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Inter-fuel Competition in Electricity Generation

A Latin American & Caribbean Experience

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Abstract

This study compares the levelized cost of electricity generated with fossil fuels (including coal, natural gas, fuel oil, and diesel) and renewable or carbon-free energy sources (including hydro, wind, solar, nuclear and geothermal). A meta-study of power generation technology capital costs determined the range of capital costs across the various technologies as well as the range of cost estimates for each individual technology from the various data sources that were examined. Applying these capital costs to a range of operating assumption (such as fuel price and plant utilization rate) resulted in a range of levelized cost of electricity for each technology. In addition, the study examined how the cost of electricity was affected by applying a cost for CO2 emissions and a cost to build new transmission infrastructure to link the power plant in question to the national grid. Finally, the study examined the potential investment cost and benefits in reducing CO2 emissions and levelized costs of electricity by repowering existing thermal power plants or switching high-carbon fuels to lower carbon alternatives. This analysis included two case studies: repowering an older natural-gas fired combustion turbine unit in Peru and repowering and fuel switching an oil-fired steam turbine unit to natural gas in Nicaragua.

Contents

Introduction

In 2010, the Ninth General Capital Increase of the IDB (GCI-9) formally recognized Climate Change as a priority. The GCI-9 establishes that the Bank will promote sustainable growth in the LAC Region, which includes pursuing global environmental sustainability and dealing with climate change while ensuring that energy requirements for development are met.

Many of the energy efficiency and renewable energy technologies that are currently available represent "win-win" mitigation activities that can be supported with a relatively high level of confidence, as these activities could: generate direct and indirect benefits that often exceed their costs, without compromising the level of services delivered or the region's economic competitiveness; delay the construction of new fuel processing and power generation capacity; reduce the countries' exposure to fossil fuel price volatility risks, increase energy sovereignty and contribute to the creation of "green jobs"; and, reduce the impacts on human health and biodiversity caused by the use of fossil fuels. There is an equally strong trade and economic rationale for directing support to GHG mitigation given the significant challenges and opportunities that the transition to a low- carbon global economy will create for business and international trade, and the opportunities for implementing environmentally sound and cost-effective activities.

The Inter-American Development Bank has commissioned this case study to compare the potential for repowering existing power generation facilities with state of the art technologies, and to compare the resulting carbon emissions reductions with alternative zero-emission technologies.

The study compares fossil fuels, including coal, natural gas, fuel oil, and diesel, as well as renewable energies including hydro, wind, solar, nuclear and geothermal. In addition, the study considers the costs of power generation externalities, including those related to climate change (namely, CO2 emissions) as well as infrastructure costs, such as building new power transmission lines or natural gas pipelines to serve new or repowered power plants. Finally, the study examined specific example power plants within the region to illustrate the potential gains from repowering or fuel switching.

Questions for Reflection

This study was guided by a number of critical questions for reflection:

- What is the current state of the art for power generation technology in terms of capital cost per kilowatt (kW) of installed capacity and efficiency (electricity produced per unit of input energy consumed)?
- How do the costs of repowering existing power plants compare with the greenfield cost to build similar power generating capacity?
- How may externalities affect both repowering and greenfield costs?
- How does the efficiency of the state of the art power generation compare with the average efficiency of currently installed power generation capacity in Latin America and the Caribbean?
- How do these values compare in the specific context of Latin America and the Caribbean?

Power generation technology background

Technologies used to generate alternating current (AC) electricity (with the major exception of photovoltaic power) use the same basic approach: a turbine uses a working fluid (such as water, steam, or air) to cause an axel to spin; this spinning axel rotates a set of magnets within a coil of conducting wires (the generator), inducing an electric current; the generator is then connected to a power transmission grid, allowing the generated electricity to reach the ultimate consumer.

Among power turbine technologies currently in operation, there are major variations in the size of the turbine and generator combination (the power output), the choice of the working fluid, and the way in which the working fluid is imbued with the required energy to turn the magnets. Examples of different technologies that are examined in this report include:

- **Hydropower plants** use the pressure of water falling downhill to turn a turbine. Hydropower plants can range in size from a few kW to several Gigawatts (GW) of output, with individual turbines reaching as large as 700 megwatts (MW) each.
- **Steam power plants** use an energy source (coal, oil and oil products, natural gas, biofuels, old tires, nuclear fission, the heat of the earth or even the sun) to heat water into a high pressure steam that is then used to turn the turbine. These units range from sub-critical units (which use steam at a temperature and pressure below the "critical point" beyond which there is no distinction between liquid and gas), super-critical (using steam at a temperature and pressure above the critical point) and ultra-supercritical (using even higher temperature and pressure). Larger boilers tend to be more efficient, and so steam power plants are usually larger than 50 MW, reaching as much as several GW for large coal fired plants or nuclear power plants.

- **Gas turbines** can also use any combustible material to heat and pressurize air to directly turn a turbine, although concerns of corrosion and wear on the turbine blades means cleaner burning fuels such as natural gas are most commonly used. Gas turbines based on aircraft engine designs can be as small as several kW, with larger frames as big as a few hundred MW.
- **Combined-cycle power plants** are essentially a gas turbine (or two) and a steam turbine linked to the same generator. Hot gas leaving the gas turbine is used to heat steam (often supplemented with additional fuel) that is then used in the steam turbine. By using the waste gas again, combined cycle plants can be highly efficient. Combined-cycle plants are generally a few hundred MW up to a GW in size.
- **Wind power plants** use the loft from air passing over an aerodynamic blade (similar to an airplane wing) to spin a central axis and thus turn a generator. Steady technological improvements have led to larger turbines, now reaching over 2 MW each on land and larger for off-shore installations. Large wind farms can include hundreds of individual turbines.
- **Photovoltaic power plants** convert sunlight into direct current electricity which is then converted to alternating current before being supplied to the power transmission grid. The output of a photovoltaic plant depends on the quality of the solar resource, the efficiency with with the solar panels convert the sunlight, and the total surface area of panels installed. Most individual panelsare very small – roof top units can be less than a kW while utility scale solar farms are now reaching up to 500 MW in size.

Power Generation Cost Components

Each power generation technology has a unique cost profile, including the capital cost to build the plant, the fixed and variable costs associated with operating the plant, and external costs linked to the plant, such as the infrastructure required to connect the plant to the power grid or costs from environmental damage caused by the plant's operations. The components of each of these cost drivers are detailed below.

- **Capital costs** are the most significant cost to power generation for many technologies. Capital costs for most technologies include:
    - **Site preparation.** Buying and preparing the land where the plant is located, building related fuel storage facilities and the buildings for the plant.
    - **Mechanical equipment** such as the turbine and generator with related installation costs, auxiliary equipment and balance of plant equipment as needed.

- **Electrical equipment** such as the plant's transformers and switchgear, control systems and instrumentation
- **Indirect costs** such as contractor overhead, fees, profit and contingency allowances; labor and materials not otherwise allocated to other categories; and start up and commissioning costs.
- **Owner's costs** can include development and preparatory studies (engineering, feasibility, environmental assessments), permitting and fees, project management, insurance and taxes.

- **Financing.** Because power plants are capital intensive and can require several years to build, the financing structure and terms can be a critical factor in overall plant costs. However, financing costs are highly project specific, affected by overall financial market trends, political and other external risks related to the plant's location, and the credit worthiness of the developer and main purchaser of the electricity to be produced. As a result, most technical analysis of power plant costs use an "overnight" cost estimate. That is, financial costs and the time value of money are not included. Instead, the plant construction costs are estimated as if they could be completed in a single day. Financing costs are then added back in when calculating how capital costs are spread across the life-time power production of the plant.
- **Fixed operating costs.** Fixed operation and maintenance (FOM) costs are incurred during the operation of the plant that are not affected by the amount of electricity produced. These costs can include labor and staffing costs, routine maintenance of the equipment and general facilities, and regulatory fees.
- **Non-fuel variable operating costs.** Variable operating and maintenance (VOM) costs are directly related to the amount of electricity produced by the plant. These can include water charges and waste/wastewater disposal charges, consumable materials such as lubricants and other gases or catalysts, ammonia (used in some types of environmental controls) and other chemicals.
- **Major maintenance costs.** These costs are typically incurred on a determined schedule based on plant usage. A major overhaul can take a plant off line for weeks or even months in the case of refueling a nuclear power plant. These costs are generally included in VOM costs as they are directly related to the plant's operating time. The related extended outage is also reflected in the plants overall availability rating.
- **Fuel costs** are the largest variable cost for non-renewable energy power plants. Fuel costs' depend on the price of the fuel and the plant's thermal efficiency (that is, the amount of fuel required to produce a unit of electricity). While most power plants are optimized to use a single fuel, some are designed to accept a range of fuels, providing greater operational flexibility.

There are a number of reasons such a great number of technologies and fuels remain competitive and in use despite having widely different cost and performance characteristics. Power plants are capital intensive and have very long useable lives—often in excess of forty years. As a result, older power plants that have paid off their capital costs remain in service even as newer, more efficient technologies become available. The lack of large-scale, cost effective electricity storage also means that electricity supply must be instantaneously matched with demand. Certain technologies, such as simple-cycle gas turbines or reciprocating engines, can more flexibly ramp power output up or down to match variations in demand. In addition, power generation technologies must be matched to the incremental need of each market as adding too much capacity at once is economically inefficient. Some markets may be too small to accommodate certain technologies, such as nuclear power plants, while other markets are too large to be able to solely rely upon technologies with small individual capacity, such as solar power plants. Technology and fuel diversification also protects against fuel price volatility or shortages of supply, making the power system as a whole more robust even if individual plants may have higher costs. The cost of environmental externalities—whether restrictions on sulfur or nitrogen oxides emissions or a price for carbon dioxide, or price support for renewable technologies—can also be volatile as regulations or subsidies change.

Power generation costs are also highly specific to the circumstances of each individual project; two projects using the same technology and similarly priced fuels can still have dramatic differences in total electricity cost owing to the site specific expenses and externalities. As a result, the intention of this analysis is to provide a high level overview of the relative cost of different technologies and major cost components from the perspective of a power system planner and not to evaluate the suitability of any single technology for a specific project or application.

