REVIVING THE RENAISSANCE:

AN ANALYSIS OF NUCLEAR POWER'S FUTURE

IN THE ELECTRIC POWER MARKET

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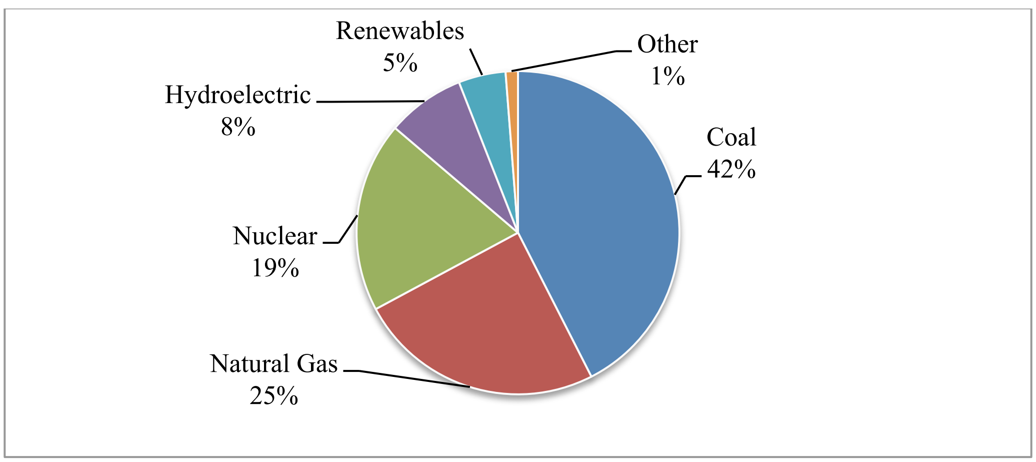
I. ABSTRACT

The purpose of this study is to find the regulatory and market conditions necessary for nuclear power to be economically viable. To this end, an adapted cost/benefit framework is used to test nuclear power's current feasibility. This framework, know as the levelized cost of energy, facilitates a comparison of nuclear power against two other base load power sources, coal and natural gas. Using the levelized cost of energy method, nuclear is found to be the most expensive of the three alternatives. A cost equivalency analysis is then performed to find the circumstances necessary for nuclear to achieve lower costs than the other base load power generating alternatives. The study concludes that a moderate carbon tax could lead nuclear power to be the lowest cost base load alternative.

II. INTRODUCTION

When shovels entered Louisiana soil in March of 1977, workers could have no idea that they were breaking ground on the last commercial nuclear plant to be built in the United States. The River Bend plant outside of Baton Rouge, Louisiana stands as a monument to thirty-four years of stalled expansion in US nuclear capacity. Today, one hundred and four nuclear reactors generate 19% of power produced in the country. In contrast, the largest production source, coal, represents close to 42% of generating capacity and runner-up natural gas claims 25%. Together, hydroelectric and other renewables make up 13% of generation.

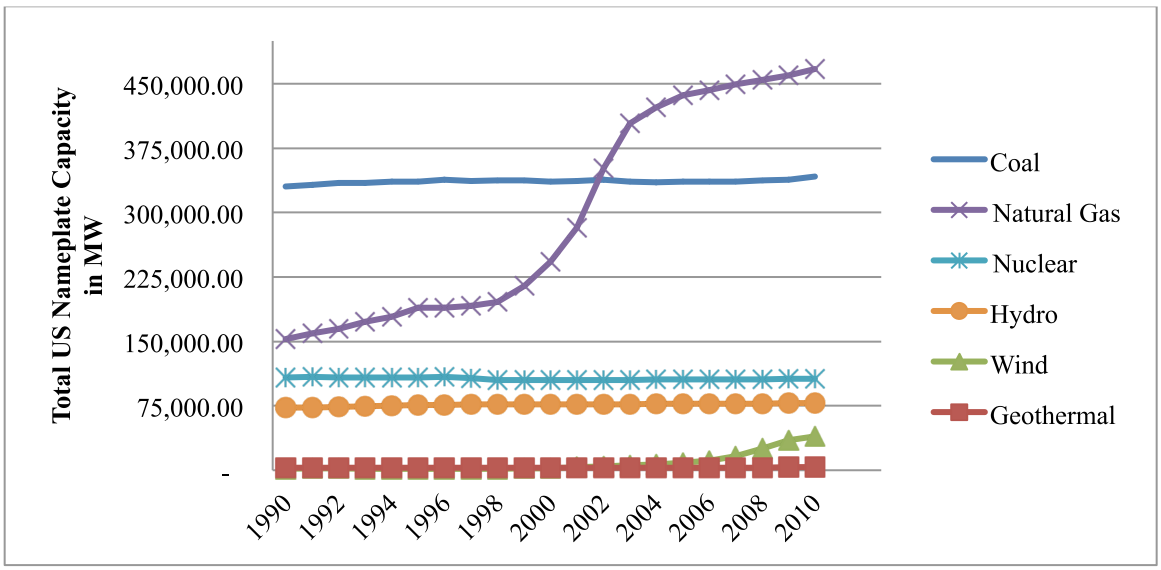
Figure 1: United States Energy Production



Data January-November 2011, Compiled from: (EIA, 2012)

Change to the country's production mix may be coming. Industry and political trends, such as deregulation and a push for lower emissions, have opened the way for new production sources to become cost effective or legally necessary. For example, many states require a certain amount of electricity in a provider's portfolio to come from renewable sources. These trends translate directly to an increase in renewables over the last several decades, particularly wind power. Additionally, state deregulation of electric utilities has broken apart many former vertically integrated monopolies (Roques et. all 2006). Competition in these reformed markets make larger, more capital-intensive generating facilities less attractive as utilities can no longer pass on costs of construction to rate payers. This has decreased the demand, by utilities, for capital-intensive coal and nuclear plants and created a shift toward smaller gas facilities. This transition can be seen in Figure 2 below, which depicts the total nameplate capacity of six major electric power sources in megawatts of electricity from 1990 to 2010. Nameplate Capacity is the capacity of the plant as quoted by the manufacturer. It is an estimate of a plants operation output under ideal circumstances.

