A Risk Informed Policy Analysis of Nuclear Power in the Electricity Markets

Defining the Problem: The expanding debate over a range of policies and proposals at the state, regional, and national levels aimed at shaping the nation's electricity generating portfolio shows the increasing urgency to reduce carbon emissions in the electric utility sector. While there is no identified panacea among the many options for reducing greenhouse gas (GHG) emissions during the generation of electricity, most energy experts and climate scientists agree that maintaining the currently operating nuclear fleet is necessary to meet climate goals[1]. The main driver for maintaining the nuclear fleet is that nuclear power does not emit carbon dioxide or other greenhouse gases in order to produce electricity. Additionally, when a nuclear power plant retires, the large gap in required generation is filled by natural gas plants, a greenhouse gas emitting fossil fuel generation type. **While maintaining the present nuclear fleet in the United States is an economical way to reduce greenhouse gas emissions, there are several types of economic risks associated with operating nuclear power plants that must be appropriately valued in order for those plants to continue operating.** To combat these risks, many different legislative proposals are being considered to keep the nation's nuclear fleet economically viable; from carbon taxes to zero emission credits. As policies are enacted on the state and federal levels, it is important that the nuclear industry be compensated for the unique economic risks this industry faces. To understand the context, this

[1] (Initiative 2018)

paper will explore the characteristics of the commercial nuclear power industry, the electricity markets in which these plants operate, the risks presented by the electricity markets, and current legislation meant to support the nuclear industry's carbon abatement function in the electricity generation portfolio.

Background: Nuclear power in the electricity generation industry has existed in the United States since the Shippingport Atomic Power Station connected to the regional power grid in the late 1950s. Since then, the industry has grown to approximately 100 operating reactors producing 20% of the electricity in the United States[2]. The average operating nuclear power plant generates approximately 1000MW of electricity and operates at a 93% capacity factor, meaning it produces its baseplate capacity 24 hours a day for 93% of the year. Compared to 40% capacity factor for coal plants, 57% for natural gas combined cycle plants, and 11% for natural gas turbine plants, nuclear power plants operate near full capacity all year producing carbon free baseload electricity[3].

The attributes that allow nuclear power plants to operate at such a high capacity factor are also the attributes that make it, "special and unique"[4]. Nuclear units generally do not follow load dispatch commands, which are the directions from the electrical system operator to raise or lower generator output, and maintain their output at as high as possible throughout their refuel cycle. A typical fuel cycle for a nuclear power plant is 18-24 months, with most of this time spent at 100% generating capacity. At the end of the fuel cycle, a nuclear power plant will shutdown to refuel; a process which takes 30 days on average. Nuclear power plants are the only currently available baseload energy source with no GHG emissions[5].

[2] (E. I. Agency, U.S. Electricity Generation by Source 2021)
[3] (E. I. Agency, Capacity Factors by Fuel Type 2021)
[4] (INPO 2004)
[5] (Mueller 2021)

Due to plant design, most commercial nuclear power plants do not ramp, or follow dispatching orders. Dispatch orders are the commands provided to electrical generators by Electrical System Operators (ESO) to balance electricity supply with grid demand.

The ESO will direct electrical generators to change their output based on the needs of the grid, and generators are obligated to follow those commands. Nuclear power plants are operated at full power most of the time due to the fact that abrupt power changes can create hours-long transients in fission products that affect reactor power output and are unfavorable for steady state plant operation. This inflexibility creates additional economic challenges explored later, but does not allow nuclear plants to lower their output according to the ESOs' pricing signals, thus creating a circumstance where nuclear power plants can lose money while operating with electricity prices below their costs.

Another challenge facing nuclear power plants when they shutdown is that they produce decay heat, or the thermal output of long-lived fission products undergoing radioactive decay in the reactor core. Though this does not directly relate to the economic output of the unit, this attribute requires that nuclear units be staffed with nearly the same compliment when shutdown as when they are operating at full capacity. The significant costs associated with maintaining the important safety equipment required to remove this decay heat in times of emergency and the highly trained and proficient personnel required to operate the plant mean that nuclear generators' costs are nearly fixed[6]. Because nuclear plants operate as fixed cost generating assets, their marginal cost, or cost to produce an additional megawatt/hour (MWh) of electricity is nearly $0[7]. With marginal costs of $0/MWh, nuclear power plants measure their true cost per megawatt-hour by dividing the total fixed costs plus the cost of risk by the total generator output

[6] (Bowring, PJM State of the Market Report FY 2020 2020)
[7] (Bowring, PJM State of the Market Report FY 2020 2020)

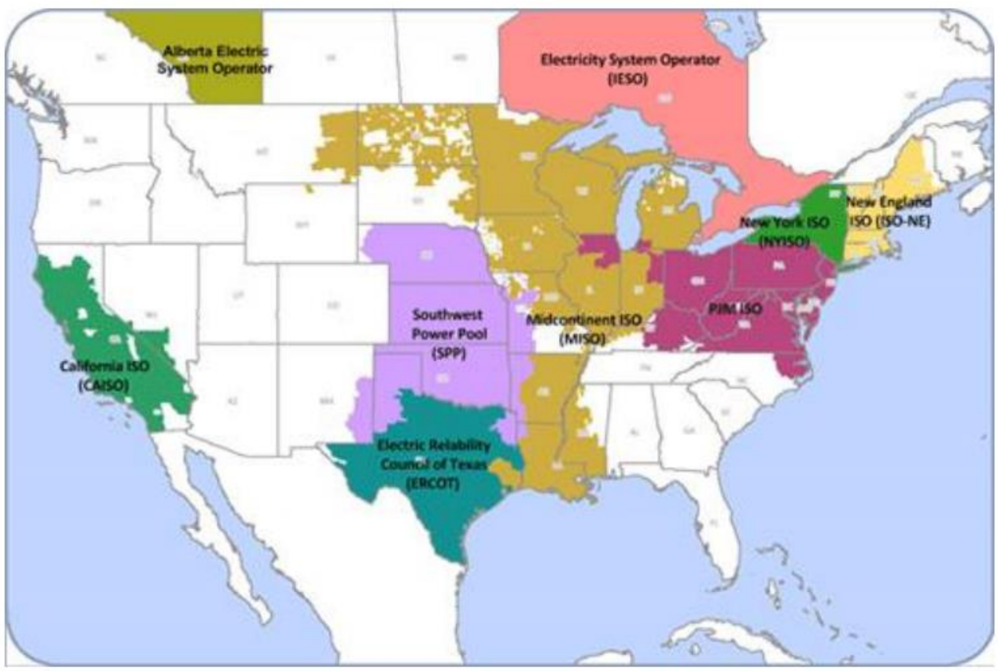
($/MWh). By this measurement, the relative cost of electricity generated by nuclear power plants goes down as the total capacity of the plant increases. Any unexpected or unplanned outage that reduces the total electricity output of the plant can significantly affect the economics of the power plant. Because of this, generator outages are planned so they are as short as possible and optimized to correspond with seasonal lows in power demand and prices (generally fall and spring).

Unplanned outages caused by equipment malfunctions or other causes outside of planned refuel outages are very impactful to the profits of nuclear power plants and as a result, the mostly all or nothing generating characteristic of nuclear power creates some of the types of economic risk unique to nuclear industry that are discussed later.

Market Background: Power generation and distribution in the United States differs widely between the different regions of the country. Approximately 2/3 of the country operates under the jurisdiction of Independent System Operators (ISO) that sell power in wholesale markets to ensure reliability and resilience by incentivizing cheap electricity generation sold in an independent exchange by the ISO. That power is then purchased in the market by Load Serving Entities (LSE) who in turn sell it to consumers in the retail electricity market. The Northeast, Mid-Atlantic, Midwest, and California operate in electricity markets in this manner.
Several areas of the country, however, continue to utilize regulated utilities whose power is sold to municipalities at a guaranteed rate of return set by public utility commissions within the individual states. The utilities in these regions are usually vertically integrated, meaning they own the generation and distribution systems to make and distribute power to the customers within their service areas. Generator dispatching in these regions is done according to the merit dispatch orders of the utility's dispatcher, and not a third party. The definition of "regulated utility" in Section 7701 of Title 26 Code of Federal Regulations, includes any utility making at

least 80% of its revenue from rates established by a state or regional regulating body[8]. Figure 1 below shows the regions of the country operating under ISOs and the parts shown in white utilize vertically integrated utilities.