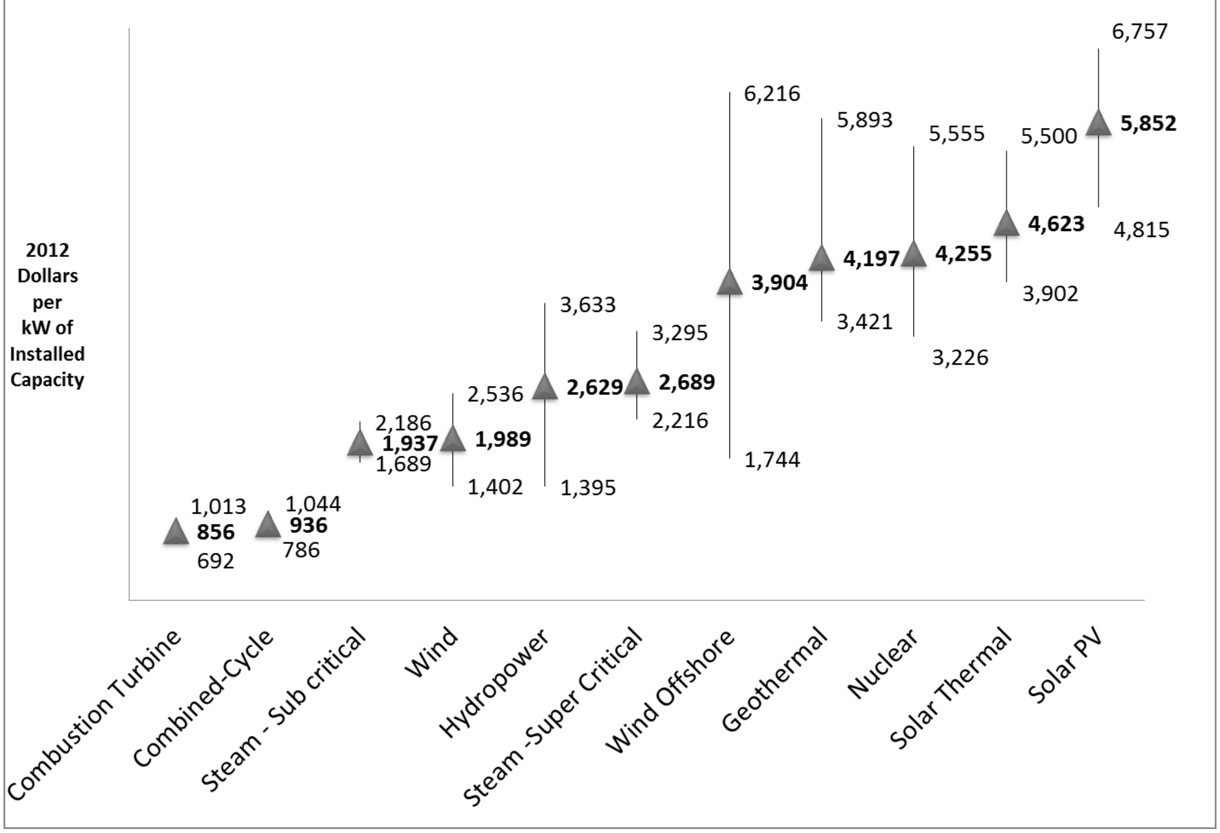
Greenfield Investment

The following section reviews the characteristics and costs of building and operating a new power plant of each technology being considered based on the major components of the cost of electricity as noted above. In addition to the costs directly related to the power plant, external costs such as new transmission lines and the cost of carbon emissions are also discussed. The cost estimates shown in this section of the report represent a generic project located in the United States without any site-specific constraints or cost drivers. A U.S. based plant was chosen owing to the availability of data and comparable analysis from a variety of independent sources.

Capital Costs

This study compares the capital costs of 11 different power generation technologies: hydro power, wind (offshore and on shore), solar PV, solar thermal, geothermal, nuclear, combustion turbine (CT), combined cycle (CC), and steam turbines (sub-critical and super critical). Numerous studies have been made of average capital costs for power generation technologies within the United States. This analysis compared the analysis of 15 different cases from 11 different studies to arrive at an average "consensus" estimate. The studies included work by private sector consulting firms, such as the U.S. Greenhouse Gas Abatement Mapping Initiative completed by McKinsey in 2007 to the detailed R.W. Beck engineering study of capital cost inputs for the 2011 update to the DOE EIA Annual Energy Outlook. For each study, the reported capital costs were adjusted to 2012 dollars using a GDP price deflator. Figure 1 shows the average estimated capital cost across the various studies for each technology, including a band showing the high and low estimates for each.

Figure 1: Overnight Capital Cost for Power Generation Technologies

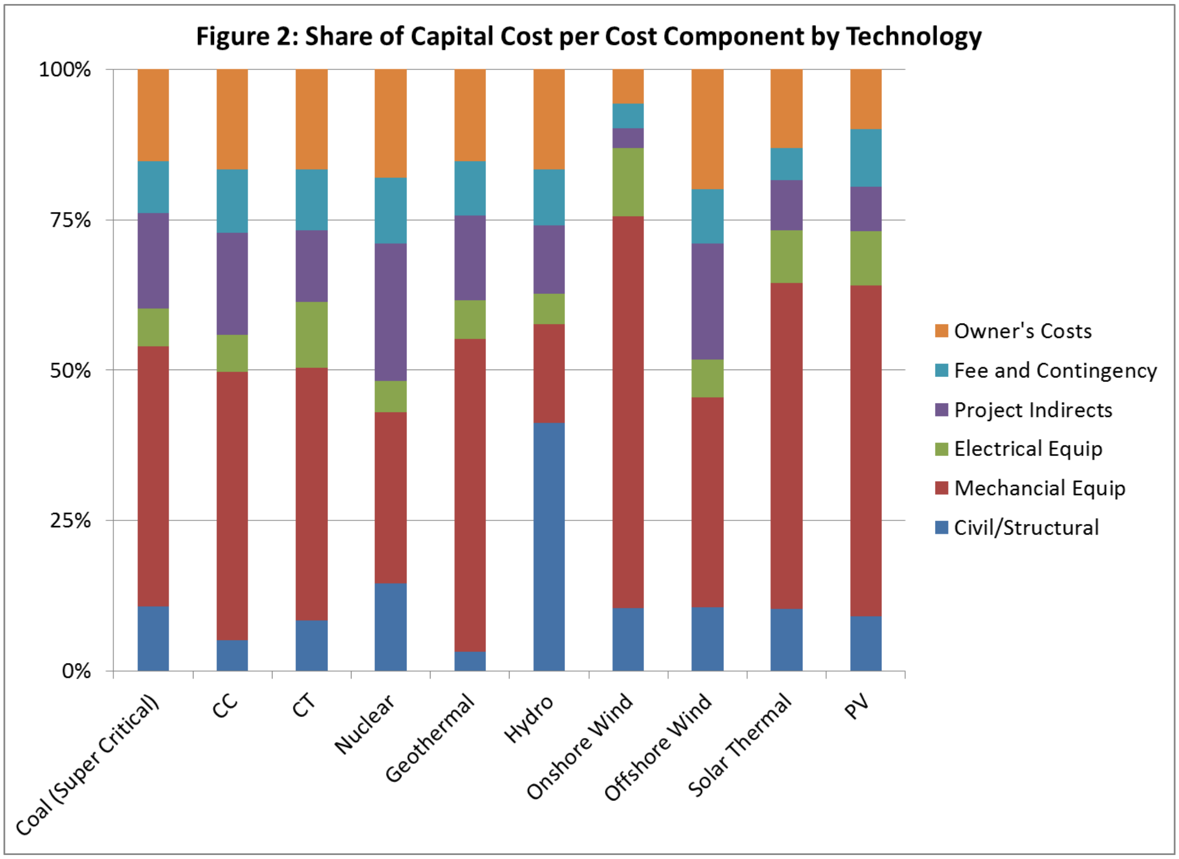


Data Source: Electric Technology Cost and Performance Data (NREL, 2010)

Estimates of capital costs range from just under $1,000 per kW for gas-fired technologies (combustion turbines and combined cycle plants) to almost $6,000 per kW for solar photovoltaic. Nuclear power, solar-thermal, and geothermal technologies all have capital costs above $4,000 per kW. It is important to note that these comparisons indicate an average solar panel cost of roughly $3 per Watt of capacity. Because solar panel prices have fallen nearly 50% in the past year alone, this study has added another solar PV case to indicate the impact of lower panel prices (see section below on the Levelized Cost of Energy).

Within each technology, the various studies also show a wide range of estimated capital costs. As shown in Figure 1, the maximum cost reported for each technology typically ranges between 40% and 80% higher than the lowest reported costs. For offshore wind power and hydropower, the range of reported costs is even more extreme, with maximum offshore wind costs more than 3.5 times the lowest reported costs, and the upper range for hydro power just over 2.5 times the lower boundary. This wide variation for hydro and off-shore wind is likely due to the more prominent role of site specific costs for these particular technologies.