Figure 2: United States Nameplate Capacity



Data source: EIA, 2010

Despite these trends, nuclear power is still economical under certain conditions. There are currently 21 proposed projects whose applications have been filed with the Nuclear Regulatory Commission (New Reactors, 2011). These filings had been part of what was being called the "Nuclear Renaissance," until the Japanese Fukushima nuclear disaster in the early part of 2011 raised new questions regarding the viability of nuclear as a power-generating source. Such questions create uncertainty regarding the economics of new nuclear power. For the "Nuclear Renaissance" to be revived, plants will need to prove that they can safely provide comparably low cost electricity under these new conditions.

Other power generating options have uncertainty working against them as well. For fossil fueled plants that emit pollutants, there exists a threat that their carbon emissions will be priced either through a market or per unit tax. Either case would dramatically escalate their cost of producing electricity. Wind power must prove that it can continue to increase efficiency and maintain competitiveness under evolving regulatory scenarios. Other remaining options, such as large scale solar, still must prove themselves more fully before they can provide a true alternative.

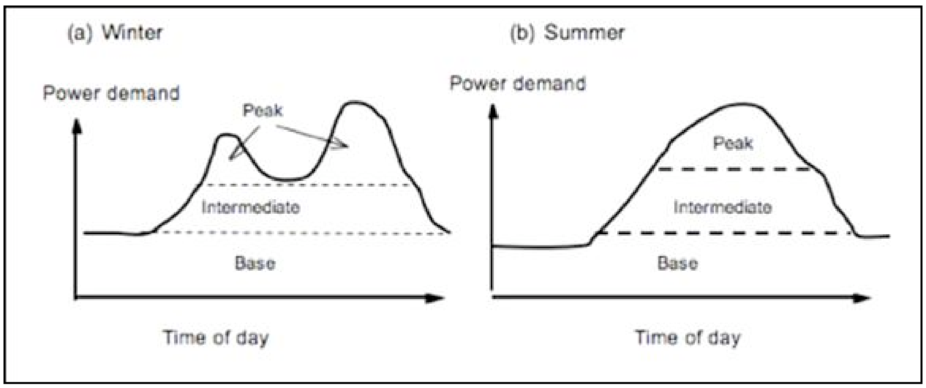
In order to successfully analyze nuclear power against alternative electricity generating options, there are two criteria that should be outlined. The first will define which alternatives should nuclear be directly compared against. The second will provide a framework for how comparisons will be made. To address both of these criteria, the following section provides necessary background information on electricity demand and a conventional method used for assessing the economic feasibility of power plants.

III. BACKGROUND

When making comparisons, it is important to keep in mind that certain sources of electricity are better suited for certain types of demand. Electricity demand depends on geographical considerations, time of day and season of the year. Electricity demand can be grouped into three categories: base load, intermediate, and peaking demand. Base load demand is the constant amount of energy that is usually required without regard to time of day (or time of year to an extent). Intermediate demand is the power that is required during high use times of the day, depending on the season, and peaking demand the power required at the highest use time of the day, depending on season. Below Figure 3 shows how demand changes through a day during the a) winter and b) summer seasons.

Figure 3: Power Demand by Time of Day

Daily Base Load Power Variations by Season



Source: Cordaro, 2008

Characteristics of different power plants make them more suited to fill different types of demand. The table below summarizes the characteristics of plants based on demand type and what generation sources have those characteristics.

Table 1: Plant Characteristics

Base Load	Intermediate	Peaking
• Large Size • High Fixed Cost • Low Marginal Cost • Most Efficient	• High Fixed Cost • Low Marginal Cost • Less Efficient	• Small Sized • Lower Fixed Cost • High Marginal Cost • Least Efficient
• Coal • Nuclear • Combined Cycle Gas	• Wind • PV Solar	• Single Cycle Gas • Oil

Comparisons of cost between base load, intermediate and peaking plants is difficult to make because of the different needs they meet. Because the focus of this paper is nuclear power, it will concentrate on plants that produce base load power when comparing costs.

The standard used as a conventional calculation to compare the economics of various generation options is known as the levelized cost of energy or LCOE. As shown in Equation 1, it is computed by dividing the present value of lifetime costs of the plant by the present value of net lifetime generation (measured in either kilowatt or megawatt hours).

Equation 1: Levelized Cost of Energy

$$LOCE = \frac{Net\ Present\ Value\ of\ Lifetime\ Costs}{Net\ Present\ \ Value\ of\ Generation}$$

This common measurement indicates the minimum amount that a utility company must charge per unit of electricity in order to "break even". Some of the limitations of the levelized cost of energy are discussed Section VIII.

IV. STUDY OVERVIEW

In the past, vertically integrated electric utilities had the benefit of cheap access to capital, as plant costs could be passed directly to ratepayers. This allowed utilities to have more freedom in choosing how demand would be met. However, due to the change in market environment, the "best" choice for how to meet demand is less clear, and the consequences for a poor choice are higher. What would it take to alleviate such market uncertainty? What potential combination of regulatory and market conditions would reduce uncertainty enough to make one choice clearly the best? This study will examine just that question as it pertains to nuclear power. What regulatory or market conditions would need to be in place to rehabilitate the “Nuclear Renaissance” and lead to the creation of a new nuclear reactor fleet.

Many studies have compared various electricity-generating sources and made assumptions that attempt to capture current and expected future circumstances. However, sometimes these methods fail to reflect in their results the large variability that exists in estimating figures with a large number of inputs that vary greatly themselves. Past studies usually include several result scenarios. These will include a “base case” that attempts to mirror current circumstances as well as one or more alternative scenarios. These types of analyses are called sensitivity analyses and are attempts at quantifying future uncertainty. Examples of alternative scenarios include hypothetical cases where a carbon tax or carbon market exists, cases where the price of fuel increases or decrease, or cases with different discount rates[1]. The values chosen for these alternative cases are often arbitrary. If a base case is estimated using a 15% discount rate, alternative cases might use values of 10% and 20% for seemingly no other reason than because they are nicely rounded. Sensitivity analyses are commonly used because their input values are easy to obtain and the results are easy to interpret. However, the fact that the values chosen to perform these analyses are more or less arbitrary is itself a confirmation about the uncertainty of the entire process.