Figure 1: Map of ISOs



Source: http://www.ferc.gov/images/maps/rto_map.gif

Of the 55 nuclear sites in the country, 26 operate in states with a deregulated energy market, meaning they operate within an ISO's wholesale market. The plants operating in these states are known as merchant generators, as they do not operate on a guaranteed rate of return model and must include the effects of market risk on their revenue[9]. The list of regulated and deregulated nuclear generating sites is provided in Figure 2:

[8] (Title 26 U.S. code Chapter 79 n.d.)
[9] (Institute 2021)

Figure 2: Regulated and Deregulated Nuclear Power Plants

Regulated Nuclear Sites		Deregulated Nuclear Sites	
Cooper	Browns Ferry	Millstone	Salem Generating Station
Brunswick	Joseph M. Farley	Braidwood Generating Station	James A. Fitzpatrick
Harris	Palo Verde	Byron Generating Station	Nine Mile Point Nuclear Station
McGuire	Arkansas Nuclear One	Clinton Power Station	R.E. Ginna
Catawba	Diablo Canyon	Dresden	Davis-Besse
H.B. Robinson	St. Lucie	LaSalle	Perry
Oconee	Edwin I. Hatch	Quad Cities	Beaver Valley
V.C. Summer	Vogtle	Calvert Cliffs Nuclear Power Plant	Limerick
Sequoyah	Wolf Creek Generating Station	Donald C. Cook	Peach Bottom
Watts Bar	River Bend	Fermi	Susquehanna
North Anna	Monticello	Palisades	Comanche Peak
Surry	Prairie Island	NextEra Energy Seabrook	South Texas
Columbia Generating Station	Grand Gulf Nuclear Station	Hope Creek	Point Beach
Turkey Point	Callaway		
Waterford 3		Source: NEI, 2021	

History of the Wholesale Markets:

As a case study of energy markets, electricity in the Mid-Atlantic states is bought and sold in both wholesale and retail markets operated under the jurisdiction of a private, non-profit ISO called PJM. PJM used to be an acronym for Pennsylvania-Jersey-Maryland, representing the states in which it operated, but has since grown to include 14 states from Illinois to New Jersey and as far south as Northern Virginia. PJM's function is to balance supply and demand on the grid and ensure the interstate requirements for electricity markets dictated by the Federal Energy Regulatory Commission (FERC) are met. While PJM does not directly manage any of the generating assets or power on the grid, it uses several types of market mechanisms to balance the appropriate supply of electricity on the grid to meet consumer demand 365 days a year.

Electricity has not always been sold in a commodities market. In fact, the sale of electricity in a market that dispatches generators based on market price is a relatively new concept. Since the early 1900s, when local utilities were beginning to expand their operations, they were vertically integrated, which means they owned every aspect of the generation, transmission, and distribution of electricity. As the demand for electricity grew, so too did the utilities' grid systems until they began to connect with neighboring utilities and states. PJM was founded in 1927 as an agreement between vertically integrated electric utilities so they could buy and sell power from each other in times of high demand.

This paradigm lasted for nearly a century until the first electricity commodity market appeared in Chile in the 1980s, as a method to lower the price of electricity by creating a competitive market that incentivized low priced electrical generation. The Chilean competitive market also served to bring investors into the country to upgrade the failing energy infrastructure that had suffered under the government-run monopoly[10]. PJM did not adopt a competitive market until the late 1990s. The process of deregulation was started by FERC Orders 888 and 889 as a way to bring more competition into the electricity markets, reduce consumer cost, and introduce new technology[11].

To ensure enough supply is available on the grid for predicted demand, PJM procures capacity through several different sub-markets within the wholesale market. The first and most basic is the spot market. In the spot market, system demand is calculated every 5 minutes and generators are told by dispatchers to either increase or reduce supply, depending on the needs of the grid. The plants that can respond to these dispatch signals tend to be fossil fuel plants, as they can vary the load by increasing or decreasing the fuel supply to their generator rapidly. In the spot market, less expensive plants are dispatched first until more load is needed, and then successively more expensive plants are dispatched until demand is met. As demand increases, so does the spot price, and all generators are paid at the rate of the most expensive generator dispatched to meet demand at that time[12]. Figure 3 shows how spot price changes with demand through the day.

[10] (Wang 2020)
[11] (FERC 2020)
[12] (Hoke n.d.)

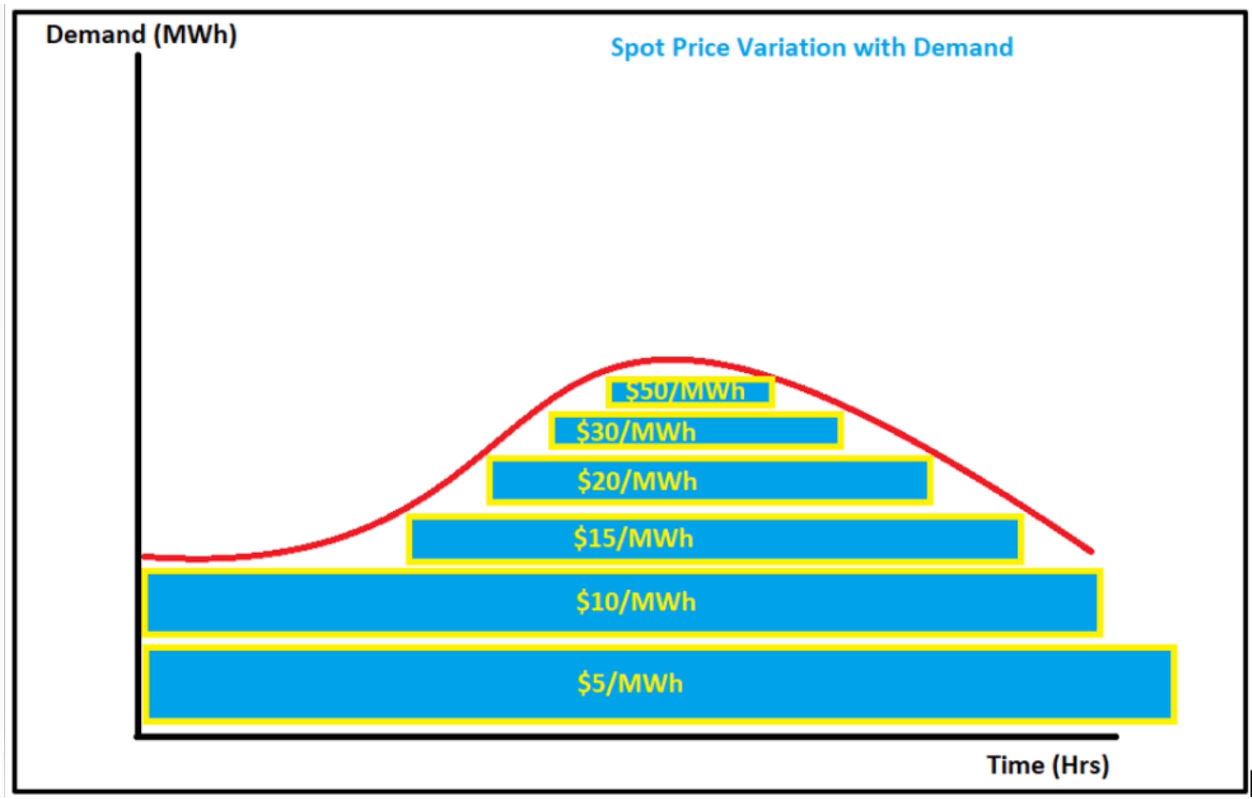


Figure 3

Spot price also changes seasonally. The times of highest demand are the summer and winter, where weather extremes can severely stress the grid on extremely hot and cold days. Because demand on the grid is constantly changing as industrial plants turn on and off loads or people arrive home from work and cool or heat their homes, the spot price can be very volatile, going negative in times of oversupply.

Aside from experiencing volatility due to weather, ambient temperatures, and grid conditions, the spot price also varies by location. The industry term for spot price is Locational Marginal Price (LMP) and is calculated at different geographical locations on the grid, as power can also be constrained by grid congestion, which means that not enough power can flow through the transmission lines as is needed in an area. Areas that experienced rapid industrial or residential growth where the transmission system is not upgraded to meet the new, higher demand will experience grid congestion, which will manifest as higher average LMP in that area. The cost basis difference between one LMP and another due to transmission line constraints is known as congestion cost.

As a market tool to ensure enough supply is available to meet forecasted demand, PJM also uses a day ahead market. The day ahead market uses a demand forecast model that predicts what demand will look like on an hourly basis the following day. Generators then bid into the day ahead market and the market is settled at 11:00 a.m. the day before the generation day. The benefit of the day ahead market is that it is more stable and not subject to the significant price volatility of the LMP real-time spot market described above. The day ahead market also requires that the generators deliver on promised demand or face punitive charges to supply makeup power. The major drawback of the day ahead market is that a generator will miss out on enormous demand spikes on the grid in extreme weather events. Though the grid in Texas, operated by the Electric Reliability Council of Texas (ERCOT), is governed differently than the PJM markets, the spikes in LMP during the severe cold weather events in the winter of 2021 are illustrative of the price volatility that a generator would miss if bid into the day ahead market instead of the real-time market. Prices in Texas in the winter of 2021 spiked to $9,000/MWh, which is 300 times higher than the typical LMP market price[13].