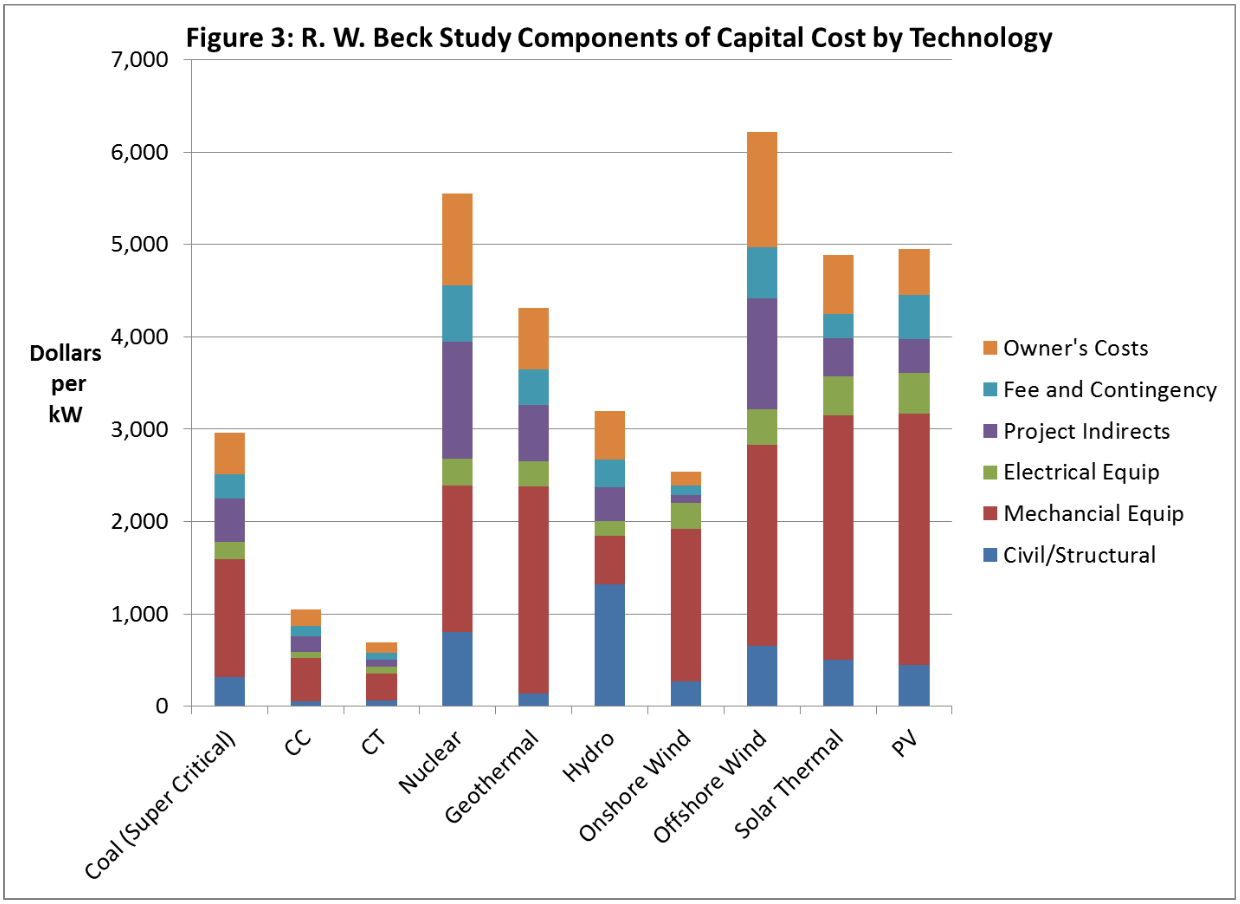
In addition to the range in total capital cost, each technology has a distinct combination of the various cost components. The R.W. Beck report that supported the DOE EIA's 2011 Annual Energy Outlook revised power generation capital costs included a very detailed assessment of the capital cost components for each technology. Figure 2 compares this component breakdown as a share of total capital costs.



Data Source: Review of Power Plant Cost and Performance Assumptions for NEMS, Technology Documentation Report. (J. Vahn, et. al. - R.W. Beck, 2010)

Not surprisingly, site preparation costs are highest for hydro power technologies owing to the costs related to preparing and building the dam. For most thermal technologies, the cost of the mechanical equipment (the turbine) is the largest component, while for nuclear power and off-shore wind, the project indirect costs are more substantial.

Figure 3 shows the actual cost for each component and each technology in the R.W. Beck study. This figure highlights how even technologies with similar turbine costs can have very different overall capital costs. For example, the cost of off-shore wind turbines is only slightly higher than for onshore turbines. However, off-shore wind projects have much higher site preparation, project indirect, and owner's cost components owing the difficulty in building a power plant in a marine environment. As a result, the overall capital cost is more than double for off-shore wind projects. A similar pattern is notable between nuclear power plants and coal-fired steam power plants: both projects use steam turbines with a similar base costs, but a nuclear power plant is far more expensive owing to the special preparation and ancillary equipment required to manage the fuel and risk of radiation leakage.

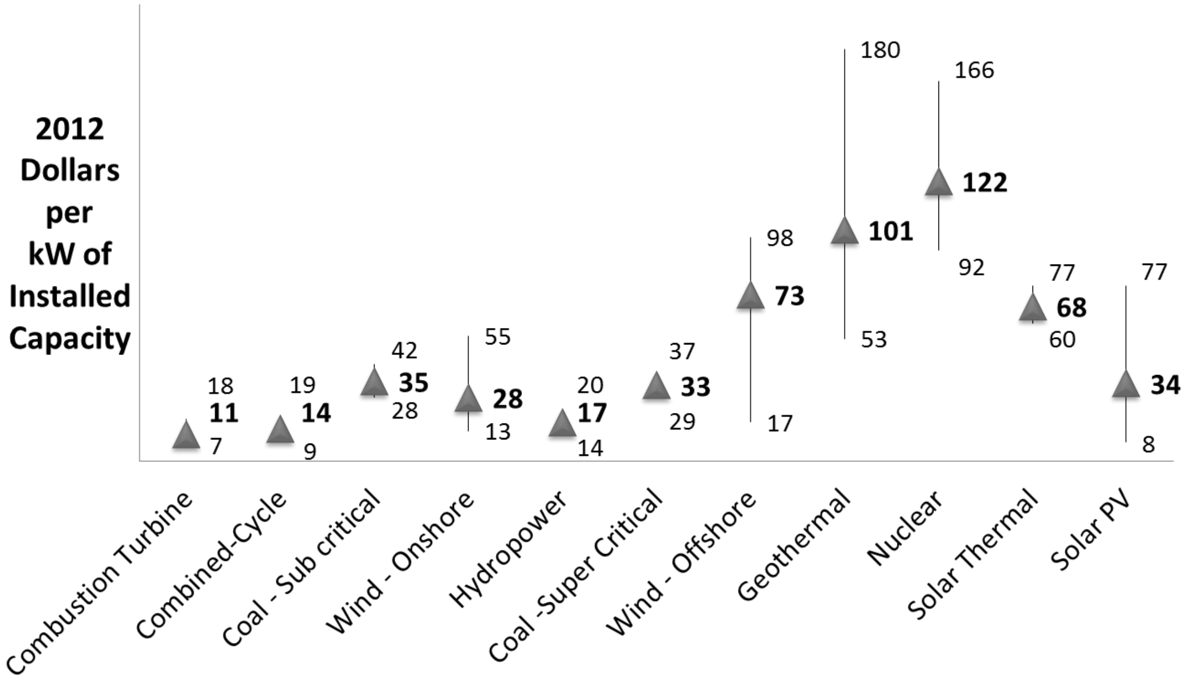


Data Source: Review of Power Plant Cost and Performance Assumptions for NEMS, Technology Documentation Report. (J. Vahn, et. al. - R.W. Beck, 2010)

Fixed and variable operating costs

Estimates for fixed operating costs—that is, costs incurred during the operation of a plant that are not affected by the number of hours the plant is operating—ranged from as low as $11 per kW of capacity per year for a combustion turbine (simple cycle) to as high as $122 per kW-year for a nuclear power plant across the various studies (see Figure 4). Coal and gas-fired power plants tend to have lower fixed operating costs, while renewable energy sources such as geothermal and solar power have higher fixed costs. Because solar PV systems have no moving parts, all operating expenses are considered fixed, helping to increase its fixed costs relative to other technologies. Variables operating costs—those that are directly tied to the number of hours a power plant operates but not related to fuel costs—also present a wide range across the various technologies, from essentially zero costs for solar to as high as $15 per MWh for geothermal.

Figure 4: Fixed O&M Costs for Select Power Generation Technologies



Data Source: Electric Technology Cost and Performance Data (NREL, 2010)

Fuel costs

Fuel expense is the final major cost component. Historically, lower cost fuels such as coal or petroleum coke have partially offset the higher capital cost of steam power plants, while lower capital cost gas-fired plants generally burned more expensive fuels, such as natural gas or diesel. Natural gas prices have also historically been far more volatile than coal, particularly given the seasonal swings in natural gas demand for space heating uses.

Since 2008, however, this conventional wisdom has been challenged, as natural gas prices first spiked in the United States, and then fell dramatically owing to the surge in shale gas production. Coal prices have also showed uncharacteristic volatility in the past few years as first Chinese demand for coal imports put pressure on globally traded stocks, and later the US coal prices fell as cheap natural gas steadily replaced coal for power generation in the United States. Indeed, earlier this year natural gas became the largest fuel source for US power generation, displacing coal from the top spot for the first time.

For this analysis, a range of potential fuel prices was used to illustrate how different fuel prices can affect the relative costs of different generation technologies. The price range selected was representative of historical price volatility for each fuel. Thus, the high estimate for coal prices is double the low price, but the high natural gas price is four times the low estimate.

Power Plant Efficiency

Higher efficiency plants can reduce the impact of fuel prices on the price of electricity. Likewise, plants with higher utilization can spread the capital cost across a greater amount of output than a plant with low utilization, resulting in an overall lower price for the electricity produced.

Power plant efficiency is determined by the technology being used, but is also influenced by the operating conditions, such as the ambient temperature and pressure, and by the condition of the turbine. Poor maintenance, or simply erosion and build-up of impurities as the unit ages, steadily reduce the plant's actual efficiency. This analysis used efficiency levels representative of the current state of the art for each technology.

Levelized cost of energy

The ultimate cost to the consumer of the electricity being generated depends on how efficient the plant is and how often the plant is used.