What this paper proposes is an alternative approach to sensitivity analyses. Rather than simply inputting new assumptions or variables into these models to try and achieve a realistic result, this study will instead make assumptions intended to give nuclear a clear cost advantage, and then discuss the likelihood of those scenarios given present

[1] A discount rate is a measure of the cost of borrowing money. It is based on the principle that because of the ability to invest, money today is worth more than money tomorrow. Discount rates allow for the value of cash flows over time to be adjusted into their “present value”.

conditions and trends. Using this method, arbitrary inputs are traded for discussions of likelihood. While this may seem like a nuance difference, it should provide informative results, and answer the question posed here; at what point does nuclear power production become feasible? The calculations and results will be discussed in the Section VII titled, “NUCLEAR COST EQUIVALENCY ANALYSIS.”

V. LITERATURE REVIEW

Many reports and papers have been published over the last decade dealing with the economics of electricity generation. These studies come from sources including academia, government agencies, advocacy groups, and consulting firms. Using the levelized cost of energy method, these studies have estimated the comparative costs of generating alternatives. In 2003, a group of faculty at MIT released a study titled “The Future of Nuclear Power” that included a LCOE comparative analysis. For their comparison, MIT selected two other plant types in addition to nuclear. Advanced coal and combined cycle gas were chosen because of their projected role in the future of generating base load power. While hydroelectric and geothermal plants are also typically considered base load sources, their potential for future growth in the United States is limited because of the geographical restrictions that are inherent to their method of energy production. In other words, most of the best places to locate such plants are already in use.

Table 2 shows a summary of the results of several studies’ base case estimates.

Table 2: LOCE Estimates and % difference from Nuclear, $/MWh

	Advanced Coal	Combined Cycle Gas	Advanced Nuclear
Study Name			
Lazard Study ('09) [C]	$111/MWh	$88/MWh	$123/MWh
	-10%	-39%	0%
UK Electricity Generation Costs Update ('09)[A]	£104	£80	£99
	5%	-23%	0%
MIT Update '(09)	$62	$65	$84
	-35%	-29%	0%
California ('10)[A,B]	$178	$169	$342
	-92%	-102%	0%
Annual Energy Outlook ('11)	$109	$63	$114
	-4%	-81%	0%

A: These studies are regional in nature and reflect different underlining conditions than the conditions of the other three studies that cover the whole of the United States. Comparison made between these and national US studies should be considered with this in mind.
B: Estimates for plants built in 2018.
C: Average of cost range

Because of the varying input assumptions of each of these studies it is not necessarily meaningful to compare the point estimates across studies. The grey lines show the percent difference in cost between gas and coal against nuclear. These can be cautiously compared. Combined cycle gas has a clear cost advantage over nuclear in all studies, while coal's advantage is much more modest. The table also illustrates a more important point as well; there can be a wide variation in these studies' results. MIT and California both have comfortable margins between nuclear and coal, however the other studies have almost none. Also in the MIT study, gas is actually just slightly more expensive than coal, but this is the only study where this is the case.

As mentioned, the figures in the table represent estimates from each studies' base case scenario, with assumptions generally designed to most closely mirror current, real world conditions. Some assumptions however are designed to highlight the impact of other variables, rather than true present conditions. The MIT study, for example, states that certain variables must be equal across technologies for a comparison to be made. Specifically, two equal variables were plant life and capacity factor. However, these two variables (particularly capacity factor) seem indicative of the relative strengths and weaknesses of plant type and should be reflective of industry conditions. Other variables that the study held equal across technology that are less surprising: net capacity, debt term, and interest rates.

As seen from Table 2, the MIT study found that nuclear power was not favorable under their base case scenario. LCOE was very close between coal and gas, but nuclear was nearly $20/MW higher. In fact, even when nuclear capital costs are reduced by 25% (a bonus for learning and process streamlining) it is still more expensive than the base case coal and gas. Only when costs are reduced from the learning bonus and a moderate carbon tax is applied does nuclear become the cheapest generating alternative (MIT, 2003, p. 42).

The "Annual Energy Outlook" study, prepared by the US Energy Information Administration, details some important information on construction costs. The report makes this note about the importance of the timeliness in constructions cost data:

> "Current information is particularly important during a period when actual and estimated costs have been evolving rapidly, since the use of up-to-date cost estimates for some technologies in conjunction with estimates that are two, three, or even five years old for others can significantly skew the results of modeling and analysis." (Updated Cost, 2010)

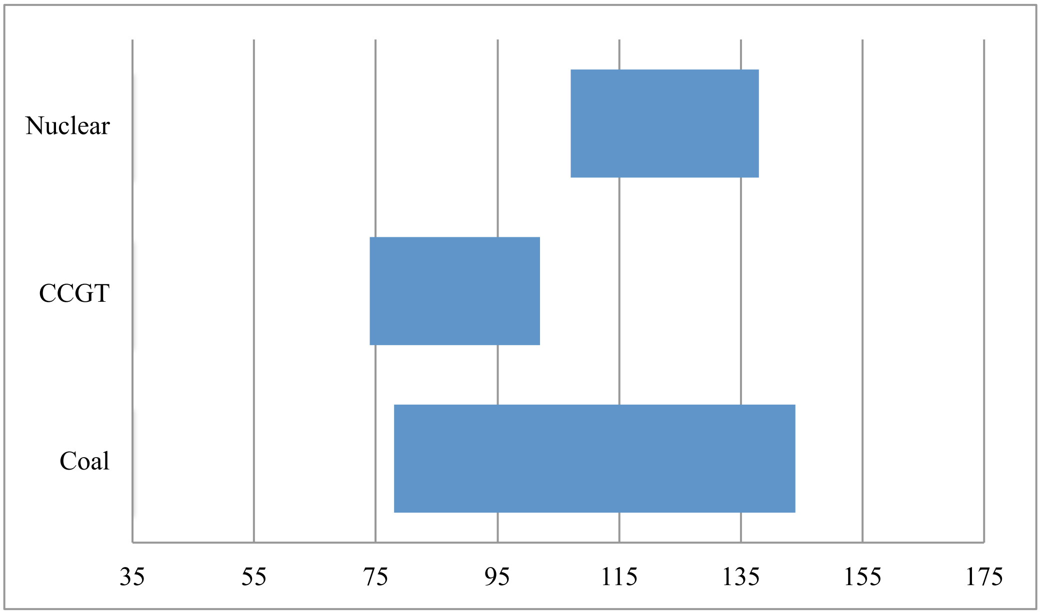
With this in mind, the more recent estimates in Table 2 should receive slightly more weight.

