity.

LCOE of carbon free power sources

To calculate the LCOE of each carbon free power alternative, assumptions related to cost, performance, useful life, and other inputs were developed. These inputs are summarized in Figure 2.

Figure 2: Summary of analysis inputs

	Assumption	Unit	SMR	Solar and battery energy storage	Natural gas	Solar	Wind
General	Cost of Equity	%	10%	10%	10%	10%	10%
	Equity Percentage	%	50%	50%	50%	50%	50%
	Cost of Debt	%	5%	5%	5%	5%	5%
	Debt Percentage	%	50%	50%	50%	50%	50%
	Tax Rate	%	21%	21%	21%	21%	21%
	Cost of Capital	%	6.98%	6.98%	6.98%	6.98%	6.98%
	Fuel Escalation (Real)	%	0%	0%	0%	0%	0%
	Inflation	%	2.50%	2.50%	2.50%	2.50%	2.50%
	Interest Rate of Sinking Fund	%	3.50%	3.50%	3.50%	3.50%	3.50%
	Useful Life Technology 1	Years	60	30	20	30	30
	Useful Life Technology 2	Years	--	15	--	--	--
Costs	Overnight Cost 1	$/kW	$4,500	$1,050	$948	$1,050	$1,670
	Overnight Cost 2	$/kWh	--	$388	--	--	--
	Fixed O&M	$/kW/Year	$95.00	$12.00	$15.00	$12.00	$26.50
	Variable O&M	$/MWh/Year	$6.89	--	$3.00	--	--
	Fuel Cost	$/MMbtu	$0.80	--	$3.50	--	--
	Technology Recapitalization #1	%	--	25%	50%	25%	25%
	Technology Recapitalization #2	%	--	50%	--	--	--
	Replacement Cost	%	--	2.50%	--	2.50%	--
	Replacement Occurrence	Year	--	15	--	15	--
	Decommissioning Cost	% of Upfront	25%	10%	20%	10%	10%
Production	Capacity Factor	%	90%	19%	62%	19%	42%
	Degradation	%	0%	0.50%	0%	0.50%	0%
	Heat Rate	Btu/kWh	10,450	--	6,150	--	--

Utilizing these assumptions, LCOE values were calculated for each of the technologies and technology combinations that support carbon free “baseload like” performance.

LCOE results

Based on this analysis, the following observations can made regarding each technology and technology combination. The results of the analysis for each technology are summarized in Figure 3.

- **Onshore wind:** Based on the analysis, onshore wind may have the lowest LCOE of the compared technologies. However, in terms of dispatchable, baseload capability, wind falls short in the sense that it is completely reliant on the wind availability. On a standalone basis, wind provides a competitive cost profile, but it is not dispatchable and cannot serve as a baseload resource. A secondary risk associated with wind is the relationship between locations with wind availability and its distance to load centers. Therefore, other grid investments such as additional transmission lines or battery storage will be required to facilitate increasing the amount of wind in the generation portfolio.

- **Utility scale solar:** Utility scale solar has the second lowest LCOE. However, it is not dispatchable and cannot serve as a baseload resource. Therefore, like wind, other grid investments are required to facilitate increasing the amount of solar in the generation portfolio.

- **Small Modular Reactor:** The Nth of a kind SMR carried an LCOE of $83.7/MWh and can serve as a baseload resource with dispatch capability. While the LCOE is $19.9/MWh higher than standalone solar, SMRs will enable greater grid stability and resilience.

- **Natural gas with carbon capture:** The only technology that can fully replicate the baseload, dispatchable power that SMRs can provide is the natural gas combined cycle technology paired with carbon capture and storage. However, natural gas combined cycle with carbon capture and storage is more expensive on a LCOE basis due largely to the addition operational cost required for carbon capture.