While the real-time and day ahead markets balance generation on a daily and hourly basis by using price signals and dispatch orders to increase supply to meet demand, PJM also has a market designed to send long-term pricing signals to generators. The capacity market, also known as the Base Residual Auction (BRA), is designed to send pricing signals three years in

[13] (Trollinger 2021)

advance of a generation year in order to signal new generators to be built or signal uneconomical generators to retire and leave the market. This market is settled in an auction that predicts the amount of load and reserves necessary to meet generation needs in a future generation year, and resources bid into this market based on a formula for their cost of generation from the PJM Open Access Transmission Tariff (OATT)[14]. Figure 4 demonstrates the process to determine the bid cost of a generator participating in the capacity market.

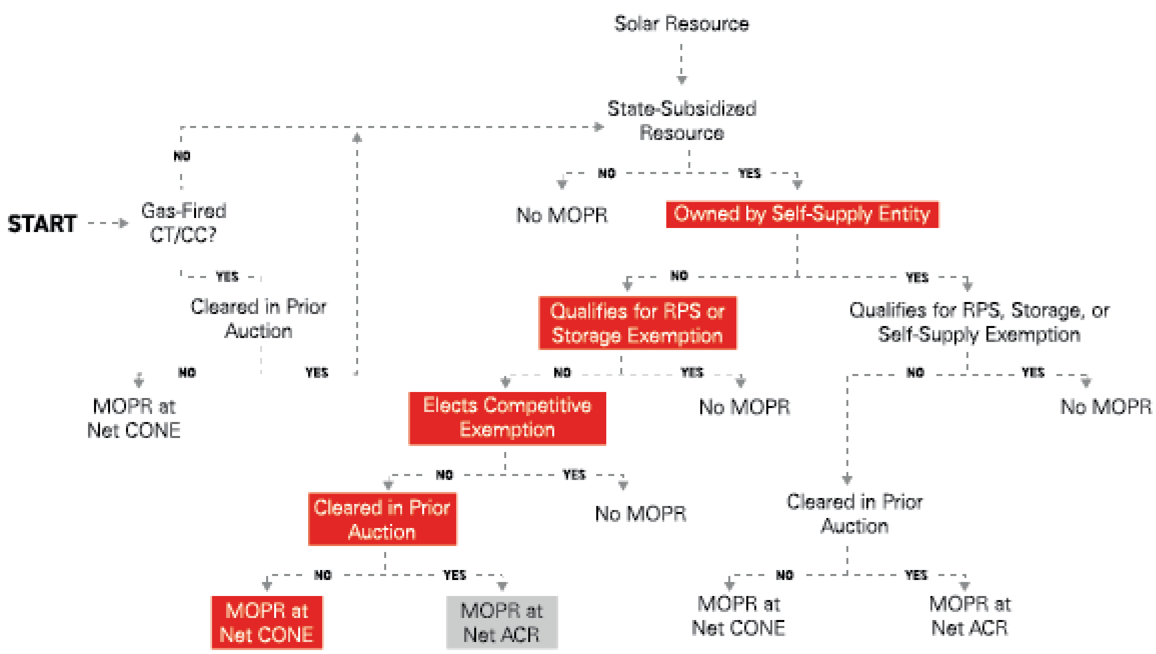


Figure 4

Source: AEP

As Figure 4 shows above, the determination that a participating generator must bid in at either the Cost of New Entry (CONE), which is a pre-defined value determined by PJM, or the Avoidable Cost Rate (ACR), derived from the formula shown below will determine whether a generator benefits from the capacity market payments.

[14] (Bowring, Avoidable Cost Rate Calculation Template n.d.)

Avoidable Cost Rate = [Adjustment Factor * (Operational Costs + Capital Costs)]

Resource Type	Proposed Net CONE
Nuclear	$1,571
Coal	$1,022
Combined Cycle	$112
Combustion Turbine	$219
Onshore Wind	$1,182
Offshore Wind	$3,315
Solar PV (tracking)	$213
Solar PV (fixed)	$400
Battery Energy Storage	$1,040
Demand Response (gen)	$254

Source: pjm.com

Figure 5

Generators that neither meet the CONE nor ACR requirements of the capacity market (as shown in Figure 4) will generally bid at $0/MWh and the generators are then merit stacked based on the price of their bids until the capacity requirement in the future generation year is met. All of the generators participating in the capacity auction are paid at the rate of the highest bid selected in the merit order fulfilling the last MWh requirement. Figure 6 shows the historical results of the capacity market.

	Auction Results		
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Reserve Margin
2007/2008	$ 40.80	129,409.2	19.1%
2008/2009	$ 111.92	129,597.6	17.4%
2009/2010	$ 102.04	132,231.8	17.6%
2010/2011	$ 174.29	132,190.4	16.4%
2011/2012[1]	$ 110.00	132,221.5	17.9%
2012/2013	$ 16.46	136,143.5	20.5%
2013/2014[2]	$ 27.73	152,743.3	19.7%
2014/2015[3]	$ 125.99	149,974.7	18.8%
2015/2016[4]	$ 136.00	164,561.2	19.3%
2016/2017[5]	$ 59.37	169,159.7	20.3%
2017/2018	$ 120.00	167,003.7	19.7%
2018/2019	$ 164.77	166,836.9	19.8%
2019/2020	$ 100.00	167,305.9	22.4%
2020/2021[6]	$ 76.53	165,109.2	23.3%
2021/2022	$ 140.00	163,627.3	21.5%
2022/2023	$ 50.00	144,477.3	19.9%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

Figure 6

Source pjm.com

In the capacity market, if a particular region has a very high capacity price, that signals to the market that new generation should be built in that area. If a region has an oversupply of generation, then low capacity prices signal some of the more uneconomical plants to retire, as they will not cover their costs.

The Out of Market Option: Generators are not required to participate in the wholesale or capacity markets. They may also choose to sell their power to a third party in contracts known as forward contracts. Explored later in the risk section, these contracts are a method by which large industrial loads or municipalities ensure a stable availability of electricity at a fixed price, or buy power from specific generator technologies to meet strategic business or environmental goals.

There is great variability in the terms of these forward contracts or the way in which they are executed, but generally, a generator guarantees to sell a certain amount of its output to a consumer for a fixed price and must meet that demand or be required to pay a replacement generator to provide electricity it fails to deliver[15].

Usually, in order to execute forward contracts, the generator and the consumer must be co-located on the same grid, but that paradigm is changing as more creative solutions to the energy transition are formulated.

What makes trading energy different than other commodities? The energy markets are very unique from more traditional financial markets for many reasons. The first is that the nascent energy markets are not as centralized or mature as financial markets such as Wall Street, in New York City. With the phenomenon of deregulation beginning in Chile in the 1980s, the energy markets in the United States are still establishing norms and emerging generation technologies routinely disrupt those norms.

Second, energy markets respond to significantly more complex price drivers than do traditional financial markets. Weather, seasonality, macroeconomic disruptions, technology changes, and changes in usage patterns all drive large fluctuations in both spot and forward pricing in the energy markets. Because of the large number of price drivers in energy markets, they are much more difficult to model. Coupled with the fact that an actual, physical product is produced, exchanged, and consumed, the difficulty in modeling market behavior can itself drive price volatility[16].

[15] (Mueller 2021)
[16] (Pilipovic 2007)

Another physical limitation of energy markets, described above, is that electricity cannot be stored in meaningfully large enough quantities to affect market prices or behavior. Electricity must be consumed the moment it is produced, and therefore the market reacts to changes in demand more erratically than occurs in financial markets (Spitzen 2010). Energy markets, while displaying high volatility, also have high mean reversion, or the rate at which pricing returns to an equilibrium value after a disruption. The mean reversion in energy markets is a function of how quickly both supply and demand sides can react to a disruption and bring both sides back into balance[17].

All of the factors above that make energy markets unique and volatile also increase pressure on both suppliers and consumers to engage in forward contracts. Forward contracts, or derivatives, are a means by which firms can consumption-smooth and lock in revenue and costs. This hedging behavior in markets also creates new types of financial risk for generators, particularly nuclear generators.

Risk Background: Electrical generators operating in deregulated wholesale markets are dispatched by price, thus causing competition to maintain low costs. Given the uncertainties related to electricity generation, the measure of profitability of a generator extends beyond just its ability to cover costs in the market, but also the costs of the risk it carries as a market participant. Risk is defined traditionally as a function of the probability and impact of an unfavorable event occurring[18]. There are many different types of economic risks present in the electricity markets including: market risk, operational risk, modelling risk, and political risk[19].