While no report finds that nuclear is the cheapest generating option, the 2009 study by Mott MacDonald, “UK Electricity Generation Costs Update,” found that nuclear was cheaper than coal, but more expensive than gas in the base case. In the UK, however fossil fuels are more expensive because of underlying market conditions and a moderate carbon tax of £14.10 a tonne (pg 57). In fact, in the absence of this tax, coal would be cheaper than nuclear. The study also projects that this tax will increase over the next 10 years, and by 2023 basic combined cycle gas and coal will be more expensive than nuclear by a factor of close to two (pg 69).

The estimates produced by the California Energy Commission in the study titled “Comparative Costs of California Central Station Electricity Generation” are based on assumptions true in California, but not necessarily true for the rest of the United States. The numbers quoted in Table 2 are based on base case estimates for the year 2018. They are high relative to the other studies due to high construction costs and state taxes as well as the impact of inflation. Accounting for these differences does not lead to any substantive change in the ranking order of the three generating options.

Lastly, the most recently available study by Lazard Ltd reports with a range of costs. The information presented in Table 2 is an average of the high and low estimates of these ranges. The spread of these ranges is a reflection of risk to owners when choosing to build a plant. Based on the Lazard studies estimates, nuclear and gas have similar risk, while coal is the riskiest by a factor of more than two.

Figure 4: Lazard Study Cost Comparison



An interesting note on the Lazard study is an assumed 20-year lifespan of power plants, a span that is much shorter than that assumed by other studies.

VI. ANALYIS

Using the levelized cost of energy method, a cost model was constructed to capture the lifetime costs and energy generation of an advanced coal plant, a combined cycle gas turbine, and an advanced nuclear plant.

A. REQUIREMENTS

In order to preform a meaningful comparison on the three identified base load electricity-generating options, the scope of the comparison must be tightly defined. This means that the same cost items should be used for each plant type. For example, if the cost of connecting a nuclear plant to the existing electrical grid is included in the analysis for the plant's cost, then transmission costs should be included for the other generating options as well.

Because the focus of this study is around the future feasibility of financing nuclear power, the costs included here will only be those that are internalized by the firm looking to build the plant. In other words, costs like those to taxpayers for subsidies and costs of pollution, will be ignored as long as those costs are not borne by the firm.

A second requirement of the model is that it should allow for the changing and addition of certain input assumptions. To be able to analyze the effects that political and financial forces could potentially have, the model must be able to incorporate these changes and evaluate them with the same criteria as the base case assumptions. Fortunately, the standard LCOE model lends itself well to such adjustments and past studies have incorporated such changes with ease.

B. MODEL OVERVIEW

As shown in Equation 1, the method of evaluating energy alternatives is found by dividing the net present value (NPV) of lifetime costs by the net present value of lifetime power generation.

Costs of electric power plants can be divided into four main categories: the cost involved in building and financing the plant (capital costs), the cost involved in running the plant (operation and maintenance costs), the costs of input needed to generate power (fuel costs), and finally the cost (in the case of nuclear) for decommissioning and spent fuel storage.

A plant's capital costs are based on its size and the financing rate it can secure. Typically, capital costs are quoted on a dollars per kilowatt basis with a figure known as overnight cost. Overnight cost is the total cost to build the plant expressed as if it was built overnight, with no inflation or financing effects. This overnight cost is then outlaid over the period of construction. While these costs could be outlaid evenly across the construction period, this study assumes that construction costs follow a sinusoidal curve, where costs escalate and then decline. This is similar to the method used in the MIT study to allocate costs across the construction period (Du & Parsons, 2009). Equation 2 shows the calculation of capital costs in dollars for a given year *n*.

Equation 2: Capital Costs

$$K_n = \frac{\left|\sin\left[\left(\frac{\pi}{t_c} \cdot n\right) + \frac{\pi}{TC} - 0.4\right]\right| \cdot O_c \cdot G \cdot 1000}{\sum_{n=0}^{TC} \left|\sin\left[\left(\frac{\pi}{t_c} \cdot n\right) + \frac{\pi}{t_c} - 0.4\right]\right|}$$

Here π represents the value of the number pi, t_c is the total construction time in years, O_c is the overnight cost in dollars per kilowatt, *G* is the gross capacity of the plant in megawatts and *n* is the year from the start of construction (beginning at the start of year 0).

Operation and maintenance costs are divided into fixed and variable components. Fixed O&M are costs that are separate from the actual output of the plant. These costs might include administrative and other costs. Fixed O&M is based on the gross capacity of the plant and is typically quoted on a dollars per kilowatt basis. The calculation for fixed O&M costs is expressed in Equation 3 Variable O&M are costs directly associated with output. Variable O&M is a function of actual output by the plant. Variable O&M costs are expressed in Equation 4

Equation 3: Fixed O&M Costs per kW per year

$$F_{OM} = f_{OM}(G \cdot 1000)$$

Equation 4: Variable O&M Costs per kW per year

$$V_{OM} = v_{OM} \cdot (G \cdot 1000) \cdot C_F \cdot 8766$$

Fixed O&M costs are found by multiplying fixed cost of O&M per kilowatt f_{OM}, by the gross capacity of the plant in megawatt hours G (with the unit adjustment). Variable costs are found similarly by multiplying the variable O&M cost per kilowatt by actual plant output: the plants gross capacity G multiplied by the capacity factor of the plant and the average number of hours the plant operates in a year (8766).