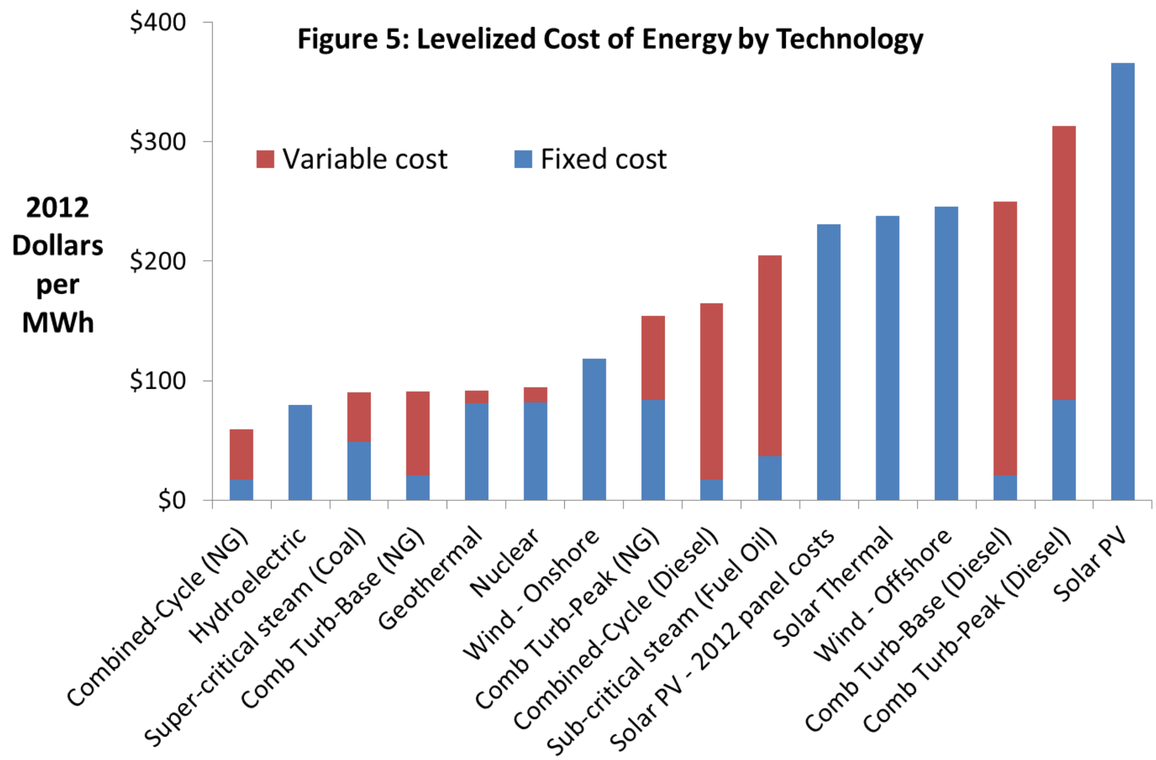
A power plant's utilization can be determined by the market conditions in which it operates (an oversupplied market would likely use each power plant less frequently than one that was undersupplied), by the relative marginal cost of each plant (least-cost plants are used first), and also by each plant's availability (each unit requires periodic maintenance, and renewable technologies that rely on wind or sun cannot operate if their energy source is absent). Table 1 shows the specific assumptions made for each technology in this study.

Table 1: Levelized Cost of Energy Assumptions by Technology

Tech	Nuclear	Steam Turbine (Sub-/Super-)		Gas Turbine (Simple/ Combined		Hydro	Geo-thermal	Wind (On / Off Shore)		Solar (Thermal / PV)	
Size (MW)	2,200	650	1,300	210	400	500	50	100	400	100	150
Efficiency (%)	34	34	38	35	53						
Utilization Rate (%)	90	85	85	15/ 60	85	50	85	25	25	30	22
Fuels	UOx	Fuel Oil / Coal		NG / Diesel							
Fuel Price ($/MMBtu)	1	16 / 4		6 / 22							
Construction Time (years)	4	4	4	1.5	3	5	3	1.5	2.5	3	1
Economic Life	40	40	40	30	30	50	30	30	30	30	20

Data Source: Review of Power Plant Cost and Performance Assumptions for NEMS, Technology Documentation Report. (J. Vahn, et. al. - R.W. Beck, 2010)

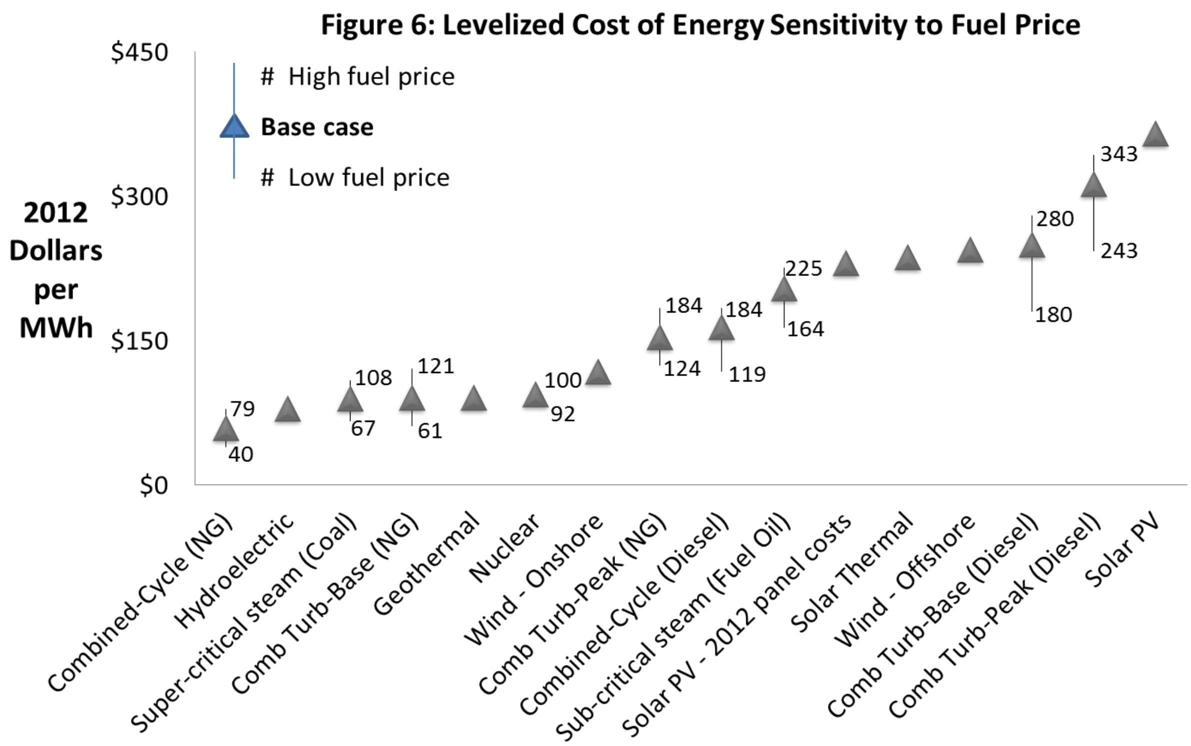
Given the many variations in technical operating characteristics, cost, utilization, and environmental footprint, one method used to compare the cost of generating electricity from different technologies and fuels is the levelized cost of energy (LCOE) produced. LCOE analysis uses the expected utilization of a plant to spread capital and fixed operating costs over the total amount of electricity it can be expected to produce over its lifetime. This methodology results in an average cost per megawatt-hour (MWh) of electricity produced. This approach can also help take into account the intermittent nature of some renewable energy sources, such as wind and solar power. Figure 5 shows the relative LCOE for each technology and fuel combination, highlighting the share from levelized capital costs and the share from operational expenses. All-in levelized costs range from a low of just over $50 per MWh for combined cycle units running on natural gas to a high of nearly $400 per MWh for solar PV units (using panel costs from 2010 – note that when panel prices were adjusted to take into account recent cost savings, the overall levelized cost from solar PV dropped to less than $250 per MWh, or slightly less expensive than off-shore wind or combustion turbines using diesel).



Data Source: Electric Technology Cost and Performance Data (NREL, 2010)

In general, thermal power plants using coal or natural gas were cheaper than renewable energy alternatives, with the exception of hydro power. Thermal plants using liquid fuels such as residual fuel oil or diesel were more expensive than many renewable alternatives, including on-shore wind and geothermal. This analysis is highly sensitive to two variables: the price of fuel (which directly affects the competitiveness of thermal technologies), and plant utilization (which affects the fixed cost share of the total and thus has a greater impact on renewable energy technologies.

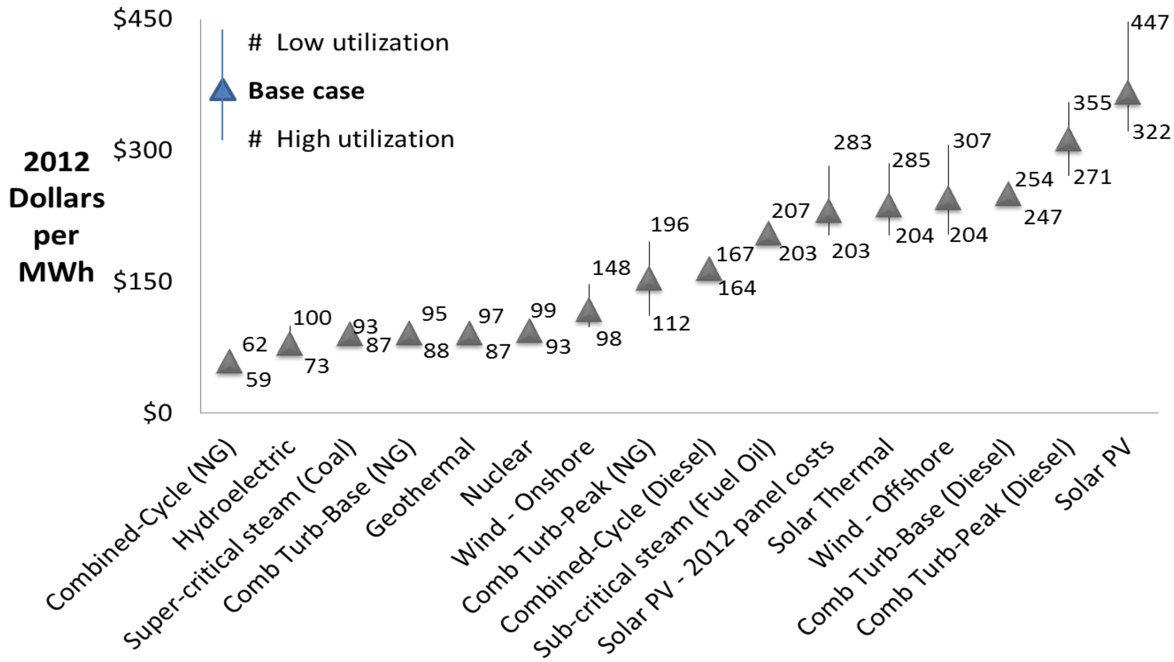
Figure 6 below shows the sensitivity of overall costs to a range of fuel prices. Even under high fuel prices, thermal technologies remain cheaper than most renewable energy options. Geothermal power and hydropower costs are in line with those of thermal power technologies under the higher fuel price level. On-shore wind energy costs are also approaching that of the more expensive thermal power options, assuming the wind resource is of sufficient quality to ensure a capacity factor of 30% or more, although solar power remains more expensive, even with the lower solar panel price case.