[17] (Pilipovic 2007)
[18] (Garvey, Analytical Methods for Risk Management: A Systems Engineering Perspective 2009)
[19] (Administration 2002)

Market risk is one of the largest drivers of hedging in the electricity markets and is the risk borne by market participants due to the price volatility of electricity. Since electricity is not storable, energy produced must either be immediately consumed or dissipated. Traditional commodity market risk analysis accounts for storable goods, but electricity's inability to be stored economically makes its prices particularly volatile. When energy prices are low, the equity values of generating companies are also low, challenging their ability to raise capital. In times of high electricity prices, however, the government typically steps in to correct a perceived market failure, and thus the electric utilities only see downside market risk[20].

Market risk can also be borne when participants sell their power into futures markets and then are unable to fulfill their contracts due to unforeseen circumstances; those generators are then forced to procure replacement power at the spot price, which could be higher than the price of the futures contract. This type of market risk is known as liquidated damages risk[21]. Liquidated damages contracts are used by utilities to sell their power into a liquid futures market. The contract guarantees that the buyer will have continuous power of a specified amount for an agreed upon amount of time. If the participating generating plant cannot deliver that power, the plant must then procure power from another generator at the cost of power at the time. The alternative to a liquidated damages contract is a unit contingent contract, which is one that is only valid when the generator selling the power is able to deliver it. The latter type of contract is not widely utilized, as the risk is completely borne by the consumer and therefore is not something procured in the market.

Operational risk is another type of risk present in the market. Operational risk is the risk that a generator will be unable to deliver its contractually obligated power due to an equipment

[20] (Administration 2002)
[21] (Huntowski 2021)

malfunction or change in generator output. Since nuclear plants are essentially zero marginal cost resources, any reduction in projected output can have a profound effect on costs. The formula for the change in cost is:

$$Actual\ Cost = Projected\ Cost * \left(\frac{1}{1 - reduction\ in\ projected\ generation}\right)$$

Therefore, a 10% reduction from projected generator output has an 11% increase in associated costs[22]. Nuclear plants are particularly prone to this type of risk since they generate an immense amount of power. When a nuclear plant experiences an outage, they typically cease generating completely, causing a large reduction in generation. This is realized as a dramatic increase in cost based on the formula above.

Yet another type of risk, Modelling risk, is associated with the difficulty in determining what risk will be in the future due to the many drivers in the electricity market. Utilities may make decisions based on imprecise economic models, and can inadvertently expose the company to more risk or different risk than the company's risk strategy allows[23]. With so many market drivers in the electricity industry, it can be a necessity to simplify market models by making some of the variables into deterministic parameters. This also decreases the precision of a given model and increases risk to the utility.

The fourth type of risk is political or regulatory risk. Regulatory risk is the risk assumed by generators operating in a heavily regulated environment in which a change in regulatory requirements or policy may significantly adversely affect the industry's economic outlook.

[22] (Group, COMMENTS OF CONSTELLATION ENERGY NUCLEAR GROUP, LLC 2016)
[23] (Pilipovic 2007)

Generators, especially asset-heavy technologies with long service lives, like nuclear, are particularly susceptible regulatory or political risk. Changes in policy that either value or disincentivize a certain technology type will have a large impact on capital heavy technology types[24]. As an example, the total cost impact of regulatory changes made by the U.S. Nuclear Regulatory Commission (NRC) since 2006 is $444 million, while the simultaneous impact of cooling water intake structure regulations on the industry by the U.S. Environmental Protection Agency (EPA) is listed at $7.3 billion. NRC annualized costs for paperwork review per operating plant is estimated at $4.2 million. Together, the cost of regulatory changes levied on the nuclear industry have driven several nuclear plant closures and have had a dramatic impact on the industry as a whole[25].

The risk of regulation or policy change is not confined to the “special and unique” aspects of nuclear power, but also its attributes as an electrical generator. The federal government has passed several pieces of legislation that impact the energy markets through regulatory changes or incentives. The focus on clean energy through the multi-pronged approach includes the Treasury Department, which has not before been an active participant in the global climate change fight[26]. The American Jobs Plan includes provisions to transition to a 100% clean energy grid through the use of renewable energy tax credits[27]. This is widely supported by proponents of climate change legislation, but Section 206 of the Federal Power Act still applies which prevents a practice in energy transmission and generation that is, “unjust, unreasonable, unduly discriminatory or preferential”[28]. This statute is the same premise under which Calpine Energy

[24] (Robin Leisen 2019)
[25] (Batkins 2016)
[26] (Treasury n.d.)
[27] (Travish n.d.)
[28] (PJM, Federal Law Guides Changes in PJM Documents n.d.)

sued PJM and eventually resulted in the Minimum Offer Pricing Rule (MOPR), a prime example of the regulatory and political risk impact in the energy markets.

Energy as a commodity: Unlike most commodities markets and even other energy markets, electricity is unique in that a unit of electricity, sold as a Megawatt-hour (MWh), cannot be stored in a meaningful amount or for a time that affects market performance. The reasons behind the inability to store electricity are both policy and technology driven, but the ramifications of generators being unable to store electricity are immense on the way in which electricity markets operate[29].

In a typical commodities market, both the producer and consumer of the good respond to pricing signals by changing supply and demand to meet the needs of the other, with the more inelastic party assuming the risk, meaning the more risk averse party pays for the cost of risk. In times of low demand, the producer can continue to produce the good, but store it until demand rises and then release the stored product into the market.

Due to technical requirements of the electricity grid, electricity must be consumed the moment it is produced and cannot be stored on the grid. Generators are unable to store the electricity they produce on site, and so adopt different strategies to ensure the energy they produce is purchased and consumed. The need to balance the grid and sell all the electricity generated would mean that, theoretically, generators would be risk averse and glean more welfare from a higher degree of certainty[30]. Following this theory, it would stand then that generators have a welfare-risk function as described in the top of Figure 7 below, where $W(\Omega)$ is the welfare function and Ω represents the decision maker's net present wealth. The $W[E(\Omega)]$ term

[29] (Spitzen 2010)
[30] (Ganda 2014)

represents the welfare of the expected value of a certain outcome, and E[W(Ω)] is the expected welfare of an uncertain outcome.

Figure 7:

To describe risk averse behavior, consider the following definitions:

if $W[E(\Omega)] > E[W(\Omega)]$, then decision makers are *"Risk Averse,"* i.e., they have higher levels of welfare with more certainty;

if $W[E(\Omega)] = E[W(\Omega)]$, then decision makers are *"Risk Neutral,"* i.e., they are indifferent toward uncertainty; or

if $W[E(\Omega)] < E[W(\Omega)]$, then decision makers are *"Risk Preferring,"* i.e., they have lower levels of welfare with more certainty.

Source: (Ganda 2014)

Because in this hypothetical, generators gain more welfare from price certainty, they engage in forward sales and futures contracts to ensure that they will have buyers for all electricity produced and "lock in" their revenues. In this scenario, the generators are risk averse, and so pay the risk premium, which is the cost of risk assumed when the generators offer their electricity in a forward market at a reduced cost in order to ensure stability[31]. This paradigm results in a market that is in backwardation, or a scenario in which futures prices are lower than spot market prices, a scenario rarely seen in other markets and driven, in part, due to the inability to store electricity at scale[32].

Lack of Demand Response:

The reality of the electricity market is that the demand side does not respond to pricing signals as it would in other commodities markets. This challenge is one of policy. Because electricity consumers account for nearly every household in the United States and the ability to reliably consume electricity without having to be concerned with an ever-changing price is paramount to a stable economy, consumers are protected from volatile price swings by the states in which they

[31] (Ganda 2014)
[32] (Spitzen 2010)

live[33]. This lack of demand response further aggravates the volatile electricity prices and makes the electricity markets even more unique. As a result of the lack of demand response to pricing signals, electrical generators are forced to dispatch and follow pricing signals set by the ISOs in order to balance grid demand.

As one study found, this lack of demand response causes additional seasonal price volatility that takes the market out of backwardation and puts it in contango, or a state when prices drop as futures prices mature, at times of high demand in the seasonal peaks. The study described the risk premia of the market in diffusion (steady state) as being positive, at which time buyers receive a discount on futures contracts because generators want to ensure that the electricity they will produce is sold. In the seasonal peaks, times of high demand, or times of uncertainty, there is an extremely strong hedging pressure on the buyer's side resulting in very sharp negative risk premia (Yuewen Xiao 2014). This relationship between price volatility and risk premium was further supported in a study of PJM spot and day ahead prices, showing that "forward premia are negatively related to price volatility"[34]. This means that in the peak seasons of summer and winter, electricity risk premiums drop, the price volatility increases, which drives commercial electricity consumers to seek futures contracts and assume the risk. This also demonstrates the effect of policy on the electricity market, as residential consumers are protected from this volatility by rate regulation from public utility commissions. The uniqueness of the electricity market drives both consumer and suppliers to minimize risk, encouraging entrance into derivatives trading with futures contracts.