In order to generate power, all base load plants assessed here burn some type of fuel. Fuel prices are normally quoted in dollars per British Thermal Unit ($/BTU). Plants have a "heat rate" at which they convert BTUs of heat into kilowatts of electricity. These two factors combine to form the cost of fuel. Fuel prices also have been shown to escalate above the rate of inflation. This effect of escalating fuel prices will be reflected in the E_f term in Equation 7. Below, Equation 5 shows the cost per kilowatt of fuel.

Equation 5: Cost of Fuel per kW per year

$$f_C = \frac{BTU}{kWh} \cdot \frac{f}{BTU}$$

Where f_C is the fuel cost and BTU/kWh and f/BTU are constant terms denoting the heat rate and fuel costs respectively.

Lastly, nuclear plants must contend with costs associated with handling spent fuel during operation. Also, when the plant does shut down the site must be suitably and safely decommissioned. Nuclear spent fuel storage costs involve a plant's storage of spent fuel on site. This may be in pools or in dry cast storage. This cost will be integrated into the model simply by adding a $0.001 charge to the fuel costs found in Equation 5. This spent fuel fee is based on the value used by the Du and Parsons study to find spent fuel costs.

Decommissioning involves dismantling the reactor, removing the works buildings and ensuring that radioactive materials are properly disposed. Several different methods of handling decommissioning costs were experimented with to find one that minimized costs. Equation 6 shows this method involves incurring all decommissioning costs in the final year of plant operation, where D is the projected cost of decommissioning in dollars, N is the plant life (in years), $t_c$is the number of years the plant is under construction.

Equation 6: Nuclear Plant Decommissioning

$$\delta = D(0^{(N+t_c)-n})$$

The calculation for the net present value of lifetime costs is summarized in Equation 7.

Equation 7: Net Present Value of Lifetime Costs

$$NPV_{LC} = \sum_{n=t_c}^{N+t_c}\{(G \cdot 1000)\left[\left(f_C {E_f}^n + V_{OM}\right)(8766 \cdot C_F) + F_{OM}\right] + \delta\}(1+r)^{-n}(1+i)^n + \sum_{n=0}^{t_c-1}(K_n)(1+r)^{-n}(1+i)^n$$

N is the plant life (in years), $t_c$is the number of years the plant is under construction, G is the gross capacity of the plant in megawatts, f_C is the fuel cost per kilowatt hour, E_f is the rate of fuel cost escalation, V_{OM} is the variable operating cost per kilowatt hour, 8766 is the number hours in an average year, C_F is the capacity factor and F_{OM} is the fixed costs per kilowatt. δ is decommissioning cost and is 0 for non-nuclear plants. r is the weighted average costs of capital, n denotes the number of years after the beginning of plant construction and i is the rate of inflation.

The lifetime output of a power plant is chiefly a function of its nameplate capacity and its capacity factor. The lifetime output of a plant is summarized in Equation 8.

Equation 8: Net Present Value of Lifetime Plant Generation:

$$NPVL_G = \sum_{n=t_c}^{N+t_c} \{[8766 \cdot (G \cdot C_F \cdot 1000)] \cdot (1+i)^n \cdot (1+r)^{-n}\}$$

N is the plant life (in years), t_c is the number of years the plant is under construction, 8766 is the number hours in a year averaged over four years, G is the gross capacity of the plant in megawatts, C_F is the capacity factor, i is the rate of inflation, r is the weighted average costs of capital and n denotes the year, with year 0 being the first year of plant construction.

C. BASE CASE MODEL INPUT

The inputs chosen for the base case model are modified from those used in Du and Parson's Update of the Future of Nuclear Power Study (2009), and other sources where noted. Table 3 shows the value of inputs used in the base case model.

Table 3: Base Case Input Assumptions

	Coal ASC	CCGT	Nuclear
Inflation	3%	3%	3%
Interest	8%	8%	8%
Expected Return to Equity	12%	12%	15%
Debt Fraction	60%	60%	50%
Tax Rate	37%	37%	37%
Gross Capacity (MWe)	1,000	1,000	1,000
Capacity Factor	85%	85%	90%
Plant Life (years)	40	40	40
Overnight Cost (kW)	2600	900	4500
Construction Period (years)	4	2	5
Depreciation Schedule (years)	15	21	15
Heat rate (btu/kwh)	8,870	6,800	10,400

Table 3: Base Case Input Assumptions (Continued)

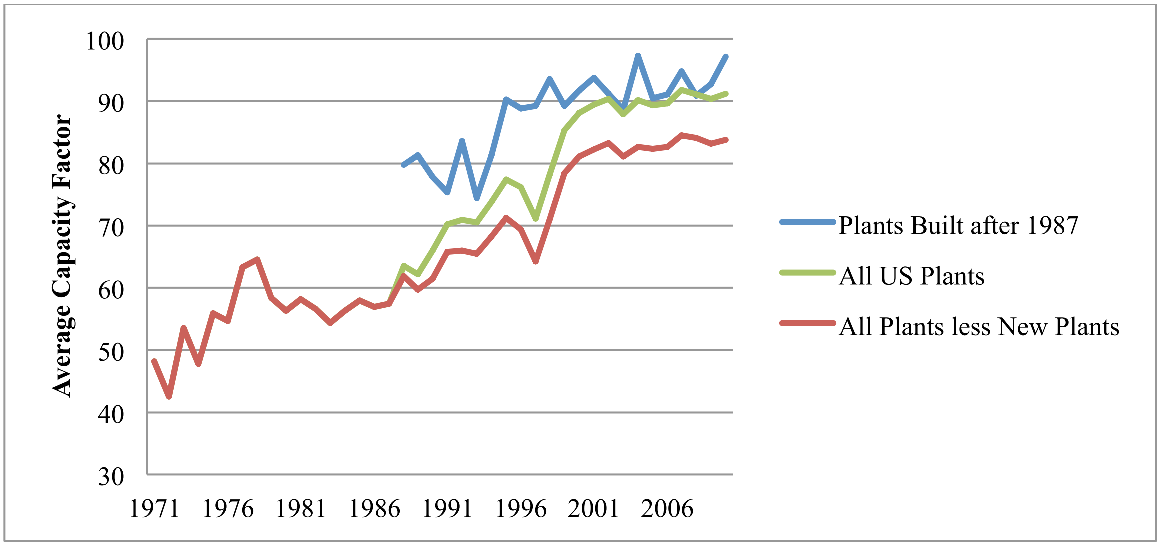
Fuel Cost (\$/MMBTU)	**2.6**	**7**	**0.67**
Fuel Cost (\$/kWh)	0.023	0.048	0.008
Real Fuel Escalation (%/year)	3%	3%	0.50%
Fixed O&M (\$/kW)	24.3	12.65	56.44
Variable O&M (\$/kWh)	3.38	0.52	0.47
Incremental Capital Costs \$/kW	30	10.8	45
Decommissioning Costs (million\$)			700
Insurance (\$/kW)	12	5	18

