SOCIAL COST OF ELECTRICITY GENERATION:

A QUANTIFICATION AND COMPARISON BETWEEN ENERGY SOURCES WITHIN PJM INTERCONNECTION

by

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ABSTRACT

In order to engage in an honest policy discussion about a 'level playing field' where different electricity generation technologies compete in the open market, it is necessary to recognize not only the private costs of electricity, but also the government subsidies and environmental externalities. While the literature is well developed in each of the individual cost analyses, there lacks a recent analysis of the combined private and external costs of electricity generation and a subsequent discussion of practically policy options to internalize external costs.

This thesis quantifies the total or 'social' cost of various electricity generation technologies for new and existing plants found within the PJM Interconnection service territory. In order to evaluate how the social costs of electricity generation technologies compare, the private costs, external costs, and government subsidies are assessed from the peer-reviewed literature, then the methodologies are analyzed and discussed, and finally the results combined to compute the social cost.

The findings are displayed in several summary measures, including the median of analyzed studies, the social cost best estimate and the high and low cost of carbon. The social cost summary measure results depend on the analyses included from the peer-reviewed literature as well as the assumed cost of carbon. In the best estimate summary measure, assuming a cost of carbon of \$30/tCO_2-eq, the electricity generation technology with the lowest social cost is existing nuclear generation (6.65 $¢_{2010}$/kWh), closely followed by existing natural gas generation (6.71 $¢_{2010}$/kWh). Combined cycle natural gas is the least expensive new generation at 8.21 $¢_{2010}$/kWh,

followed by hydropower (9.25 ¢$_{2010}$/kWh) and onshore wind generation (9.98 ¢$_{2010}$/kWh), as well as SCGT (13.08 ¢$_{2010}$/kWh), new coal (14.02 ¢$_{2010}$/kWh) and new nuclear (14.21 ¢$_{2010}$/kWh). Existing coal generation has a social cost of 21.33 ¢$_{2010}$/kWh, due to high external cost. Solar PV and offshore wind have the highest social costs at 22.36 ¢$_{2010}$/kWh and 24.95 ¢$_{2010}$/kWh, respectively, due to high private costs.

These results are not intended to serve as justification for any specific policy action, but the methodology could be used to perform more in depth and targeted analyses to better understand the social cost of electricity. An important conclusion is that by even including the lowest estimates of external costs and subsidies, the order of technologies in a least social cost comparison changes. Analyzing the costs of electricity without including the government subsidies and external costs does not tell the full story.

Chapter 1

INTRODUCTION

Context for Thesis Research

Since the days of Edison electricity has afforded humanity irreplaceable comfort and opportunity. However, these benefits come at a cost, in terms of the economic price paid for the electricity but also in terms of the un-priced external costs. Economic prices or private costs are derived from the cost of paying for the facilities to generate and transmit electricity: to construct them, to upkeep them, to staff them, and to fuel them. The external costs stem from uncompensated impacts inherent to the generation lifecycle; particulates resulting from the combustion of coal lead to respiratory illness and carbon dioxide resulting from the combustion of natural gas influences global climate change. Individual electricity generation technologies impose different external costs, but all technologies involve some tradeoff when compared to a pristine environment.

During the 112th U.S. Congress much discussion focused around removal of government subsidies to provide a 'level playing field'. In energy this manifests largely as a call to remove federal tax credits for various generation types. However, in order for policymakers to make informed energy policy decisions pertaining to cost-efficient generation, they require the best cost/benefit analysis available. This fact is acknowledged in a recent governmental push in the offshore wind arena seeking to overcome market barriers (see DE-FOA-0000414 and DOE, 2011). In order to have a truly 'level playing field' where different electricity generation technologies compete on the open market without any subsidies, it would be necessary to remove all market distortions. This includes internalizing the external costs of energy generation.

The externalities of most traditional energy technologies are well documented, dating back to research in the 1980s and ‘90s (Hohmeyer, 1988; Ottinger et al., 1990; Pearce et al., 1992; ExternE, 1995a-b; and Lee et al., 1995). As the methodology refined, the research expanded to include renewable energy technologies generally characterized by low external costs, such as solar photovoltaic, onshore wind and eventually offshore wind (ExternE-Pol, 2005; NEEDS, 2008; NEEDS, 2009). While interest in external costs has returned to the U.S. national policy discussion (NRC, 2010), there is a limited record of inclusion of externalities in energy policy decision making. Furthermore, since private and external costs are not static, but rather vary as technologies change, operations become more efficient or fuel prices fluctuate, updated assessments are required periodically. Other than the recent Greenstone and Looney (2012), there lacks an updated analysis of the combined private and external costs and benefits of electricity generation technologies similar to the European Commission sponsored Cost Assessment of Sustainable Energy Systems (Markandya et al., 2010) or the older Hohmeyer (1992) and Kammen and Pacca (2004), and a subsequent discussion of practical policy options to internalize externalities to ameliorate an economic market failure.

In addition to externalities, to fully remove market distortions, existing tax subsidies (e.g., tax credits for all energy sources, in varying quantities and loan guarantees for nuclear and renewables) and in-kind government contributions (e.g., military support for petroleum transport) should be eliminated. Tax subsidies and in-kind contributions are charged to taxpayers at-large rather than directly to the generators or consumers of electricity. The commonly accepted economic policy arguments behind tax subsidies for energy technologies: that it is in the national interest to subsidize emerging technologies to expedite cost-competitiveness, and that relative environmental benefits of technologies are not fully accounted for in the market; are not applicable to mature generation techniques. The current argument behind in-kind government contributions—especially for petroleum—is that mature technologies are essential to the national economy, although there does not seem to be a reasoned argument that in-kind subsidies should be free.

Goals for Research

The goal of this research is to assess the total or 'social' cost of various electricity generation technologies found within the PJM Interconnection service territory (subsequently described). This is achieved by combining the private costs of electricity with the external costs, benefits, and government subsidies in order to understand how the social costs of technologies compare. The private costs are taken from U.S. government analyses. Government subsidies and the external costs and benefits are assessed in the peer-reviewed literature. Because this thesis seeks to assess current, traditional generation costs and renewable generation costs the study includes an analysis of the following technologies: coal; natural gas, both combined cycle gas turbine (CCGT) and simple cycle combustion turbine (SCCT); nuclear; hydro; solar photovoltaic; onshore wind; and offshore wind. This is by no means a comprehensive list of generation technologies, but it represents 98.8% of generation within the PJM service territory and all the renewable electricity generation with the exception of landfill gas and solid waste incineration (MMU, 2011) as well as technologies with substantial potential. The social costs are subsequently compared across energy sources and policy options to internalize externalities are discussed. This study is geared specifically towards the PJM service territory where substantial renewable energy build-out is expected in the future.

Research Questions

This project seeks to answer the following questions:

- What are the private costs and government subsidies of coal, natural gas (both CCGT and SCCT), nuclear, hydro, solar photovoltaic, onshore wind, and offshore wind in U.S. dollars per kWh?
- What are the external costs and benefits associated with coal, natural gas (both CCGT and SCCT), nuclear, hydro, solar photovoltaic, onshore wind, and offshore wind in U.S. dollars per kWh?
- What are the government subsidies for coal, natural gas (both CCGT and SCCT), nuclear, hydro, solar photovoltaic, onshore wind, and offshore wind in U.S. dollars per kWh?
- How do the social costs compare between renewable energy and traditional energy sources, such as coal, natural gas and nuclear, on a per kWh basis?
- What is the net social cost or benefit of additional renewable energy capacity to the PJM grid?
- Given the results from the first five questions, what are some policies that can bring power generation decisions closer to economic rationality?

The remaining chapters are organized as follows. The following chapter, the literature review, provides background information about the electricity sector and the various energy generation technologies discussed in this thesis, including a lengthy introduction to offshore wind power because less has been written on this subject. Furthermore, chapter 2 discusses the body of peer-reviewed literature related to energy externality studies, in an effort to inform the reader of past work and provide a basis for the thesis. Subsequently, chapter 3 outlines the methods and studies used to answer the research questions with sufficient detail and transparency that a reader could replicate the analysis. Chapter 4, the calculation of social costs, presents the private costs of and subsidies to PJM electricity generation sources according to market data and peer-reviewed literature. Additionally, the various external costs and benefits of energy sources are calculated and discussed from values found in the literature. In chapter 5, the results of the calculations chapter are presented, including appropriate figures, tables, and graphs. In final chapter—chapter 6—the results are discussed in a way that provides further analysis and context to the numbers found in the previous chapter; including policy options to internalize externalities. As part of the last chapter, areas for further exploration, policy recommendations, and final comments are discussed.

Chapter 2

LITERATURE REVIEW

This chapter provides an introduction to the independent system operator PJM Interconnection and background information about the environmental impacts of prominent electricity generation technologies within PJM. An overview of the origins and various methodologies of energy externality studies, as well as an analysis of externality study policy relevance, provides context for the scope of work and a framework for this thesis.

Electric Sector Overview

PJM Interconnection (henceforth PJM) is a federally-regulated, profit-neutral independent system operator (ISO) which coordinates the wholesale transfer of electricity and manages the high-voltage electric grid across thirteen states and the District of Columbia. The PJM region covers over 60 million people and spans from North Carolina in the south, through Pennsylvania in the north, to the Atlantic Ocean in the east and to Chicago in the west (Figure 1) (PJM, 2012a). The electricity generation capacity within PJM consists of mainly fossil fuel-fired power plants (both coal and natural gas) and nuclear power plants with small amounts of renewable energy (mainly hydro and onshore wind) (Figure 2). The ISO region has a peak generation capacity of 185,600 megawatts (MW) (PJM, 2012a) and average load of 82,541 MW (MMU, 2012).

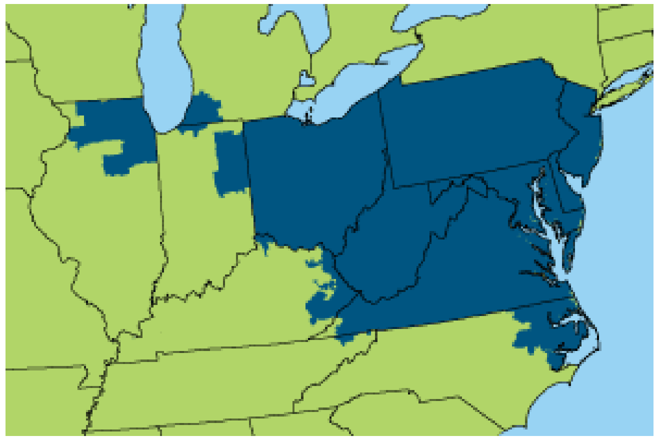

Figure 1 **The PJM Interconnection service territory (PJM, 2012a).**

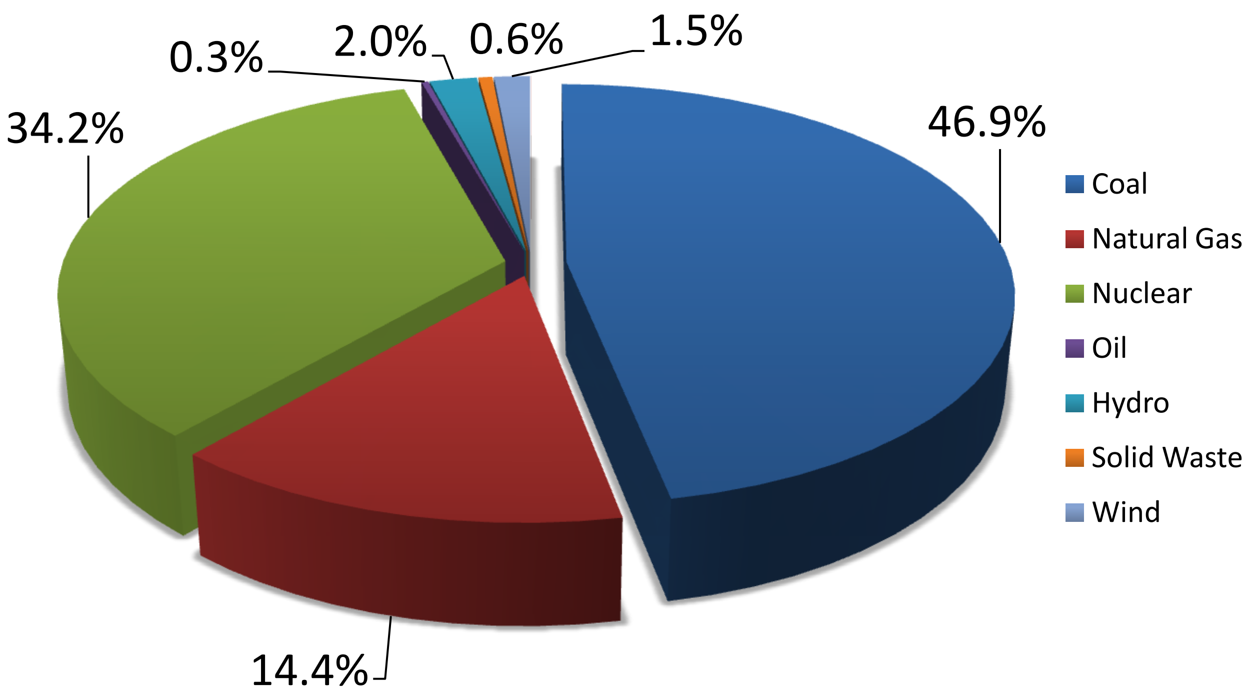

Figure 2 **2011 PJM Interconnection electricity generation by source. Data from MMU (2012).**

Since renewable energy sources have no fuel costs, renewable operators can profitably bid into the wholesale market when other types of generation are priced out of the market. For that reason the addition of renewable generation can displace higher-priced coal and natural gas generation at the margins. According to the former PJM market analysis team—the now independent Market Monitoring Unit (MMU)—in 2010 wind power generation within PJM displaced 70% coal generation and almost 22% natural gas (complete results displayed in Figure 3) (MMU, 2011). However, in 2011 wind amounted to only 1.5% of the total energy consumed in PJM and 650 MW of capacity (MMU, 2012). An internal PJM study of the impacts of 10 GW, 20 GW, and 30 GW of offshore wind power interconnected at equal levels across four integration sites found that 10 GW offshore wind would displace roughly 49% natural gas and 51% coal generation (McGlynn, 2010). These ratios are not constant, the displacement ratio changes as the penetration of offshore wind increases or the relative fuel costs of coal and natural gas change. Based the results of these two studies, the generation displacement depends on the location of the additional renewable generation and the amount of renewable energy added to the system.