- **Utility scale solar with battery storage:** Solar with battery storage has the highest LCOE of the compared technologies. However, a solar and storage technology can provide the baseload, dispatchable power that SMRs provide. Solar paired with battery storage introduces the risk of not meeting the energy needed to provide baseload, dispatchable power if there are extended periods of low solar production due to cloudiness or bad weather. This can be negated through oversizing solar paired with oversizing the energy capacity of the battery storage. This, however, leads to an increased LCOE.

Figure 3: Technology LCOE before IRA tax benefits

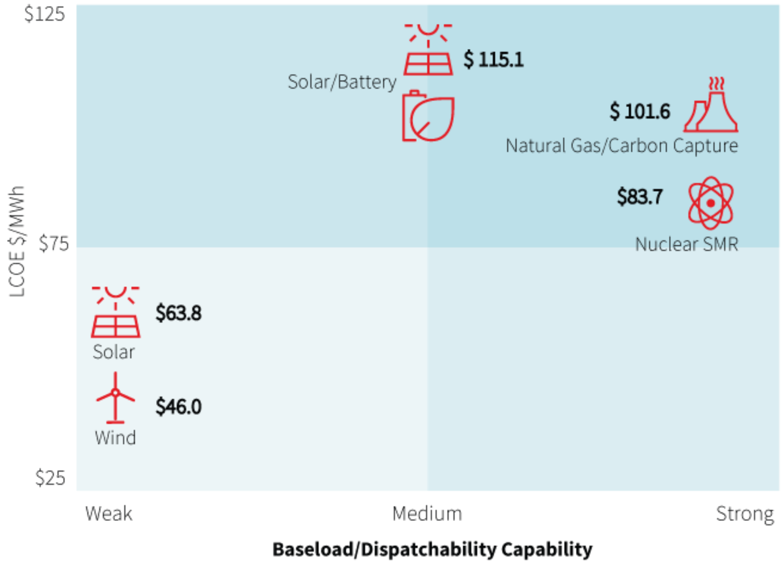
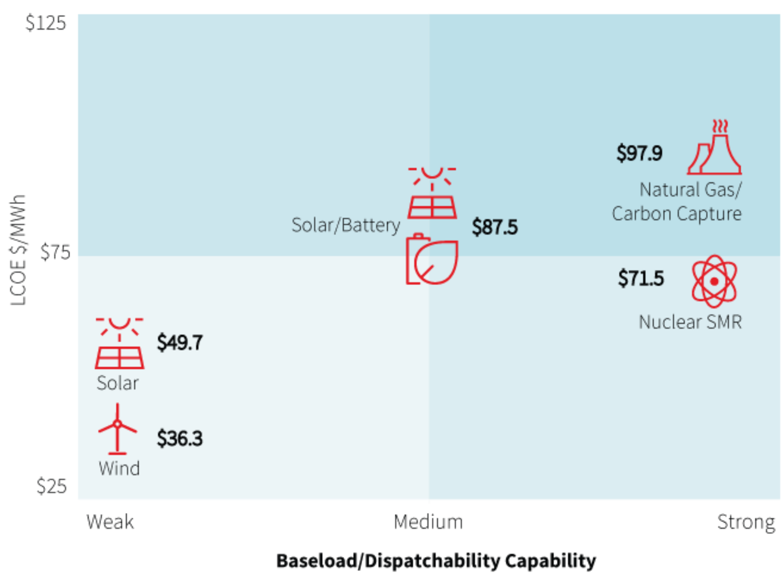


Figure 4: Technology LCOE after IRA tax benefits



Importantly, the technologies exist in varying states of maturity. The economics of each source is therefore examined assuming a mature state or “nth of a kind” deployment. However, it is acknowledged that new technologies such as flow batteries, SMRs and carbon capture methods are likely to experience manufacturing cost reductions with the build-out of supporting industrial ecosystems.

As detailed below, the Inflation Reduction Act modified tax incentives for carbon free energy technologies. The provisions of the IRA were examined to understand the impacts of the new tax provisions on LCOEs.
While the IRA extended the Production Tax Credit for carbon free technologies, to simplify the analysis, only the ITC was considered for this paper.