A 3% rate of inflation is consistent with many estimates for long run inflation. Rates for financing costs (interest and equity costs) are more difficult to approximate. We use an 8% rate for interest, 12% for equity financing coal and gas and 15% for nuclear. The higher equity rate for nuclear reflects the slightly higher risk perceived by investors for that type of plant.

Gross capacity here is assumed to be 1,000 megawatts. Changing this value has no effect on model output, as all costs (even fixed costs) are truly variable and based on the plants gross capacity.

Capacity factor represents a power plant's availability averaged over the course of a year. Du and Parsons use an assumed 85% capacity factor across the three technologies. However, Shrader-Frechette argues that this number is inaccurate and instead proposes that Capacity factor should be based on the mean historical performance of US plants, around 70% (2009). Shrader-Frechette fails to recognize, however, the trend in operational efficiency of nuclear reactors over their lifetime. Over the last four decades, operators of nuclear plants in the United States have increased the availability, and therefore the capacity factors, of their units. Are gains in efficiency found in the industry as a whole transferred to new reactors when they are built? Consider Figure 5 below. It shows that reactors built after 1987 came online at higher capacity factors and maintained better performance than older reactors in the US fleet. It also shows the portion of the higher average capacity factor seen in the US fleet is a result of these newer plants. This amount is seen in the difference between the "All US Plants" and "All Plants less New Plants" lines. Lifetime average capacity factor of these new plants is approximately 89%

Figure 5: Average US Capacity Factor, 1971-2010



Compiled data from IAEA PRIS Database and EIA Nuclear Reactor Operational Status, Table 1

This report will assume that historical trends will continue to hold and that new nuclear reactors will operate with a lifetime capacity factor of 90%. This number is consistent with estimates from the US Energy Information Administration (EIA, 2010a)

Many studies assume a 40-year operational lifespan for all plant types analyzed here. Currently, nuclear reactors are licensed by the Nuclear Regulatory Commission to operate for 40 years (New Reactors, 2011), but there is good reason to believe that nearly all nuclear reactors operating today will receive a 20-year license extension. A coal plant can operate for a similar timespan, 40 to 60 years. Picking a precise lifespan can be difficult though. Where nuclear plants have a regulatory framework that creates a specific timeline for their operational life, coal plant owners are solely responsible for deciding when a plant should be closed. Gas plants are even more difficult, because the majority of the construction of this plant type has occurred too recently to attain a proper sense of when they will shut down. For these reasons, the base case will assume a 40-year operational life for all plant types.

Overnight cost estimates can be difficult to calculate, particularly for nuclear plants, which have few observations to base calculations on. Because of the competitive environment in which all types of plants are being built, existing figures are not itemized (to protect trade secrets), and instead are reported in a single, inclusive number. This means that separating financing, transmission, initial fuel and other costs must be done by approximation. Du and Parsons use the projections of six recent proposals for nuclear as the basis for their number. Using a few assumptions, they found the overnight cost range of these plants range between \$3,500/kW and \$4,800/kW and conclude to use \$4,000/kW in the model. The Du and Parsons study uses a similar methodology for calculating the cost of coal and gas plants. They arrive at, what they consider to be, an underestimate for the overnight costs of these plant types, based on their judgment and reported figures by the EIA. EIA reported overnight costs in their 2011 Annual Energy Outlook for coal, gas and nuclear at close to \$2,630/kW, \$920/kW, and \$4,570/kW respectively (EIA, 2011a). Because these estimates are more recent, we will use them in the model.

Construction times are based on typical builds for coal and gas and the average time estimated by utilities with proposed nuclear plant builds.

Heat Rate is a measure of the plants efficiency at converting heat to energy. Du and Parsons offer revised estimates for coal and gas, updated from those found in the 2003 MIT study. The nuclear heat rate was not revised. These revisions are consistent with estimates used in the (EIA, 2011a)

Fuel costs in the Du and Parsons study escalate at a fixed rate of 0.5%/per year (above the rate of inflation). This escalation is less than the average long-run EIA forecasts (Figure 86, AEO 2011). We will use the EIA estimate of 3% real escalation for coal and gas, and .5% for nuclear.

D. BASE CASE RESULTS:

Table 4 shows the results of the base case analysis. We see that coal is the cheapest generating option, at 5.1¢/kWh. Gas comes in second at 6.4¢/kWh, and nuclear is the most expensive at 6.9¢/kWh. These results are consistent with those of the MIT study and the Du and Parson's update with regard to cost ranking.

Table 4: Base Case Results

Coal	**Gas**	**Nuclear**
5.1¢/kWh	6.4	6.9

These results imply that if short run costs were the sole consideration of a utility, coal plants would be built exclusively. While this is not the only consideration for utilities, it does explain the large role that coal plays in the supply of US electricity.

