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Highlights

- Coal accounts for about 81 percent of Utah's electricity, natural gas for approximately 15 percent, with most of the remaining 4 percent coming from hydroelectric or wind projects. Blue Castle Holdings, a Utah-based energy development business, is preparing license applications which, if approved, would pave the way for Utah's first commercial nuclear power plant.
- The economics of nuclear power, as compared with coal and natural gas, depends a great deal on "unknowns" such as the construction cost of new nuclear plants, future natural gas prices, and future charges, if any, on CO_2 emissions. This study evaluates the cost of nuclear-, coal- and gas-based electric power over a range of plausible values of those and other unknowns.
- We consider two sets of scenarios (Scenarios I and II) that define the power plant characteristics. The levelized cost of electricity (LCOE) is the basic measure used to assess the economics of each scenario. One scenario in each set is designated the "base case," the other scenarios resulting from particular variations of an unknown.
- Nuclear power is more expensive than either coal or natural gas based on recent construction cost estimates, baseline forecasts for future coal and natural gas prices, and current charges for CO_2 (zero). In the base case for Scenarios I, the LCOE for coal is $59/MWh, for natural gas is $62/MWh, and for nuclear is $89/MWh. In the base case for Scenarios II, the LCOE for coal is $61/MWh, for natural gas is $68/MWh, and for nuclear is $106/MWh. Lower than expected construction costs of new nuclear power plants, high natural gas prices, and a significant charge on CO_2 emissions all favor the economics of nuclear power.
- Nuclear power tends to carry financial risks polar to those of natural gas plants. Whereas construction cost is a prime risk factor for nuclear power, fuel cost is a prime risk factor for natural gas. This is for two reasons. First, construction costs are about 80 percent of the LCOE for nuclear while fuel costs are about 70 percent of the LCOE for natural gas. In the base cases for Scenarios I, for example, we find that a 50 percent increase in construction cost translates into a 36 percent increase in the LCOE for nuclear, but only 8 percent and 22 percent increases in the LCOE of natural gas and coal, respectively. Second, construction cost uncertainty is greater in the case of nuclear power, while fuel cost uncertainty is greater in the case of natural gas.

A Review of the Costs of Nuclear Power Generation

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Introduction

In late March 2012, South Carolina's Virgil C. Summer plant was awarded a combined Construction and Operating License (COL) by the U.S. Nuclear Regulatory Commission (NRC), one month after the Georgia-based Vogtle plant became the first new nuclear build so awarded by NRC since 1978—one year before the accident at Three Mile Island.

Currently there are 18 nuclear power projects with applications under review by NRC. The developers of other proposed nuclear power projects are still involved in the lengthy process of completing their applications. One project—the Blue Castle Project—still in this early stage is proposed by its developer, Blue Castle Holdings (BCH), to be located a few miles northwest of Green River, Utah.

This article summarizes a recent report published by BEBR on the costs of nuclear-powered electric generation as compared with its chief fossil fuel competitors, namely coal and natural gas.[1] The purpose of the study was to give some indication of the size of the financial gap, if any, between nuclear power and these alternatives, and particularly the range of that gap across plausible values for financial factors that seem especially subject to uncertainty or that figure prominently in a plant's financial performance.

We generally find nuclear power to be more expensive than either natural gas or coal. The details supporting this conclusion are to be found in the remainder of this article and in the full report.

One important thing to note is that Blue Castle's business plan does not necessarily include building and running the plant themselves, selling electricity in a competitive market as a merchant operator. Rather, they may acquire the necessary licenses from NRC—the licenses are transferrable—then sell those licenses to an entity who would construct and operate the plant.[2] Essentially, then, the product Blue Castle would offer to the buyer (of a granted COL) is the option to almost immediately begin construction, rather than first complete the lengthy and expensive licensing process on their own.

We do not model the value of such an option since we aim for a comparison of financial performance across several different power generation technologies and since options of some sort or other would arise in each, significantly adding to the complexity of the study.[3]

Completing the licensing process for a nuclear power plant is a very expensive and lengthy process: The Virgil C. Summer and Vogtle plants noted above both applied for the COL in March 2008. The Blue Castle Project is therefore still at an early stage, having not yet submitted a license application to the NRC. In fact, Blue Castle is in the late stages of preparing an application for an Early Site Permit (ESP). The application for an ESP covers site-specific issues, including geological and meteorological assessments, environmental impact assessments, and evacuation planning. Certain types of work can take place at the site on an NRC-issued Limited Work Authorization before receiving either the ESP or COL, but major work will have to wait on a granted COL.

The ESP, unlike the COL, is not tied to a particular design of nuclear reactor. The nuclear reactor assumed in this study is the Westinghouse AP1000, which is the design being installed at both the Virgil C. Summer and Vogtle sites. Each AP1000 reactor produces 1,100 MW of power. This analysis assumes that two AP1000 reactors would be installed at the site, for 2,200 MW of total power. Blue Castle may choose to go with a different reactor design, obviously, although at present only four designs are certified by NRC (other designs are seeking certification). Since numbers concerning electric power and electric work appear in subsequent sections of the article, next we briefly review those concepts in context.

Electric power in this report is stated in terms of watts. Since we are dealing with a large amount of power it is easier to report power in thousands of watts (kilowatts, or KW) or even millions of watts (megawatts, or MW). Thus the hypothetical plant at the Blue Castle site generates 2.2 billion watts of power. Power is a rate. Speaking a little loosely, electrical work over a given period of time is the sum of the electrical power generated over the same period. The flow of water from a faucet is analogous to power, whereas work is analogous to the amount of water than has accumulated in the tub into which this water is flowing.

Electrical work is measured in watt-hours. That is simply a name for the work that is done in one hour by a constant power of 1 watt. For example, a 60-watt light bulb requires 60 watts of power at every instant and over the course of one hour consumes 60 watt-hours of work (hereafter, simply "electricity"). The hypothetical plant at the Blue Castle site would produce 2,200 MW of power at each instant. Over the course of a year, then, the plant would produce about 17.3 million MW-hours (abbreviated MWh), assuming that on average the plant produced power at 90 percent of its rated capacity.

If 2,200 MW were installed at the Blue Castle site it would be the most powerful electric generating station in the state, ahead of the Intermountain Power Agency's 1,800 MW coal-fired plant in Delta, Utah. Presently, Utah has about 7,500 MW of electric generating power located in the state, so the addition of a site at Blue Castle would raise the statewide capacity by about 30 percent.

In 2010, about 42 million MWh of electricity were produced in the state. Total electricity sales in the state amounted to about 28 million MWh in 2010, 9 million of this to residential consumers. The average electricity consumption of a household in the Mountain West is about 1 MWh per month.[4] So another way to view the size of the proposed plant is that it would produce enough power for approximately 1.6 million households.

Lastly, since coal and natural gas figure prominently in this article, we note that coal provides about 81 percent of the electricity generated in Utah and natural gas provides about 15 percent. Most of the remaining 4 percent is from hydroelectric and wind power.

Summary of Findings

The results of the analysis suggest that new nuclear power would be more costly than that from either coal or natural gas, but that there are plausible scenarios under which nuclear power is less costly than either coal or natural gas. Particularly important issues bearing on the cost of nuclear power vis-a-vis coal and natural gas are the future prices of coal and natural gas, future regulations on carbon dioxide emissions, more stringent ambient air quality standards, and the cost of constructing (but not the cost of operating) new nuclear power plants.

Nuclear power also has a different risk profile than coal and natural gas. Because of the lack of recent experience in building nuclear power plants in the U.S. there is considerable uncertainty surrounding the cost of new nuclear construction that would be realized in practice. Since construction costs make up a large fraction of the total cost of nuclear power, construction cost uncertainty translates into an important financial risk facing new nuclear power plants. This may be contrasted with a standard natural gas power plant, where fuel costs (the price of natural gas), but not construction costs, are both subject to a great deal of uncertainty and represent a large part of total costs. Consequently, for natural gas a key risk is fuel cost risk. Coal is intermediate, having greater fuel price risk than nuclear, but less than natural gas; greater construction cost risk than natural gas, but less than nuclear. These statements apply to the standard varieties of coal and natural gas plants currently operating in the U.S. and newer but still relatively standard nuclear power technology.

This study requires specification of technical and financial characteristics of the power plants considered as well as broad economic conditions. Two sets of project-level characteristics are utilized; one drawn from a 2009 report by the Massachusetts Institute of Technology (MIT) and the other from a 2010 report published by the U.S. Energy Information Administration (EIA). Economic conditions, including future inflation rates and prices for coal and natural gas are based on EIA data. Scenarios are defined as combinations of power generation technology (with its associated technical and financial characteristics) and economic conditions. For example, in what we refer to as Base Case I for nuclear power, the power plant is assumed to have a nameplate capacity of 2,200 megawatts, a construction cost of about $4.3 million per megawatt, a lifetime of 40 years, to produce electricity at 90 percent of its nameplate capacity, etc. These assumptions associated with each scenario are the inputs of a discounted cash flow analysis.