Data Source: *Electric Technology Cost and Performance Data* (NREL, 2010)

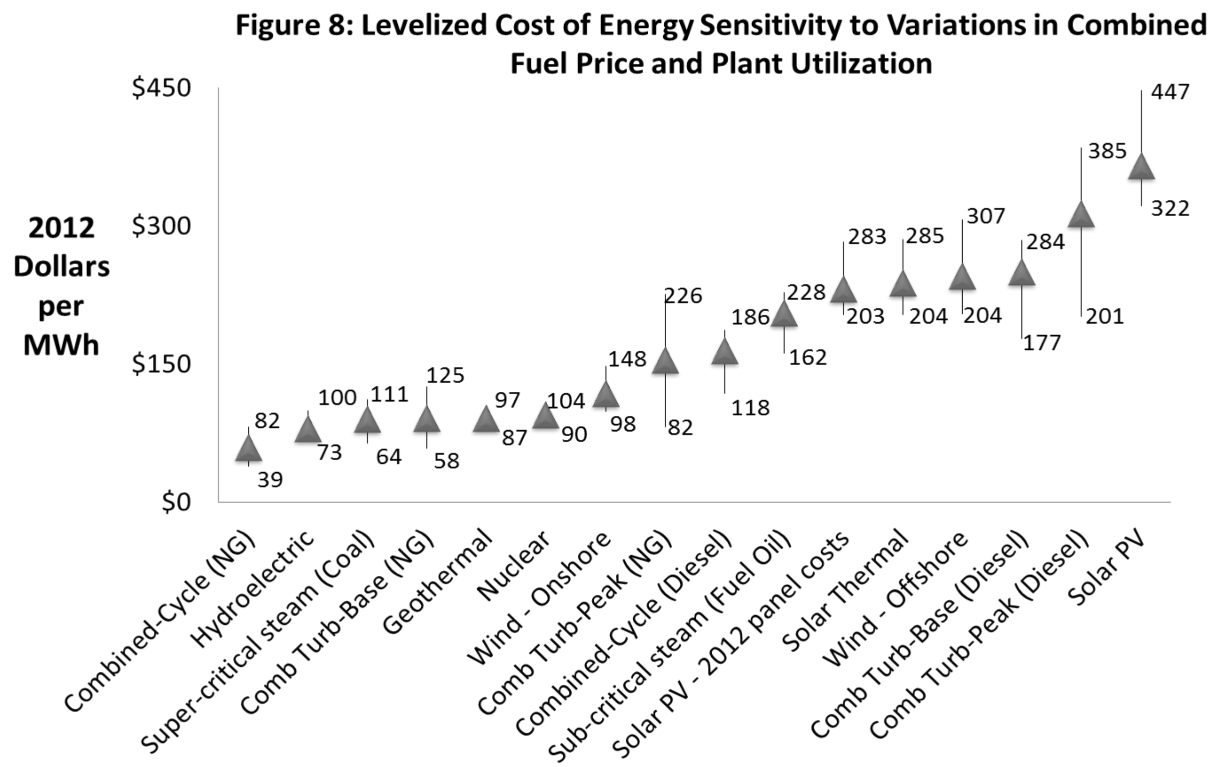
Figure 7 shows the sensitivity of overall costs to a range of plant utilization levels. Changes in plant utilization affect the levelized cost of all technologies, although renewable energy technologies show a greater sensitivity. Lower cost technologies, including hydro power, remained clustered near $100 per MWh at the upper end of the range, while higher cost technologies, including thermal plants using liquid fuels, off-shore wind and solar power, remain over $200 per MWh even in the lower cost estimation.

Figure 7: Levelized Cost of Energy Sensitivity to Plant Utilization Rate



Data Source: Electric Technology Cost and Performance Data (NREL, 2010)

To bring to two variables together, Figure 8 illustrates the combined impact of variations in fuel prices and plant utilization, ranging from an upper bound of high fuel price and low plant utilization to a lower bound of low fuel prices and high plant utilization.



Data Source: Electric Technology Cost and Performance Data (NREL, 2010)

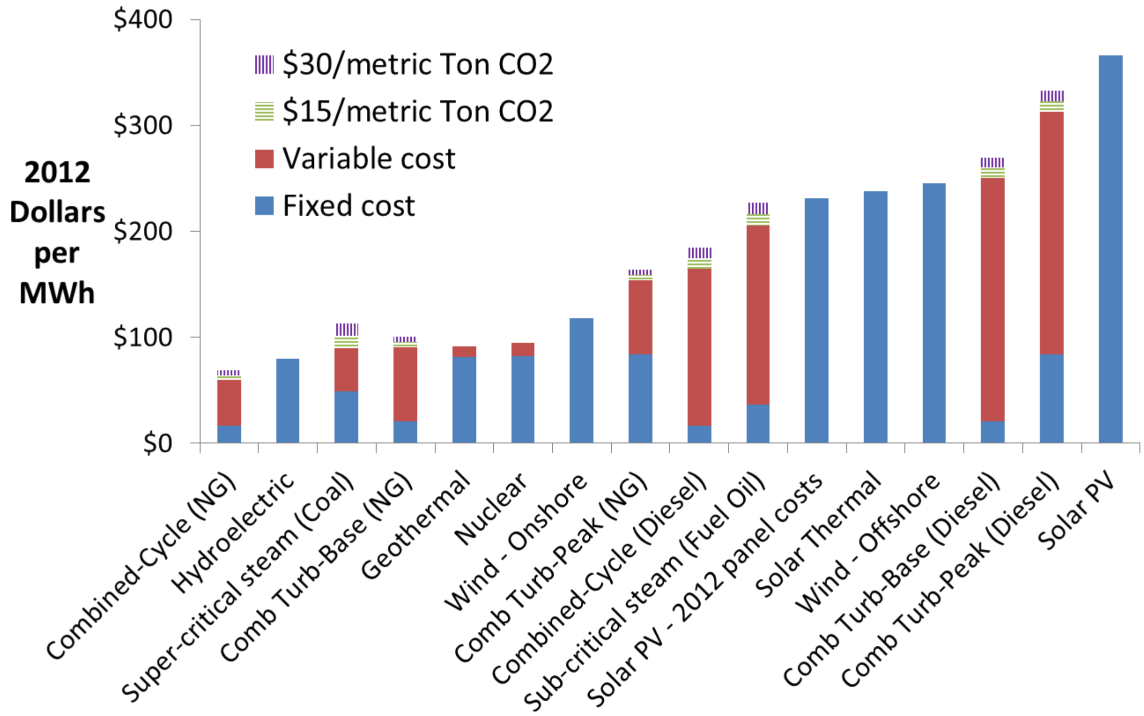
Given the importance of site and project specific costs in determining the ultimate cost of building a power plant, the relatively small range in cost variations across many technologies suggests that there is no clear “best” technology to pursue. Rather, there are two broad cost ranges: in the first, thermal power technologies burning natural gas and coal for fuel are grouped with hydro power, geothermal, nuclear, and on-shore wind technologies. In the second, thermal power technologies burning liquid fuels such as residual fuel oil and diesel are grouped with solar thermal, solar PV, and off-shore wind.

This tight band of cost ranges places additional importance on any external costs that a power plant may face. This study examines two potential external costs: the expense of building additional transmission lines to connect the power plant to the natural grid, and the expense from applying a cost to the plant’s carbon dioxide emissions. Each of these potential external costs are examined in detail below.

Externalities: Carbon Emissions Costs

Figure 9 below shows the impact of two different carbon price levels: $15 per ton and $30 per ton. These price levels are consistent with a number of government proposals for carbon tariffs, and are well above current carbon prices in the European emissions market and the newly established California emissions market, both of which are currently below $10 per ton.

Figure 9: Levelized Cost of Energy with a Carbon Price



Data Source: Electric Technology Cost and Performance Data (NREL, 2010)

Despite a relatively high carbon price, the overall impact on the cost of electricity is minimal, and does not generally shift the position along the cost curve of natural gas or liquid fuel fired generators. The major exception are the coal-fired units, where the higher carbon content of the fuel makes the super-critical coal unit costs similar to on-shore wind and more expensive than geothermal or nuclear power.

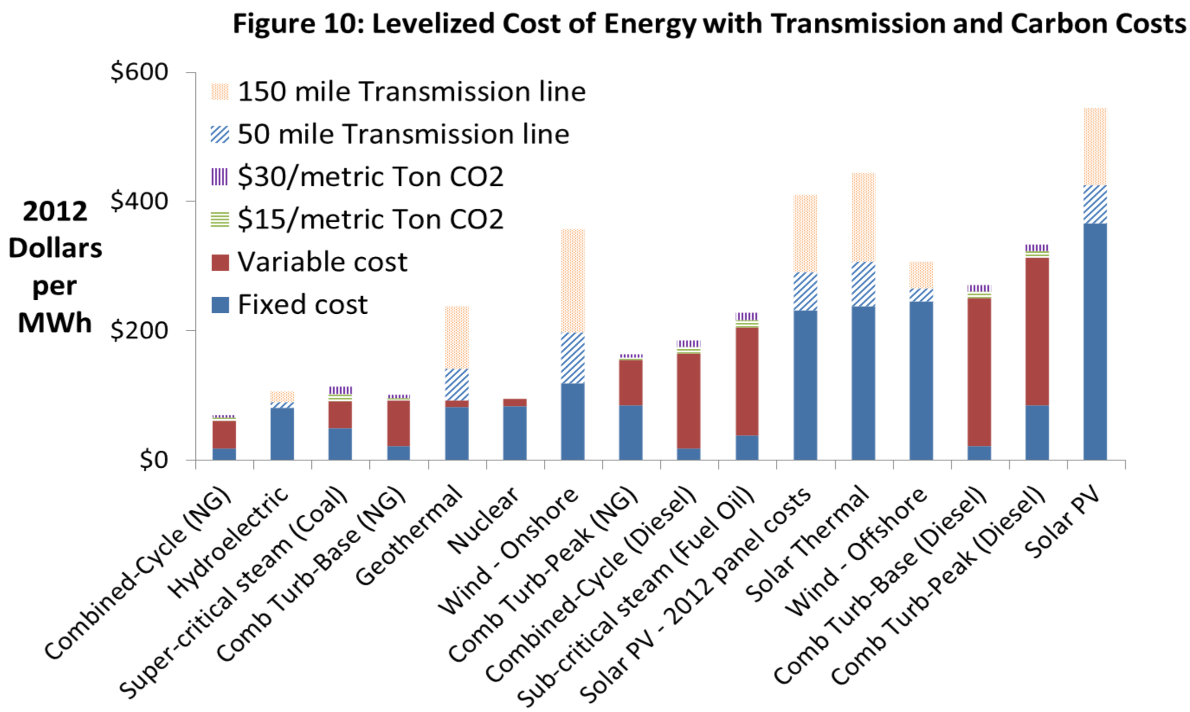
Externalities: Transmission Infrastructure Costs

The cost to build and operate a power plant is not the only cost contributing to the final price of electricity for the consumer. Once the power plant is built, it must be connected to the transmission grid and subsequently to a local distribution system. These costs are generally accounted for separately in the final electricity bill. Indeed, the power plant cost analyses referenced above assume that the plant is located near the required supporting infrastructure. For natural gas or liquid fueled plants, it is assumed that the plant is within one mile of a relevant pipeline or distribution point. Coal fired power plants are assumed to be within reach of a railroad or navigable waterway for coal delivery. All power plants are assumed to be within one mile of a suitable transformer station on the main power transmission grid.