E. CARBON TAX CASE

The first alternative case compares costs when government places a price on carbon emissions. While fossil fuel plants can emit many forms of pollutants, this study will focus on the primary driver in global climate change, CO_2. There are many ways that this price could be implemented, but we will assume that government will enact one flat rate tax quoted in dollars per metric ton (tonne) of CO_2. Some simple conversion calculations are needed to translate this tax into the unit used in the model, \$/kWh.

Equation 9: Carbon Dioxide Costs

$$C_{CO2} = \frac{Tax}{tCO2} \cdot \frac{tCO2}{BTU} \cdot \frac{BTU}{kWh}$$

The first term represents the tax rate expressed in terms of \$/metric ton of CO2. The second is the number of metric tons of CO2 per BTU of energy produced, and the last term is the plant's heat rate expressed in BTUs per kilowatt-hour.

The first term's value can only be assumed, as there is presently no national US policy that taxes carbon emissions. However, two bills have been proposed to implement such a tax. Both propose an initial tax rate that escalates annually (one at a nominal rate, one at a 10% real rate). While Du and Parsons' study handles a carbon tax as a fee added onto levelized cost, this method does not allow for the effects of the tax to properly be seen as it escalates (Pew, 2008).

The value for emissions per BTU comes from the EIA's "Reporting of Green Gases Program." Unfortunately, this information is limited because companies voluntarily report it.[2] Reported emissions for coal were 95.52kg/MMBTU for coal and 53.06kg/MMBTU for gas.

F. CARBON TAX CASE RESULTS

Table 5 shows the results in the case of a carbon tax. It compares the costs from the base case to the two legislative tax cases mentioned above. The first is a tax of \$2.72

[2] A consideration regarding the volunteered information is that companies may only want to voluntarily report the emissions from their high preforming plants. This could bias emissions to heat ratios downward and lower the cost effects from taxes.

per tonne of CO_2 that escalates at a nominal rate of \$2.72 per tonne of CO_2 per year. The second case is a higher \$15 per tonne of CO_2 tax that escalates at a 10% real rate every year.

Table 5: Carbon Tax Case Results

	Coal	Gas	Nuclear
Base Case	5.1¢/kWh	6.4	6.9
\$2.72/tCO_2	7.1	6.5	6.9
\$15/tCO_2	11.7	7.1	6.9

As seen from Table 5, a price on carbon makes coal the most expensive option, even in the lower tax case. In the lower tax case, gas is cheapest option. In the higher tax case nuclear become the cheapest option.

G. ALTERNATIVE FINANCING CASE

Another scenario that could make nuclear plants more attractive is to reduce the cost of capital utilities face to finance them. Recall that we assumed a 15% required equity return for nuclear, compared to 12% for coal and gas, the difference being due to higher perceived investment risks. If nuclear could attain closer parity in its equity costs, it is likely that it would be a more competitive option, all else equal. A potential source for this reduction could come in the form of construction work in progress financing (CWIP). Typically, a regulated utility is not allowed to recoup a plant's costs (through increased consumer electric rates) until the new plant is operational. This means that returns owed to debt and equity investors will compound over the period of construction, leading customers to face higher long run electric rates. CWIP is a regulatory measure enacted by a state's legislature that allows a utility to increase rates incrementally from the beginning of the new reactor's construction. Several states have moved to pass CWIP legislation. Georgia, South Carolina and Florida have all approved measures to reduce the cost of reactors being built in their states. The estimated lifetime cost reduction for these reactors is well over a billion dollars. To be clear, this option is only available in states that are regulated and have a commission that sets the maximum allowable price for electricity.

Incorporating a construction work in progress scenario into the model will be accomplished by lowering the required return on equity from 15% to 12%. The justification for this change comes from the reduced risk investors face by being able to receive their returns earlier; the risk that a construction delay will defer returns is now minimized or eliminated.

H. ALTERNATIVE FINANCING CASE RESULTS

Table 6 shows the results in the alternative financing case. While nuclear is now slightly cheaper than gas, coal still has a comfortable cost advantage.

Table 6: Alternative Financing Case Results

Coal	**Gas**	**Nuclear**
5.1¢/kWh	6.4	6.0

VII. NUCLEAR COST EQUIVALENCY ANALYSIS:

As previously stated, the goal of this paper is to determine at what value of various inputs nuclear power is competitive. This will be accomplished using Equation 10. This equation solves for the value of levelized cost of energy where nuclear is α percent cheaper than coal.

Equation 10: Cost Equivalency

$$\left(1+\frac{\alpha}{100}\right)\mathrm{LCOE}_{\mathrm{Nuclear}} = \mathrm{LCOE}_{\mathrm{Coal}}$$

Here nuclear is benchmarked against coal because coal was found to be the lowest cost alternative in this study's base case. For nuclear to be the "best choice" then, its energy most be produced an even lower cost than coal's. Additionally, to eliminate ambiguity in choice, a cost advantage must be clear. The α term compensates for the uncertainty contained in the model to provide this clarity. This study will assume a value of 5 for α.

Using Equation 10, we can find the value of each input that provides nuclear a cost advantage. Initially, each input variable will be changed while holding all else equal. This will help to isolate that variable's effect on levelized costs, and allow for assumptions to be made about the likelihood of such a value being practically observed. Some input variables are not suited be changed, either because they have such a minimal impact on the results or they are less flexible by their nature. Table 7 lists the variables that were analyzed and the corresponding values found that bring nuclear into cost equivalency with coal.

Table 7: Input Values Needed for Nuclear Cost Equivalency

Input	Needed Value	Original Value
Plant Life	>100[a] years	40 years
Overnight Cost	$2610.08/kW	$4,500/kW
Capacity Factor	N/A	90%
Construction Period	N/A	5
Fuel Cost	N/A	$0.00697/kWh
Fixed O&M	N/A	$63/kW
Variable O&M	N/A	$0.47/kWh
CO2 Tax Rate[b]	$4.82[c]/tCO2	$0
Weighted Average Cost of Capital	6.414%	10.020%
Coal Fuel Price Escalation Rate	6.22%	3%

a: The model does not solve for plant life values over 100
b: In the base case
c: With assumed 10% real escalation rate.