Table 1
Scenarios I Base-Case Assumptions
(dollar amounts are in current 2011 dollars)

Parameter	Coal	Nuclear	Gas
Construction	2013	2013	2013
Operations	2017	2018	2015
Lifetime (years)	40	40	40
Nameplate (MW)	1,300	2,200	540
Capacity Factor	85%	90%	85%
Heat Rate (BTU/kWh)	8,870	10,400	6,800
EPC ($/kW)	$2,059	$3,579	$840
Owner's Costs ($/kW)	$412	$716	$168
Incremental ($/kW/year)	$29	$43	$12.35
Variable (mills/kW/year)	3.84	0.45	0.51
Fixed ($/kW/year)	$26.00	$61.00	$16.10
Fuel ($/MMBTU)	$1.92	$0.72	$5.00
Waste ($/MWh)	NA	$1	NA
Decommissioning ($/KW)	NA	$342	NA
Depreciation	20	15	15

Source: BEBR and MIT-2009.

Table 2
Scenarios II Base-Case Assumptions
(dollar amounts are in current 2011 dollars)

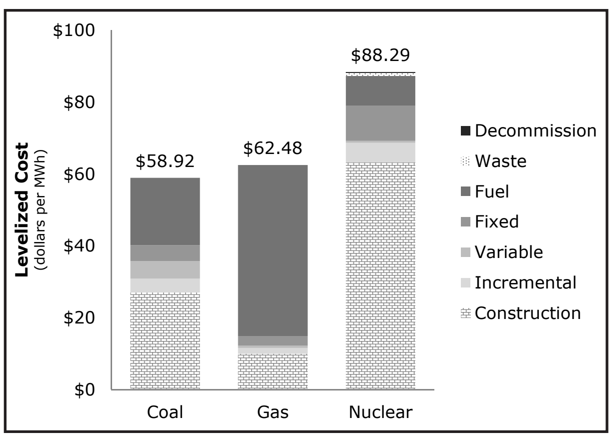
Parameter	Coal	IGCC	Nuclear	Gas	NGCC
Construction	2013	2013	2013	2013	2013
Operations	2017	2017	2018	2015	2015
Lifetime (years)	40	40	40	40	40
Nameplate (MW)	1,300	520	2,200	540	340
Capacity Factor	85%	85%	90%	85%	85%
Heat Rate (BTU/kWh)	8,800	10,700	10,400	7,050	7,526
EPC ($/kW)	$2,452	$4,539	$4,455	$953	$2,009
Owner's Costs ($/kW)	$441	$908	$981	$191	$402
Variable (mills/kW/year)	4.32	8.18	2.08	4.01	7.53
Fixed ($/kW/year)	$30.20	$70.50	$90.40	$16.85	$35.41
Fuel ($/MMBTU)	$1.92	$1.92	$0.72	$5.00	$5.00
Waste ($/MWh)	NA	NA	$1	NA	NA
Decommissioning ($/KW)	NA	NA	$432	NA	NA
Depreciation	20	20	15	15	15

Source: BEBR and EIA-2010.

The levelized cost of electricity (LCOE) is the basic measure used to assess the economics of each scenario. The LCOE is the minimum constant price a project must receive on each unit of electricity it generates in order to recoup exactly the cost of producing that unit, including a competitive return on investment. We determine the LCOE for each of the scenarios described in the Scenarios section. See Table 1 for Base Case I specifications and Table 2 for Base Case II specifications.

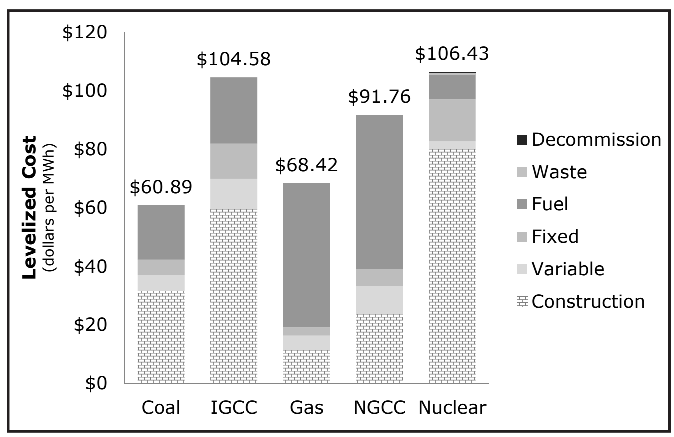
The LCOE for each plant considered in Base Cases I and II is shown in Figures 1 and 2, respectively, and the accompanying tables (Tables 3 and 4). These tables show the total LCOE for each technology and also the breakdown of this total into the various cost drivers. For Scenarios I it can be seen that the total cost per MWh of coal is about $59, for natural gas is about $62, and for nuclear is about $89. Scenarios II, which adds advanced technologies for coal (IGCC) and natural gas (NGCC), and uses

Figure 1
Levelized Costs in the Scenarios I Base Case



Source: BEBR.

Figure 2
Levelized Costs in the Scenarios II Base Case



Source: BEBR.

Table 3
Levelized Costs in the Scenarios I Base Case
(dollars per MWh)

Cost	Coal	Gas	Nuclear
Construction	27	9.95	63.24
Incremental	3.89	1.66	5.45
Variable	4.88	0.63	0.57
Fixed	4.4	2.69	9.7
Fuel	18.75	47.55	8.38
Waste	0	0	0.73
Emissions	0	0	0
Decommission	0	0	0.22
Total	58.92	62.48	88.29

Source: BEBR.

Table 4
Levelized Costs in the Scenarios II Base Case
(dollars per MWh)

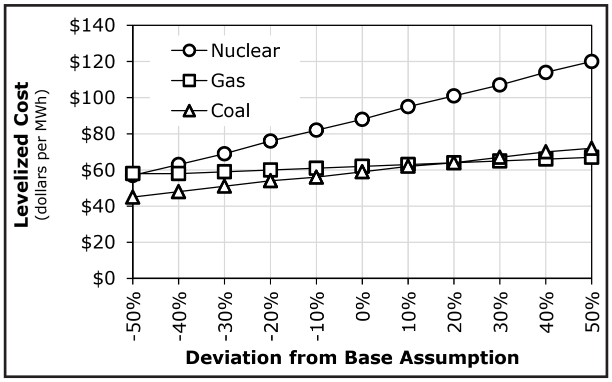
Cost	Coal	IGCC	Gas	NGCC	Nuclear
Construction	31.61	59.51	11.3	23.81	80.02
Variable	5.51	10.41	5	9.39	2.62
Fixed	5.16	12.04	2.82	5.93	14.4
Fuel	18.61	22.62	49.3	52.63	8.38
Waste	0	0	0	0	0.73
Decommission	0	0	0	0	0.28
Total	60.89	104.58	68.42	91.76	106.43

Source: BEBR.

slightly different technologies for "standard" coal and natural gas, shows $61 for coal, $105 for IGCC, $68 for natural gas, $92 for NGCC, and $106 for nuclear.

The breakdown of total costs gives an indication where each technology is financially most susceptible. In Scenarios II, for example, the cost of natural gas as a fuel is shown to make up over 70 percent of the total cost of natural gas-fired generation. It also shows that almost 80 percent of the total cost of nuclear is due to the upfront construction costs. Note that the breakdown includes the category "emissions." In the full report we show the breakdown of total costs in the even that generators are subject to a tax on carbon dioxide (CO_2) emissions. In this article we show only show the sensitivity of total LCOE to various charges per ton of CO_2 emissions.

Figure 3
Scenarios I: Sensitivity of Levelized Cost to Construction

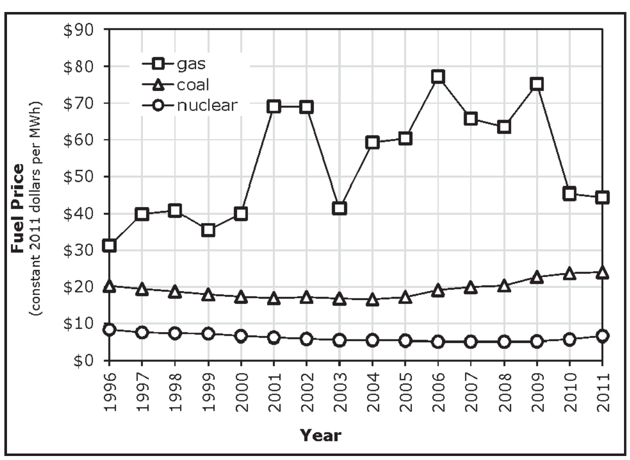


Source: BEBR.

Construction costs are expenditures associated with acquiring and preparing the site of the plant and the materials and construction of the plant itself. The share of construction costs in total costs (capital intensity) is an important distinguishing feature of power plant technologies, having implications for the financial risk profile of a power project.

Nuclear power plants are highly capital intensive. In addition, because of the lack of recent experience building nuclear power plants in the U.S., considerable uncertainty surrounds what construction costs would be in practice. These two facts combine to make construction costs a key risk factor for new nuclear power. With much lower capital intensity and considerable recent construction experience, construction cost uncertainty poses far less risk to natural gas plants. Again, coal plants are intermediate.

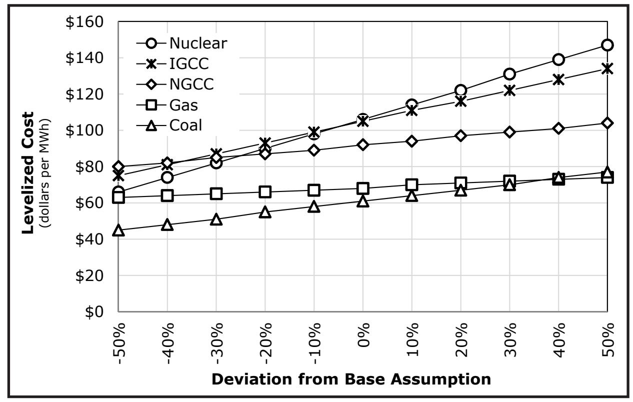
Figure 5
Historic Fuel Costs for Electric Power Generation



Source: Nuclear Energy Institute.