[33] (Spitzen 2010)
[34] (Spitzen 2010)

Liquidated Damages Risk:

Because nuclear power plants are designed to run at full output and are considered a baseload generation source, the plants do not follow pricing demand signals of the ISO and must sell power at the market price, unless entered into forward or futures contracts. The design of nuclear power plants creates further challenges that are not present in other technologies, as they produce so much power that the addition or subtraction of a nuclear plant from the grid can influence the market enough that prices change significantly as a result[35].

This effect is particularly damaging to nuclear plants that have entered into liquidated damages futures contracts, which are different from unit contingent contracts in that they require the unit selling power forward to pay for replacement power if the unit were unable to meet its commitment to provide electricity to the consumer. As described above, a nuclear plant unable to meet its obligation to provide electricity due to an unforeseen equipment challenge will likely cause a dramatic rise in electricity prices. The generator will then have to procure replacement power for the buyer at a much higher price than was offered in the liquidated damages contract.

Risk in Legislation and Practice:

As discussed previously, there are many factors that cause the aggregate cost of risk to be proportionally higher for nuclear generating facilities than other technologies operating in wholesale markets or within bilateral power purchase agreements. As shown below in Figure 8, the aggregate cost of risk can be as much as 25% of the total operating cost of the plant. It is for this reason that the appropriate valuation of risk be considered when determining the amount of need for a nuclear generator applying for state or federal assistance.

[35] (Group, Comment from the Constellation Energy Nuclear Group, LLC on the Clean Energy Standard 2016)

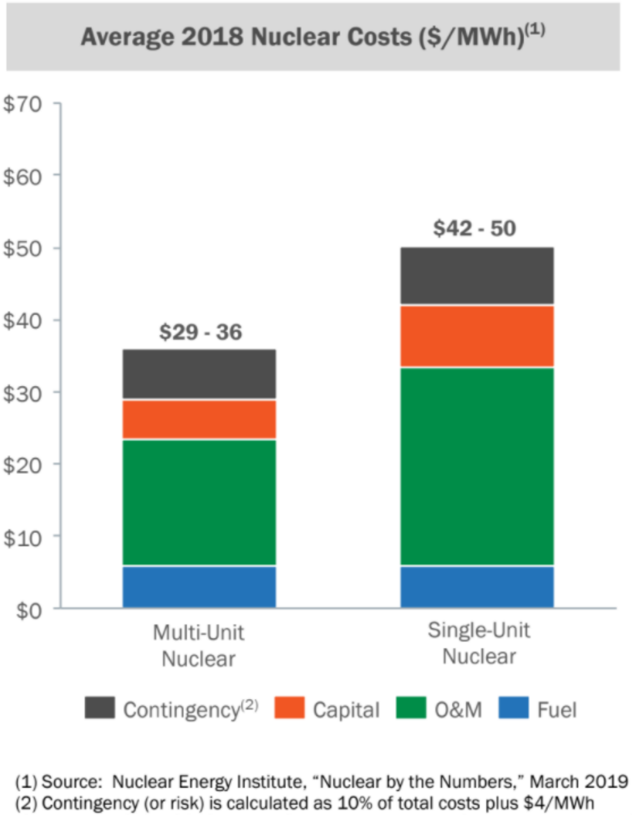


Figure 8

Source: Confidential

In some cases, pieces of the aggregate cost of risk have already been built into existing legislation or business practices of the ISOs. For instance, in the calculation for the bid price into PJM's capacity auction, most participating nuclear plants would be required to bid at their Avoidable Cost Rate (ACR) less operating revenues, or the cost to the utility that would be avoided if the plant were to shutdown, rather than receive capacity payments. Figure 4 and the accompanying equation for ACR show what this entails for the generating entity, with the adjustment factor equaling 110% to account for operational risk[36].

[36] (PJM, Open Access Tariff 2021)

The Midcontinent Independent System Operator (MISO) also accounts for risk in a slightly different way. In setting capacity market rules, MISO combats price volatility risk through a sloped resource adequacy demand line. The effect of this sloped demand line is an expected 5% increase in cleared resource adequacy payments, and a reduction in LMP price volatility risk for generators bidding into the capacity market[37]. Figure 9 shows the graphical representation of the sloped demand line's effect on clearance price and Figure 10 shows the resulting net revenue differences based on utility type.

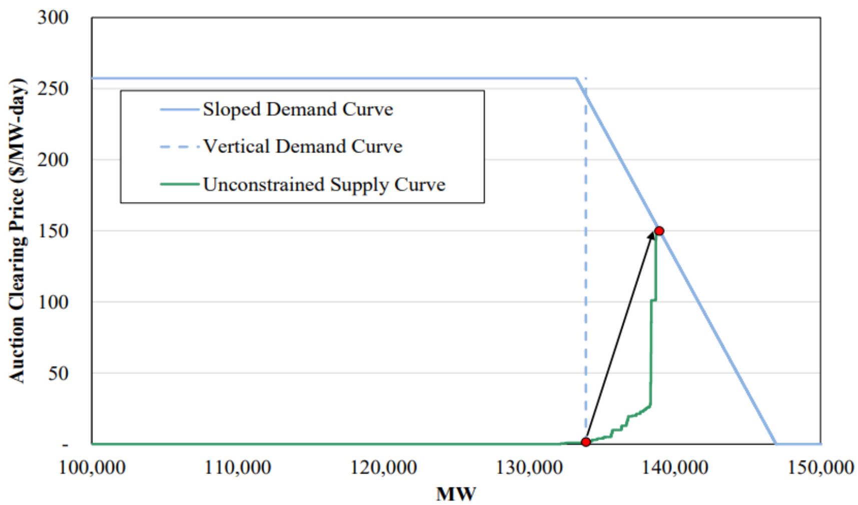


Figure 9

Source: (Economics, 2020 State of the Market Report for the MISO Electricity Market 2021)

2021–2022 PRA

Type of MP	Net Revenue Increases	Net Revenue Decreases	Total
Vertically Integrated LSEs	$185.6M	-$65.8M	$119.8M
Municipal/Cooperative	$89.1M	-$50.3M	$38.8M
Merchant	$349.8M	-$61.4M	$288.4M
Retail Choice Suppliers		-$447.0M	-$447.0M

Reforming the Accreditation of Capacity in MISO

Figure 10

Source: (Economics, 2020 State of the Market Report for the MISO Electricity Market 2021)

[37] (Economics, 2020 State of the Market Report for the MISO Electricity Market 2021)

As shown in Figure 10, the cost of risk in the electricity markets can be immense, and a 5% adjustment in the valuation of market prices to reduce volatility risk can significantly impact generator's revenues.

Recent legislation at the state level has also acknowledged the significance of the cost of risk to nuclear generators. In the fight against global climate change, several states have taken proactive action to preserve carbon-free nuclear generators within their state by offering zero emissions credits or financial support to qualified nuclear generators.

In 2016, the State of New York adopted legislation aimed to keep its nuclear generating facilities open in order to preserve their carbon-free generating attributes through the transition to renewable energy. In order to achieve its climate goals, the Clean Energy Standard, as the bill was known, created a zero emissions credit (ZEC) that would be required to be purchased from the operating nuclear plants by the state's LSEs. The price of the ZEC is based on the EPA's social cost of carbon minus the revenues earned through New York's participation in the Regional Greenhouse Gas Initiative (RGGI) and less the revenues earned through the wholesale market above the price of $39/MWh. The equation below shows the calculation and Figure 11 lists the expected values for social cost of carbon to calculate the ZECs[38].

Social Cost of Carbon − Baseline RGGI Effect − Amount Zone A Forecast Energy Price and ROS Forecast Capacity Price combined exceeds $39/MWh = Upstate ZEC Price

Source: (Commission 2016)

[38] (McDermott 2016)

Tranche 2	$46.79	Average of April 2019 - March 2021 USIWG on SCC estimates (July 2015)
Tranche 3	$50.11	Average of April 2021 - March 2023 USIWG on SCC estimates (July 2015)
Tranche 4	$54.66	Average of April 2023 - March 2025 USIWG on SCC estimates (July 2015)
Tranche 5	$59.54	Average of April 2015 - March 2027 USIWG on SCC estimates (July 2015)
Tranche 6	$64.54	Average of April 2027 - March 2029 USIWG on SCC estimates (July 2015)

Figure 11

Source: (Commission 2016)

The structure of the New York Clean Energy Standard was a direct result of the U.S. Supreme Court Case, *Hughes v. Talen Energy Marketing*, which overturned state subsidies that were used as “make-up” payments to revenues not received in a generator’s participation in the wholesale or capacity electricity markets. New York addressed this and the cost of risk by tying the value of ZECs to the carbon-free attributes preserved, but also included the cost of market risk in its forecasting use of $39/MWh market adjustment. By this method, New York’s unique approach to the problem of risk circumvented previous legal challenges to legislation designed to confront market shortfalls directly[39].