As seen in Table 7, there is no realistic value for plant life that satisfies Equation 10, and so while it is likely that a nuclear plant will be online for 60 years, this alone should not materially change the mind of a utility when choosing a base load power source for increased demand.

Looking next to overnight cost, we see that a dramatic reduction of close to $1,900/kW is need, an almost 42% decrease. Even on its face such a reduction seems staggering. When one takes into account the upward trend in nuclear construction costs, this reduction seems even more difficult to imagine.

Like plant life, capacity factor had no realistic upward value that met the necessarily condition. The next four variables also had no material effect on their own, even when set to zero. However, implementing a carbon tax of $4.82/t$CO_2$ would bring nuclear's LOCE lower than coal's. This price for carbon dioxide falls in between the two prices proposed in recent congressional legislation.

Weighted average cost of capital would need to fall significantly to achieve the necessary cost savings on its own. There are an infinite number of combinations of interest and required equity rates that could achieve this, but all of them are lower than the assumed rates for coal and gas. Barring any extreme circumstances, it will be unlikely that rates for nuclear would fall to such low levels.

Finally, the last value in Table 7 shows that nuclear would achieve "best choice" status if the rate of fuel price escalation over the next 40 years were to exceed their EIA forecasted levels by a factor of about two. This would represent a fairly large deviation from the forecast and would represent again something unlikely to happen.

VIII. MODEL LIMITATIONS

The results in Table 7 could lead to a questioning of nuclear power as an economically feasible source of base load power. However, this conclusion is inconsistent with currently proposed nuclear reactor builds. Why would any rational utility choose to build a nuclear reactor over a coal plant? There are many considerations that could be driving their decision. Here are four factors that could explain firms' decisions to build new nuclear reactors.

1. Carbon Pricing Risk Aversion:

   The language surrounding a price on carbon emissions has become more favorable over time. This in turn leads to increasing risk for coal and gas plants. As time goes on this risk is likely to increase as carbon pollution builds and the perceived threat of climate change becomes more universal. This will lead utilities to move toward plants that emit less CO_2 and other pollutants (National Energy Technology Laboratory, 2010),(Jaskow & Parsons, 2009).

2. Positive Movements in Nuclear Power:

   Over the last two decades, nuclear power has made large gains in efficiency. Average capacity factors have risen, and operational costs have decreased. Nuclear fuel prices have remained stable through this period as well, and they certainly have shown less volatility than gas prices (Jaskow & Parsons, 2009).

3. Regional/Firm Level Cost Differences:

   This study's model looks to average plant costs across the United States, but regional effects can play a large role in determining the final cost of a plant. This type of effect is highlighted by the large differences between the estimates found in the California study in 2010 and the estimates found in the EIA study in 2011. Many factors create these differences. State level regulation, construction costs and labor costs, and electric grid capacity are just a few of the differences that locality can create. Firm level differences also matter. In addition to the project itself, the firm's financial position plays a large role in the interest and equity rates it can obtain. The firm may also have learning or logistic advantages it can leverage to reduce costs.

4. Change in Licensing Procedure:

   Seeing the success of regulatory processes in other countries like China and Korea, the Nuclear Regulatory Commission created a streamlined process for licensing applications in the United States. The new process creates more certainty that if plant construction is approved, the plant will be licensed to operate (Jaskow & Parsons, 2009).

5. Fixed Costs

   Regarding construction costs, while it appears to be the convention to calculate a plant's construction cost with a linear relationship to its generation capacity,[3] this does not allow for utilization of economies of scale. The model does find a difference in cost between a 1,000-megawatt plant and a 10,000-megawatt plant. In other words, it does not handle fixed costs well. Trying to incorporate a true fixed cost element to the model though would involve a high degree of approximation.

6. First-of-kind Premium

   The last issue surrounds learning and first-of-kind (FOK) premiums. For nuclear power there is a large cost and risk associated with lack of knowledge of how to build new reactor designs. Where a utility might build a coal or gas plant every few years, the costs estimates used in this study are based on those faced by utilities trying to build new nuclear reactors for the first time in more

[3] Recall the calculation for plant construction cost effectively being: Gross (nameplate) Capacity times overnight cost per unit of gross capacity.

than two decades. This means that estimates contain a large FOK premium. With these FOK premiums in mind, the US government in 2005 passed the Energy Policy Act. This bill provided loan guarantees to a limited number of first mover utilities looking to build new nuclear capacity, which will help to alleviate FOK premiums. Once learning has occurred, a more developed supply chain emerges and building processes have streamlined FOK premiums will disappear. It is unclear whether the savings effects of the 2005 Energy Policy Act are imbedded in the overnight or financing costs. If they are not, this is another limitation of that model that could be corrected.

IX. CONCLUSION

It should be noted what the implications of this study are and are not. This study does not necessarily predict utility behavior. Considering the results, one might expect coal plants to be built the most frequently because it was found to be the cheapest base load power generator, but the construction trends highlighted in Figure 2 do not support this idea. However, it does potentially explain why such a large portion of the US's electricity supply comes from coal. The model's potential unsuitability to make behavioral projections follow directly from the limitations noted in Section VIII. These limitations should be kept in mind when trying to ascertain the actions of utility companies.

An implication that does follow from the results is the effect of a carbon tax on nuclear power's economic viability. While the amount of tax found by this study, $4.82 per metric tonne, is contingent on the model that was used and input assumptions made, this should not invalidate the conclusion that the application of a carbon tax of some amount will lead nuclear power to be the lowest cost alterative.

In a market that has been evolving rapidly over the last two decades, it seems appropriate to reassess nuclear's role. While further innovation, regulation, demand growth and other forces will continue to drive change in the electric power industry, increased future demand must be prepared for today. Nuclear power will almost certainly play role in this future on a small scale. However, the nuclear industry is not doomed to a near term future where it diminishes. Under the right conditions the nuclear renaissance can be revived and a new fleet of reactors could be created.

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