Regarding the sensitivity of LCOE to construction costs, in Base Case I we find that an increase of 50 percent in the cost of construction entails an increase of 36 percent in the overall cost of nuclear power, but increases of only 8 percent and 22 percent, respectively, for natural gas and coal-powered plants. Figures 3 and 4 show the overall sensitivity of LCOE to construction costs in Base Cases I and II.

Figure 4
Scenarios II: Sensitivity of Levelized Cost to Construction



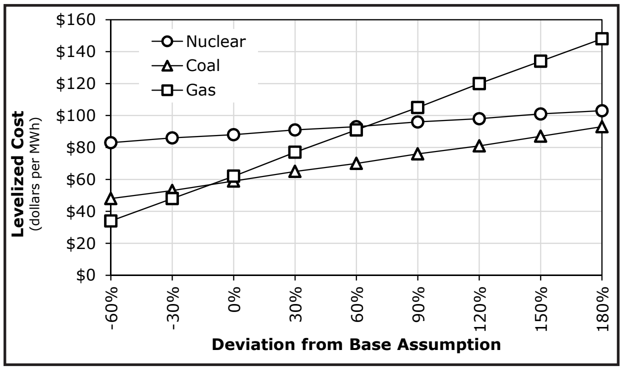
Source: BEBR.

A variety of periodic costs are incurred once construction is complete and a project enters its operations phase. These are classified as fuel costs, variable costs, fixed costs, and incremental capital costs. Fixed costs and incremental capital costs depend only on the plant's generation capacity, while fuel costs and variable costs depend only on the fraction of the plant's capacity that is utilized.

Compared to coal- and gas-based power, the cost of nuclear power is far less sensitive to the cost of fuel. For example, in Base Case I, a doubling of the cost of nuclear fuel leads to an approximately 10 percent increase in the total cost of nuclear power generation. Doubling the cost of coal and natural gas leads to increases of approximately 32 and 77 percent, respectively, in the cost of coal- and natural gas–based power generation. Natural gas prices have historically experienced more volatility than coal, leading to a greater sense of uncertainty about future natural gas prices than coal prices. Consequently, it would be fair to say that fuel price risk is greater for natural gas than for coal, and much greater for both than for nuclear. Figure 5 shows the recent history of fuel prices for coal, natural gas, and nuclear power plants. Figures 6 and 7 show the overall sensitivity of LCOE to fuel costs in Base Cases I and II.

Nuclear power plants are long-lived, having the potential to operate 60 or more years, 20–30 years beyond the typical lifetime

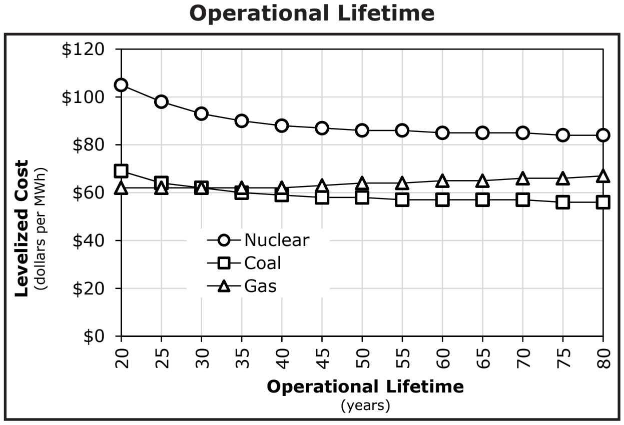
Figure 6
Scenarios I: Sensitivity of Levelized Cost to Fuel Cost



Source: BEBR.

of a coal or natural gas plant. From an LCOE point of view, this additional lifetime does not, however, translate into substantial savings on the cost of generating electricity from the plant: increasing the lifetime of a nuclear power plant from 40 years to 60 years reduces the LCOE by about 4 percent. This fact, which may be surprising, arises because the benefits of producing 20 additional years' worth occur 40 years into the future and so are rather small when discounted to present-value terms (see below). A general rule is that additional lifetime becomes less important

Figure 8
Scenarios I: Sensitivity of Levelized Cost to Operational Lifetime

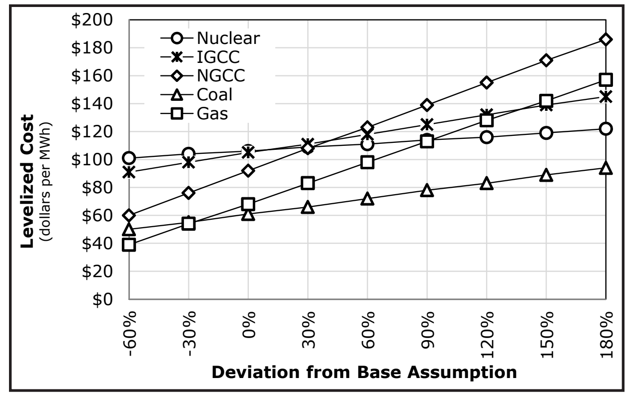


Source: BEBR.

for the economics of the plant the longer the plant's original lifetime, the higher the discount rate applied to its cash flows, and the lower its capital intensity. Figures 8 and 9 show the overall sensitivity of plant LCOE to the lifetime of the plants in Scenarios I and II.

Because of the high capital but low operational costs of nuclear power, it is important for a nuclear power plant to consistently operate near capacity (i.e. to attain high capacity utilization), especially in its early years of operation. If the capacity utilization of nuclear falls from 85 to 70 percent, LCOE increases by 20 percent. For natural gas and coal, such a reduction in capacity utilization increases LCOE by about 6 and 12 percent respectively. Again this reflects the intensity of fuel costs in the overall generation costs of these technologies. Capacity utilization at (mature) nuclear power plants has increased dramatically since the 1980s and currently sits at about 90 percent. Figures 10 and 11 show the overall sensitivity of plant LCOE to the capacity utilization of the plants in Scenarios I and II.

Figure 7
Scenarios II: Sensitivity of Levelized Cost to Fuel Cost

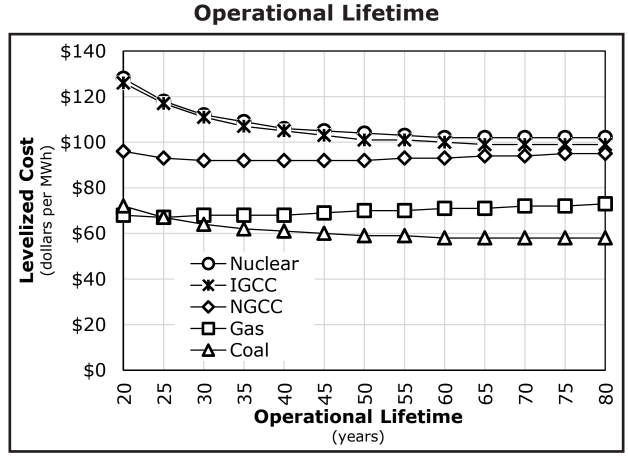


Source: BEBR.

The analysis accounts for federal, state, and local tax liabilities and interactions among them. We did not, however, carry out a sensitivity analysis of LCOE on tax rates, potential tax credits, or depreciation schedules. See the section on taxes, below, for details.

A high discount rate (opportunity cost of capital) disfavors power generation projects with high front-end costs. Nuclear projects are therefore more vulnerable to a higher cost of capital compared with coal and especially with natural gas. For example, we find that increasing the discount rate from 8 percent to 12 percent increases the levelized cost of nuclear power by 50 percent, the levelized cost of coal power by 30 percent, but the levelized cost

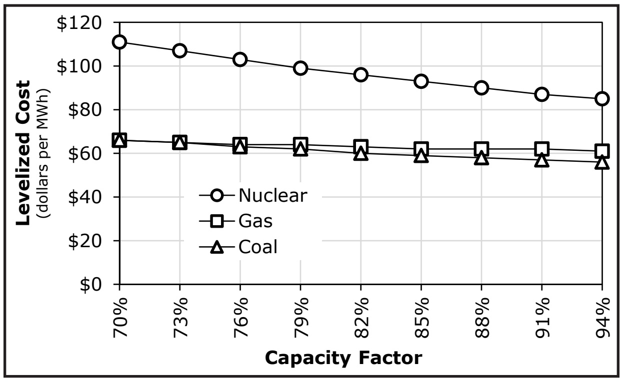
Figure 9
Scenarios II: Sensitivity of Levelized Cost to Operational Lifetime



Source: BEBR.

of natural gas power by only 10 percent. A high discount rate would also disfavor projects whose revenues are loaded more toward the end of the project's life; but with all scenarios considered here, the plants operate and generate revenue uniformly throughout their operational lifetime. Figures 12 and 13

Figure 10
Scenarios I: Sensitivity of Levelized Cost to Capacity Factor

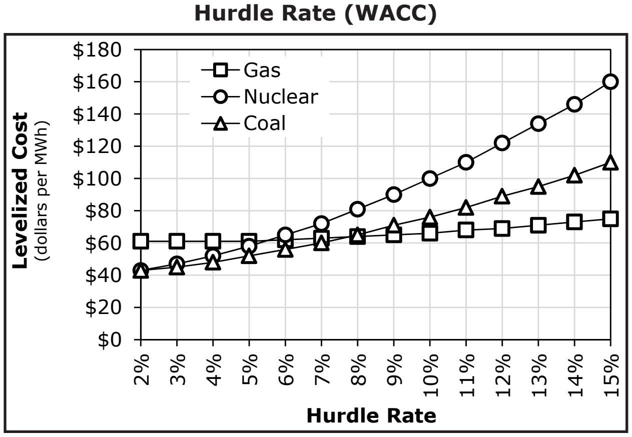


Source: BEBR.

show the overall sensitivity of plant LCOE to the discount rate applied to the cash flows of the plants in Scenarios I and II.