This assumption is valid for technologies that can be placed in any suitable location. The location of many renewable technologies, however, is dictated by the available resource base: hydro power plants must follow the course of suitable rivers, wind farms must be placed to capture the strongest available wind. In these cases, substantial investment in transmission infrastructure may be required and so the related costs could reasonably be included. In a like manner, switching coal or fuel oil fired plants to natural gas may require significant investment in new pipeline capacity, and these costs should also be included in the calculus.

Transmission cost per mile can vary significantly depending on the capacity of the lines, the nature of the terrain being traversed, and the length of the regulatory process to approve the required rights-of-way and related permits. Placing transmission lines underground (as required in some urban environments) or undersea can increase costs by up to an order of magnitude. In February, 2009 Lawrence Berkeley Livermore Lab released a meta study of 40 transmission planning studies—many including multiple scenarios—undertaken to assess the cost to connect new wind farms across the United States to the transmission grid. These studies showed a wide range of incremental transmission costs, ranging from zero to over $1,500 per kW of additional generating capacity for one wind farm—a level close to two-thirds of the expected capital cost to build the wind turbines themselves.

The average cost, inflated to 2012 dollars, was roughly $3 million per mile of transmission line. The cost of building new transmission lines can therefore become prohibitively expensive for new power plants in remote locations. The impact of additional transmission costs on the final cost of electricity delivered to the end customer is affected by the length of the transmission line and the amount of power being sent over the line (that is, the volume of electricity sold over which the capital costs of transmission can be spread). Figure 10 shows the impact on the cost per MWh produced of building a 50-mile and a 150-mile transmission line solely for the use of the power plant in question (that is, the entire cost of building the line is attributed to the power generated from the power plant).



Data Source: Electric Technology Cost and Performance Data (NREL, 2010) and The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies (Mills, A., R. Wiser, and K. Porter, 2009).

Brownfield Investment

Investing in existing power plants, known as brownfield investment, is another approach to expanding power generation capacity or improving the environmental performance of electricity supply. Brownfield investment can include repairing old or damaged equipment, replacing existing equipment with newer components, and adding additional equipment to allow older units to burn different fuels (most generally, switching from coal or fuel oil to natural gas).

Aging power plants naturally lose efficiency as parts wear and contaminants, such as soot in a boiler or silt in a reservoir, accumulate. Postponing scheduled maintenance can also lead to declining performance—a problem in many developing countries with limited surplus power generation capacity or funds available for major maintenance. Simply investing a system-wide overhaul can help return plant performance to near its initial conditions.

The steady improvement in power generation efficiency and power output over the past several decades raises the potential to significantly improve the performance of existing power plants with updated equipment. Such upgrades can include replacing older turbines and boilers with new equipment able to withstand greater temperatures and pressures. Older hydro power plants can also see significantly higher output from the same dam and reservoir, as newer turbine designs are better able to extract energy from the same water resource. This requires much greater investment than simple maintenance, but has the potential to improve a plants performance beyond its original specifications and still at a lower cost than a greenfield project.

Finally, the global surge in natural gas supply over the past few years, built on the promise and widespread distribution of shale gas and other newly discovered resources, can make fuel switching a viable option to reduce carbon emissions from older fossil fueled power plants.

This section of the report will examine two types of brownfield investment: repowering and refurbishing aging power plants, and fuel switching older oil and coal fired units to natural gas.

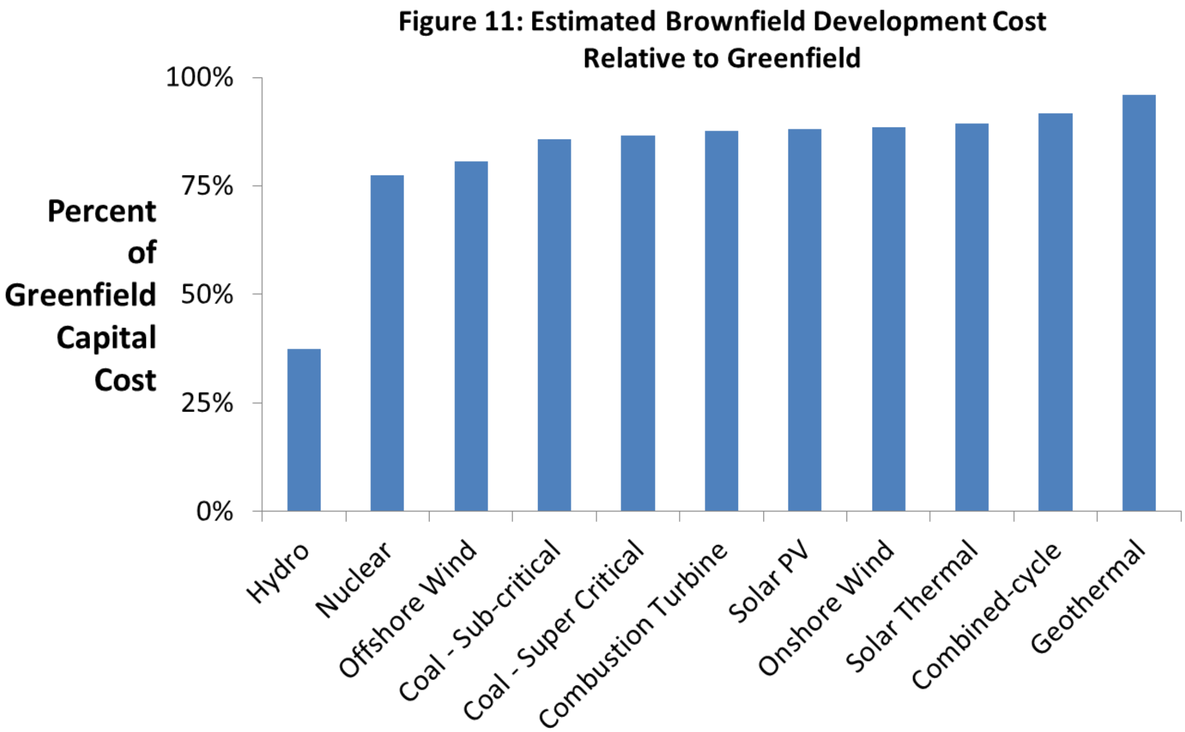
Repowering aging power plants

Repowering older power plants can involve a wide range of activities, depending on the status of the existing equipment and the ultimate goal of the repowering exercised. This analysis examined the option to fully replace the power plants' turbine in order to upgrade them to the current state of the art technology. A major upgrade of this nature would also likely require a full upgrade of the existing electrical components in order to match any increase in power output from the turbine and to reduce any potential losses from aging electrical equipment. As such, for most power generation technologies, the potential savings from brownfield investment come from the limited additional work required for civil works and site preparation, and from the existing related infrastructure (such as transmission lines to connect the plant to the grid and fuel-related infrastructure such as pipelines, storage tanks, railroad links, etc.). Even so, some additional site preparation will likely be required for a major upgrade, as newer turbines may not fit within the existing buildings, and there are some costs related to decommissioning or removing the older turbines and units at the site.

In comparing the potential brownfield costs for each technology, we assumed a small percentage of the civil and site preparation costs would be required, ranging from 5% of the original cost for wind turbines, hydropower plants, and solar PV installations to 25% in the case of steam turbine based technologies, such as coal-fired power plants, geothermal, solar thermal, and nuclear power plants. The full cost of mechanical and electrical components is assumed, and the remaining cost components (project indirect, fees and contingency, and owners cost) are assumed to be the same percentage of total project costs as for greenfield (that is, the cost for each of these components was reduced in line with the overall reductions in total project cost).

Economic Benefits

The results of this analysis show that the cost savings from brownfield investment can vary significantly according to the specific technology (see Figure 11).



Data Source: Review of Power Plant Cost and Performance Assumptions for NEMS, Technology Documentation Report. (J. Vahn, et. al. - R.W. Beck, 2010)

Geothermal power, with a relatively low share its costs in civil and structural work, saw the least benefit, with brownfield investment at just a 4% discount from new build. The thermal-based technologies as well as wind power saw cost savings of roughly 8-14% off of greenfield capital costs, as site preparation made a slightly larger share of the total costs. Off-shore wind and PV installations (based on the recent low cost for solar panels) suggested a potential savings of almost 20% off of the price of building from scratch. Nuclear power also saw a high level of savings, reaching a roughly 23% discount, but hydropower was by far the most cost effective. Because civil works on the dam and reservoir preparations account for more than 40% of the cost of a new hydropower project, fully replacing the working components of existing plants was estimated to cost slightly more than one-third the price of building a new dam, a discount of 62 percent. Refurbishing hydropower projects has the added benefit of enabling greater power production from the same resource base as newer turbine designs are more efficient. Recent refurbishment projects have been able to increase power output by 10-15% from initial nameplate capacity—and actual output from older hydro plants is often well below the original nameplate given plant and reservoir deterioration.

Environmental Benefits

The environmental benefits from brownfield investment derive from the improvements in efficiency at the original plant, and the avoidance of breaking ground for new power plants. Installing state-of-the art equipment can significantly reduce the amount of fuel used to generate each unit of electricity, resulting in fewer carbon emissions per MWh produced.