When the State of Illinois adopted similar legislation in December 2016, it used the same tack as New York to prevent a challenge in the courts. The difference with Illinois’ adaptation of the ZEC law was that the bidder eligibility required that plants intending to receive the zero emissions credits provide a tally of costs that would only be reasonably avoided if the plant were to cease operation. That valuation also specifically listed the operational and market risk

[39] (Walton 2016)

components unique to the plants applying for the ZEC[40]. Again tying the amount of subsidy to the social cost of carbon, Illinois avoided the issue of market manipulation present in *Hughes v. Talen Energy Marketing*, but also specifically included the cost of operational and market risk in the valuation. The method of calculation of risk is not prescribed in the legislation or the form, but rather left to the generator to determine what the cost of associated risks is in order to meet eligibility requirements.

New Jersey followed suit with ZEC legislation similar to both New York and Illinois, but did not include a market adjustment function. Instead of adjusting the ZEC based on revenues received by the nuclear generating stations, the ZEC law in New Jersey included an adjustment for each 3 year tranche that allowed the New Jersey Board of Public Utilities to review and approve a reduction of ZEC payments, should the BPU identify the full amount was no longer required to maintain the nuclear plant's carbon-free generation attributes[41]. In the determination, the law states the BPU shall consider, "the cost of operational risks and market risks that would be avoided by ceasing operations"[42] without specific direction as to what that value entails.

At the federal level, the cost of risk with respect to the economic viability of the nation's nuclear fleet has also been recognized and included in legislation. The "Infrastructure Investment and Jobs Act (IIJA or the Act) directs the Secretary of Energy (Secretary) to establish a Civil Nuclear Credit (CNC) Program to evaluate and certify nuclear reactors that are projected to cease operations due to economic factors and to allocate credits to selected certified nuclear reactors via a sealed bid process"[43]. The details of the program's execution are still being developed, but the legislation establishes a federal nuclear credit available to eligible nuclear generators in

[40] (I. P. Agency 2016)
[41] (Jersey 2018)
[42] (Jersey 2018)
[43] (Energy 2022)

merit order, which considers many criteria, including, “accounting for the operational risk and market risks faced”[44] . Similar to the ZEC programs enacted at the state level, the federal program does not specify how the cost of risk is to be calculated by each facility, but the Department of Energy has solicited input for a credit application vetting process that includes this criterion.

Findings and Recommendation:

Given as established above:

1. The markets in which the nation’s fleet of nuclear generators participate are very disparate, depending on the state in which they operate and the agreements under which the utilities sell their power;
2. The risk tolerance of the utility owners and operators of the nation’s nuclear facilities varies based upon the market strategy of that individual company;
3. The drivers for risk of nuclear generators’ participation in electricity markets is very complex and includes many inputs;
4. The cost of risk for nuclear generating stations is a large portion of the overall operating cost;
5. That if utility owners and operators of the nation’s nuclear facilities do not recover the cost of risk in the market or through state or federal subsidies, those stations will cease operation;
6. The continued operation of the nation’s nuclear facilities is critical to meeting climate change goals of both the nation and many of the states;

[44] (Energy 2022)

Legislation created to preserve the nation's currently operating nuclear fleet should take into account the cost of risk and allow individual stations to determine what that cost entails in order to determine eligibility and payment for the specific legislation developed.

To accomplish this, the risk types in any application for inclusion in a nuclear subsidy program should be broken down into the two largest risk contributors; operational risk and market risk. In the discussion of Avoidable Cost Rate above, which is a measure of cost avoided if the unit were to retire due to economic reasons, the PJM Open Access Tariff Attachment DD, Section 6.8 allows a 110% operational risk adjustment. This adjustment assumes that operational risk contributes an additional 10% of market cost to the overall cost of operation of the unit and has become an accepted industry value of operational risk. This value is also approved as reasonable by the Federal Energy Regulatory Commission[45].

Market risk is more complicated and individual to the unit and utility in question. Since market risk varies based on the type of forward contracts or bidding practices in which a nuclear plant participates, and also depends on the physical location of the plant, the utility should be able to determine this risk value, within reason to apply for inclusion in subsidy programs. Market risk also depends on the utilities' ability to fulfill any shortfalls in contractually obligated generation through other generators in their portfolio; another reason that the value of market risk can differ between utilities.

With nuclear power providing over half of the carbon free electricity generation in the U.S., it is important that these plants be reimbursed for their clean energy attributes. In determining the

[45] (PJM, Open Access Tariff 2021)

amount of need for a subsidy program, nuclear plants should be allowed to account for the significant amount of financial risk to which they are subject.

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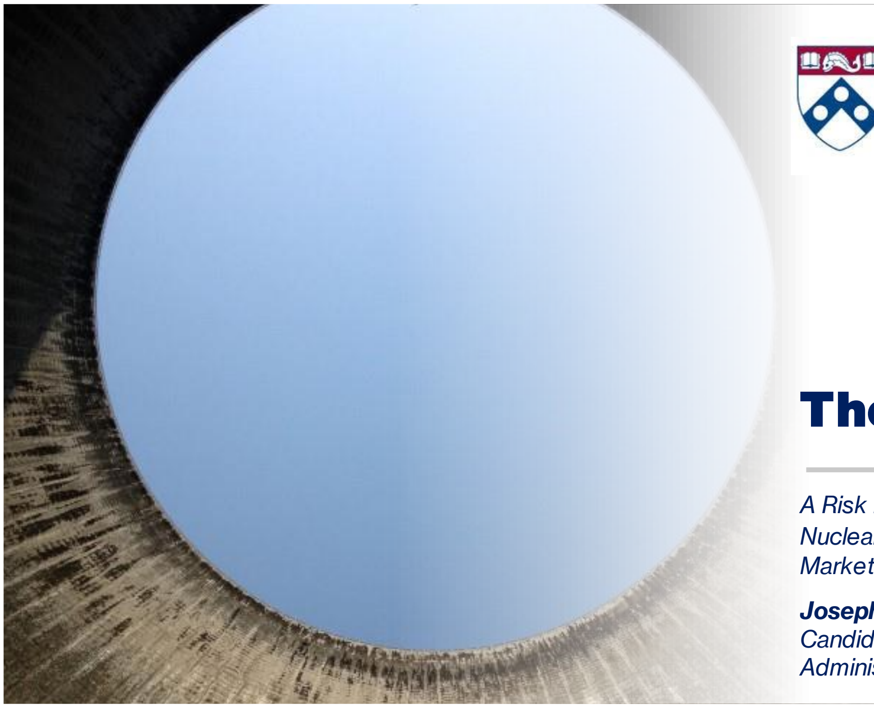


Fels Institute of Government
UNIVERSITY of PENNSYLVANIA

The Cost of Risk

A Risk Informed Policy Analysis of Nuclear Power in the Electricity Markets

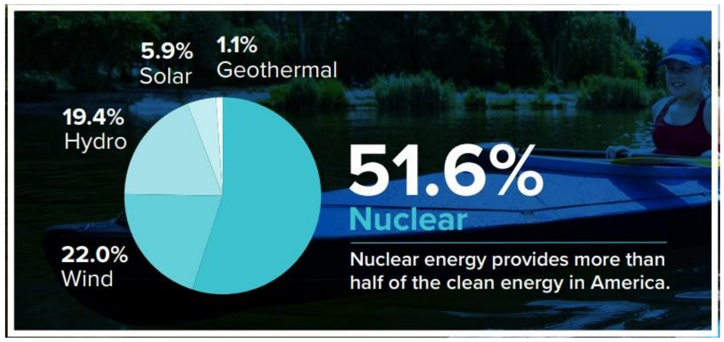
Joseph Milo
Candidate for Master of Public Administration 2022

Agenda

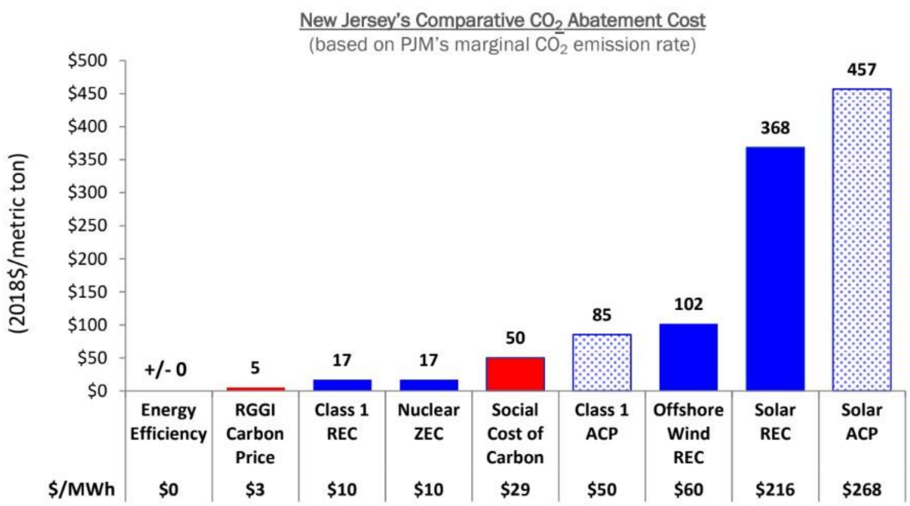
- Nuclear Power in the U.S.
- Electricity Markets
- Financial Risk Management
- Legislation
- Recommendations