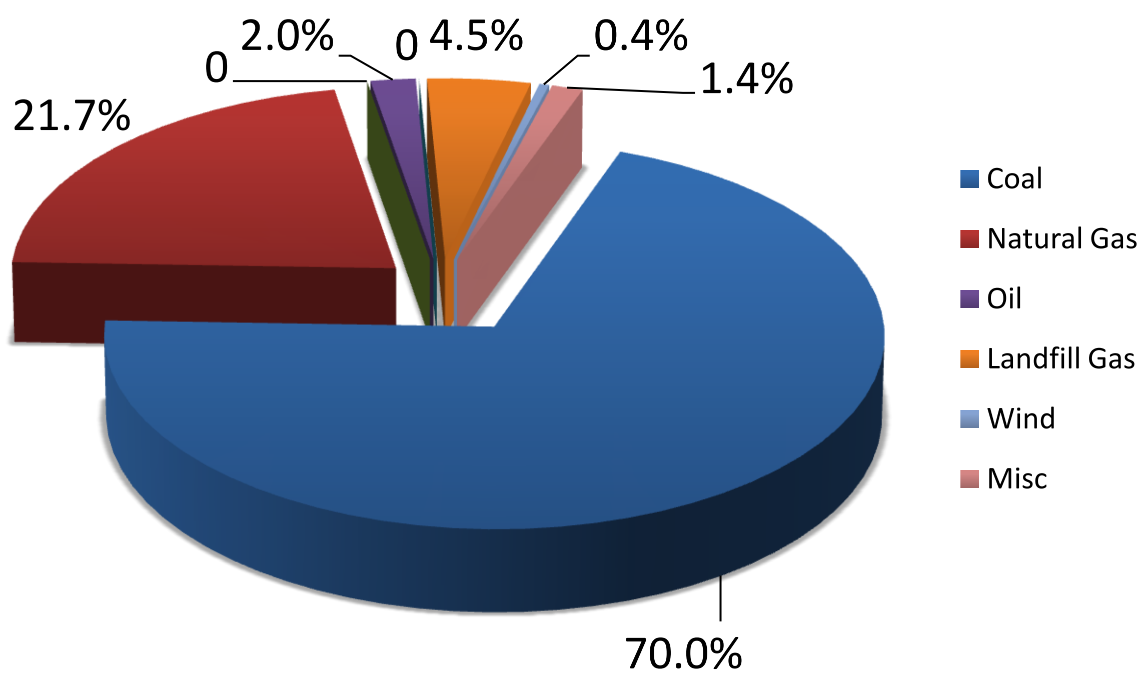

Figure 3 Generation displaced by wind power at the margins. Adapted from MMU (2011).

Overview of Electricity Generation Technologies

Coal

In 2011 almost 47% of the demand within PJM was satisfied by coal power (MMU, 2012), this is more than the national average of 45% (EIA, 2012a). Bituminous coal is the most commonly used type of coal within PJM, followed by the lower heating grade—but lower sulfur content—sub-bituminous coal (EIA, 2012). Both variations are commonly known as ‘hard’ coal. The extraction of coal is performed through ecologically damaging surface mining or underground mining. To generate electricity, bituminous coal is transported from mines in Kentucky, West Virginia and Pennsylvania, and sub-bituminous coal is transported from Wyoming and Montana to power generation stations where it is used as the heat input into a thermal power station. In a thermal power station, the coal is combusted to heat water into superheated steam. The resulting steam is run through a steam turbine that is connected by a shaft to a generator which spins rapidly to produce electricity. The steam then passes through a condenser where the excess heat is rejected to a heat sink (either a body of water or the atmosphere via a cooling tower). Coal power plants, especially older plants, have lower ramp rates than natural gas power plants which make them less adept at ‘load-matching’ or continuously varying output to match electricity demand.

Coal External Impacts

From mining, to processing, to transport, to combustion, and to interment of waste, coal generation inflicts severe impacts upon the human and natural environment during its lifecycle (lifecycle defined as per ISO, 2006). The construction of coal power plants modifies the existing landscape. The extraction of coal through either underground mining or surface mountaintop removal is inherently accident prone and toxic to workers (ExternE, 1995a); not to mention the scarring and poisoning it causes the local ecology and natural environment (Fox, 1999). Combustion of coal yields myriad undesired solid waste and pollution problems including: sulfur dioxide (SO_2), nitrous oxides (NO_x), ozone, particulate matter, fly ash, bottom ash, heavy metals (e.g., mercury) and other known carcinogens (ExternE, 1995a). Acid rain from SO_2 emission damages the built environment, forests, fisheries and other ecology. Air pollution such as smog and haze from the release of particulate matter, ozone, and chemical transformation of SO_2, NO_x can lead to respiratory illnesses, lung disease, heart disease and ultimately premature mortality (Mustafic et al., 2012). Through consumption of contaminated organisms and bioaccumulation, heavy metals, such as mercury, rise up the food chain and can eventually cause cancer in humans. Fly ash and bottom ash are precipitated out of emissions but become a solid waste problem which must be stored indefinitely in landfills where minerals from the ash can leach into groundwater (EIA, 2012). Furthermore, the intake water for cooling impinges and entrains billions of pelagic animals, and the rejection of excess heat to the environment increases surface water temperature and affects biological life (Jarvis, 2005). In addition to the aforementioned local impacts, coal combustion releases carbon dioxide (CO_2), which influences global climate change and ocean acidification (IPCC, 2007). Because of existing governmental regulations, not all of these environmental and societal impacts are un-priced in the economic price of coal, but many are considered uncompensated external costs.

Natural Gas

More than 14% of the PJM demand was met by natural gas power in 2011, an increase from the almost 12% in 2010 (MMU, 2012), but less than the national average of 20% (EIA, 2012a). Natural gas, which is composed of at least 80% methane, is extracted through onshore or offshore wells and transported through pipelines across the country to generating stations. Some natural gas is imported through offshore Liquid Natural Gas terminals, although according to the Energy Information Administration, or EIA, (an agency of the U.S. Department of Energy) only about 2% of the natural gas consumed in the United States was imported through LNG terminals (EIA, 2012b). Thus, the imported fraction will not be treated separately here. Recently, natural gas extraction from the Marcellus and Utica Shale Formations within the PJM region has received substantial interest and scrutiny. Shale gas extraction through hydraulic fracturing requires the introduction of fluids into underground shale deposits to fracture the rock formations and allow the emission of natural gas. Hydraulic fracturing expansion has substantially dropped the natural gas price and revitalized rural regions, but it has also induced concerns about fugitive methane releases and contaminated groundwater (Mouawad & Krauss, 2009).

There are two different natural gas power plant configurations considered in this thesis: simple cycle combustion turbine (SCCT) and combined cycle gas turbine (CCGT). The SCCT configuration includes a combustion turbine fueled by natural gas which is connected to an electric generator. The natural gas is heated to cause rapid expansion through combustion, which turns the turbine. The downside of SCCT is that a combustion cycle only utilizes a portion of the thermal energy available in natural gas, and therefore, substantial energy in the heated exhaust gas is wasted in the process. However, the benefit of simple cycle power plants are their ability to ramp up and down, or cycle, rapidly without need to stay online for any extended period of time (a requirement for coal, nuclear or even CCGT power plants). This allows them to match load and meet peak demand when electricity demand is high, for this reason SCCT power plants are known as ‘Peakers’. Furthermore, this makes them well suited to serve as backup generation for variable solar and wind generation.

The CCGT configuration takes advantage of the remaining heat in the exhaust gas through the addition of a steam turbine. In a CCGT, as in a SCCT configuration, system natural gas first fuels a combustion turbine, however, rather than waste the remaining thermal energy, the exhaust gas is then used as the heat input in a thermal power system. The otherwise waste energy, heats steam, which expands, and the pressure turns a steam turbine connected to a generator. As a result of the additional turbine, a CCGT power plant achieves higher efficiency, which, as will be subsequently be addressed, means higher capital cost but lower operating expense than a SCCT plant. A modern combined cycle power plant can achieve up to 60% efficiency while simple cycle plants are normally about 35-40% efficient (Casazza & Delea, 2010).

Natural Gas External Impacts

The lifecycle impacts of natural gas vary depending on how the gas was extracted. In general, natural gas has fewer impacts when compared to coal, but many of the same issues remain, albeit to a smaller degree. Conventional natural gas well drilling disturbs the surrounding environment and wells leak methane and other known greenhouse gases, some of which are trapped or flared to reduce the carbon footprint. Combustion of natural gas releases SO_2 and NO_x which cause air pollution problems, however the concentrations are much lower than coal. Similarly, natural gas emits about half as much CO_2 as coal to generate the same amount of electricity. The emitted amounts are, nonetheless, far from negligible. In addition, as in other thermal plants, water—often allocated for free or below market price—is required as a heat sink in the process.

The new hydraulic fracturing, or fracking, techniques employed in the Marcellus Shale present a litany of additional environmental problems. Fracking requires extensive amounts of water to displace natural gas. The water could otherwise be used for irrigation, human consumption or to sustain ecology. Furthermore, some groundwater aquifers in areas near hydraulic fracking show increased concentrations of methane high enough to be considered a combustion risk

(Osborn et al., 2011). The chemicals used in the extraction process have the potential to seep into the groundwater as well. Additionally, fugitive methane emissions increase an estimated 30-200% from the fracking process compared to conventional extraction (Howarth et al., 2011). Moreover, since methane has about a 72-times greater 20-year impact in climate change than CO_2, over the short-term, natural gas extracted through fracking could have a larger warming potential than coal (Howarth et al., 2011). Over 100 years, the lifecycle greenhouse gas emissions of electricity generated from natural gas extracted through fracking and coal are estimated to be about the same (Howarth et al., 2011).

Nuclear

Within the PJM region more than 34% percent of the demand was met by nuclear power in 2011 (MMU, 2012), which is substantially more than the national average of about 21% (EIA, 2012a). Pressurized-light water and boiling water nuclear power plants, like coal and natural gas, use a thermal power system consisting of a steam turbine connected to a generator. However, unlike traditional fossil fuel power plants, the fuel source used to heat water is atomic energy, supplied by the breakdown of unstable radioactive elements through nuclear fission. In the United States, the most widely used nuclear fuel is uranium (EIA, 2012c). Most the uranium mined in the United States comes from Wyoming and is extracted through *in situ* leaching (NRC, 2010). Nuclear power plants do not cycle generating capacity to follow demand because of the time required to initiate or terminate the fission reaction, and therefore, nuclear units generally run continuously.

Nuclear External Impacts

The mining, construction, refining and transportation of materials required for nuclear power, such as concrete and nuclear fuel, require substantial amounts of energy (ExternE, 1995b). Since, at least a portion of that energy is derived from fossil fuels, pollutants and CO_2 are emitted. Like other thermal power plants, nuclear plants require substantial amounts of water for cooling which depletes local reserves and can impact the ecological and human environment (Sovacool, 2009a).

The most problematic impact from nuclear is the resultant radioactive waste. Low-level waste such as mine tailings and anything which gains radioactivity must be buried and stored away from biological contact. In the US, no long-term solution exists for high-level waste, such as spent nuclear fuel rods. As a consequence, the waste is stockpiled in dry-casks and storage ponds at the nuclear generating stations around the country. Human interaction with radioactive material increases the risk of cancer and hereditary defects (ExternE, 1995b). Nuclear power plants also have a risk of disastrous failure. Although the overall risk of a nuclear meltdown is low, because the probability is low, the damage would be enormous, which is critical for public perception of the generation technology. The recent disaster in Fukishima, as well as the Chernobyl meltdown demonstrated just how devastating a nuclear catastrophe can be.

Hydro

Hydroelectric power accounted for 2% of the electricity generated within PJM in 2011 (MMU, 2012), less than the national average of almost 8% (EIA, 2012a). Electricity is generated from hydropower by the damming or diversion—as is the case in the run-of-river technique—of rivers. When a river is dammed, the water stored behind the dam in a lake or reservoir is fed through the dam, past the blades of turbines, which spin generators to generate electricity. The kinetic energy of falling water is transferred to mechanical energy, which in turn is used to generate electricity. Similarly, in the run-of-river hydropower some water is diverted from a river into a separate channel, and the kinetic energy from free-flowing water is used to turn a mechanical turbine to spin a generator. Given sufficient water levels, hydroelectric power tends to operate full-time, because once the major capital investment in the dam is made, the marginal cost of operation is low. However, hydropower can be run as variable generation by varying the water flow or even provide energy storage through specialized pumped storage plants.