As shown in Figure 4 the new tax provisions lowered all carbon free power sources but did not meaningfully enhance or detract from the relative competitiveness of any technology. The notable exception was Natural Gas with Carbon Capture due to the fact that the tax incentives benefit only a portion of the capital outlay required for this technology, and due to the methodology used for capturing the increased cost associated with carbon capture, the ITC provided minimal benefit to the technologies’ LCOE.

Tax incentives for carbon free power

The Infrastructure Investment and Jobs Act of 2021, commonly known as the Bipartisan Infrastructure Law ("BIL"), and the Inflation Reduction Act of 2022 ("IRA") (collectively the "New Laws") – provide significant financial incentives to develop and construct both renewable and nuclear energy facilities along with transmission and other energy incentives.

The New Laws expand the amount of Clean Electricity Production Tax Credits ("PTC") and Clean Electricity Investment Tax Credits ("ITC") as set forth in Figure 5 and Figure 6. The PTC and ITC are available to both nuclear and renewable projects. In addition, where public power utilities, non-profit utilities, tribal utilities and TVA own the nuclear or renewable project, each can take advantage of the direct pay option under the IRA. The new laws also expand the tax credits to permit direct payments for multiple forms of carbon-free energy development and production. The New Laws apply to "qualified facilities" which are facilities used for the generation of electricity and placed in service after December 31, 2024, for which the anticipated greenhouse gas emissions rate is not greater than zero.

Figure 5. Nuclear production and investment tax credits

Tax credit/direct payment	Tax value	Increase in rates available
Clean Electricity Production Credit (PTC) – paid over 10 years	2.5 cents/kWh (w/ Apprentice requirements being met), indexed to inflation 0.5 cent/kWh (with w/out Apprentice)	Both ITC and PTC projects can receive stackable 10% bonus credits for either or both of the following: • Meeting domestic content thresholds • Locating facilities in fossil-fuel-dependent "energy communities". In addition, projects under 5 MW can also receive additional "environmental justice" bonus credits
Clean Electricity Investment Credit (ITC) – paid in one payment	30% of initial capital (w/ Apprentice requirements being met) 6% of initial capital cost (w/out Apprentice)	

In employing the tax incentives, the developer of the project will need to determine whether to select the PTC or ITC as they cannot both be accessed for one project. To evaluate each, the developer will analyze the present value impact of each credit along with including all of the potential bonus provisions.

The ITC is a one-time payment while the PTC is paid over the initial ten (10) years of the project operations based on the performance of the project. The paragraphs that follow summarize the new carbon free (technology neutral) ITC and PTC which applies to both nuclear and renewable projects.

PTC and direct pay – power output incentives

A PTC gives a taxpaying entity a tax credit for power output in terms of a fixed dollar amount per unit of output. A PTC is only paid out when the intended product (e.g., clean energy generation) is delivered, and thus can be considered a form of results-based subsidy. For projects reliant on intermittent resources (e.g., wind), the realization of target returns has often been uncertain.

Unlike ITCs, PTCs require the taxpayer to sell electricity to an unrelated third party and excludes utility companies that are not investor owned. Section 13701 of the IRA added new § 45Y, the clean electricity production credit, to provide a tax credit for electricity produced by the taxpayer at a qualified facility and either (1) sold by the taxpayer to an unrelated person during the taxable year, or (2) in the case of a qualified facility which is equipped with a metering device which is owned and operated by an unrelated person, sold, consumed, or stored by the taxpayer during the taxable year. For the application of PTCs, a facility will be considered a qualified facility for a period of ten years beginning on the date it is placed in service.

Section 45Y(a)(1) provides that the amount of the credit is equal to the product of (A) the kilowatt hours of electricity produced and sold to an unrelated person (or sold, consumed, or stored if the facility is equipped with a metering device) by the taxpayer during the taxable year, multiplied by (B) the applicable amount with respect to such qualified facility. Section 45Y(a) (2) provides that the applicable amount is generally 0.3 cents (adjusted for inflation), which can be increased to 1.5 cents (adjusted for inflation) if requirements for prevailing wage and apprenticeship are met. Figure 6 provides details of each of the credits along with each of the bonuses available.