Largest Source of Carbon-Free Power

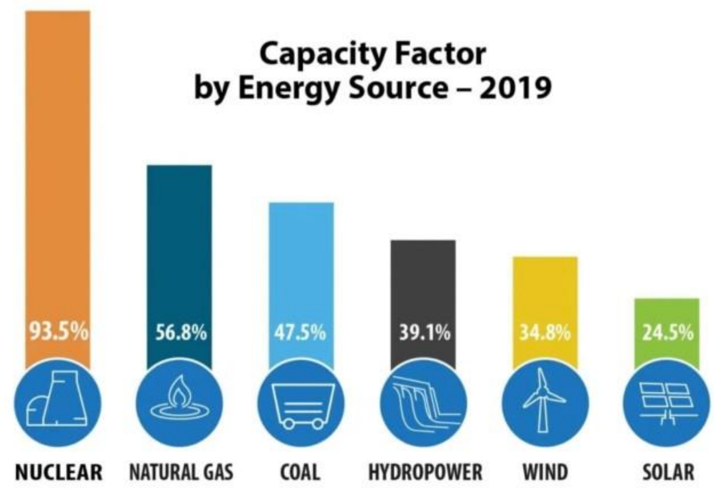
- 93 reactors in 28 states
- Nuclear industry avoids 471 million tons of carbon dioxide per year in U.S.
- Nuclear accounts for 20% of total electricity generated in U.S.



Source: nei.org



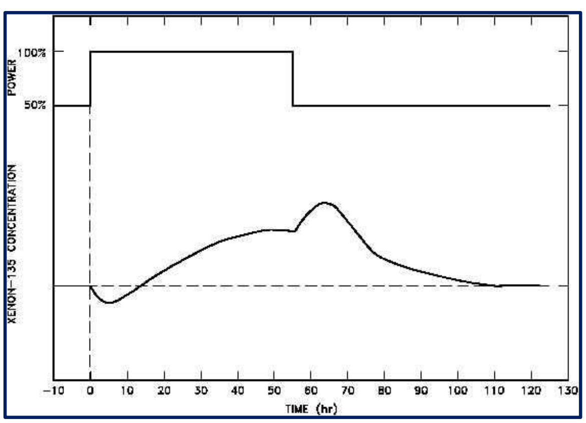
Sources: National Academy of Sciences' 2020 carbon price, carbon intensity from PJM, NJ BPU 2018 Compliance Report for Class 1 & SREC costs , non-compliance costs for energy year 2019, 2018 weighted average RGGI auction price. Offshore wind subsidy is the difference between the OREC price for 2024 and the calculated value of PJM energy and capacity using the BPU reference prices.

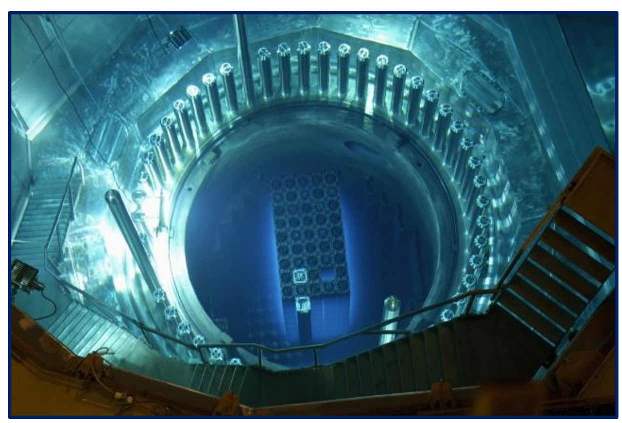


Source: nei.org

93%

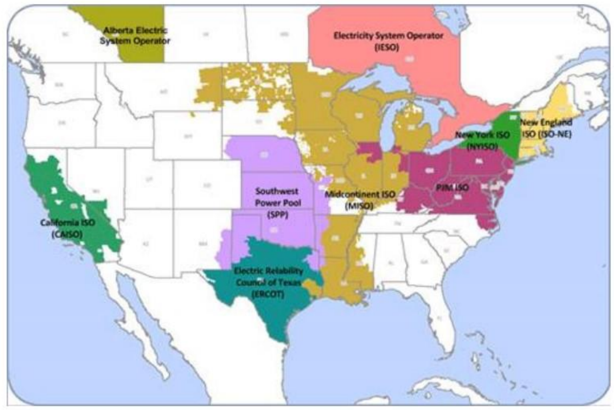
Special and Unique



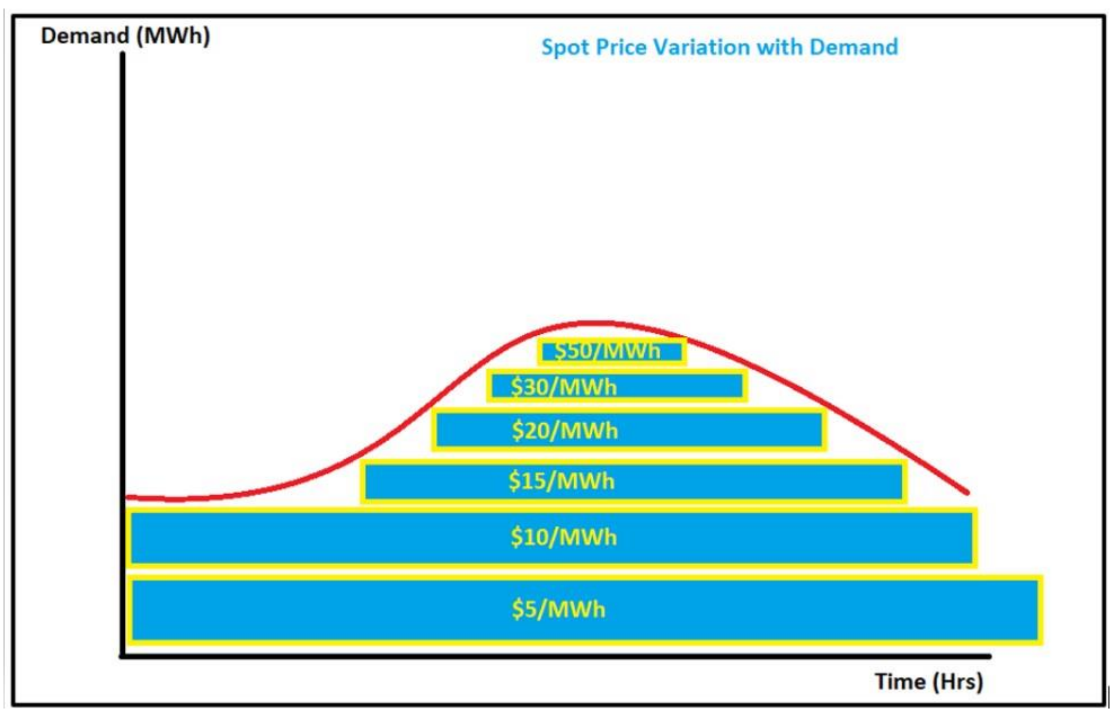


Market Overview

- Most of the country's electricity is bought in wholesale markets
- The remainder is from vertically integrated utilities
- There are three sub-markets in the wholesale market: spot market; day ahead market; and capacity market

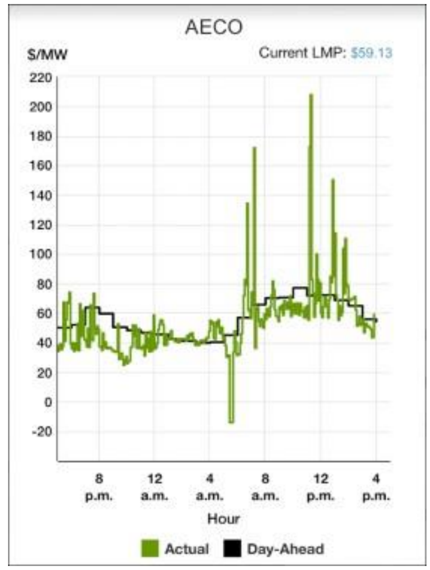


Source: http://www.ferc.gov/images/maps/rto_map.gif



Spot Market v. Day Ahead Market

- Spot price is very volatile
- Day Ahead price is based on forecasted demand and is less volatile
- Downside of day ahead market is that generator will miss out on large price spikes
- No great difference in overall price between the two over time