Any future public policies implying restrictions or financial penalties on carbon dioxide emissions favor the economics of nuclear power by disfavoring natural gas and especially coal. The cost of nuclear power is completely insensitive to CO_2 charges, as CO_2 is not a byproduct of nuclear power generation. Both coal and natural gas are vulnerable to future carbon dioxide constraints. Due to the carbon intensity of coal as a fuel compared with natural gas, standard coal plants are especially at such risk. In our base cases, a $30/ton charge on carbon dioxide emissions increases the LCOE from coal by 46 percent and from gas by 20 percent. See Figures 14 and 15 for the overall sensitivity of LCOE to charges on CO_2 emissions.

Figure 12
Scenarios I: Sensitivity of Levelized Cost to the Hurdle Rate (WACC)

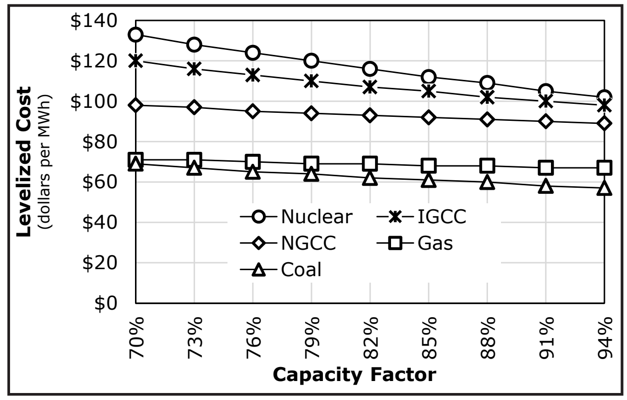


Source: BEBR.

Table 5 gives the cost of natural gas power for various combinations of natural gas prices and CO_2 charges. Gas prices range between $2 and $20 per MMBTU, and CO_2 charges range from $0 to $100 per ton. For example, if over the lifetime of the project CO_2 prices were $50/ton and natural gas prices were $8/MMBTU, then the levelized cost of electricity from such a project would be $101/MWh.

Table 6 gives the cost of coal-based power for various combinations of coal prices and CO_2 charges. Coal prices range between $1 and $7 per MMBTU, and CO_2 ranges from $0 to $100 per ton. For example, if over the lifetime of the project CO_2 prices were $50/ton and coal prices were $2/MMBTU, then the levelized cost of electricity from such a project would be $105/MWh.

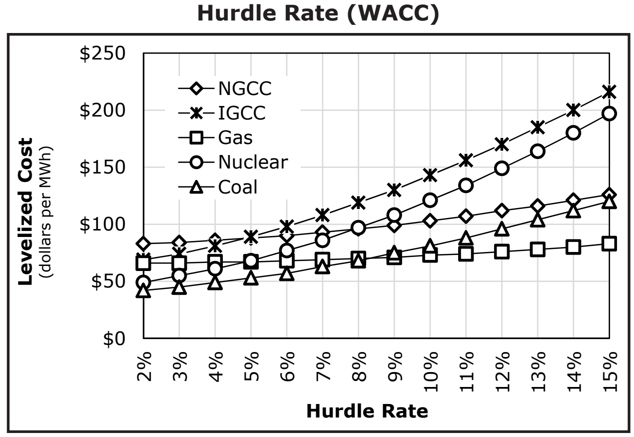
Figure 11
Scenarios II: Sensitivity of Levelized Cost to Capacity Factor



Source: BEBR.

In the absence of charges for CO_2, coal prices need to exceed an inflation-adjusted $5.00 per MMBTU before coal becomes a more expensive option than nuclear power. With a $25/ton charge on CO_2, however, coal becomes the more expensive option once coal prices exceed about $2 per MMBTU (approximately the current price of coal). An important point to note here is that the cost of coal increases more rapidly with increasing CO_2 charges than does natural gas power, owing to the lower CO_2 emissions of natural gas plants on a per-unit-of-electricity-generated basis. At $50 per ton of CO_2, coal-based power is more expensive than nuclear for any reasonable price of coal.

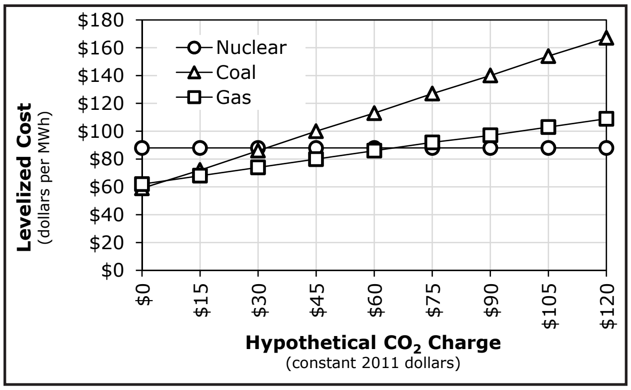
Figure 13
Scenarios II: Sensitivity of Levelized Cost to the Hurdle Rate (WACC)



Source: BEBR.

To calculate an estimate of the overall cost of electricity generated from a given technology, certain technical and financial

Figure 14
Scenarios I: Sensitivity of Levelized Cost to Cost of CO_2 Emissions



Source: BEBR.

characteristics of that technology need to be specified, as do the broader economic conditions to which the operation would be subject. Economic conditions, including future inflation rates and prices for coal and natural gas are based on EIA data.

Scenarios

To calculate an estimate of the overall cost of electricity generated from a given technology, certain technical and financial characteristics of that technology need to be specified, as do the broader economic conditions to which the operation would be subject. Economic conditions, including future inflation rates and prices for coal and natural gas are based on EIA data. Details on the way these specifications figure into the estimation of levelized costs are given in the section Levelized Costs, below.

Table 5
Levelized Costs ($/MWh) of Gas-Fired Generation for Given Gas and CO_2 Prices

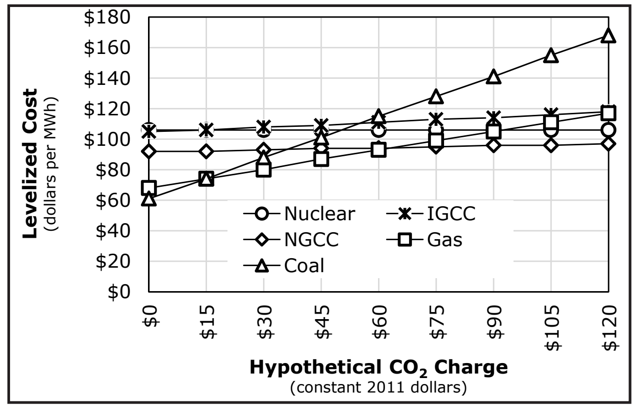
	Gas Price								
CO_2 Price	**$2**	**$4**	**$6**	**$7**	**$8**	**$10**	**$12**	**$16**	**$20**
$0	24	43	62	72	81	91	110	148	186
$25	34	53	72	82	91	101	120	158	196
$50	44	63	82	91	101	110	129	167	205
$100	63	82	101	111	120	130	149	187	225

Source: BEBR.

This study considers two sets of specifications, referred to as Specifications I and Specifications II. Specifications I is drawn from a 2009 report by the Massachusetts Institute of Technology (MIT) and are standard technologies for coal, natural gas, and nuclear power plants. A 2003 MIT report (MIT 2003) discusses the technical details of these technologies. Specifications II is based on a 2010 report published by the U.S. Energy Information Administration (EIA). Along with standard coal and natural gas technologies similar to those in Specifications I, Specifications II includes two technologies with carbon-capture capability: one a standard natural gas combined cycle and the other an integrated gasification combined cycle (IGCC) coal plant.

Although Specifications I draws significantly from the 2009 update (MIT 2009) to the 2003 study *The Future of Nuclear Power: An Interdisciplinary Study* (MIT 2003), because the goal is to estimate costs for plants located in Utah, we make several modifications to the specifications given in MIT 2009. First, dollar amounts are adjusted for inflation. For example, in the case of a nuclear power plant, MIT 2009 gives $4,000 per KWh for construction cost (the sum of EPC and owner's costs) in year 2007 dollars. Expressed in year 2011 dollars this becomes $4,295 per KWh. Second, construction, incremental capital costs, and both variable and fixed costs were inflated by 15 percent for the natural gas power plant as an adjustment for lost efficiency due to elevations typical for locations in Utah. The adjustment factor (15 percent) is drawn from PacifiCorp 2011. Applying the elevation adjustment factor, the construction cost for the natural gas plant given in MIT 2009—$850 per KWh—becomes $1,008 per KWh in 2011 dollars.

Figure 15
Scenarios II: Sensitivity of Levelized Cost to Cost of CO_2 Emissions



Source: BEBR.

The IGCC plant and all the natural gas plants considered in this report use a "combined cycle" technology. This means that the gas is burned in a gas turbine, then the heat in the exhaust stream is used to produce steam to power a steam turbine. The use of what would otherwise be waste heat gives combined cycle plants high thermal efficiency. A beneficial side effect of high thermal efficiency is that less fuel needs to be burned.