In addition, upgrading power generation equipment can increase the amount of power generated at the plant. In thermal units, this is generally achieved by returning the plant to its original nameplate capacity. Increasing a plant's output would require larger turbines and essentially a wholesale redesign of the power plant from the ground up, significantly reducing any cost savings from greenfield investment beyond the potential sharing of transmission or fuel delivery infrastructure. For hydropower plants, however, advances in turbine designs can allow greater power output from the same amount of water, essentially increasing the plant capacity by 10-15%. This capacity increase can offset the need to build new carbon-based generation capacity, further helping to limit emissions growth.

Fuel Switching

In addition to improving power plant efficiency, brownfield development can also switch the fuels that a power plant uses to generate electricity. This is most often done to reduce costs, generally by switching from a liquid fuel to natural gas. Using cleaner fuels within a gas turbine can also improve the plant's operational characteristics as reducing the pollutants in the fuel can also reduce the wear on turbine blades, extending the plant's effective life and reducing the frequency of major repairs and maintenance.

Fuel switching can also provide significant environmental benefits, beyond those gained from improved power plant efficiency. Switching from coal or residual fuel oil to lighter fuels such as diesel or natural gas reduces the amount of CO2 and other pollutants such as sulfur dioxide emitted per unit of fuel consumed. Natural gas has the least carbon of any fossil fuel and has no sulfur, making it one of the most environmentally friendly. In addition, solid fuel plants can combine wood chips or other biomass with their fuel mix to bring a renewable fuel element to their operations.

Latin America and Caribbean Experience

In many ways, Latin America's electricity sector is among the greenest in the world. Hydropower provides nearly 40 percent of all power generation across the continent, while clean-burning natural gas, and not coal, is the primary fossil fuel used for power generation. Renewable energy (including large-scale hydropower) plays a major role in electricity generation, accounting for 543 billion kilowatt-hours (kWh), half of the 1,072 billion kWh of electricity consumed continent-wide. This figure is also heavily skewed toward Brazil, however. Brazil consumed 385 billion kWh of renewable energy (almost exclusively hydropower), representing 92 percent of the 420 billion kWh of overall electricity consumption in that country.

Energy supply and demand trends suggest that fossil fuels will provide a growing share of Latin America's electricity needs in the future. According to the EIA's long-term outlook, electricity generated from renewable sources (not including hydropower) in Latin America is expected to more than double between 2007 and 2035, rising from roughly 20,000 gigawatt-hours (GWh) per year to 50,000 GWh per year. Even so, non-hydro renewable energy remains less than 4 percent of total electricity production in the continent. Nuclear power generation was expected to double in the timeframe, although still constituting less than 3 percent of the total, although nuclear power 's future is increasingly uncertain follow Japan's recent disaster. More notably, hydropower is expected to decline in importance, falling from 40 percent of overall supply today to just 34 percent of the total by 2035, despite a 50 percent increase in hydropower output. The fuel that carries the bulk of incremental demand growth—as well as displacing some generation from dirtier fuels such as residual fuel oil and coal—is natural gas.

Brownfield Development in the Latin American Context

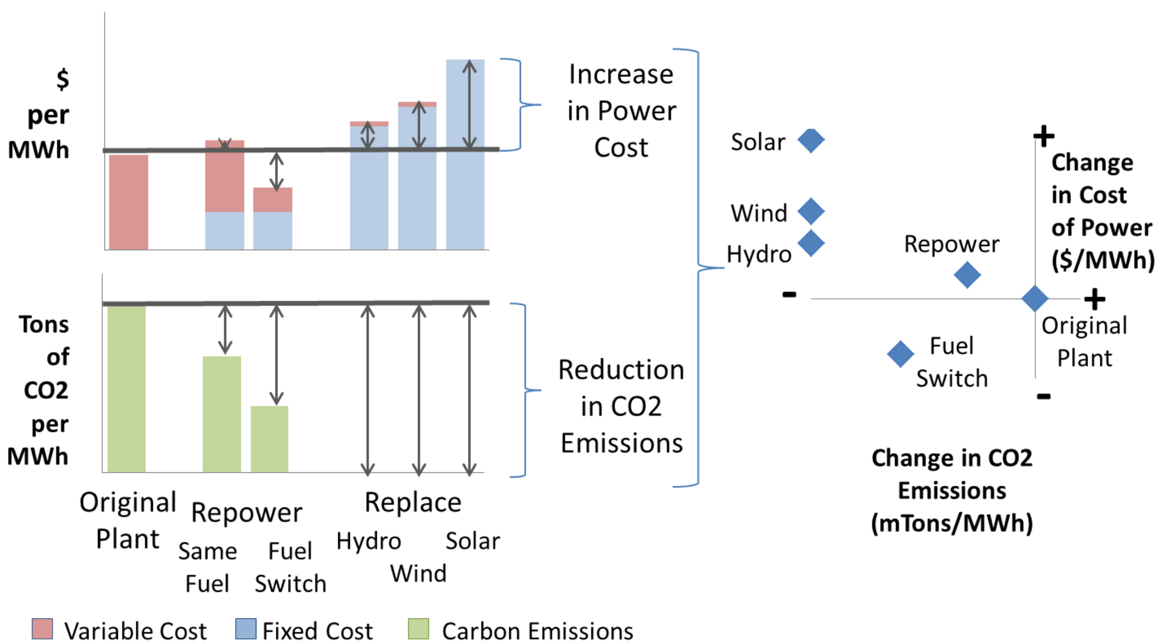
The section applies the above brownfield cost analysis to specific cases in Latin America. First, the basic methodology used to compare the economic and environmental benefits of brownfield development is described. Next, two specific cases are examined: repowering an natural-gas fired gas turbine power plant in Peru and upgrading an existing steam fired power plant in Nicaragua to state-of-the-art technology and switching its fuel to natural gas.

Methodology

Each case compares the benefit of brownfield development across two variables: reduction of the all-in cost of electricity generated and reduction of CO2 emitted per unit of electricity produced. To determine the improvement in each variable, the original baseline cost and CO2 emissions were calculated using current data for the plant efficiency, fuel cost and carbon content. The expected cost and CO2 emissions post-investment were then calculated using the estimated capital cost for brownfield development and the state-of-the-art efficiency for the particular technology. In addition, the all-in cost was calculated for the equivalent power output from hydro (with and without new transmission lines), wind, and solar power. This was done in order to compare the cost of the relative reduction in CO2 emissions from the cost of eliminating the CO2 emissions entirely by replacing the thermal plant with a zero-emission technology.

The change in cost and CO2 emissions for each of the new investment options (brownfield repowering, hydro, wind, and solar) relative to the original plant cost and emissions was then calculated and plotted on a two-dimensional graph. Presenting the relative change of both variables in the same figure helps to visualize the tradeoff between cost of power and reduced CO2 emissions. In this combined figure, investment that result in lower overall cost of electricity and lower CO2 emissions are shown in the lower left hand quadrant. Investments that result in a higher cost of power while reducing CO2 emissions appear in the upper left hand quadrant. A schematic of this methodology is shown in Figure 12 below.

Figure 12: Electricity Cost and CO2 Emission Improvement from Brownfield Development



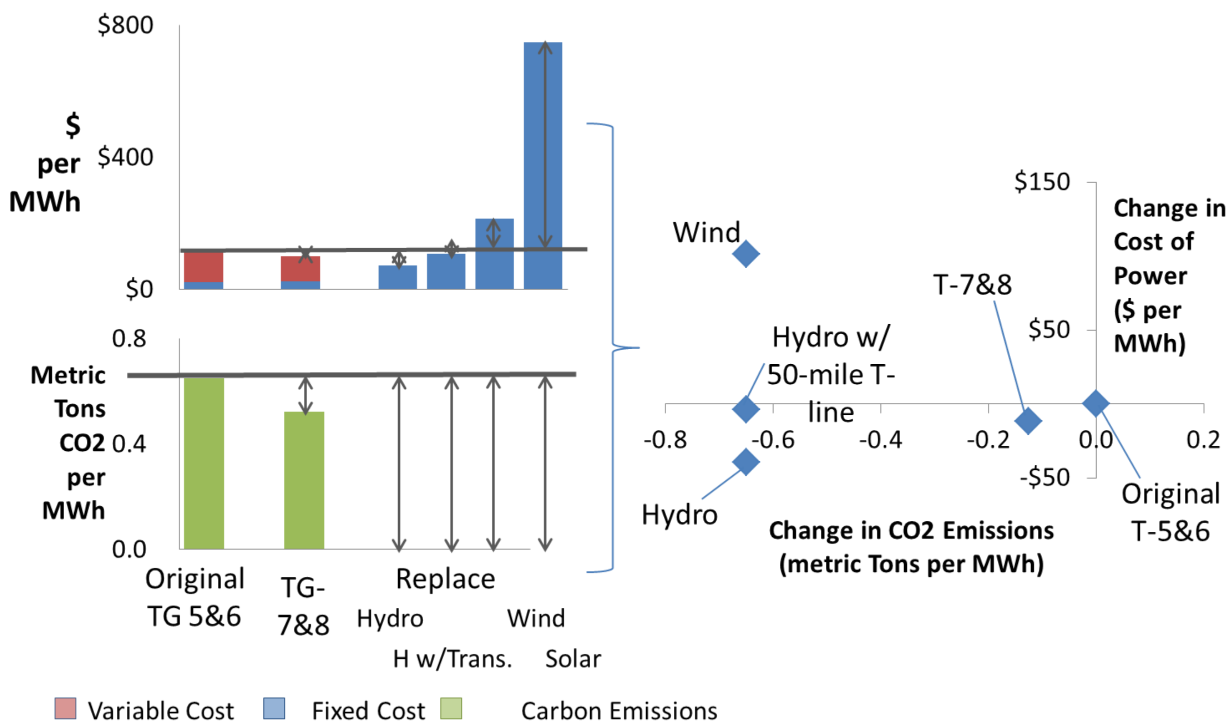
Data Source: Energy Narrative

This methodology was applied to two cases: replacing older natural-gas fired gas turbines in the EDEGEL S.A. Santa Rosa plant in Peru, and switching the fuel-oil fired steam turbines in the GEOSA Nicaragua plant to a state-of-the-art natural gas fired steam turbine.