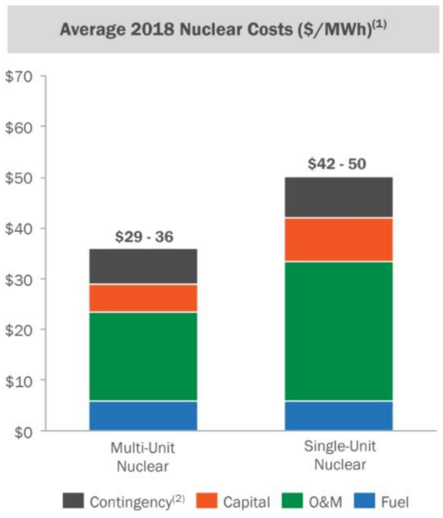
Source: PJM Now App

	Auction Results		
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Reserve Margin
2007/2008	$ 40.80	129,409.2	19.1%
2008/2009	$ 111.92	129,597.6	17.4%
2009/2010	$ 102.04	132,231.8	17.6%
2010/2011	$ 174.29	132,190.4	16.4%
2011/2012[1]	$ 110.00	132,221.5	17.9%
2012/2013	$ 16.46	136,143.5	20.5%
2013/2014[2]	$ 27.73	152,743.3	19.7%
2014/2015[3]	$ 125.99	149,974.7	18.8%
2015/2016[4]	$ 136.00	164,561.2	19.3%
2016/2017[5]	$ 59.37	169,159.7	20.3%
2017/2018	$ 120.00	167,003.7	19.7%
2018/2019	$ 164.77	166,836.9	19.8%
2019/2020	$ 100.00	167,305.9	22.4%
2020/2021[6]	$ 76.53	165,109.2	23.3%
2021/2022	$ 140.00	163,627.3	21.5%
2022/2023	$ 50.00	144,477.3	19.9%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

Capacity Market

- Send long-term price signals
- Retires uneconomical plants
- Brings new generation in areas of high demand
- Ensure sufficient capacity for highest load days
- Market settled 3 years in advance



(1) Source: Nuclear Energy Institute, "Nuclear by the Numbers," March 2019
(2) Contingency (or risk) is calculated as 10% of total costs plus $4/MWh

Types of Risk

- Market Risk
- Operational Risk
- Modelling Risk
- Regulatory Risk

Regulatory Risk:

Since 2006, the U.S. NRC has imposed over $444 million in regulation changes

Changes required by the U.S. EPA have cost the industry $7.3 billion

Modelling Risk:
The price drivers for electricity market are so numerous, that they cannot be accurately modelled. This leads to inaccurate predictions
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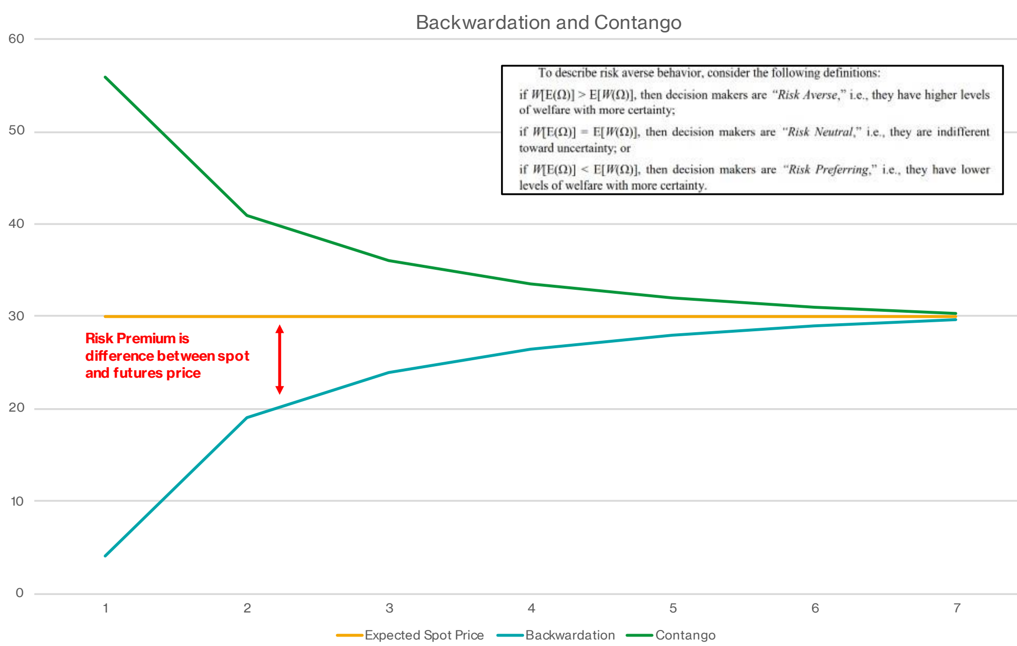

Backwardation and Contango
60
50
40
30
20
10
0
1
2
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6
7
To describe risk averse behavior, consider the following definitions:
if $W[E(\Omega)] > E[W(\Omega)]$, then decision makers are "*Risk Averse*," i.e., they have higher levels of welfare with more certainty;
if $W[E(\Omega)] = E[W(\Omega)]$, then decision makers are "*Risk Neutral*," i.e., they are indifferent toward uncertainty; or
if $W[E(\Omega)] < E[W(\Omega)]$, then decision makers are "*Risk Preferring*," i.e., they have lower levels of welfare with more certainty.
Risk Premium is difference between spot and futures price
Expected Spot Price
Backwardation
Contango

Legislation and the Cost of Risk

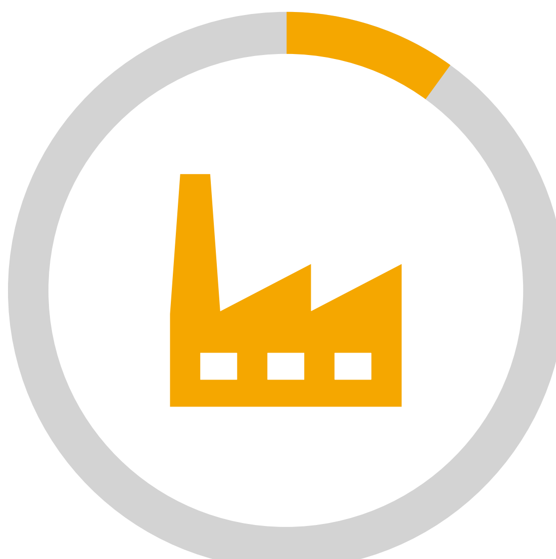
- Legislation designed to keep nuclear plants operating in the market include bills in NY, IL, NJ, CT and recently the Federal Infrastructure Bill with the Civil Nuclear Credit
- These bills have taken varied approaches to address the cost of risk in the market for nuclear plants

	New York	Illinois	Connecticut	New Jersey
General Description	Under the state's clean energy standard, load serving entities must purchase Zero Emission Credits from NYSERDA who purchases them from the eligible nuclear plants.	Utilities in the state contract with zero emission facilities to procure all of the zero emission credits produced in a year by the facility.	Utilities enter into contracts with zero carbon electric generation resources selected through a Department of Energy and Environmental Protection RFP.	Electric public utilities will purchase Zero Emission Certificates (ZECs) from certified nuclear plants in an amount equivalent to all of the output of the plant.
Vehicle for Passage	Regulatory	Legislative	Legislative	Legislative
Term of Program	12 years (6- two year tranches)	10 years	Between 3 and 10 years for Nuclear	Eligibility is for 3 years at a time
Eligibility Quantity	27,618,000 Mwhs; the total output of the 3 eligible plants from July 2015-June 2016.	20,118,672 Mwhs - 16% of 2014 electric utility sales	Total annual energy solicited <= 12M MWhs	Not to exceed 40% of total energy consumed in energy year 2017 (June 2017-May 2018), which is ~27,000,000 MWh/year
Annual Purchased Quantity from Eligible Resource	Capped at each facility's annual output from July 2015-June 2016	All of the production from an eligible facility	Contracted amount under the RFP	All of the production from an eligible facility
Price	$17.48/mwh for 1st period plus ~$2.3/period thereafter	$16.50/mwh for 6 years plus$1/year thereafter	Below forecasted market prices unless nuclear units qualify as "at risk", then they can bid above market	~$10/mwh for initial 3 years
Beginning Date	April 1, 2017	June 1, 2017	Contracts by Summer 2019	Contracts by Summer 2019
Explicit need requirement for eligibility	Yes	Considered in ranking of applicants	Yes – if nuclear wants to bid above market	Yes
# of Nuclear Plants Participating	3 – Ginna, Fitzpatrick and Nine Mile	2 – Quad Cities and Clinton	2 – Millstone and Seabrook (in NH, owned by Next Era and not an "at-risk" plant)	2 – Salem and Hope Creek

Source: Energy Innovation Reform Project “the cost of operational risks and market risks that would be avoided by ceasing operations”

-NJ ZEC Legislation

10% + Utility Specific Market Risk




Thank you!
Questions?