Table 6
Levelized Costs ($/MWh) of Coal-Fired Generation for Given Coal and CO_2 Prices

	Coal Price						
CO_2 Price	**$1**	**$2**	**$3**	**$4**	**$5**	**$6**	**$7**
$0	50	60	69	84	89	99	108
$25	73	82	92	107	112	121	131
$50	95	105	115	129	134	144	154
$100	140	150	160	174	179	189	199

Source: BEBR.

Upstream of the "gasification" part, IGCC plants are similar in concept to combined cycle natural gas plants. But up to and including gasification, they are quite apart from both natural gas plants and traditional coal plants. Whereas traditional coal-fired plants burn coal directly and remove unwanted byproducts after complete combustion has taken place, IGCC plants generate electricity through burning a coal-derived gas (referred to as a synthesis gas, or "syngas") after the byproduct-precursors are removed. The gas is produced by placing coal in a pressurized vessel (the "gasifier") with steam, but without enough oxygen for complete combustion to take place. Under these conditions, the molecules in the coal break apart and undergo a series of chemical reactions to form hydrogen, carbon monoxide, and other gaseous compounds. With IGCC, unwanted elements such as sulfur, mercury, and particulate matter are then removed from the syngas and the carbon monoxide (a criteria pollutant) is converted to carbon dioxide. Since the gas is still under pressure, pre-combustion cleaning with IGCC is more efficient than the post-combustion cleaning of traditional plants. This ability to capture CO_2 efficiently is one of the main benefits of IGCC.

The cost estimates for the plants with carbon-capture capability include only the "capture" part of carbon capture and sequestration. Much still needs to be resolved on the "sequestration" side, including the issue of who owns the liability of the CO_2 once it's sequestered. It is important to bear this in mind when comparing the estimates of the LCOE for IGCC and natural gas combined cycle with carbon capture with that of the inherently CO_2-free nuclear power.

This report defines a scenario as a particular combination of power-generation technology, project-specific costs such as construction costs, and broader costs such as fuel or the hurdle rate.

Below is a listing and brief description of the defining characteristics of the power plants analyzed in this report; Tables 1 and 2, above, indicate the values those characteristics have under the two base case scenarios.

Construction The year construction on the power plant begins.

Operations The year operation of the completed power plant begins (first commercial production of electricity). The time required to construct the plant is the difference between the year of initial operation and the year of initial construction.

Lifetime The number of years the plant is assumed to be in commercial operation.

Nameplate The capacity for the plant to produce electricity, measured in megawatts (MW).

Capacity Factor A percent which indicates the utilized fraction of the plant's maximum capacity to produce electricity.

Heat Rate The amount of energy (measured in BTUs) in the fuel utilized by a power plant needed to produce one unit of electricity (measured in kilowatt-hours [KWh]).

EPC Engineering, procurement, and construction costs. These are the costs associated with the purchase and installation of the plant's power system.

Owner's Cost Expenses ancillary to the power system including, for example, the cost of acquiring and preparing a site for the power plant.

Incremental Annual capital expenditures subsequent to the initial expenditure.

Variable Non-fuel costs that vary with the amount of electricity generated.

Fixed Costs that do not vary with the amount of electricity generated.

Fuel Cost of fuel per million BTU (MMBTU) as of the initial year of operations.

Waste A fee imposed by the federal government on each unit of electricity generated by a nuclear power plant. Such fees are intended to fund an eventual federal solution to the problem of long-term nuclear waste.

Decommissioning Costs associated with decommissioning the nuclear power plant at the end of its operational life. Operators contribute into a sinking fund to finance this end-of-life cost.

Depreciation Capital costs are generally subject to IRS depreciation rules. For coal plants, depreciation takes place over a 20-year period while for natural gas and nuclear it takes place over a 15-year period.

Levelized Costs

The levelized cost of electricity (LCOE) is the price that must be charged on each unit of electricity sold from a power plant in order to recoup exactly the cost of producing it, including a competitive return on investment. In order to compute a project's LCOE its cash flows have to be estimated.

A cash flow is the difference between a project's revenues and costs during a certain interval of time. In this report, cash flows are based on 1-year intervals, with *t* referring to the end of year . In other words, the cash flow for year *t*, denoted CF_t, is the sum of the differences between revenues R_t and costs C_t incurred between the end of the previous year *t–1* and the end of year *t*. Revenues and costs over the life of the power plant are estimated using the technical and financial specifications discussed above. Such cash flows are then discounted by an estimate of the opportunity cost of capital for the project (see The Discount Rate, below). The sum of the discounted cash flows is the net present value (NPV) of the project. If *d* is the discount factor,

$$NPV = d \times CF_1 + d^2 \times CF_2 + d^3 \times CF_3 + ... + d^t \times CF_t$$

where it is understood that both revenues and costs depend on the price of electricity *P*. Revenue depends on *P* in that revenue equals the product of price and electricity sales. Cost depends on price too because taxes are included among the costs and the project's tax bill depends on its revenue.

In this formulation, all costs are known, as is the amount of electricity sold during each period of the power plant's life. If an amount received for each unit of electricity sold is specified, then the NPV of the project can be computed. The standard rule is that if the NPV is positive then, because the project's opportunity cost of capital is accounted for, this project is worthwhile as an investment. On the other hand, if the NPV is negative, then the funds that would have been invested can be better invested elsewhere.

Consider a price *P* received on each unit of electricity sold such that the NPV for the project is positive. It follows that there is some lesser price P^* for which NPV is still positive. In other words, the project is viable if P is the going price but will also be viable if the going price is merely P^*. But then what's true of P is true of P^*: there is a price P^{**}, less than P^*, at which the project would still be viable; that is, the NPV is still positive when the price of electricity is P^{**}. The LCOE is the answer to the question: What is the lower bound on the price of electricity that ensures viability? The LCOE is therefore the price of electricity that results in an NPV of exactly zero.

For the projects analyzed in this report, all revenue is derived from sales of electricity. Further, the sales occur uniformly over the operating lifetime of each plant. Almost all the costs of a power plant occur in one of two stages: a construction period and an operations period.[5] Some power technologies (e.g. natural gas power plants) incur much of their total cost during the operations phase (e.g., as purchases of natural gas). Other technologies (e.g. nuclear power plants) incur much of their cost during construction. Costs, unlike revenues, can be quite lumpy for some of the projects of this study. Tables 7 and 8 detail the levelized costs used in this study.

Table 7
Levelized Costs in the Scenarios I Base Case
(dollars per MWh)

Cost	Coal	Gas	Nuclear
Construction	$27.00	$9.95	$63.24
Incremental	$3.89	$1.66	$5.45
Variable	$4.88	$0.63	$0.57
Fixed	$4.40	$2.69	$9.70
Fuel	$18.75	$47.55	$8.38
Waste	$0.00	$0.00	$0.73
Emissions	$0.00	$0.00	$0.00
Decommission	$0.00	$0.00	$0.22
Total	$58.92	$62.48	$88.29

Source: BEBR.

Table 8
Levelized Costs in the Scenarios II Base Case
(dollars per MWh)

Cost	Coal	IGCC	Gas	NGCC	Nuclear
Construction	$31.61	$59.51	$11.30	$23.81	$80.02
Variable	$5.51	$10.41	$5.00	$9.39	$2.62
Fixed	$5.16	$12.04	$2.82	$5.93	$14.40
Fuel	$18.61	$22.62	$49.30	$52.63	$8.38
Waste	$0.00	$0.00	$0.00	$0.00	$0.73
Decommission	$0.00	$0.00	$0.00	$0.00	$0.28
Total	$60.89	$104.58	$68.42	$91.76	$106.43

Source: BEBR.

Subsequent sections discuss further details on the components of the cash flows described above. However, before discussing such details it will be useful to briefly review the findings of past work.

Three studies carried out since 2000 are particularly relevant to the present one. Two of these were carried out by MIT (MIT 2003 and MIT 2009) and the other by the University of Chicago (University of Chicago 2004). The methods employed by these studies are similar to each other and to those of the present study. Table 9 lists the basic findings of the three studies.

Table 9
Estimated Costs per MWh of Electricity Generated

Study	Coal	Natural Gas	Nuclear
MIT Nuclear 2003	$42	$38–$56	$42–$67
Chicago 2004	$33–$41	$35–$45	$47–$71
MIT Nuclear 2009	$62	$65	$84

It is important to bear in mind that the estimates shown in Table 9 reflect different sets of assumptions regarding such things as construction costs, fuel costs, and the developer's discount rate. In addition, the estimates are quoted in different years' dollars. The estimates reported by the University of Chicago study are given in year 2004 dollars, while those of the MIT studies are given in year 2002 and year 2007 dollars, respectively.

The 2003 study by MIT (MIT 2003) estimates that the levelized cost of coal-based generation is $42/MWh, compared with $38/MWh to $56/MWh for natural gas, and $42/MWh to $67/MWh for nuclear. The range of estimates given for gas-based power reflects different assumptions concerning the price of natural gas. For nuclear, the range reflects different assumptions regarding construction costs, operations and maintenance costs, and the developer's discount rate (hurdle rate). Thus, in the scenarios considered by MIT 2003, natural gas comes out between slightly less expensive than coal and the best-case nuclear scenario and a point about equal with base-case nuclear.