Hydro External Impacts

Hydroelectric power, like all other power sources, produces pollutants during its lifecycle. The mining and production of concrete and steel used in the construction of hydroelectric dams requires energy, and therefore produces pollution. Although most of the construction of dams in the United States took place a half-century ago, it is important to remember that the damming of rivers destroys the environments behind the dam, be they natural, human, agricultural, etc. By inundating previously uncovered land, newly flooded biological resources slowly undergo anaerobic decomposition, releasing the potent greenhouse gas methane. Furthermore, the construction of a dam changes river water flow, chemistry, temperature, sedimentation, and therefore impacts the biodiversity both upstream and downstream. One such impact is preventing fish, such as salmon, from returning to spanning sites. Additionally, dams impinge and entrain aquatic life. Lilley and Firestone (2008) estimate that almost 366 fish are killed per gigawatt-hour (GWh) generated from hydropower.

Solar Photovoltaic

Solar photovoltaic (PV) power constituted a minute (0.007%) portion of the PJM generation in 2011 (MMU, 2012), which is less than the national average of 0.04% (EIA, 2012a). Solar PV panels exploit the photovoltaic principle that some materials produce an electric current when exposed to light, discovered in 1839 by A.

E. Becquerel (Wenham et al, 2007). The photovoltaic principle occurs when the energy from light exceeds the minimum energy level required to excite an electron and cause it to break free of its static state and conduct away as current. Solar power is variable generation that is available when the sun is shining. Small penetrations of solar power are easily integrated into the grid mix, and as penetration increases solar power can be balanced by cycling natural gas power or by storage (Zweibel et al., 2008).

Solar Photovoltaic External Impacts

While solar PV does not directly emit any pollutants, solar panels require energy, toxic chemicals, solvents and materials to manufacture; all with non-negligible environmental costs. Other lifecycle impacts include the energy required to transport and install the panels. Furthermore, depending on how the panels are deployed, local ecosystems can be impacted through the removal of habitat. On the other hand, if solar panels are installed near electric loads in a distributed manner, solar power can have a positive impact to the grid through reduced need of electric transmission and distribution systems estimated on the order of $0.09-0.25 per kilowatt-hour ($/kWh) (Pepermans et al., 2005; Perez et al., 2011). A study which assessed the fossil fuel external and private costs avoided by solar power projects in Pennsylvania and New Jersey found the benefit to be $0.26-0.32 per kWh (Perez et al., 2012).

Onshore Wind

With more than 60 GW of wind capacity at the end of 2012, the United States is second only to China (76 GW) in terms of installed wind power capacity (GWEC, 2013), and is the country with the most electricity generated from wind power (BP, 2012). Moreover, the U.S. installed wind capacity grew by 28% in 2012 (AWEA, 2013) and the industry employs 75,000 people (AWEA, 2011a). However, wind power accounts for only a fraction—about 3%—of U.S. electricity consumption (EIA, 2012a) and comprises only 1.5% of the electricity generated within PJM (MMU, 2012). Wind power currently contributes higher percentages in European countries such as the United Kingdom (4%), Germany (6%), Spain (17%) and Denmark (26%) (GWEC, 2011).

Wind power—both onshore and offshore—harnesses the kinetic energy from the wind through the blades of a wind turbine and transfers it into mechanical energy. The mechanical energy is converted to electricity through a shaft connected to a generator. Wind power, like solar power, is variable generation that is dispatched when available and can be balanced by existing grid generation capacity. In fact, the U.S. Department of Energy (DOE) determined that 20% of the national electricity demand could be met by wind power by 2030 without major storage projects and at an incremental cost of only 2% (DOE, 2008). Denmark—which already has 26% wind power—has a more ambitious plan to use 50% wind energy by 2025 by balancing large penetrations of wind with storage and transmission connections to neighboring countries (EA Energy Analyses, 2007).

Onshore Wind External Impacts

Wind power does not have any direct pollutant emissions, but like other renewable energies, emits pollutants through its lifecycle. Refining and manufacturing of steel and concrete required for wind turbines, as well as their transport, installation, and maintenance; necessitates consumption of fossil fuel energy and therefore emission of pollutants (Vestas, 2006). Wind project operations have elicited public health concerns related to noise, shadow flicker and electromagnetic fields (CKPHU, 2008). However, other than annoyance, researchers have not found evidence of any direct links to medical problems (CMOH, 2010). Similarly, researchers at Lawrence Berkeley Laboratory found that despite reported aesthetic concerns about wind turbines reducing property values, neither the view of nor the proximity to a wind facility has a consistently measurable or statistically significant effect on home sale price (Hoen et al., 2009).

Perhaps the most common complaint related to wind power is the avian impact (Sovacool, 2009b). Avian mortality from collision is an issue for wind power, but 75% of wind projects surveyed in 2010 had a mortality rate of 3 or fewer birds per MW each year (NWCC, 2010). Overall, avian casualties due to wind turbines are several orders of magnitude lower than other anthropogenic sources like buildings, cars, and cats (Erickson, 2001).

Bats face concerns of high mortality rates due to wind turbine facilities (Arnett et al., 2008). These deaths raise concern about potential population level impacts, especially at a time when many species of bats are known or suspected to be in decline (Blehert et al., 2009). While the aerodynamics of modern blades is far superior to prior designs at efficiently generating energy, the improved designs have also increased the frequency of bat fatalities (NWCC, 2010). Researchers found bat causalities to be 10 or fewer per MW each year at 75% of wind facility sites (NWCC, 2010).

Offshore Wind

There are U.S. offshore wind projects in various stages of permitting and pre-construction, yet as of this writing, none have yet been installed in United States state or Federal waters. European countries dominate the offshore wind market. The first project, named “Vindeby” was installed off the Danish island of Lolland in 1991. Since 2000 the European industry has experienced steady growth and there are currently ten countries with projects installed for a total of 3,813 MW capacity across the continent (EWEA, 2012). The most recent European projects are using larger turbines—5 MW turbines or larger are becoming more commonplace—to reduce costs, and are being installed in deeper waters further away from shore. China and Japan are the only countries outside Europe with offshore wind installations. The Shanghai East Sea Bridge Wind Project (Qi, 2010) and the Jiangsu Rudong Project combined provide China with more than 250 MW of offshore wind capacity (GTC, 2012). Aided by supportive government policy, the Chinese offshore wind industry is expected to see substantial growth offshore during the next decade (BTM Consult, 2010). China hopes to install 5 GW of offshore capacity by 2015 and 30 GW by 2020 (GTC, 2012). Japan has several offshore wind turbines installed close to shore at the Sakata offshore wind project and is expected to commission more projects in the near future.

The first U.S. offshore wind project was proposed in Massachusetts by Cape Wind LLC in 2001. As the first proposed project in the United States, federal agencies were unsure of how to permit and regulate Cape Wind. The U.S. Army Corp of Engineers was tasked with permitting responsibility, because offshore wind turbines qualify as an obstruction to navigation under the *River and Harbors Act of 1899* (Williams & Whitcomb, 2007). Furthermore, the project almost immediately became embroiled in a bitter legal and public relations battle with a passionate group of well-funded and well-connected Cape Cod locals who did not wish to see the project proceed (Williams & Whitcomb, 2007). Combined, these two factors made the permitting process extremely slow. Ten years and two environmental impact assessments later the Cape Wind construction and operations plan was approved by U.S. Department of the Interior (DOI) Secretary Ken Salazar on April 19th, 2011. The project has installed the first offshore meteorological tower for the purpose of measuring wind speed and direction for a commercial project in the United States and is still likely to be the first large-scale offshore wind project in North America.

In addition to Cape Wind there are a multitude of projects in various stages of planning, permitting, data-collection or preconstruction, mainly up and down the East

Coast, but also in the Great Lakes and the Gulf of Mexico. Major projects are planned offshore New Jersey, Delaware, Rhode Island, Massachusetts, Michigan and Texas. There are also several Canadian projects proposed, some in the Great Lakes and thus close to U.S. shores. To limit risk and cost, the early projects will more than likely be installed in depth of less than 30 meters using monopile or gravity based foundations common in European projects. There are also small test projects of a few turbines planned offshore of Texas, Rhode Island, and New Jersey, and in Lake Erie. The first small project installed will be notable because it should mark the first wind turbine offshore the United States.

U.S. Offshore Wind Policy & Incentives

With the adoption of the *Energy Policy Act of 2005* the permitting and regulation of offshore wind was transferred to the Bureau of Ocean Energy Management (BOEM; formerly Minerals Management Service) (MMS, 2009). In April 2009, the BOEM released the federal framework governing offshore energy projects situated on the Outer Continental Shelf (OCS) in federal waters, including offshore wind power. The BOEM grants leases, easements and rights-of-ways for OCS energy projects and under President Obama's and Secretary Salazar's "Smart from the Start" initiative has thus far opened up 'Wind Energy Areas' (WEA), or designated offshore wind development regions, off the coast of four states: New Jersey, Delaware, Maryland, and Virginia (DOE, 2011). Processes similar to the WEA are ongoing in Massachusetts and Rhode Island as well. The WEAs are available for commercial leasing to generate power, and BOEM released a finding of no significant impact (FONSI) of offshore wind projects within the Atlantic WEA through an Environmental Assessment in January 2012 (BOEM, 2012). The FONSI should help streamline the permitting process and reduce the total required time to start producing electricity.

The federal government supports offshore wind through a variety of programs including tax credits, low interest loans and funding for basic research. The policy currently driving wind industry growth, the Production Tax Credit (PTC), allows companies to claim energy generated as a Federal Tax Credit to the amount of $0.022/kWh for first 10 years of production. The PTC originated with the *Energy Policy Act of 1992* and has been renewed several times (Bolinger et al., 2009), including in January 2013 under the *American Taxpayer Relief Act of 2012*. It is currently set to expire at the end of 2013. The Investment Tax Credit (ITC) allows companies to claim 30% of the total system cost as a Federal Tax Credit, however to be eligible, construction of the project must have started by December 31st, 2010 (Bolinger et al., 2009). In lieu of the ITC or PTC, the *American Recovery and Reinvestment Act of 2009* (ARRA) under Section 1603 of the Internal Revenue Code, allows the payment of 30% of the total system cost in a cash grant (often referred to as the "cash grant" program) however to be eligible, project construction must have started before Dec 31st, 2011 and must have been placed in service by the end of 2012.

The DOE offered a loan guarantee program under Section 1705 of the ARRA. The program was allocated $2.5 billion to support $30 billion of loan guarantees. In order to qualify for the guarantee, project construction must have begun before the end of September 2011. An additional ARRA program, subsequently renewed under the *American Taxpayer Relief Act of 2012*, the bonus depreciation is set to expire at the end of 2013. The federal Modified Accelerated Cost-Recovery System (MACRS) allows companies to depreciate wind turbines over five years instead of the entire expected twenty year lifetime. However the *Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010* permitted accelerated cost-recovery so that 100% of the capital cost can be depreciated in the first year (JCX, 2010). The bonus depreciation is estimated by experts to be worth about 10% of the total capital costs (value calculated using model from Levitt et al., 2011). The MACRS schedule currently allows 50% of the capital cost to be depreciated in the first year and expires December 31, 2013.

The aforementioned programs have proven extremely important in the development of a land-based US wind industry; however they are all likely to expire before the first offshore projects begin installation. Federal incentives are necessary for offshore wind projects because of the high cost due to perceived risk associated with early projects and because traditional fossil-fuel and nuclear generation is artificially cheap due to government subsidies, liability limitation, and the exclusion of externalities in electricity prices. By removing existing subsidies for mature technologies and adding the external costs to the economic cost of electricity, it is possible that the federal government could remove the need to subsidize renewable energy to compensate for un-priced benefits. This would allow the market to decide based on real prices. However, it still may be necessary to incentivize early projects to expedite offshore wind deployment.

On top of the aforementioned programs the DOE is in charge of funding research and development (R&D). The ARRA provided the first federal offshore wind R&D budget for turbine research and testing facilities to the tune of $90 million for Fiscal Year (FY) 2009 and FY 2010 (DOE, 2011). The Offshore Wind Innovation and Demonstration (OSWInD) initiative allocated an additional $50 million to be spent over three years on R&D projects starting in FY 2011 (DOE, 2011). The BOEM also provides research funding to assess potential environmental impacts through the Environmental Studies Program and safety through the Technology Assessment and Research Program.

Offshore Wind External Impacts

Offshore wind and land-based wind have similar environmental and societal impacts, such as lifecycle pollutant emissions, visual impacts and avian mortalities.

However, while onshore wind may annoy surrounding inhabitants, offshore wind project are located far enough from habitation that noise and shadow flicker are not issues. On the other hand, offshore wind power installation, operation, maintenance and decommissioning introduce the potential for impacts to the marine environment.

Aquatic Life

There are multiple ways that turbines can impact marine animals, both during the installation stage and the operation stage. Possible impacts include hearing damage from pile driving, habitat disruption due to pile driving, ship strikes, and behavioral changes due to electromagnetic radiation from subsea cables. In the US, marine mammals are protected from 'takings' under the *Marine Mammal Protection Act* (1972). It is challenging to quantify the wildlife effects of offshore wind projects due to the notorious difficulty of locating and studying marine animals. Shipping traffic associated with offshore wind projects in England are accused of causing about 50 mysterious seal deaths (Bugler, 2010). However the claim is disputed by the project owners (Hill, 2010). Overall, a couple of *in situ* European impact studies have been performed, and thus far, the results are promising.