The IRA also includes a domestic content bonus for the PTC, which allows taxpayers to increase their PTC by 10 percent, so long as the applicable requirements are met or in relation to qualified facilities located in applicable energy communities. Finally, the IRA requires a limited reduction of the PTC where tax- exempt bonds are used to provide the financing for the qualified facility.

The PTC amendments apply to facilities that are placed in service in 2022 and after, with the exception of the following provisions, which apply to facilities placed in service in 2023 and beyond: (1) tax-exempt bond financed facilities, (2) domestic content, (3) certain phaseout provisions, (4) energy communities and (5) hydropower.

A chart summarizing ITC and PTC values over time is presented in Figure 6. Generally, project owners cannot claim both the ITC and the PTC for the same property, although they could claim different credits for co-located systems, like solar and storage, depending on what further guidance is issued by the Internal Revenue Service (IRS).

Under the IRA's elective pay (sometimes referred to as the direct pay) provisions, "applicable entities" (defined below), including tax-exempt and governmental entities that would otherwise be unable to claim renewable energy credits because they do not pay federal income tax, can now benefit from certain clean energy tax credits by treating the amount of the credit as a payment of tax and a cash refund resulting from a decreased overpayment of tax.

For example, as a result of the IRA, a state or local government or non-profit that makes a clean energy investment (e.g., installs solar panels or constructs a SMR) that qualifies for the ITC can file an annual tax return (via Form 990-T) with the IRS to claim "elective pay" for the full value of the investment tax credit, provided the investment meets all of the requirements guidance set forth in the guidance, including a pre- filing registration requirement. As the state or local government or non-profit would not owe other federal income tax, the IRS would then make a cash refund payment in the amount of the credit to the local government or non-profit.

"Applicable entities" that can use the elective pay include tax-exempt organizations, States and their political subdivisions, tribal governments, Alaska Native Corporations, the Tennessee Valley Authority, rural electric co-operatives, U.S. territories and their political subdivisions, and agencies and instrumentalities of state, local, tribal, and U.S. territorial governments.

The applicable entity or electing taxpayer generally must own the property that generates the eligible credit (or otherwise conduct the activities giving rise to the underlying eligible credit). That ownership can occur through various structures. For example, an applicable entity or electing taxpayer could directly own the property, could own it through a disregarded entity, or could own an undivided interest in an ownership arrangement treated as a tenancy-in-common or through other means.

Figure 6: Tax incentive summary[1]

Summary of Investment Tax Credit (ITC) and Production Tax Credit (PTC) Values Over Time

			Start of construction						
			2006 to 2019	**2020 to 2021**	**2022**	**2023 to 2033**	**The later of 2034** (or two years after appica- appica- ble year*)	**The later of 2035** (or three years after appicable year*)	**The later of 2036** (or four years after ble year*)
ITC	**Full rate** (if project meet labor	Basic	30%	26%	30%	30%	22.5	15%	0%
		Domestic content bonus				10%	7.5%	5%	0%
		Energy community bonus				10%	7.5%	5%	0%
	Base rate (if project does not meet labor	Basic credit	30%	26%	6%	6%	4.5%	3%	0%
		Domestic content bonus				2%	1.5%	1%	0%
		Energy community bonus				2%	1.5%	1%	0%
	Low-income bonus (1.8 GW/yr cap)	<5 MW projects in LMI communities or Indian land				10%	10%	10%	10%
		Qualified low-income residential building project/ qualified low-income economic benefit project				20%	20%	20%	20%
PTC for 10 years ($2022)	**Full rate** (if project meet labor	Basic credit			2.6¢	2.6¢	2.0¢	1.3¢	0.0¢
		Domestic content bonus				0.3¢	0.2¢	0.1¢	0.0¢
		Energy community				0.3¢	0.2¢	0.1¢	0.0¢
	Base rate (if project does not meet labor	Basic			0.5¢	0.5¢	0.4¢	0.3¢	0.0¢
		Domestic content bonus				0.1¢	0.0¢	0.0¢	0.0¢
		Energy community bonus				0.1¢	0.0¢	0.1¢	0.0¢