A 2004 study carried out by the University of Chicago (University of Chicago 2004) also finds coal and natural gas-based power less expensive than nuclear. The levelized cost of coal is given as a range between $33/MWh and $41/MWh, compared with $35/MWh to $45/MWh for natural gas and between $47/MWh and $71/MWh for nuclear. The worst-case cost of nuclear is approximately twice the cost of best-case natural gas or coal. On the other hand, best-case nuclear is slightly more expensive than either worst-case natural gas or coal.

The most recent of these studies is a 2009 study by MIT (MIT 2009)—an update of the 2003 study—which gives estimated levelized costs of $62/MWh for coal, $65/MWh for gas, and $84/MWh for nuclear.

Construction Costs

Not only is nuclear power more sensitive to proportional changes in construction cost, but because of the dearth of recent nuclear plant construction experience in the U.S. point-estimates of nuclear power construction costs are subject to considerably more uncertainty than those of coal- and gas-fired plants. The lack of recent construction experience also implies that costs may decline significantly as new nuclear power units are built ("learning by doing"). This reasoning also applies to advanced fossil fuel and renewable energy competitors to nuclear power.

The construction cost of a power plant is based in part on the "overnight cost" of construction. This is the cost of construction if such could be done overnight. The concept is useful because it gives a measure of construction expenditures that is exclusive of the costs of financing those expenditures. The overnight cost itself is the sum of engineering-procurement-construction (EPC) cost and the owner's cost. The EPC cost is that associated with the basic equipment and construction labor for the plant's power system, while owner's costs include ancillary expenditures (e.g. cooling facilities, onsite buildings and land).

Owner's costs are often estimated as a fraction of EPC costs. The fraction usually runs between 10 and 20 percent, with 20 percent being more typical. An important factor in the size of owner's costs is the extent of prior development of the proposed plant site. Power units added to the site of a pre-existing project (a "brownfield" site) are able to forego some of the costs that would be necessary to develop a new site (a "greenfield" site).

The most significant difference between the 2003 and 2009 studies is the estimated construction cost for nuclear power. In particular, the estimated overnight construction cost for nuclear power increased from $2,000 per KW reported in the 2003 study to $4,000 in the 2009 study. Why the large increase? The study reports an estimated 15 percent annual increase in the cost of new construction over the five-year period 2002 to 2007—the years on which the 2003 and 2009 studies are based. The estimate of 15 percent is based on a combination of actual builds overseas and proposed builds in the U.S.

Other recent sources seem to lend support to the $4,000/KW estimate given by the 2009 MIT study. A recent article by the World Nuclear Association (WNA 2011) summarizes much of the public information concerning estimates of the construction costs of nuclear power. First, it notes that as of mid-2008 overnight engineering, procurement, and construction costs (EPC) for a nuclear reactor were quoted at about $3,000/KW without owner's costs. Generally, owner's costs are estimated at about 20 percent of overnight costs, so that in this case the sum of EPC and owner's cost comes to about $3,600/KW. WNA 2011 refers to estimates by the U.S. Energy Information Agency (EIA 2010)—the main source of technical and financial specifications for the Scenarios II of the present study—in which the sum of EPC and owner's cost is estimated as $5,339/KWh, up from the estimated $3,902/KWh in the previous year.

Regarding overseas developments, the article notes that China reports expecting total construction costs of between $1,600/KW and $2,000/KW. The article goes on to say that if the above estimates for U.S. and China are correct, the implication is that the costs are about hree times higher for the same plant built in the U.S. versus China. As to the difference, they note that in addition to the differing labor rates between the two countries, "Standardized design, numerous units being built, and increased localization are all significant factors in China." In addition, they give two tables which show costs of generation as estimated by the International Energy Agency (IEA). These tables show a great variety in estimated costs by power source across different countries, with nuclear coming in less expensive than other options in some cases and more expensive in others.

Lastly, the article turns to proposed developments in the U.S. It is stated that Florida Power and Light recently reported $3,108/KW to $4,540/KW (EPC plus owner's costs) as its estimate for two new reactors at its Turkey Point site. Costs are also reported for other proposed developments, but in those cases it is not clear of what exactly the costs consist (e.g. whether overnight costs are included and whether net of financing costs).

Estimates for the cost of nuclear power have generally risen in recent years. Speaking to this issue, a 2008 article (Kidd 2008) from *Nuclear Engineering International* states:

> There is now a huge range of numbers in the public domain about the costs of new nuclear build. It has become clear that estimates produced by vendors a few years ago of below $2,000/kWe on an overnight basis (i.e. without interest costs) were wide of the mark, at least for initial units in a market such as the USA. It is also clear that such estimates were presented on a very narrow basis, ignoring important cost categories such as necessary investment in local power grids, while costs have recently been spiraling upwards, owing to a variety of important features. Recent public filings and announcements suggest that there is now a "sticker shock" in US new build, with cost estimates now commonly in the $3,000–$7,000/kWe installed range, depending on what is being included. Progress Energy's estimates for its new planned AP1000 units in Florida were particularly startling—a price tag of $14 billion plus another $3 billion for necessary transmission upgrades.
>
> Indeed, it would be fair to credit Moody's Investors Service for being "ahead of the game" on assessing this, as in October 2007 they produced a report entitled *New Nuclear Generation in the United States: Keeping Options Open vs Addressing an Inevitable Necessity*, which estimated the all-in costs of a nuclear plant to be between $5,000 and $6,000/kWe. The report did however provide a note of caution, stating: "While we acknowledge that our estimate is only marginally better than a guess; it is a more conservative estimate than current market estimates." Explaining the shortcomings of cost estimates in more detail, the report stated: "All-in fact-based assessments require some basis for an overnight capital cost estimate, and the shortcomings of simply asserting that capital costs could be 'significantly higher than $3,500/KWe' should be supported by some analysis."

The lower end of the estimates given by Florida Power and Light ($3,108) and the high given by Moody's ($6,000) bracket the two estimates of overnight costs used in the present study.

Fuel and Other Operations and Maintenance Costs

A variety of periodic costs are incurred once construction is complete and a project enters its operations phase. These are usefully classified as fuel costs, variable costs, fixed costs, and incremental capital costs. Fixed costs and incremental capital costs depend only on the plant's generation capacity, while fuel costs and variable costs depend only on the fraction of the plant's capacity that is utilized. Compared with coal- and gas-based power, the cost of nuclear power is less sensitive to the cost of fuel (Tables 10 and 11). For example, a doubling of the cost of nuclear fuel leads to an approximately 10 percent increase in the total cost of nuclear power generation. Doubling the cost of coal and natural gas leads to increases of approximately 32 and 77 percent, respectively, in the cost of coal- and natural gas–based power generation. Since natural gas power plants are particularly sensitive to natural gas prices and since natural gas prices are particularly volatile, fuel price risk is considerably higher for natural gas plants than for either coal or nuclear. Natural gas–based power plants in fact carry more fuel-price risk than coal-based plants not because the overall cost of generation from gas is less sensitive to natural gas prices than is the overall cost of generation from coal to coal prices—they are roughly equally sensitive—but because the price of natural gas appears less certain than that of coal.

Table 10
Scenarios I: Levelized Costs Evaluated at Fuel Costs that Deviate from Base-Case Costs as Indicated
(dollars per MWh)

	Deviation from Base Case Fuel Cost								
	−60%	−30%	0%	30%	60%	90%	120%	150%	180%
Coal	$48	$53	$59	$65	$70	$76	$81	$87	$93
Gas	$34	$48	$62	$77	$91	$105	$120	$134	$148
Nuclear	$83	$86	$88	$91	$93	$96	$98	$101	$103

Source: BEBR.

Table 11
Scenarios II: Levelized Costs Evaluated at Fuel Costs that Deviate from Base-Case Costs as Indicated
(dollars per MWh)

	Deviation from Base Case Fuel Cost								
	−60%	−30%	0%	30%	60%	90%	120%	150%	180%
Coal	$50	$55	$61	$66	$72	$78	$83	$89	$94
IGCC	$91	$98	$105	$111	$118	$125	$132	$139	$145
Gas	$39	$54	$68	$83	$98	$113	$128	$142	$157
NGCC	$60	$76	$92	$108	$123	$139	$155	$171	$186
Nuclear	$101	$104	$106	$109	$111	$114	$116	$119	$122

Source: BEBR.

The attractiveness of nuclear power depends on the future course of coal and natural gas prices. The cost of generating electricity from nuclear power is relatively insensitive to the cost of nuclear fuel and particularly to the cost of uranium, the basic component of nuclear fuel.

We find that if current conditions (e.g. moderate natural gas and coal prices with no charge for carbon dioxide emissions) typify those of the next 30–40 years, nuclear power would turn out to be approximately 40 percent more expensive than either natural gas or coal on a per-unit-of-electricity basis. There are, however, plausible combinations of future fossil-fuel prices and carbon dioxide (CO_2) emissions charges under which nuclear power is significantly less expensive than that based on either natural gas or coal.

Current delivered natural gas and coal prices per million BTU (MMBTU) are approximately $5.00 and $2.00 respectively. Higher natural gas and coal prices and/or charges based on CO_2 emissions raise the cost of generating electricity from these sources and so improve the relative economics of nuclear power. We find that if inflation-adjusted natural gas prices are greater than about $7.50 per MMBTU over the next 30–40 years, then natural gas power will be more expensive than nuclear even without a charge on CO_2 emissions. With a $25/ton charge on CO_2, such a "break-even-with-nuclear" point is reached at $6.50 per MMBTU.