The Danish Energy Authority (DEA) assessed the environmental impact of two prominent offshore wind projects, Nysted and Horns Rev. First and foremost, the DEA report found that once installed the turbines served as artificial reefs reversing any initial impact to benthic communities and marginally increasing fishing stocks (DEA, 2006). Similarly, researchers Snyder and Kaiser (2009) found that localized fish kills could occur during project construction, but fish stocks would likely rebound, and in the long-term, turbines could act as aggregation devices. Furthermore, the DEA found that there was no correlation between impact to fish behavior and electromagnetic fields around electric cables. Most importantly, the agency ruled that overall impact to marine mammals was negligible (DEA, 2006). After some initial reduction in population around the installation sites due to sound emissions from pile driving, both the seal and the porpoise populations rebounded. The seal stocks returned almost immediately after the termination of pile driving, while the porpoises required a few years to return (DEA, 2006).

Initial marine wildlife impact studies commissioned by the Royal Belgian Institute for Natural Sciences for the offshore wind projects Thorton Bank and Belwind arrived at similar conclusions (Degraer & Brabant, 2009). Benthic communities surrounding turbines recovered after construction, and new species, including some alien species, were found a few months after initial installation. The turbine foundations had a higher species density than the baseline soft-substrate sea-bottom, thus demonstrating a positive impact on biodiversity. Moreover, noise levels during operations were not found to be an issue for marine mammals (Degraer & Brabant, 2009).

Marine Birds & Bats

Offshore wind turbines pose a navigation risk for birds on their migratory journey. The breadth of the turbines presents a collision risk, especially under poor visibility conditions (Drewitt & Langston, 2006). During a 15 month study in the North Sea Huppop *et al.* (2006) found 442 deceased birds, 50% of the mortalities which occurred during two extremely foggy nights. Fortunately, the majority of birds, an estimated 71% to 86%, avoid offshore projects by flying around them (Densholm & Kalher, 2005; DEA, 2006). The downside is this tendency adds distance to migration and reduced habitat. As the cumulative area occupied by turbines increases, so does the length of the route, which could ultimately have a significant impact on avian journeyers (Fox et al., 2006). In addition, as birds tend to avoid turbines, traditional fishing habitat could be lost. Again, this is more of a cumulative issue that could drive ecological unit disconnection as the number of offshore wind farms increases.

Collision presents the most immediate avian risk. Under the *Migratory Bird Treaty Act* (1918) any taking of a migratory bird crossing international borders is illegal. Whether or not the act will be enforced as it pertains to wind projects is a matter of debate (see Lilley & Firestone, 2008). *The Endangered Species Act* (1973) protects several other avian species, including the albatross. While it is difficult to gather accurate data about bird mortality in an offshore setting, the Danish Energy Authority estimates a collision rate of just 0.02% for common eider birds passing the Nysted Project each spring (DEA, 2006). The collision rate and behavioral response appears to be species and site specific, making it difficult to generalize about impacts (Drewitt & Langston, 2006).

The effects of offshore wind turbine and bats are not well quantified. Studies have certainly shown the occurrence of bats offshore (Ahlen et al., 2007; Sjollema et al., 2010), but the prevalence and likely impact is unknown.

Visual Impact

There is a dearth of information about the likely effect to coastal housing prices from offshore wind (Musial & Ram, 2010). A pristine view of the ocean is incorporated into coastal property values, so the modification of this view could influence property values. A survey study of 501 home owners and 45 realtors in Cape Cod and Martha's Vineyard found that the presence of offshore turbines in Nantucket Sound was believed to decrease property values (Haughton et al., 2004). The study found the perceived visual impact or 'disamenity' to property value would be about 4% for houses with a coastal view and over 10% for beachfront homes. The total welfare loss for the area due the Cape Wind project would therefore be estimated at $1.3 billion (Haughton et al., 2004). It is important to note that this is perceived loss and due to the lack of hedonic studies there are no available data to compare. As is subsequently evident, it is likely that actual impacts to property will be significantly smaller. For comparison, surveys of residents and real estate agents show that perceived property value impacts from power lines are often overestimated by an order of magnitude (Kroll, 1992).

Researchers at the University of Delaware performed a preferential-choice study to determine the viewshed disamenity for the state of Delaware from offshore wind turbines (Krueger et al., 2011). The results from these studies include an implicit coastal property impact value. As previously mentioned, installation of offshore turbines could decrease coastal properties because they detrimentally impact pristine ocean views. The turbines also could negatively impact coastal vacationers or anyone who does not want to see the landscape changed. The perceived value of the impact to coastal residents' lives and property is revealed in the Willingness-to-Pay (WTP) to move turbines further offshore. However, it is impossible to separate the property and other disamenity values from the Krueger *et al.* study.

The University of Delaware study calculated a substantial benefit to moving turbines from a baseline distance from shore of 0.9 miles to about 9 miles (Krueger et al., 2011). The study found that after 9 miles the benefit of moving turbines further offshore does not increase as quickly. In order to calculate the viewshed cost the WTP responses for two different groups of respondents were used: coastal and inland households—the study does not include out-of-state vistors. The Krueger *et al.* (2011) study estimates the total cost to Delaware residents associated with turbines installed 3.6, 6, and 9 miles offshore the coast to be $4.2 million, $1.1 million, and $870,000 annually in perpetuity, respectively. Evidently there is a tangible visual impact related to offshore wind projects.

The Theory behind Energy Externalities

The emergence of the concept of social costs, which are distinct from the private costs borne by market actors, dates back to Arthur Pigou's seminal *The*

Economics of Welfare (1920). In welfare economics—as well as this thesis—the terms social costs, private costs and externalities or external costs (used interchangeably) are defined according to the framework originated by Pearce and Sturmey (1966). The social cost encompasses both the *compensatory* private costs, as well as the *compensatable* external costs unrepresented in an economic exchange. In short, the social cost represents the entire cost of an activity while private costs and externalities are distinct subsections. Private costs include labor, capital, fixed and variable costs, and other traditional economic costs, which are included in the market price for goods and services. External costs occur when an economic exchange negatively affects a third-party without permission or compensation (Kolstad, 2010). By that same logic, external benefits occur when an economic exchange positively impacts a third-party and compensation is not charged (Note: there are of course positive externalities, however, when the term externality is used in this thesis it is referring to external costs, positive externalities are referred to as external benefits).

Negative externalities from electricity generation may come in the form of environmental, human health, ecological, or property value costs (Kammen & Pacca, 2004). Examples of environmental costs are the uncompensated impact of SO_x and NO_x from combustion of coal or the emission of carbon dioxide, which leads to global climate change. Moreover, power plants may have external health costs such as increased occurrence of asthma or cancer risk due to exposure to particulate matter or mercury, respectively. Electricity generation may also depress local property values due to pollution or aesthetic concerns.

In the 1980's as economists started to acknowledge the importance of energy externalities, studies were performed to estimate the previously un-quantified environmental, health, and property costs from energy generation. While the methodology has evolved through time, the expression of the final result as externality 'adders' remains constant. Externalities are quantified through a variety of means as a price ‘adder’ in terms of a cost per unit of energy—typically U.S. dollars per kWh of electricity ($/kWh)—so that they may be added to the economic price of electricity to derive the ‘real’ or social cost (Pearce, 2001).

Studies which estimate the costs of externalities are often widely debated and furthermore reveal a broad range of possible costs (Kammen & Pacca, 2004). The cost range may be an order of magnitude for a single study and several orders of magnitude when comparing studies (Sundqvist, 2004). The ranges in costs and discrepancies between studies stem from monetary valuation uncertainty and use of differing methodologies.

Energy Externality Estimation Methods

Unfortunately, unlike with direct economic costs, there are no markets from which to directly determine the value of an externality. Therefore externalities are valued through a variety of means, including: damage function models, contingent valuation studies, or abatement costs (Schleisner, 2000; Matthews & Lave, 2000). Depending on the method selected, the monetary estimates can vary substantially (Sundqvist, 2004). The methods can be roughly divided into two groups: the abatement cost approach and the damage cost approach. Furthermore, within the damage cost approach there are two method subsets: the top-down method and the bottom-up method.

The abatement cost approach uses the cost of controlling an externality as the implied damage value. For example, if a coal power plant is required to install a dry scrubber to remove SO_2 from the flue gas, the value of removing the pollutant can be derived by the total cost of the technology, divided by how much pollution it is expected to remove. A major critique of this method is as Pearce *et al.* (1992) observe: that regulators know the optimal level of pollution and design regulations accordingly. Furthermore, the externality value can change, depending on the abatement technology required, as regulations change over time.

The damage cost approach seeks to empirically assess the costs incurred due to an externality. The top-down method uses previous estimates of nationwide or statewide damage costs and total externality emissions to achieve an approximation of damage per unit of pollution (Hohmeyer, 1988; Kim, 2007). The top-down damage cost method is often criticized because it fails to account for the site-specificity of emission impacts from a single power plant (Sundqvist, 2004).

The bottom-up method derives externality damage function from specific power plants and then estimates the cost per unit damage to extrapolate total externality costs (Figure 4) (Schleisner, 2000). The damage functions are impact assessments of each individual burden to human health or the environment (represented by Figure 4: Step 1). The impacts are monetized by either using market data or, when no such market exists, by using techniques to extract or estimate the market value (represented by Figure 4: Step 2). Damage monetization techniques include estimation of human health costs from public health, lost work days, or epidemiology; market value of harvestable wildlife, timber, or plants; hedonic studies; or contingent valuation (CV) studies that assess an individual's WTP to avoid or Willingness-to-Accept (WTA) impacts (Sundqvist & Soderholm, 2002). The resulting externality adder—in terms of dollars per unit energy—can be added to the private cost of electricity (represented by Figure 4: Step 3).

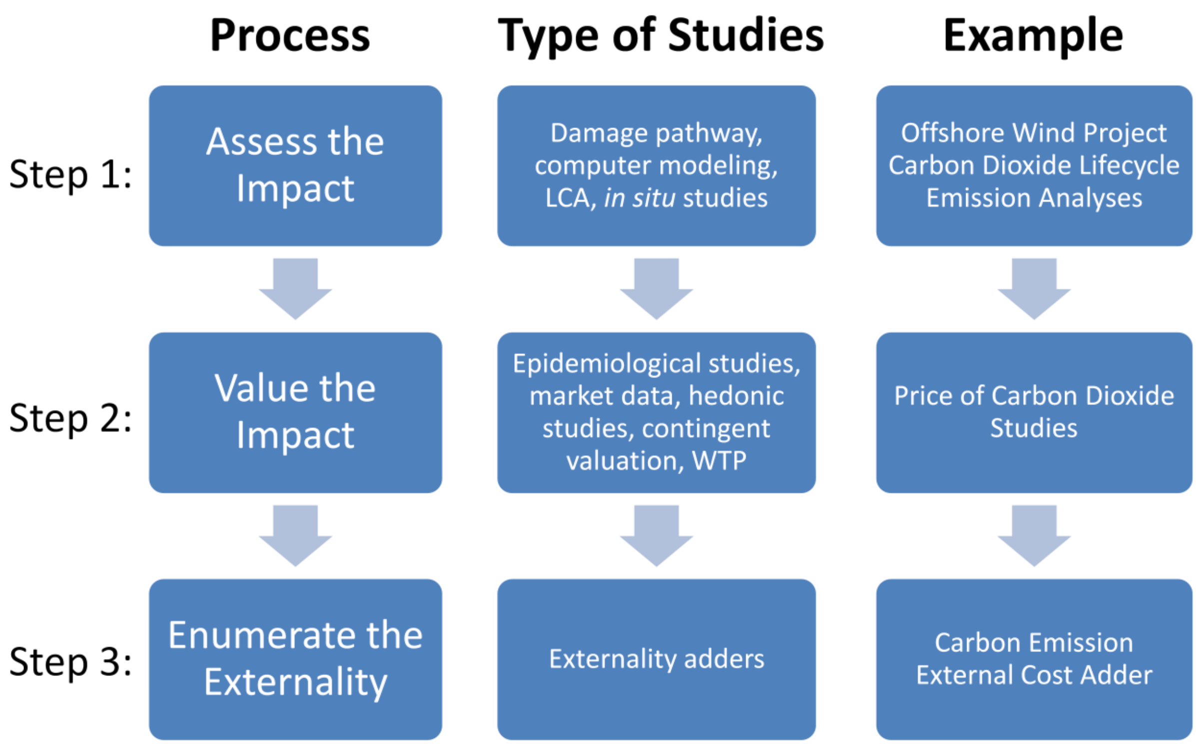

Figure 4 **Bottom-up externality methodology overview. The methodology can be broken into three steps, each with its own type of studies. For an example, the carbon dioxide externality pathway is displayed.**

The estimation of both the damage function and the monetary value are crucial in the bottom-up method; a misrepresentation of either can result in a vastly exaggerated cost. Furthermore, because the damage values are based on a specific power plant or plants, the results can be very site-specific, depending on population density around the plant and the physical transport of the emissions. For example a coal plant located near densely populated New York City would have a substantially higher human health impact than a similar coal plant in the Catskill Mountains.