a "Applicable year" is defined as the later of (i) 2032 or (ii) the year the Treasury Secretary determines that there has been a 25% or more reduction in annual greenhouse gas emissions from the emissions from the production of electricity in the United States as compared to the calendar year 2022.
b "Labor requirement" entail certain prevailing wage and apprenticeship conditions being met.

Additional nuclear power and renewable power incentives exist at both the federal and state level for specific projects but are not considered in this analysis as they may vary by both location and technology application. The analysis that follows considers the incentives would be applicable in all states although it is recognized that in some states, the incentives for renewable but not nuclear energy exist for utility scale projects.

[1] https://www.energy.gov/eere/solar/federal-solar-tax-credits-businesses

Investment tax credits and direct pay – Upfront financial support

ITCs provide a company with a tax credit or a tax- exempt entity with a direct payment for a specified percentage of capital expenditures for qualifying energy projects. ITCs are an investment-based subsidy, as they provide upfront financial support for the construction of a project that is expected to deliver a specified good or service in the future. The ITC depends on the capital investment, which is the amount it costs to place the project into service. An ITC generally applies to new equipment – businesses can claim an ITC in the year it is placed into service. Projects can then spread ITC benefits over multiple years by “carrying forward”. The tax credit rate and other credit parameters depend on the type of property or technology for which the credit is being claimed; even public utility companies can now benefit from the ITC.

Section 13702 of the IRA added § 48E, the clean electricity investment credit, to provide an investment tax credit for qualified property. The credit amount for any taxable year is equal to the applicable percentage of the qualified investment for such taxable year with respect to any qualified facility and any energy storage technology. The applicable percentage for both qualified facilities and energy storage technology is generally 6 percent. The applicable percentage can be increased to 30 percent if prevailing wage and apprenticeship requirements are met. For both ITC and PTC there is also an increase in the amount of the credit in the amount of 10% for a domestic content bonus and 10% if the project is located within an “energy community” including a current community that hosts a coal plant and an additional 10% bonus for small projects under 5 MW for environmental justice bonus credits. Figure 6 provides details of each of the credits along with each of the bonuses available.

The varying level of impact that interest rates can have on technologies

The cost of debt and equity directly impacts the Levelized Cost of Electricity for a technology. The higher the interest rates, the higher the cost of capital for the project and therefore the higher the cost providing electricity and other services from an energy project.

Hence, the upfront cost of the project and the long- term borrowing cost for the capital to build the project need to be analyzed. A key piece in the comparison of the LCOE between technologies is the cost of capital used in the analysis. In recent years, interest rates have been held at historic lows, but have been rapidly increasing over the past two years. With the extended time horizons for the development of certain energy projects, the team evaluated base case scenarios for each technology but also included a scenario with a sensitivity on interest rates returning to pre-COVID levels and its impact on the cost of capital.

There are two primary impacts that interest rates have on a company's cost of capital 1) an impact on the cost of equity and 2) an impact on the cost of debt.

Typically, an investor that invests in the equity of the project is paid a higher return than a debt investor due to the riskier nature of equity investing. The price of an equity investment is based on the risk rate and a risk premium that compensates investors for the additional risk of investing in the equity of a company. When interest rates decrease, the risk-and return to the equity investor tends to decrease as well. As a result, the cost of equity historically increases or decreases depending on the changes in the interest rates and the average rates of return for equity investors on projects with similar risk profiles.