Operational Lifetime and Capacity Factors

Chief among the ongoing financial risks is the risk associated with the use of the plant's capacity to produce electricity. In the earlier years of nuclear power plants, the amount of electricity generated out of the maximum that could be generated (the "capacity factor") was quite low, averaging about 50 percent in the 1980s, for example. This started to change in the 1990s and for the last decade capacity utilization at nuclear power plants has averaged about 90 percent. Such plants are rather mature, but the age of a plant wouldn't seem to work unambiguously in favor of higher capacity usage. Thus, there would seem to be reason to expect that new nuclear plants could enjoy such high capacity rates from near the start of operation. It is critical that consistently high capacity usage is realized early in the plant's lifetime.

Nuclear power plants are potentially long-lived, with feasible lifetimes of 60+ years.[6] From an LCOE point of view, however, the lifetime of a nuclear plant is not especially critical as long as the plant lives and operates near capacity for about 30 years. Figures 8 and 9, above, and Tables 12 and 13 show the sensitivity of LCOE to the plant's operational lifetime. In these figures, note that the LCOE for natural gas (including NGCC) actually increases slightly with increasing lifetime. This is a consequence of EIA-projected increases in the real cost of natural gas. Adjusting for the effect of rising natural gas prices, the LCOE for natural gas does decrease with increased lifetime, but only very slightly. In other words, if we ask, How much would need to be

Table 12
Scenarios I: Levelized Costs Versus the Operational Lifetime of the Power Plant

	Operational Lifetime (years)												
	20	25	30	35	40	45	50	55	60	65	70	75	80
Coal	$69	$64	$62	$60	$59	$58	$58	$57	$57	$57	$57	$56	$56
Gas	$62	$62	$62	$62	$62	$63	$64	$64	$65	$65	$66	$66	$67
Nuclear	$105	$98	$93	$90	$88	$87	$86	$86	$85	$85	$85	$84	$84

Source: BEBR.

charged for every unit of electricity sold in order that a natural gas plant could be replaced in 20 years versus 40?, the answer would be, perhaps surprisingly, just a few percent of the price charged per unit for a 20-year unit. The answer is similar, but not quite as extreme for coal and nuclear power. But as the figures and tables show, the additional current value added by a nuclear power plant that lives 60 years versus one that lives 40 years is quite small ($88 per MWh for a 40-year plant, $85 per MWh for a 60-year plant).

Table 13
Scenarios II: Levelized Costs Versus the Operational Lifetime of the Power Plant

	Operational Lifetime (years)												
	20	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**	**65**	**70**	**75**	**80**
Coal	$72	$67	$64	$62	$61	$60	$59	$59	$58	$58	$58	$58	$58
IGCC	$126	$117	$111	$107	$105	$103	$101	$101	$100	$99	$99	$99	$99
Gas	$68	$67	$68	$68	$68	$69	$70	$70	$71	$71	$72	$72	$73
NGCC	$96	$93	$92	$92	$92	$92	$92	$93	$93	$94	$94	$95	$95
Nuclear	$128	$118	$112	$109	$106	$105	$104	$103	$102	$102	$102	$102	$102

Source: BEBR.

Taxes

The power plants analyzed in this report pay state and federal corporate taxes and local property taxes. Local taxes (LT) are ordinarily assessed on the market value of an asset. In this report local taxes are approximated by a levy equal to 0.95 percent (LR) of a measure of taxable income in which neither state nor federal corporate income taxes are deductible. The state corporate income tax rate is a flat 5 percent (SR). The progressive federal corporate tax rates are approximated by a flat rate of 37 percent (FR). Local taxes are deductible from both state and federal taxable income. State corporate income taxes are deductible from federal taxable income. Thus the effective tax rate (ER) on taxable income is calculated as

$$ER = LR + (1 - LR) \times SR + (1 - LR - (1 - LR) \times SR) \times FR,$$

which is equal to 40.7 percent in this case.

State (SIT) and federal taxes (FIT) are based on taxable income, which starts as gross revenue (REV) minus the sum of depreciation (DEP), fixed operations and maintenance expenses (FOM), non-fuel variable operations and maintenance expenses (VOM), incremental capital costs (INC), fuel costs (FUEL), charges for nuclear fuel disposal (WAS), and contributions to the decommissioning fund (DEC).

$$LT = LR \times (REV - DEP - FOM - VOM - INC - FUEL - WAS - DEC)$$

Local taxes are deductible from revenues when calculating taxable income for the purpose of computing the Utah corporate income tax, but the federal corporate income tax is not.[7] Therefore we compute SIT as:

$$SIT = SR \times (REV - LT - DEP - FOM - VOM - INC - FUEL - WAS - DEC)$$

Taxable income for the purposes of the federal income tax (FIT) is computed in the same way as for SIT, except that SIT is a deduction in the calculation of federal taxable income. The federal income tax (FIT) is assumed to be a flat 37 percent charge against taxable income, which is gross revenue (REV) minus the sum of depreciation (DEPR), incremental capital expenditures (CAPEX), non-fuel operations and maintenance expenses (OM), fuel costs (FUEL), state corporate income taxes (SIT), and local taxes (LOCAL). In the case of federal taxable income, both state and local taxes are deductible.

$$FIT = FR \times (REV - DEPR - CAPEX - OM - FUEL - SIT - LOCAL)$$

The Discount Rate

A power plant generates revenues and costs throughout its lifetime. Revenues are based on electricity sales during the operational phase of the plant, while costs occur during both the construction and operations phases. The difference between revenues and costs during some period of time is the plant's cash flow. Cash flows will be negative during the construction phase because in this phase there are costs but no revenues. Cash flows would hopefully, but not necessarily, be positive during most or all periods of the operations phase.

Because in order to assess the total value of a project we need to add together cash flows from different points in the future, it is necessary that future cash flows be rendered in a common unit of value. Customarily that unit is the *present value* of the cash flow. Usually, though not necessarily, a cash flow received "now" is more valuable to the investor than the same cash flow received at a later date. This occurs when funds in hand now can be employed in activities that generate a sufficiently positive financial return. Similarly, a negative cash flow is usually less costly to the investor the farther into the future it occurs. In such typical cases, re-expression of future amounts in terms of their present value is referred to as *discounting* and the rate of translation from one period to the next is called the *discount rate*, which is denoted by *r*. Thus, an amount that occurs *k* periods in the future is rendered in present-value terms through *k* successive applications of one-period discounting. In order to carry these calculations out, a discount rate needs to be determined for each scenario.

Before investment in a particular project takes place, the investor will have numerous alternative investments available. These investments will vary in apparent risk and expected reward (rate of return). The rate of return on those alternatives with similar risk as the proposed investment establishes a lower-bound on the rate of return for the proposed investment. This lower-bound rate of return is called the *hurdle rate*. The hurdle rate is thus said to establish the opportunity cost of investing one's funds in the proposed project: If the rate of return on the proposed project is at least equal to the hurdle rate, then the investor is doing as well or better to invest in the proposed project as in any alternative with similar risk.

In practice, the hurdle rate for a project is often established by the *weighted average cost of capital* (WACC). The WACC is a weighted average of the required rates of return to investors in the equity and debt of the project, where the weights are the shares of equity and debt in total project value. Both the shares and required rates depend on the risk-reward profile of the project. Generally, higher rates of return and/or a greater equity share is required for higher-risk projects.

Table 14
Calculating the Discount Rates

Fuel	Equity	Debt	Equity Rate	Debt Rate	Tax Rate	Discount Rate
Nuclear	50%	50%	13.66%	6.74%	40.70%	7.86%
Gas	50%	50%	13.66%	6.74%	40.70%	7.86%
Coal	40%	60%	10.70%	6.74%	40.70%	6.80%

Source: BEBR.

The components of WACC for the projects analyzed in this report are from the 2009 MIT *Update* (MIT 2009), with minor modifications to account for a different assumption regarding inflation. The required rate of return on equity for a nuclear power plant is assumed in MIT 2009 to be 15 percent nominal, while both coal and natural gas plants are assumed in MIT 2009 to require rates of return on equity of 12 percent nominal. These nominal rates incorporate a rate of inflation of 3 percent. Adjusting the nominal rate for an up-to-date projection of the inflation rate of 1.8 percent, the nominal rate of return on equity for a nuclear power plant is 13.66 percent, and 10.7 percent for both coal and natural gas. For nuclear, coal, and gas, MIT 2009 assumes an 8 percent nominal rate of return to debt. Again adjusting for different inflation assumptions, this study assumes a 6.74 percent nominal rate of return to debt. Lastly, MIT 2009 assumes a 50-50 split between debt and equity for nuclear and a 60-40 split for both coal and natural gas. Using these components the WACC can be computed for each plant.

Table 15
Scenarios I: Levelized Costs Versus the Hurdle Rate (WACC) for the Power Plant

	Hurdle Rate													
	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
Coal	$43	$45	$48	$52	$56	$60	$65	$71	$76	$82	$89	$95	$102	$110
Gas	$61	$61	$61	$61	$62	$63	$64	$65	$66	$68	$69	$71	$73	$75
Nuclear	$43	$47	$52	$58	$65	$72	$81	$90	$100	$110	$122	$134	$146	$160

Source: BEBR.

Letting s_e stand for equity share, $(1 - s_e)$ for debt share, r_e for required rate of return on equity, r_d for required pre-tax rate of return on debt, and *t* for tax rate, the WACC is calculated as follows:

$$\text{WACC} = s_e \times r_e + (1 - s_e) \times r_d \times (1 - t).$$

Since payments to debt are tax deductible, the after-tax cost per unit of debt is $r_d \times (1 - t)$ where *t* is the marginal tax rate. This difference between the pre- and post-tax cost of debt is referred to as the *tax shield* of debt. Table 14 summarizes the components and value of the WACC for each plant.