Different methodologies can certainly produce vastly dissimilar cost estimates for externalities. A survey paper of externality studies concluded that studies that used the abatement cost method found significantly higher externality costs than either the top-down or bottom-up method (Sundqvist, 2004). Moreover, externality studies for the same technology may vary in scope. Some studies look only at the fuel cycle, while other studies consider the entire electricity lifecycle from extraction of required material to disposal of waste and plant decommissioning (Schleisner, 2000). Another common difference between studies is the treatment of carbon dioxide emissions—or in older studies, the failure to consider it at all (Pearce, 2001; Sundqvist & Soderholm, 2002).

The History of Energy Externality Assessments

Early externality studies such as those preformed by Hohmeyer (1988), Ottinger *et al.* (1990), and Pearce *et al.* (1992) utilized the top-down damage cost approach. The seminal shift away from the aggregated approach came in 1991 when the European Commission Directorate General and the U.S. DOE collaborated to assess the external costs of energy (Krewitt, 2002). The joint research employed the bottom-up methodology (ExternE, 1995a). The first Externalities of Energy or 'ExternE' results were presented in 1995, at which point the Americans ceased their involvement in the project and the European Commission proceeded alone (Eyre, 1997). Several U.S. states (e.g., New York and Minnesota) engaged in their own external cost assessments based on, or to supplement, the national Lee *et al.* (1995) study. However, for the most part U.S. interest waned as the focus in the electricity industry shifted towards deregulation. Subsequent European ExternE studies, released in 1999 and 2003, further revised external cost valuations through updated energy lifecycle analyses, premature mortality analyses, carbon dioxide valuation and other damage pathways, as well as considering new electricity generation technologies (ExternE-Pol, 2005; European Commission, 2005).

Under the Sixth Framework Programme, the European Commission followed the ExternE efforts by funding the New Energy Externality Development for Sustainability (NEEDS) and Cost Assessment of Sustainable Energy Systems

(CASES), which further refine the methods and expand the project scope of ExternE (NEEDS, 2009; Markanyda et al., 2010). Around the same time, two significant studies were published in the United States: the National Research Council of the U.S. National Academy of Sciences published the "Hidden Costs of Energy" study (NRC, 2010) and Epstein *et al.* (2011) assessed the cost of coal externalities. Unlike the European NEEDS study, which aims to assess external costs of future generation, the recent American studies assess the cost of existing U.S. generation.

Policy Implications of Energy Externality Studies

Under perfect market conditions the external cost of energy would be incorporated into the market price of energy, and externality studies would prove superfluous. However, this is not the case. The energy market is imperfect both because of environmental externalities unrepresented in the market price and because of imperfect competition (Kim, 2007). In short, left alone, the energy market will produce suboptimal results (Owen, 2006). However, theoretical economic modeling has shown that internalizing externalities into energy prices results in a more efficient allocation of goods and services and therefore lower overall—combined internal and external—costs (Rafaj & Kypreos, 2007). In order to surmount market shortcomings, policymakers must implement corrective market instruments.

Energy externality studies are necessary because policymakers require accurate technological economic information from scientists to make informed energy policy decisions. Since the U.S. electricity system is publicly-regulated, yet owned by a mix of private and public entities, companies do not include externalities in their economic decision-making models. Furthermore, even public bodies do not know the external values to use, or in some cases, do not even understand the concept. Thus, external costs of electricity generation should serve as a valuable resource for policymakers to help guide investment and policy. Although any single paper may not be sufficiently compelling to change decisions, it is important to build a body of high-quality, scientifically-defensible research producing usable externality values. Without this scientific basis, we can never expect policy to move toward greater rationality and greater economic efficiency.

Critiques

A survey of the peer-reviewed literature reveals a general concern that due to the broad range of monetary values derived from energy externality studies, the studies are of limited policy relevance (Eyre, 1997; Stirling, 1997; Krewitt, 2002; Owen, 2006; Kim, 2007). At least a portion of the variation in results stems from externality studies utilizing different methodologies to compare across energy technologies (Schleisner, 2000). Early top-down studies revealed substantial externalities which led to much critique, and eventually, modification of study methodology. More recent European studies such as ExternE and NEEDS use consistent bottom-up methodology across technologies and also analyze multiple sites to understand location specificity of externalities (European Commission, 2005; NEEDS, 2009). The ExternE study, in particular, has been criticized for its complexity and for the decision to mainly analyze modern energy generation technologies, which limits the policy significance of the externality adders (Kim, 2007). The comprehensive National Research Council assessment, on the other hand, focuses on the existing U.S. electricity generation and therefore does not experience the same problem (NRC, 2010).

Indeed, due to the large uncertainties (often greater than an order of magnitude) and lack of data associated with energy externalities, the goal of a single 'real' cost of energy may be infeasible (Krewitt, 2002). As ExternE researcher Nick Eyre (1997; p.6) states, "It seems an inescapable conclusion that, for some important impacts, reliable monetary valuations are not a realistic objective." Furthermore, there are certainly issues about the subjective nature of some externality impact valuations and assessments (Stirling, 1997). Therefore, it is imperative to provide ample justification for all assumptions and retain perspective as to the use of externality adders as policy tool. Evidently, externality studies do not provide fixed value of the 'real' cost of energy. They do however; help provide a range of values to previously un-quantified costs and impacts stemming from energy generation. If the low end of the range of external costs is above zero, then using any point in the range of externalities is more accurate than ignoring external costs. As Ottinger (1997) observes, by ignoring these externalities and thus effectively pricing them at zero, it artificially deflates the externality price and limits the policy relevance. Therefore, even if a range of values is the result, they can still be a valuable policy tool. Overall, the energy externality methodology is well developed and has relevance in energy planning, in formulation of regulation by regulatory bodies such as state public service commissions, in public awareness, in priority setting, and for setting rates of environmental taxes (Pearce, 2001).

Applicability

Thus far, energy externality studies have proven useful in the policy realm for a couple reasons. First, externality studies revealed the previously unknown fact that because of significant external costs, electricity is underpriced. In particular, the ExternE studies revealed the previously unknown public health risk presented by particulate matter, which led to more stringent regulation (Krewitt, 2002). Second, the studies allow for characterization of electricity generation technologies based on their respective social costs (Eyre, 1997). From these findings, policymakers are able to design policies to address externalities. Corrective market instruments available to decision-makers include Pigovian Tax, cap and trade, top-down regulation and mandates (e.g., policies set by state public service commissions, which approve or disapprove power plant construction, and approve rates charged by investor-owned utilities for power), or subsidies (Eyre, 1997). The aforementioned mechanisms each posses caveats in terms of political nuances, transaction costs, equity and distributional effects, and long term efficiency, among others (for more information see Owen, 2006 or Kolstad, 2010). Determining and implementing the correct combination of policies and instruments is certainly not trivial, and differs from country to country, but without energy externality studies, the dialogue would not have progressed this far.

Within the United States there is a modest history of incorporating externalities into energy planning decisions at a state level. Before deregulation of vertically-integrated utilities occurred in many states in the late 1990s, several—including California, New York and Massachusetts—mandated that utilities consider environmental and human health externalities in the construction of new generation (Matthews & Lave, 2000). State regulators recognized that utilities chose new generation solely based on the lowest private cost of energy, and thus mandated that utilities calculate and include the external costs—through externality adders—in the evaluation. New generation decisions were then made accord to the technology with the lowest combined internal and external cost per unit energy (Connors, 1993). While revolutionary in design, an unforeseen problem with the regulation pertained to dispatching new plants. External costs were not incorporated into dispatch decisions, and thus when comparing between fossil fuel plants, new plants with low externality costs were not necessarily used because they may have had high private costs (Matthews & Lave, 2000). In fact, this could lead to a bias against new generation, and perversely incentivize continued and expanded use of old, high externality plants because of their low private costs (Freeman, 1996). This would not usually be a consideration for renewable electricity generation, because renewable generation does not have a fuel cost, and thus variable operating costs (which are usually what determine dispatch order) are generally lower than the costs of fossil fuel power plants.

In deregulated electricity markets (like in the Northeast and Mid-Atlantic), privately owned, independent generators compete in the market, based on marginal price. While there are still permits required by state and local government, in many cases the public service commissions wield less influence over construction of new generation assets, and therefore externality adders are not as directly important to policy decision-making. Still, externality adders are important when the power plant is contracted to a regulated utility that is required to assess the externalities of its integrated resource plan (see Title 26 of the Delaware Administrative Code statute 3010 5.2 and 6.1.4), involved with an emissions trading scheme (e.g., the Regional Greenhouse Gas Initiative), or is involved in another commission-controlled decision (e.g., PPAs for Cape Wind). When state commissions do not control generation decisions directly, states can by separate legislative authority employ Renewable Portfolio Standards (RPS) to require publicly-regulated distribution utilities to purchase renewable power. Even in these areas, externality pricing is still valuable to help grasp previously un-quantified electricity costs, help orchestrate RPS and other policies, and to differentiate among technologies.

Chapter 3

DESCRIPTION OF METHODS

This chapter outlines the research design and identifies the data collection and data analysis methods utilized in this thesis. Furthermore, this chapter discusses the treatment of uncertainty and lack of data.

The goal of this thesis is to determine and compare the social costs of electricity generation within the PJM market. Social costs are equated by combing the private costs of electricity with the external costs and benefits. The private costs, subsidies and external costs and benefits are assessed from the peer-reviewed literature. This thesis serves more as a meta-study than an original social cost quantification analysis because no individual damage assessments or monetization studies are performed.

Private Costs Studies

Initially, it was hoped that PJM market data would be used to assess the private economic costs of electricity generation within the PJM service territory. Unfortunately, while PJM publishes the average annual cost of electricity, it does not publicly supply annual average energy costs broken down by technology. However there are other sources from which to obtain these values. The current electricity costs are taken from the peer-reviewed literature. In addition, the Energy Information Administration, or EIA, (an agency of the U.S. Department of Energy) estimates the national Levelized Cost of Electricity (LCOE) from new generation built in the year 2016 which offers a glimpse into the cost of new electricity generation plants (EIA, 2011b).

All monetary values are converted using consumer price index and purchasing power parity (PPP) to U.S. 2010 dollars and presented in terms of U.S. dollars per kWh. Following the recommendations from the CASES study outlined in Markandya *et al.* (2010), consumer price index is used instead of inflation to accurately reflect *sector specific* price fluctuations, and PPP is used instead of conversion rates to represent purchasing power between countries because it is a more accurate representation of electricity costs and WTP between countries.

Subsidy Studies

The market cost of electricity is subsidized by the federal government through financial incentives and R&D outlays which distort the true private costs of electricity (Badcock & Lenzen, 2010). Financial incentives include direct spending, tax credits, accelerated depreciation, import/export restrictions, below-market lending, low-interest loans, and liability caps (Koplow, 2004). If private cost studies do not internalize subsidies into the market cost of electricity production, it is necessary to include federal subsidies to assess the social cost. On the other hand, for future electricity costs, LCOE is calculated without the inclusion of federal subsidies, which renders the inclusion of subsidies unnecessary.

Federal energy subsidies are calculated in peer-reviewed literature. The U.S. energy subsides are estimated by government agencies such as the EIA (2011c) as well as research institutes such as the Environmental Law Institute (ELI, 2009). All monetary values are converted using consumer price index and PPP to U.S. 2010 dollars.

External Cost Studies

The external costs from electricity generation are estimated from peer-reviewed literature. The externality studies to be reviewed include comprehensive national studies, such as the National Research Council's assessment of the "Hidden Cost of Electricity" (NRC, 2010) and the European Council's NEEDS assessment (NEEDS, 2009). If specific types of externalities are unavailable in the comprehensive studies, they are supplemented, when appropriate, by studies which focus on a single technology or external cost.

The externality studies reviewed in this thesis utilize a bottom-up externality assessment methodology. The bottom-up quantification method is well established in the peer-reviewed literature, as reviewed above (see Schleisner, 2000 and Sundqvist, 2004) and is the method of choice for the recent externality studies of global interest (European Commission, 2005; NEEDS, 2009). Typical bottom-up externality studies assess lifecycle damages caused by an individual power plant through damage functions and then monetize the damage through economic valuation studies (e.g., epidemiology, hedonic studies, contingent valuation, etc.). Damages vary depending on technology, but include: impacts to human health, climate change, environment (e.g., biodiversity, biological resource, acidification, land use change), and visual disamenity. Indeed, individual studies assess different damages and thus, to the extent possible, effort is made to separate damage values between human health, environmental and climate for discussion and analysis. In order to convert qualitative assessments to quantitative figures, externality studies use economic valuation studies to price the externalities as externality adders so that they can be compared among technologies and across studies.

All monetary values are converted using consumer price index and PPP to U.S. 2010 dollars. The study is geared to the PJM Interconnection region. The external costs and benefits are tabulated and presented in terms of U.S. dollars per kWh. The original intention was to include external cost figures in terms of animal lives per GWh and biological mass per GWh; however, the data are not available.

External Benefits

The environmental benefits of electricity technologies are relative; dependent on the energy generation technology that was displaced. For example, if wind power displaces coal power then the relative difference in externalities can be considered the net social benefit of the added power. Thus in order to determine the benefit, it is imperative to understand exactly what is displaced. Which generation resources are displaced depends on a number of issues including the time that the energy is generated, generation ramp rates, and load requirements. Because the external costs were included for each electricity generation technology, it is not necessary to count the abated costs as an external benefit.