For debt investments, the interest rates incurred by a project are typically set based on a floor (such as the 10-year or 30-year Treasury) plus a risk premium based on the risk of the project. For example, in project finance, when a project is investment grade, the spread (the difference between the base rate and the rate for the project) is smaller than a project that is not investment grade. Hence, a lower cost of debt reduces the interest expense associated with servicing the debt, which positively affects the overall cost of capital (and vice a versa for high rates).

The impact that interest rates have on the various technologies was assessed to understand the magnitude of such impact. The LCOE model assumed that interest rates would fall back to pre-COVID levels, in other words, around a 2-3% interest range. This would then reduce the cost of debt, and would cause a reduction in the cost of equity. See Figure 7 for the sensitivities on each of the variables for the cost of capital equation.

Figure 7: Cost of capital equation variable sensitivities

Cost of Capital Variable	Value	Change
Cost of Equity	8.00%	-200 bps
Cost of Debt	2.50%	-250 bps
Percentage of Equity	50.00%	0 bps
Percentage of Debt	50.00%	0 bps
Tax Rate	21.00%	0 bps
Adjusted Cost of Capital	**5.25%**	**199 bps**

As seen in Figure 8, the model found that the renewable, intermittent energy captured the majority of the benefit of lower interest rates due the relatively high capital costs for the technology compared to the total LCOE of the technology. A reduction in interest rates provides a positive impact, or reduction in LCOE for the capital cost of the technology, and a negative impact, or increase in LCOE, for the operational costs of the technology. The Capital Costs of the technology are impacted due to the denominator in the LCOE formula increasing, therefore decreasing its contribution to the LCOE calculation. The O&M and recurring expenses increase as they are not discounted as heavily, increasing the present value cost of the operational expenses. Therefore, renewable, intermittent technologies capture a large benefit from lower interest rates due to these technologies having high capital costs and low operational expenses in relation to their LCOE composition. These technologies benefit comparatively more than the Nuclear SMR from a reduction in interest rates due to structure of the LCOE formula.

Figure 8: Cost of capital sensitivity results

Technology	Change
Nuclear SMR	-4%
Solar	-12%
Wind	-11%
Solar + BESS	-15%
Natural Gas	8%

Summary and conclusions

When comparing the cost to finance, design and construct a new nuclear power facility (an SMR), PV and wind with battery that are designed to provide power 24 hours/7 days a week, and natural gas combined cycle with carbon capture and storage, the traditional renewable technologies perform well from an economic perspective. Nuclear energy (SMRs) carry an initial cost premium, but also provide significant value to the grid in the terms of providing reliable, dispatchable, baseload energy. As the above analysis suggests, the cost of improving the intermittent technologies with battery energy storage demonstrates the competitiveness of SMRs under comparable use cases.

Investment Tax Credit does not change the results of which technology is the lowest cost option; however, it does reduce the LCOE for all technologies, providing a benefit to utility customers through lower cost electric generation. The IRA provides benefits to all technologies; however, when applying an ITC to technologies that have high operational costs such as natural gas with carbon capture, the ITC fails to provide equal benefits across all technologies.

In building out a decarbonized grid, SMRs will be able to provide significant value in providing stability for the grid and will become an important energy resource that can complement more economical technologies such as wind and solar.

Authors:

Seth Kirshenberg is a partner and co-leader of the energy practice at Kutak Rock LLP, where he has completed billions of dollars in federal energy projects. Seth have worked for federal, state and local governments for over 25 years assisting them to implement P3 programs, including energy programs around the world.

John Tuebner is a senior associate with the Clean Energy and Infrastructure Advisory Group at JLL. He has supported federal, state, local and commercial clients over the past 6 years assisting in the evaluation and implementation of variety of energy project technologies.

Brian Oakley is a Director with Summit Consulting, LLC and has over 30 years of experience in providing financial advisory services to public and private energy and infrastructure client. Mr. Oakley has advised on over $100 billion in infrastructure and energy transactions and served as an advisor to governments, bond trustees and lenders.