The sensitivity of the levelized cost of electricity to the discount rate depends on how the plant's cash flows are distributed over time. Projects front-loaded with larger negative cash flows, such as nuclear power or advanced coal plants, are more susceptible to higher discount rates.

Table 16
Scenarios II: Levelized Costs Versus the Hurdle Rate (WACC) for the Power Plant

	Hurdle Rate													
	2%	3%	4%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%
Coal	$42	$45	$49	$53	$57	$63	$68	$75	$81	$88	$96	$104	$112	$120
IGCC	$69	$74	$81	$89	$98	$108	$119	$130	$143	$156	$170	$185	$200	$216
Gas	$66	$66	$67	$67	$68	$69	$70	$71	$73	$74	$76	$78	$80	$83
NGCC	$83	$84	$86	$88	$90	$93	$96	$99	$103	$107	$112	$116	$121	$126
Nuclear	$49	$55	$61	$68	$77	$86	$97	$108	$121	$134	$149	$164	$180	$197

Source: BEBR.

For example, we find that increasing the discount rate from 8 percent to 12 percent increases the levelized cost of nuclear power by 50 percent, the levelized cost of coal power by 30 percent, but the levelized cost of natural gas by only 10 percent. A high discount rate would also disfavor projects whose revenues are loaded more toward the end of the project's life; but with all scenarios considered here, the plants operate and generate revenue uniformly throughout their operational lifetime. Figures 12 and 13, above, and Tables 15 and 16 show the levelized cost of electricity over a broad range of discount rates.

CO_2 Charges

Carbon dioxide is a byproduct of the combustion of fossil-fuels in air. Assuming full combustion, each atom of carbon from the fuel bonds with two atoms of oxygen from the air, eventually yielding a number of CO_2 molecules equal to the number of carbon atoms in the fuel. Burning one pound of coal or natural gas creates more than one pound of CO_2. In order to determine the amount of CO_2 emitted during some period of time (e.g. a year) by a plant burning a certain fuel (and in the absence of carbon capture), we determine

1. the amount of CO_2 produced for each unit of fuel burned
2. the amount of fuel which must be burned to generate each unit of electricity, and
3. the total number of units of electricity generated by the plant during the period.

The amount of CO_2 produced for each unit of fuel burned varies by fuel, as it depends on the share of carbon in the weight of the fuel (the "carbon intensity" of the fuel). Even within broad categories of fuel, such as "coal" and "natural gas," carbon intensity varies. In this report, 1 MMBTU (equal to 85.5 lbs of 11,700 BTU/lb. coal) of coal is assumed to generate 204 lbs of CO_2.[8] The carbon content of natural gas is taken to be 76 percent by weight. With 1 standard cubic foot (SCF) of natural gas energy-equivalent to 1,026 BTU and having a weight 0.042 pounds, it follows that 1 MMBTU of natural gas generates 114 pounds of CO_2 upon combustion.[9]

The amount of fuel, as measured by BTU, that must be burned to generate each KWh of electricity is a measure of the thermal efficiency of the plant (called the plant's "heat rate"). The coal plant in Scenarios I, for example, requires 8,870 BTU of coal in order to generate 1 KWh of electricity; equivalently, 8.87 MMBTU (758 lbs of 11,700 BTU/lb. coal) of coal are required to make 1 MWh. The gas plant in Scenarios I requires 6.8 MMBTU to produce 1 MWh.[10]

The total amount of electricity generated by the plant during a given period is the product of the capacity of the plant ("nameplate capacity"), the fraction of this capacity that is used during the period ("capacity utilization rate"), and the number of hours during the period. For example, the coal plant of Scenarios I has a nameplate capacity of 1,300 MW and a capacity utilization rate of 85 percent. With an average 8,766 hours per year (accounting for leap years), this plant would generate 9,686,430 MWh per year. The natural gas plant of Scenarios I, with a nameplate capacity of 540 MW and capacity utilization rate of 85 percent, would generate 4,023,594 MWh per year.

Putting these three factors together we compute CO_2 emissions per year for each plant in each scenario. For example, in Scenarios I the coal plant emits 8,763,701 tons of CO_2 per year and the gas plant emits 1,559,545 tons per year. With a $25 per ton charge on CO_2 emissions, these plants would face annual emissions charges of $219 million and $39 million respectively.

It bears repeating that the gas plant in this case generates less than half the amount of electricity of the coal plant: scaling these amounts to the output of the plant, the coal plant emits almost 1 ton of CO_2 for each MWh of electricity generated, while the gas plant emits about 0.39 tons per MWh of electricity generated.

Conclusions

This article presents estimates of the levelized cost of nuclear power as compared to several natural gas and coal technologies. The findings suggest that nuclear power may be more expensive on an LCOE basis than either coal or natural gas but that there are plausible scenarios under which nuclear is competitive with, or outperforms both.

Terms

Watt (W) Unit of power.

Kilowatt (KW) 1,000 watts.

Megawatt (MW) 1,000 kilowatts (i.e., 1 million watts).

Watt-hour (Wh) One watt of power applied over a time interval of one hour.

Kilowatt-hour 1,000 watt-hours.

Megawatt-hour 1,000 kilowatt-hours (i.e. 1 million watt-hours).

British Thermal Unit (BTU) Unit of power equal to about one-third (0.293) of a watt.

MBTU 1,000 BTUs.

Cash Flow The difference between a project's revenues and costs during a certain period of time.

Discount Rate The rate of translation in the value of money from one period to the next.

Discounted Cash Flow The result of applying the discount rate to an undiscounted cash flow.

Net Present Value (NPV) The sum of all the project's discounted cash flows over its lifetime.

Hurdle Rate The discount rate at which the NPV of a project is zero (any higher discount rate implies a project with positive NPV).

Levelized Cost of Electricity (LCOE) The amount an operator would need to charge, at least, on each unit of electricity they produce in order to cover all the costs of producing the unit, including construction costs, various operations costs, and a return on investment competitive with that of ventures offering a similar risk/reward tradeoff.

Greenfield Site A site that is not the location of an existing or previously existing power generation facility.

Brownfield Site A site where a preexisting power generation facility is located.

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Endnotes

1. This research was funded by Blue Castle Holdings and PacifiCorp. Blue Castle is an energy development company pursuing development of Utah's first nuclear power plant in Green River, Utah. PacifiCorp is the parent company of Rocky Mountain Power, a public utility serving Utah, Wyoming, and Idaho. Neither Blue Castle nor PacifiCorp necessarily endorse the methods or findings presented in this report.

2. See *Nuclear Engineering International*, "A New Kind of Nuclear New-Build," December 2011, authored by staff of Blue Castle Holdings. "The BCH business model is to assume the political, financial and site development risk for preparing a nuclear plant for construction and operation.... Upon or prior to the completion of licensing in 2016, BCH intends to involve a qualified nuclear utility (or utility ownership team) to support plant construction when overall conditions are favourable and financially advantageous."

3. Consider, for example, a natural gas plant. In this analysis we assume that the natural gas plant produces power consistently at 85 percent of its nameplate capacity, no matter the price of the natural gas (natural gas prices are, over a plausible range, a large fraction of the overall cost of producing power from a natural gas plant). In fact, however, a merchant natural gas operator may choose to generate power only when the price of natural gas is low enough to ensure profitability. Such an operator is said to have the right, but not the obligation, (i.e., to own the option) to sell electricity in the open market. This option doesn't exist for operators contractually obligated to supply electricity.

4. See the 2005 Residential Energy Consumption Survey (RECS). According to RECS, the 7.6 million households in the Mountain West region consumed a total of 82 million MWh of electricity in 2005—10.8 MWh per household, or 0.9 MWh per household per month. RECS is a detailed household-level survey of energy use. The U.S. Energy Information Administration has administered RECS every four years since 1978. Results on electrical energy consumption by area for the most recent survey, carried out in 2009, were not available at the time of this writing. In RECS, the Mountain West region consists of Arizona, Colorado, Idaho, Montana, New Mexico, Nevada, Utah, and Wyoming.

5. There will also have been some pre-construction planning, but although these activities can go on for a considerable period of time, costs associated with planning will ordinarily be a small fraction of total plant costs.

6. Of the 104 operating reactors, 66 have already obtained 20-year extensions on their original 40-year operating license, and 16 have filed with NRC for renewal.

7. The State of Utah currently waives the state corporate income tax for nuclear power plants.

8. The Energy Information Agency publication *Carbon Dioxide Emission Factors for Coal* (EIA 1994), reports on the carbon content of a large number of coal samples taken from various parts of the U.S. The publication does not report the carbon content of these samples by region, but rather gives the average pounds of carbon dioxide resulting from combustion of 1 MMBTU of regional coal. For the Utah samples, this number was 204.1. The implied carbon content factor, *f*, for 11,700 BTU/lb. coal is determined by solving $f \times (1{,}000{,}000/11{,}700) \times (44.01/12.01) = 204.1$. Thus, this coal is 65 percent carbon by weight.

9. $1{,}000 \times 1{,}000/1{,}026 \times 0.042 \times 0.76 \times 44.01/12.01 = 114$.

10. Since 1 MWh is equivalent to 3.412 MMBTU, the coal plant in this case can be seen as extracting 38 percent of the energy. The gas plant is more efficient, extracting 50 percent of the energy in the natural gas.

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