Ranges of Values

While no new modeling efforts or damage estimation studies are performed as part of this thesis, individual impact or assessment studies reviewed include uncertainty, rendering treatment of uncertainty necessary. Articles reviewed in this thesis face uncertainty stemming from: data uncertainty, model uncertainty, uncertainty about policy and ethical choices, uncertainty about the future, and idiosyncrasies of the analyst (Rabl & Spadaro, 1999). Data uncertainty—including damage functions—and model uncertainty are scientific uncertainty. While uncertainty about policy and ethical choices—e.g., choice of discount rate—uncertainty about the future and idiosyncrasies of the analysis—e.g., assumptions given incomplete information—are non-scientific.

Uncertainty within individual studies or as a result of meta-survey from several studies is denoted with value ranges as per Sundqvist (2004). Moreover, when calculations are performed involving values from several studies, the median value, rather than the mean, is used. This is partially to account for studies which contain some consideration of probability of outcome, as to not skew data by over-weighting high values with low likelihood. Furthermore, an additional analysis excludes some outlier studies at the discretion of the author with proper justification. The result is two tabulations of externality values. The first is an analysis of median externality values and the second an analysis of the author's 'best judgment' of externality values based on his examination of the externality studies' methodologies. The inclusion of studies within the best judgment analysis is done with proper justification.

When discrete numbers are not available to enumerate impacts, individual discretion is employed and all assumptions are explicitly noted. When there are instances whereupon analysis of the literature determines that they are likely social or environmental impacts from an externality, but with a dearth of quantification, a note is included that further research is needed, thus avoiding ignoring a potential impact, which would artificially set damages to zero (Ottinger, 1997).

Chapter 4

CALCULATION OF SOCIAL COSTS

This chapter describes the derivation of the social cost values. The social costs values are then presented in the subsequent chapter 5, the results chapter. Chapter 4 includes an analysis of the peer-reviewed externality, private cost, and subsidy studies considered in this thesis. The models and assumptions employed in the studies are identified, and the results are elucidated. Furthermore, all externality and private cost values are converted from their reported currency to 2010 U.S. dollars equivalent using purchase power parity and consumer price index.

Externality Studies

First, six externality studies are reviewed: External Costs of Energy (ExternE), New Energy Externality Development for Sustainability (NEEDS), Cost Assessment of Sustainable Energy Systems (CASES), the "Hidden Costs of Energy" by the National Research Council of the National Academies of Science, Epstein *et al.* (2011), and Muller *et al.* (2011). Each study includes an assessment of at least one current or future electricity generation technology. The chosen studies represent the most recent externality analyses from Europe and the United States. Additionally, in a separate review, the costs of avian and bat mortality from wind power are computed.

The study reviews are outlined as follows: first the study is contextualized, then the methodology is explained and assumptions are explicated, and finally the results are presented. Additionally, the currency conversion and consumer price index adjustment used to convert results to 2010 U.S. dollars are included after each study.

At the end of this section there is a table which summarizes and compares the methodologies of each externality study (Table 1).

External Costs of Energy (ExternE)

The ExternE studies are a series of multi-country analyses performed by multidisciplinary teams at universities and research institutes across Europe. The studies estimate the external costs and benefits of current fossil fuel, nuclear and renewable electricity generation within European Union countries. The ExternE studies were funded by the European Commission with the stated goal of informing and improving energy policy decision-making. Originally begun in 1991, the most recent ExternE studies were published between 2003 and 2005.

The ExternE studies utilize a bottom-up damage cost methodology to determine the social and environmental impacts of various pollutants emitted during the entire power generation lifecycle. The damages assessed include those from pollutants: particulate matter—both 'fine particles' of less than 2.5 microns diameter ($PM_{2.5}$) and 'inhalable coarse particles' of diameter less than 10 microns but more than 2.5 microns (PM_{10}); SO_2**;** NO_x**;** Volatile Organic Compounds (VOC); ammonia; heavy metals; and radionuclides as well as damages related to greenhouse gas (GHG) emissions and accidents. Not all of these pollutants are emitted during the lifecycle of each electricity generation technology analyzed.

Methodology

The first step of the ExternE methodology is to determine the deposition of emissions of power plants through the air, water and soil. The second step is to assess the dose-response function —also known as impact pathway—of the emitted pollutants to human health, agriculture, the built environment, and ecology. The third and final step is to monetize the damages. The entire process is performed by the impact pathway EcoSense model. The model is site specific, and thus the distinct geologic, atmospheric, surrounding population density, land use and emission details of electricity generation sites can be modified to produce unique plant damage results. The model uses monetary valuations of damage. The monetary values are derived through techniques such as estimation of human health costs from public health records, lost work days, or epidemiology; market value of harvestable wildlife, timber, or plants; hedonic studies; or CV studies.

The damage valuation of $PM_{2.5}$ emissions is of particular importance. $PM_{2.5}$ is either directly emitted during the combustion cycle or forms in the atmosphere after SO_2 and NO_x undergo chemical reactions (Muller, 2011). Medical studies link $PM_{2.5}$ concentrations to increased risk of cardiovascular and respiratory disease and mortality (see Dockery et al., 1993; Pope et al, 2002; and Schwartz et al., 2008). The EcoSense model uses the $PM_{2.5}$ dose-response as per Pope *et al.* (2002) (European Commission, 2005); however other medical studies have found three times higher mortality rates per dose of $PM_{2.5}$ concentration than the Pope *et al*. analysis (see Dockery et al., 1993 and Schwartz et al., 2008). Externality studies which use the higher dose-response rate as per Schwartz *et al.* (2008) correspondingly find higher health damages.

The external cost of each technology was estimated at two different locations in each European country. The damages from a representative power plant were assessed at an 'average' location and a specific electricity generation plant.

For damages which are not calculated by the EcoSense model, such as GHG-related impacts and accidents related to transportation of fuel, the marginal costs of the damage and the lifecycle damages are assessed and then multiplied together to compute the total costs.

Assumptions

The ExternE study uses both the Value of Statistical Life (VSL) and Value of a Statistical Life Year (VSLY) to assess the impacts of human mortality. The VSL is used to estimate the costs of mortality due to a transport accident (i.e. a rail accident during a coal shipment), while the VSLY is used to monetize mortality due to pollution from electricity generation. Previous assessments suggest that studies which use VSL for accidents and VSLY for pollution related deaths report lower external cost values than studies which exclusively use VSL to value mortality (Sundqvist, 2004). This is because the VSLY damages apply only to the number of years lost from the average lifespan, rather than a single VSL value in each case. Since most pollution related fatalities occur within the elderly demographic with shorter remaining life expectancy, VSLY values are lower than a flat VSL across all mortalities. The ExternE VSL and VSLY are €1 million and €50,000/year respectively (European Commission, 2005).

The external cost of damages related to the emission of GHGs are determined to be between €18-46 per metric tonne CO_2 equivalent (tCO_2-eq), and for the ExternE central assessment a value of €19/tCO_2-eq is used.

Results

The external cost values for coal are found to be between 2-15 $€_{2000}$ cents/kWh (European Commission, 2003). The wide range of values is due to differences in the location of the power plant, the grade of coal and the external cost of carbon. Natural gas external costs are evaluated to be between 1-4 $€_{2000}$ cents/kWh, nuclear external costs between 0.2-0.7 $€_{2000}$ cents/kWh, hydro external costs 0.03-1 $€_{2000}$ cents/kWh, and PV external costs 0.6 $€_{2000}$ cents/kWh (European Commission, 2003). The variation is again attributable to the location of the plant and the assumed external cost of carbon. Wind external costs are determined to be very low (between 0.05-0.25 $€_{2000}$

cents/kWh), predominantly from steel and concrete production. Also, when bird and bat external costs were monetized, they are found to be insignificant (European Commission, 2003). The study authors are quick to note that the results are location specific and therefore it may not be possible to generalize. However, the results are useful to compare between technologies. Moreover, the researchers note that the aforementioned values are only subtotals and that not all impacts were completely assessed (European Commission, 2003).

The Germany specific results of the EcoSense model are used as a representative mid-point of the ExternE study. The coal external costs are determined to be 4.05 $€_{2000}$ cents/kWh, mostly from direct emissions of pollutants during electricity generation (ExternE-Pol, 2005). External costs of natural gas CCGT and SCGT are determined to be 1 $€_{2000}$ cents/kWh and 1.5 $€_{2000}$ cents/kWh respectively, again mostly from direct emissions during electricity generation (ExternE-Pol, 2005). Nuclear external costs are calculated to be 0.19 $€_{2000}$ cents/kWh, the majority of which stem from long-term, low-level radiation (ExternE-Pol, 2005). Renewable energy generation from PV has external costs of 0.41 $€_{2000}$ cents/kWh, while hydro (0.05 $€_{2000}$ cents/kWh), onshore wind (0.09 $€_{2000}$ cents/kWh), and offshore wind (0.12 $€_{2000}$ cents/kWh) have relatively small lifecycle external costs (ExternE-Pol, 2005).

Conversion

For this thesis, the aforementioned values must all be converted to 2010 U.S. dollars. The foreign currencies are converted to U.S. dollars (US$) through the PPP adjustment, and the historical values are converted to 2010 US$ with the consumer price index. The PPP conversion from the 17 Euro countries to the US$ in 2000 is 0.879 $/€ (OECD, 2011). The consumer price index adjustment from 2000 US$ to 2010 US$ is 1.266 (BLS, 2012).

New Energy Externalities Development for Sustainability (NEEDS)

The NEEDS study is an extension and update of the ExternE analysis. Like ExternE, NEEDS is also a multi-country, multi-year study funded by the European Commission and performed by multidisciplinary researchers at multiple universities and institutes across Europe. The study's goal is to assess the externalities of future electricity generation technology in European countries installed in 2010, 2025, and 2050 (NEEDS, 2009).

The technologies included in the NEEDS study which are relevant for this thesis are coal, CCGT, PV, and offshore wind. The NEEDS bottom-up damage cost methodology is similar to that employed in ExternE, where the external costs from lifecycle pollutant emissions are calculated through the EcoSense model. The damages assessed include lifecycle emissions of particulate matter (both $PM_{2.5}$ and PM_{10}), SO_2**,** NO_x**,** VOC, ammonia, heavy metals and radionuclides, as well as GHG emissions, biodiversity loss due to land use changes and accidents (NEEDS, 2009).

Methodology

The first thrust of the NEEDS study is a comprehensive assessment of lifecycle damages and emissions of each technology considered. Next, the marginal costs of emissions emitted from average new plant configurations located in areas of average population density are calculated using the EcoSense model. The emphasis on the average plants, rather than actual generation, is because of the unknown configuration of future generation. The marginal costs are then multiplied by the lifecycle emissions per quantity of electricity generated (kg/kWh) to estimate the external costs associated with each generation technology. For damages which are not calculated by the EcoSense model such as GHG related impacts, land use change and accidents, a similar procedure of assessing the marginal costs of the damage and then multiplying by the lifecycle damage is followed. The marginal costs of GHG emissions are assessed with the FUND model developed by climate researcher Richard Tol (Tol, 2002). To determine the future external costs, the energy system modeling program MARKAL/TIMES is used to predict the changes in economy energy intensity, electricity generation composition by source and learning curves to estimate 2025 and 2050 external costs (these future costs are not relevant to this thesis, which compares only current costs).

Assumptions

NEEDS, like ExternE, uses VSL when assessing the cost of accidents during the electricity generation lifecycle and climate change related mortality, and VSLY when assessing the cost of pollution related mortality. The NEEDS VSLY is slightly reduced from the ExternE value to €40,000/year (NEEDS, 2006).

The marginal damages related to GHG emissions according to the FUND model are €7/tCO_2-eq without equity weighting and €98/tCO_2-eq with equity weighting (NEEDS, 2009). Equity weighting refers to whether GHG related damages which occur to wealthy people are equally valued as those that occur to poor people, or if—as in the equity weighted case—the damage to poor people is valued higher because it is proportionally a larger impact. The GHG marginal abatement cost of €23.5/tCO_2-eq is assumed as a central value (NEEDS, 2009).

Results

The external cost values for a new coal plant are found to be between 1.9-10.1 $€_{2000}$ cents/kWh, depending on the marginal damages of GHG. With the marginal abatement cost of GHG, the central external value for new coal generation is 3 $€_{2000}$ cents/kWh (NEEDS, 2009). New natural gas (CCGT) external costs are evaluated to be between about 0.7-4.7 $€_{2000}$ cents/kWh, most of which stems from the valuation of GHG emissions (NEEDS, 2009). New nuclear external costs are found to be between about 0.09-0.15 $€_{2000}$ cents/kWh, new solar (a mix of PV and thin film technologies) external costs 0.55-1.12 $€_{2000}$ cents/kWh, and new offshore wind external costs 0.07-0.14 $€_{2000}$ cents/kWh (NEEDS, 2009). The values are separated into human health, biodiversity, biological resource, acidification, land use change and climate change costs. Regardless of the valuation of GHG related damages, most of the costs across all technologies stem from climate change related damages and human health impacts. The NEEDS researchers acknowledge that because some impacts cannot be monetized, "The report presents quantifiable external costs, which do not represent the total external costs related with electricity generation" (NEEDS, 2009, p. 5).

Conversion

The PPP conversion from the 17 Euro countries to the US$ in 2000 is 0.879 $/€ (OECD, 2011). The consumer price index adjustment from 2000 US$ to 2010 US$ is 1.266 (BLS, 2012).

Cost Assessment of Sustainable Energy Systems (CASES)

Like NEEDS, the CASES study is a one-time extension of the ExternE assessment funded by the European Commission. The CASES study is a multi-country, multi-year study performed by multidisciplinary research teams at multiple universities and institutes across Europe. The CASES analysis was performed separately from and concurrently with the NEEDS study.