Case 1: EDEGEL Santa Rosa Units 5&6

EDEGEL's Santa Rosa plant was selected as a case study because a recent expansion had added newer gas turbines (Units 7&8) to the existing older units (Units 5&6). In this way, we were able to use actual operational data from Units 7&8 to examine the difference in cost and CO2 emissions from the older, less efficient Units 5&6. Figure 13 below shows the relative cost of electricity and related CO2 emissions from the original Units 5&6, the newer Units 7&8, and compares them with the cost and CO2 emissions to generate an equivalent amount of electricity using hydro, hydro with a new 50-mile transmission line, wind, or solar.

Figure 13: EDEGEL S.A. Santa Rosa Upgrade Analysis



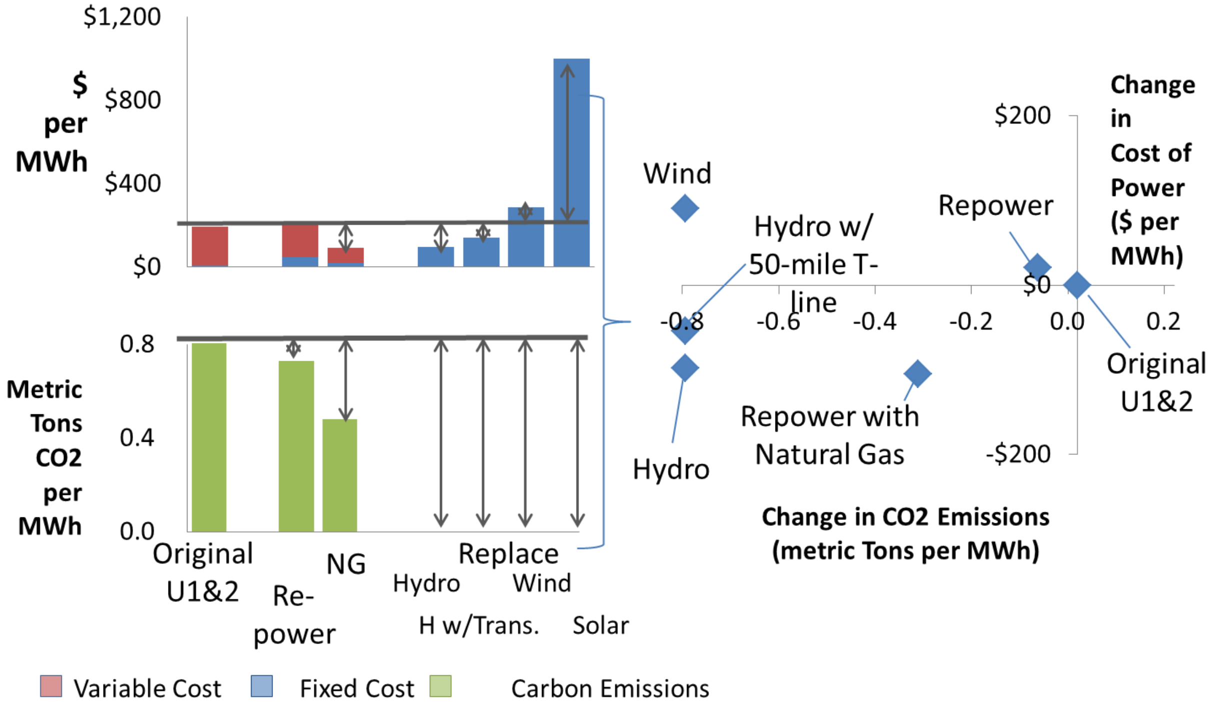
Data Source: Anuario Estadistico de Electricidad, 2010 (Ministerio de Minas y Energia, 2011).

The greater efficiency of the new units resulted in both cheaper electricity and lower CO2 emissions, although the reduction in cost and emissions was relatively small. Replacing the older units with the equivalent in hydro power would have saved even more money and reduced emissions further, unless new transmission lines were needed in which case the cost saving were almost entirely erased. Replacing the older units with wind or solar capacity would have increased the cost of electricity significantly.

Case 2: Repowering and Fuel Switching GEOSA Nicaragua

GEOSA's Nicaragua plant was selected as a case study in order to illustrate the potential benefit of introducing natural gas to Central American power markets. Units 1&2 of the Nicaragua power plant are aging but not significantly less efficient than the current state-of-the-art. In this case, the reduction in operating costs gained from improved efficiency was entirely offset by the additional capital cost to upgrade the plant, resulting in a slightly higher overall cost of electricity. Switching to natural gas, however, had a more significant effect on both cost and CO2 emissions as natural gas is a cheaper and less-carbon intense fuel than residual fuel oil (see Figure 14 below).

Figure 14: GEOSA Nicaragua Upgrading and Fuel Switching Analysis



Data Source: Estadísticas del Sector Eléctrico, 2011 (Instituto Nicaragüense de Energía, 2012).

As in Case 1 above, the brownfield invest and change in cost and emissions was also compared with replacing the equivalent power generation with new hydro capacity, hydro with a new 50-mile transmission line, wind, and solar. In this case, replacing the unit with hydro power resulted in similar reduction in costs while completely eliminating CO2 emissions. Should the hydro unit need a new transmission line, however, the cost savings were greatly reduced. As in Case 1, the relative cost of wind and solar were higher than the original units.

Conclusions and Recommendations

This report has demonstrated the range of capital and operational factors that determine the cost to generate electricity from a variety of mainstream technologies and fuels. Five key conclusions that can be drawn from the analysis, and related recommendations are:

- **Available power generation technologies and fuels have unique benefits and challenges.** Each has its own combination of characteristics that can make a fuel or technology better or worse suited for a particular application. No one technology, however, can be said to be "the best" for all potential applications. Some variables that determine the niche that each technology can fill include:
  - **Size.** The basic unit of capacity for the technologies examined ranged from a kilo-watt or less for solar power panels and small diesel motors up to 700 MW for the largest hydro and steam turbines. The smallest efficient nuclear power plant is significantly larger than the largest solar panel array or wind farm yet built. Because electricity cannot be stored, incremental capacity additions must be sized to the needs of the individual market, making some technologies more appropriate than others.
  - **Operational performance.** Power systems need to be able to ramp power output up and down rapidly to respond to changes in demand. Large steam turbines, especially coal fired and nuclear units, are too slow to be able to match changes in the system load, while smaller gas turbines and hydro units with reservoirs for water storage can be much more flexible. In addition, intermittent renewable energy sources such and wind and solar can be unpredictable, providing clean energy when the sun shines and the wind blows, but needing back up support when the sun does not shine and the wind does not blow.
  - **Cost.** In addition to variations in overall cost, power generation technologies cover a range of capital and operational costs. The availability of investment capital, and the cost of capital for major investments, can affect the relatively attractiveness of different technologies. In addition, both capital costs and fuel costs are constantly changing due to market forces that can be extremely difficult to predict, especially over the lifetime of a power plant.
  - **Infrastructure requirements.** Thermal power plants need ready access to fuel and related logistics such as ports and pipelines, as well as cooling water. Renewables must be located wherever the resource is –along a river, a sunny desert, or a seaside ridge where the wind blows. All power plants need to near transmission lines in order to reach

the market. A power system's current fuel and transmission infrastructure will influence the relative attractiveness of different technologies.

- o **Environmental impact.** All power generation technologies impact the environment, but each as its own unique signature. Fossil fuel plants emit pollutants and CO2, hydro units flood large areas of land and disrupt water ways and fish migration. Wind turbines can kill birds and some find their appearance and noise to be a nuisance. Solar panels can cover large areas of land, disrupting local vegetation and animal habitats. Nuclear plants generate radioactive waste that lasts for centuries.

Recommendation: Rather than attempt to pick the "best" technology, power system planners should instead determine which technologies and fuels are well suited to their particular circumstances and then seek to create a diversified portfolio of options. Doing so can protect against major disruptions in any one technology or fuel, help balance capital and operational costs, and mitigate environmental impacts.

- **Transmission costs are significant although often overlooked.** A new transmission line can significantly increase the cost of new generation, and so must be taken into account when considering different technology options. Major hydro projects can provide relatively low cost clean power, but any cost savings are lost if the units are located far from demand centers and the existing transmission grid. Likewise, for rural populations that are not yet connected to the power grid, small distributed generation technologies may be more cost effective than investing to extend the country's transmission system.

  Recommendation: The cost of any expected new transmission build should be taken into account when assessing the relative cost of power generation technology options.

- **CO2 price must be high to have an impact.** Among the various fossil fueled power plants, only coal plants see a significant increase in cost for relatively modest charges for CO2 emissions. Indeed, the relatively large price difference between liquid fuels and natural gas provides a much stronger incentive to switch fuels than any currently regulated CO2 price would.

  Recommendation: System planners who wish to use a CO2 price to incentivize power developers to choose cleaner technologies must set the price relatively high to have an noticeable impact. Lower prices will not incentivize investment in fuel switching or renewable projects on its own, although it could provide additional tax revenue.

- **Costs are highly project specific, so do not read too much into general studies.** While general technology cost assessments can provide rough estimates, the actual cost of each technology is highly dependent on project-specific factors. Technology providers continually adjust prices to match changes in supply and demand or the cost of basic materials. Large companies may be able to secure discounts that smaller customers cannot, while government backed projects may enjoy a lower cost of capital. Even fuel costs depend on the specific negotiations and leverage of each purchaser, and in turn fluctuate dramatically across time. As a result, it is impossible to determine the exact cost of a particular technology in a particular project without undergoing detailed feasibility studies and preliminary price discovery with a number of suppliers.

  Recommendation: Power sector planners should not underestimate the level of uncertainty when it comes to technology costs or future operating costs. Country-level analysis can provide a more accurate picture of the relative costs of each technology, but even then any forecast should be treated with care.

- **Brownfield investment has great potential to reduce costs and CO2 emissions**. Hydro power plants are the most cost effective as repowered dams can increase capacity at a fraction of the cost of building a new hydro unit. Upgrading older thermal plants can also be beneficial, especially if the plant can be switched to a lower cost fuel.

  Recommendation: The growing abundance of natural gas in the United States and across Latin America could support significant cost and emissions reductions by substituting out more expensive and polluting liquid fuels. Power system planners could assess the cost to build the needed natural gas infrastructure and compare it with the potential savings over time as an important first step.

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