The CASES study has the same goal as this thesis: to quantify the social cost of electricity generation. However, while this thesis assesses the social costs for both current and new U.S. generation and, in addition, includes an analysis of government subsidies, CASES focuses on the external and private costs of new European electricity generation. As such, the CASES study presents both private and external costs of future electricity generation technologies for European countries (Markandya et al., 2010).

Methodology

In the CASES assessment, the private costs of each technology are calculated by first estimating the capital costs, lifetime fuel and operations and maintenance (O&M) costs of a new plant based on market prices. Next, with a discount rate of 5% for future costs, the net present value (NPV) of total costs is calculated. Then, accounting for the plant capacity, expected lifetime, and capacity factor, the lifetime electricity generation is computed. The plant cost NPV is normalized by the expected lifetime electricity generation to obtain a levelized cost of electricity (LCOE). The LCOE provides a cost estimate of electricity supplied to the grid connection busbar in dollars per unit energy (usually ¢/kWh). The CASES LCOE is calculated irrespective of country-specific policy measures that distort the cost of electricity, such as electricity taxes or subsidies. Furthermore, the analysis does not include any additional cost of the electrical grid in terms of required transmission or upgrades.

The external costs are assessed following the same methodology the ExternE studies. First, the lifecycle emissions and damages of various electricity generation technologies—from material extraction to plant decommissioning—are compiled. Then the marginal costs of pollutant emissions from electricity generation are quantified through the EcoSense model. Finally, the lifecycle emissions per quantity of electricity generated are multiplied by the marginal cost of emissions. The external impacts to human health, agriculture, the built environment, and ecology are monetized through this process. The damage of GHG emissions are monetized with marginal emission values from the FUND and PAGE (a similar model to FUND) models. The social costs are determined for the present (which is represented by the year 2007 as the midpoint of the 2005-2010 study), 2020 and 2030.

Assumptions

The VSL and VSLY inherent to the CASES calculations are €3 million and €40,000/year, respectively (Markandya et al., 2010).

The lower bound GHG marginal cost estimate from the FUND and PAGE models is €4/tCO_2-eq. The upper bound is €53/tCO_2-eq, and the central value is taken to be the average of the median runs of the FUND and PAGE models of €23/tCO_2-eq (Markandya et al., 2010).

Results

According to the CASES assessment, the private costs for a new hard coal condensing plant are 3.33 $€_{2005}$ cents/kWh and the central estimate of external costs is 3.14 $€_{2005}$ cents/kWh, for a total social cost of 6.47 $€_{2005}$ cents/kWh (Markandya et al., 2010). The private costs of a new natural gas CCGT plant are determined to be 4.81 $€_{2005}$ cents/kWh, while the external costs are smaller than coal at 1.39 $€_{2005}$ cents/kWh, for a social cost of 6.2 $€_{2005}$ cents/kWh (Markandya et al., 2010). A SCGT plant has higher private and external costs than a combined cycle plant at 6.58 $€_{2005}$ cents/kWh and 2.08 $€_{2005}$ cents/kWh, respectively, for a social cost of 8.66 $€_{2005}$ cents/kWh (Markandya et al., 2010). New nuclear plants have the lowest overall cost because of un-quantified external costs such as long-term fuel storage. The private costs for nuclear are 3.10 $€_{2005}$ cents/kWh and the external costs are 0.21 $€_{2005}$ cents/kWh, for a social cost of 3.32 $€_{2005}$ cents/kWh (Markandya et al., 2010). New large-scale (>100 MW) run-of-the-river hydro projects were found to have a social cost of 6.85 $€_{2005}$ cents/kWh with an external cost of only 0.04 $€_{2005}$ cents/kWh (Markandya et al., 2010). Onshore wind and offshore wind were found to have similar social costs of 6.21 and 6.45 $€_{2005}$ cents/kWh, respectively (Markandya et al., 2010). The result is indicative of the low capital cost of offshore wind installation in Europe. The external costs of wind power are 0.09 $€_{2005}$ cents/kWh for onshore and 0.10 $€_{2005}$ cents/kWh for offshore. The external costs of solar PV are about 0.89 €$_{2005}$ cents/kWh. But, new solar PV projects have the highest social cost of 36.6 €$_{2005}$ cents/kWh for land-based developments and 44.8 €$_{2005}$ cents/kWh for rooftop projects (Markandya et al., 2010).

A peculiarity of the CASES study is that for onshore wind, offshore wind and solar PV power, the private and external costs of backing-up up the power plants are included in the final social cost calculation. A CCGT plant was the assumed backup. While it is true that renewable power are variable generators which fluctuate generation periodically, all electricity generators come offline at some point for planned or unplanted maintenance. Thus, to integrate back-up costs for some technologies and not others is not valid. For this reason the CASES private and external costs of wind and solar are likely overvalued.

Conversion

The PPP conversion from the 17 Euro countries to the US$ in 2005 is 0.857 $/€ (OECD, 2011). The consumer price index adjustment from 2005 US$ to 2010 US$ is 1.117 (BLS, 2012).

Hidden Costs of Energy—National Research Council

In the late 2000's, the U.S. Congress commissioned the National Academies of Science to investigate the external impacts of the country's energy use. The study was performed by the National Research Council (NRC) and included multiple researchers at various universities and institutes across the United States. The result, titled "Hidden Costs of Energy", assesses the external cost of current electricity generation within the United States.

Unlike the ExternE and related studies, which model the external costs of a typical plant in various locations, the NRC study modeled and monetized the emissions impact of every major coal and natural gas power plant in the United States. The result is a more thorough assessment of the external costs resulting from power plant emissions. However, the NRC study does not monetize the upstream and downstream external costs of damages not related to direct power plant emissions, including: lifecycle emissions, resource extraction, and accidents to the public. Furthermore, the report only monetizes externalities related to coal and natural gas power and merely qualitatively describes the external impacts of nuclear, wind and solar power. The NRC assessment only addresses external costs, because based on previous national studies (e.g., Lee et al., 1995) the external benefits of fossil fuel generation (e.g., crop fertilization from SO_2, NO_x) were determined to be miniscule when compared to human health damages.

Methodology

Instead of the EcoSense model used in ExternE and related studies, the NRC employs the Air Pollution Emission Experiment and Policy analysis model (APEEP) to determine the deposition of emissions of power plants through the air, water and soil and assess their marginal damage to human health, visibility, crop yields, timber yields, building materials and recreation (NRC, 2010). The pollutant emissions analyzed are SO_2, NO_x, and particulate matter (both $PM_{2.5}$ and PM_{10}). The APEEP uses a reduced-form air-quality model, which simulates basic atmospheric conditions but lacks the ability to simulate complex chemical transformation and dispersion of emissions of more advanced process-based models. However, unlike the costly and time-consuming process-based models, APEEP allows for multiple runs sufficient to assess the marginal damages of emissions at each of the 406 coal power plants and 498 natural gas power plants (of 5 MW capacity or greater) modeled in the NRC study (NRC, 2010). The marginal damages from each plant and pollutant are then multiplied by the total emissions during 2005 from each individual power plant found in the National Emissions Inventory (NEI) maintained by the U.S. Environmental Protection Agency (EPA, 2011). The resulting total costs are normalized by the total electricity generated at each plant to obtain a cost per unit energy.

To assess the human heath damage, the morbidity and mortality dose-response functions used by the EPA in regulatory impact analyses are included in the APEEP model (NRC, 2010). APEEP, like EcoSense, uses the $PM_{2.5}$ dose-response as per Pope *et al.* (2002). However, the NRC (2010) sensitivity analysis found that with the higher dose-response rate from Dockery *et al*. (1993), the external costs from coal and natural gas would be three-times as large. As will subsequently be discussed, the Epstein *et al*. (2011) article questions the Pope *et al*. dose-response function and suggests the updated Schwartz *et al.* (2008) function, which is similar to the Dockery *et al*. dose-response rate.

Assumptions

Unlike the ExternE and NEEDS analyses, the NRC calculates the external costs from pollution related mortality with VSL instead of VSLY. The authors suggest that this decision is justified because the literature is not adequately settled as to the effect of age on the value of a statistical life (NRC, 2010). In other words, no matter the age of the pollution-related mortality, the costs are equally valued. The NRC study uses a VSL of $6 million in 2000 US$, which was settled upon after a comprehensive literature review (NRC, 2010).

The study offers a range of costs related to GHG emissions. Based on a doubling of atmospheric GHG concentrations from climate models FUND, RICE and DICE, the cost of GHG emissions is likely between \$10-\$100/tCO_2-eq (NRC, 2010). The wide range is due to the predicted temperature increase, the possibility of catastrophic events, the timing of emissions, the assumed discount rate, and whether the damages are equity weighted. Based on many model results, if the climate-related impacts are expected to be high, then the cost per tCO2-eq is $10 with a discount rate of 4.5%, $30 with a discount rate of 3% and $100 with a discount rate of 1.5% (NRC, 2010, p.302). The NRC determines that mid-range, best estimate value is $30/tCO_2-eq (NRC, 2010).

Results

According to the NRC (2010) assessment, the emissions related external costs of the current U.S. coal power fleet range from 0.19-12 ¢$_{2007}$/kWh, and the average external cost is 3.2 ¢$_{2007}$/kWh. The human health costs related to SO_2 emissions compose 85% of the total cost. The range in external costs stem from the coal sulfur content, the variation in emissions control technology, the age of the plant and to a lesser extent, the population density surrounding the plant. The most egregious plant damages are heavily weighted in the Ohio River Valley and Mid-Atlantic regions (NRC, 2010, p. 88). Given that many of the plants with the highest external costs are located within the PJM region, the external costs within the PJM region may be higher than the national average cost. The study finds the external costs related to GHG emissions range from 1-10 ¢/kWh, with a best estimate of 3 ¢/kWh.

The plant-by-plant estimates of natural gas (combined CCGT and SCGT) external costs vary from 0.001-0.55 ¢$_{2007}$/kWh, and the average cost is 0.16 ¢$_{2007}$/kWh (NRC, 2010). Most of the damages (56%) are related to human health costs from direct emission of $PM_{2.5}$. The variation of external costs is due to the differences in emissions intensities between plants and the population density surrounding the plants. The plants with the worst damages are located along the Eastern Seaboard, California, Texas and Florida (NRC, 2010, p. 119). Again, given that many of the plants with the highest external costs are located along the Eastern Seaboard within the PJM region, the external costs within the PJM region may be higher than the national average cost.

The external costs related to GHG emissions range from 0.5-5 ¢/kWh, with a best estimate of 1.5 ¢/kWh.

The NRC does not monetize the externalities from nuclear, wind, or solar power but does include a brief qualitative literature review. The researchers cite the results from the Oak Ridge National Lab/Resources for the Future (Lee et al., 1995) study which found that, including the risk of an accident, the external cost of nuclear power is 0.025 $¢_{2007}$/kWh. The Oak Ridge study did not include conversion, enrichment, fuel-fabrication or internment of low-level waste. The researchers also cite the ExternE (1995b) study which found, with no discount rate, the external cost to be about 0.25 $¢_{2007}$/kWh. The ExternE study included fuel conversion, milling, enrichment and low-level waste. The NRC researchers determined that improving upon the methods is beyond the scope of the project and ultimately unnecessary because the methodology has not changed. These values are mentioned in the interest of comprehensiveness but are not included in the subsequent results chapter.

The externalities of solar power are 0.1-0.2 $¢_{2007}$/kWh according to Fthenakis & Alsema (2006). The costs mainly stem from lifecycle GHG emissions and the emission of lead and particulate matter during the fabrication of panels. There are also concerns about downstream recycling and disposal of panels to avoid chemicals leaching into groundwater. The externalities of wind were found to be insignificant and thus are not quantified in the NRC literature review (NRC, 2010).

Conversion

The consumer price index adjustment from 2007 US$ to 2010 US$ is 1.052 (BLS, 2012).

Full cost accounting for the life cycle of coal—Epstein *et al.*

The Epstein *et al.* (2011) study assesses and monetizes the external costs of the entire lifecycle of coal electricity generation: from coal extraction to disposal of waste. Performed by multidisciplinary, multi-researcher team of U.S. epidemiologists, public health academics, economists, and energy experts, the Epstein *et al.* study was based on prior, unpublished work commissioned by Greenpeace. The study utilizes the NRC analysis of the entire coal generation fleet as the study core but expands the upstream and downstream lifecycle scope. Unlike the NRC study which only monetized the impacts from direct pollutant and GHG emissions during the electricity generation phase, the Epstein *et al.* study monetizes the damages from coal transport related fatalities, the public health impacts of coal mining in Appalachia, methane emissions from coal mines, and the lost economic value of abandoned mine land, as well as the direct pollutant and GHG emissions during the electricity generation phase. The paper presents the external cost estimates as a range and includes a best estimate based on the authors' expertise and reasoning.

Methodology

The Epstein *et al.* article analyzes the health, property and environmental damage from SO_2, NO_x, and particulate matter emitted during the electricity generation with the same method as the NRC study. The marginal costs of each pollutant at 406 coal plants nation-wide are assessed through APEEP model. Then, the total emissions at each plant (from the National Emission Inventory) are multiplied by the marginal costs to obtain the total cost. Finally, the total plant costs are normalized by the amount of electricity generated at each plant.

Not surprisingly, when the Pope *et al.* (2002) $PM_{2.5}$ dose-response function is used, the Epstein *et al.* study concludes that the average external costs related to direct pollutant emissions from the US coal fleet were the same as the NRC study (3.2

¢$_{2008}$/kWh). However, with the higher mortality rates per dose of $PM_{2.5}$ suggested in the Schwartz *et al.* (2008) study, the external costs are found to be almost three times as large (9.3 ¢$_{2008}$/kWh). The authors contend that the Schwartz *et al.* study uses more advanced techniques to derive the dose-response function. Furthermore, they view it as the commonly accepted dose-response function and therefore justify its inclusion as their best estimate of external costs (Epstein et al., 2011).

For certain damages, such as the public health impacts due to coal mining in Appalachia and the lost value of abandoned mines, a top-down methodology is used to assess the external costs. It is worth noting that the argument could be made that the public health impacts due to coal extraction are not externalities because the costs would be reflected in reduced housing prices. However, due to imperfect information the market costs are not properly represented in housing prices and therefore the external costs are included.

In the top-down method, first, a literature review determines the likely total damage in terms of number of fatalities, injuries, or disrupted land acreage. Then, the damage is monetized through the VSL or a value from the literature. Lastly, the total cost is divided by the total electricity generated by U.S. coal plants to obtain the external cost per unit energy.

Assumptions

The Epstein *et al.* study assumes the same values as the NRC study, and like the NRC only uses VSL to assess pollution related health costs. The VSL is $6 million in 2000 US$ which is equivalent to $7.5 million in 2008 US$.

The climate related damages from GHG emissions range from a low estimate of $10/t$CO_2$-eq to a high estimate of $100/t$CO_2$-eq, with a best estimate of $30/t$CO_2$-eq.

Results

The low-range external cost estimate for U.S. coal electricity generation is 9.20[1] ¢$_{2008}$/kWh (Epstein et al., 2011). The majority of the external cost (4.36 ¢$_{2008}$/kWh) stems from the public health impacts to non-miners due to coal mining. The other major components are the direct emissions of pollutants during combustion (3.23 ¢$_{2008}$/kWh) and climate change-related damages (1.06 ¢$_{2008}$/kWh). The low-range estimate includes the NRC assessment of external costs from direct emission of pollutants, and the low-end estimate of climate change related damages of \$10/tCO_2-eq. However, because of the inclusion of the public health impacts from coal mining, the low-range Epstein *et al.* estimate is higher than the NRC best estimate.

The best estimate for externalities from US coal electricity generation is 17.68[1] ¢$_{2008}$/kWh (Epstein et al., 2011). The majority of the external cost (9.31 ¢$_{2008}$/kWh) stems from the direct emissions of pollutants during the combustion cycle. The best estimate case utilizes the more conservative Schwartz *et al.* $PM_{2.5}$ dose-response function which increases the damage estimate of pollutants emitted during the combustion cycle by almost a factor of three. The other major components are the public heath burden to coal mining communities in Appalachia (4.36 ¢$_{2008}$/kWh) and climate change-related damages (3.06 ¢$_{2008}$/kWh).

The high-range external cost estimate is 26.62[1] ¢$_{2008}$/kWh (Epstein et al, 2011). Climate change-related damages from GHG emissions compose the majority of the cost (10.70 ¢$_{2008}$/kWh), since the assumed marginal cost of GHG is \$100 /tCO_2-eq. Impacts from the direct emissions of pollutants during combustion constitute the second highest damages at 9.31 ¢$_{2008}$/kWh, and the public health burden to coal mining communities in Appalachia is a distant third at 4.36 ¢$_{2008}$/kWh (Epstein et al., 2011).

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[1] The Epstein *et al.* (2011) study includes subsidies in the external cost computation, but in all cases they were removed since this thesis distinguishes between externalities and subsidies.

The authors acknowledge that there are additional costs which are difficult to estimate and were not included, although they represent real costs (Epstein et al., 2011). These un-quantified costs include the ecological impacts of toxic metals and chemicals; eutrophication of freshwater and estuarine bodies from nitrogen deposition; long-term mental health impacts to inhabitants of coal mining regions; and physical risks from coal sludge, slurry, and other waste internment. However, even without the monetization of those impacts the Epstein *et al.* study concludes that at the low-end, the external costs of coal electricity are 1.5 times higher than the best estimate of the NRC study. This demonstrates the importance of the inclusion of all external impacts, since the public health impacts from coal mining to the surrounding communities constitute a significant portion of the external costs. Additionally, the use of a different dose-response function leads to three-times higher health related damages from direct pollutant emissions during the combustion cycle.

Conversion

The consumer price index adjustment from 2008 US$ to 2010 US$ is 1.013 (BLS, 2012).

Environmental Accounting for Pollution in the United States Economy—Muller *et al.*

The Muller *et al.* (2011) study assesses the external costs of the direct pollutant emissions during the combustion cycle of both coal and natural gas power. The study was performed by economists at Middlebury College and Yale University and is an updated version of an unpublished manuscript by the same authors (Muller et al., 2009). The Muller *et al.* study is included to serve as a foil for the NRC study. The Muller *et al.* study is very similar to the NRC analysis, as both studies only consider emissions from the generation phase; employ the same model; and individually analyze the marginal cost of emissions from each of the plants which constitute the U.S. coal and natural gas generation fleet. The major differences between the two studies pertain to the valuation of human health impacts and climate change-related damages.

Methodology

Like the NRC study, the Muller *et al.* study assesses the marginal human health, visibility, crop yields, timber yields, building materials and recreation costs using the APEEP model at 10,000 sites in the country (not all are electricity generation sites) of five key pollutants: SO_2, NOx, particulate matter ($PM_{2.5}$ & PM_{10}), VOCs and ammonia[2]. The marginal costs of each pollutant are multiplied by the total emissions at each plant retrieved from the National Emission Inventory, and then the resulting total costs are normalized by the electricity generated at each plant. Greenhouse gas emissions and marginal damages are also analyzed in this study using the same method as the NRC assessment.

The Muller *et al.* analysis uses the Pope *et al.* (2002) dose-response function between particulate matter concentration and mortality. The major difference between the Muller *et al.* and the NRC study is the use of variable VSL, instead of a single VSL that is not age-dependent. The Muller *et al.* study adopts a VSL dependent on age, similar to the European VSLY calculation.

Assumptions

The assumed VSL is $6 million in 2000 US$ and the VSLY varies by age (it is $265,000/year for a 35 year old) (Muller et al., 2011).

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[2] VOCs and ammonia were initially included in the NRC (2010) study, but the external costs were not included in the final calculation due to lack of emissions data in the National Emissions Inventory.

The climate change damages from GHG emissions are valued from \$1.6/tCO_2-eq to \$17.7/tCO_2-eq with a best estimate of \$7.4/tCO_2-eq in 2000 US\$ as per Nordhaus (2008)[3].

Results

The external costs of coal electricity generation are 2.8 $¢_{2000}$/kWh without climate change damages and between 2.97 and 4.72 $¢_{2000}$/kWh including climate change damages, with a central estimate of 3.59 $¢_{2000}$/kWh (Muller et al., 2011). Almost 95% of the non-climate change-related damages come from pollutant-related mortality; mostly either through direct emission of small particulates ($PM_{2.5}$) or through the chemical conversion of SO_2 and NO_x to small particulates (Muller et al., 2011). The external costs of natural gas electricity generation (combined CCGT and SCGT) are 0.085 $¢_{2000}$/kWh excluding climate change damages and between 0.24 and 1.13 $¢_{2000}$/kWh including climate change damages, with a central estimate of 0.56 $¢_{2000}$/kWh (Muller et al., 2011).

The coal and natural gas values are lower than NRC (2010) results, mainly because of the low magnitude of the climate change related damages. However, it is worth noting that without climate change damages the NRC and Muller *et al.* results are comparable (3.37 $¢_{2010}$/kWh versus 3.55 $¢_{2010}$/kWh, respectively, after accounting for inflation) even though the Muller *et al.* uses an age dependent VSL, or VSLY, which normally produces lower external costs (Sundqvist, 2004). It is unclear whether the NRC and Muller *et al.* non-climate change-related costs are comparable because of the inclusion of VOC and ammonia in the Muller *et al.* analysis, or due to some less obvious assumptions and model modifications.

[3] In their study, Muller *et al.* present GHG related damages in tons of carbon equivalent (tC) which equals 3.667 tCO2-eq.

In order to determine the importance of the constant VSL and dose-response function, the authors performed a sensitivity analysis. With a constant VSL, the non-climate change damage increases 2.5 times because most of the air pollution-related deaths occur within the elderly population (Muller et al, 2011). Rerunning the model with the Schwartz *et al.* $PM_{2.5}$ dose-response function also increases the external costs more than two-times (Muller et al., 2011). While the Muller *et al.* paper did not discuss this, if there is no overlap between the constant VSL and the Schwartz *et al.* dose-response rate, the net externality increase would be a magnitude of five. The APEEP model was also calibrated against the state-of-the-art, process-based community multiscale air quality model (CMAQ) and achieved similar results.

Conversion

The consumer price index adjustment from 2000 US$ to 2010 US$ is 1.266 (BLS, 2012).

External Cost of Avian & Bat Mortality

Avian and bat mortality are not widely addressed in externality studies of wind power. The original ExternE studies monetized the impacts, but because they were determined to be miniscule the assessment was dropped from future studies (ExternE, 2003). In the interest of comprehensiveness, avian and bat mortality are monetized in this thesis.

Methodology

In order to calculate the monetary damage of wind power-related avian and bat mortality, observational data about the number of birds killed per turbine is multiplied by the estimated value of a bird and then divided by the average electricity produced by a turbine.

The National Wind Coordinating Collaborative (NWCC) reviewed the avian mortality at U.S. wind facilities. The study concluded that the average site had fewer than 0.2 raptor fatalities per MW/year and that seventy-five percent of the sites had 3 or fewer total bird fatalities per MW/year (NWCC, 2010). According to the review, songbird collision accounts for three quarters of the casualties. Despite these statistics, the morality rate is unlikely to affect the North American songbird population (NWCC, 2010).

Economists assess birds' economic value from what the public is willing to pay to preserve habitat through contingent value surveys or the travel cost spent by bird enthusiasts (Rouche, 2001). The results vary greatly by methodology and usually are site or species specific, which limits the applicability for this study. A single songbird fatality may be valued under a dollar, while fatalities of birds listed under the *Migratory Bird Treaty Act* can warrant fines of up to $2,500 per bird. An alternate method is to assess an avian mortality value based on the replacement cost and the relative scarcity of species (Hampton, 2001). An analysis performed by the State of California Department of Fish & Game found the restoration cost for common birds to be $120 (Hampton, 2001), which falls in the middle of the valuation range, and represents the bulk of the birds impacted by turbines both onshore and offshore. Thus, for this study the figure of 3.2 combined bird fatalities per MW/year at the value of $120 per bird is used in the external cost estimate for onshore and offshore avian mortality. In order to calculate the electricity generated by a turbine, the turbine capacity is multiplied by the number of hours in a year (8760 hours) and by a net capacity factor of 30% for onshore wind and 35% for offshore wind.

The NWCC (2010) study found that 75% of the wind facilities reported bat mortality to be 10 or fewer per MW/year. Unfortunately, there is a dearth of economic valuations of bats; therefore the external cost of bat mortality is conservatively estimated to be the same as the avian restoration cost of $120 per individual bat.

Results

The resulting onshore wind avian and bat externalities are 0.015 $¢_{2001}$/kWh and 0.046 $¢_{2001}$/kWh, respectively, for a total of 0.060 $¢_{2001}$/kWh. The resulting offshore wind avian and bat externalities are 0.013 $¢_{2001}$/kWh and 0.039 $¢_{2001}$/kWh, respectively, for a total of 0.052 $¢_{2001}$/kWh. The avian and bat mortality externalities amount to less than half of the pollutant related external costs for both onshore and offshore wind according to the CASES study. Although these costs are small, they are included as additional external costs in this thesis because it makes this study more comprehensive, especially given the widespread perception that avian mortality is a major impact of wind power.

Conversion

The consumer price index adjustment from 2001 US$ to 2010 US$ is 1.231 (BLS, 2012).

Table 1 Overview of the methodology and results of the externality studies analyzed in this thesis.

Externality Study	Location	Year Published	Technologies	Year Considered	Costs Considered	Model	Damages Assessed	$PM_{2.5}$ Dose-Response	Total Value of Life (VSL)	Value of life per year lost (VSLY)	CO_2 Value (Low-Median-High)
ExternE	European Union	2005	All	Current	External	EcoSense	SO_2, NO_X, PM, VOC, Heavy Metals, Radionuclidies, Accidents, GHG	Pope *et al.*, 2002	€1,000,000	€ 50,000	€18-46
NEEDS	European Union	2009	Coal, Natural Gas Combined Cycle, PV, Offshore Wind	Future	External	EcoSense & MARKAL/TIMES	SO2, NOX, PM, VOC, Heavy Metals, Radionuclidies, Land Use Change, Accidents, GHG	Pope *et al.*, 2002	€3,000,000	€ 40,000	€7-23.5-98
CASES	European Union	2008	All	Future	Private & External	EcoSense	SO2, NOX, PM, VOC, Heavy Metals, Radionuclidies, Accidents, GHG	Pope *et al.*, 2002	€3,000,000	€ 40,000	€7-99
NRC	United States	2010	Coal, Natural Gas	Current	External	APEEP	SO2, NOX, PM, GHG	Pope *et al.*, 2002	$6,000,000	None	$10-30-100
Epstein *et al.*	United States	2011	Coal	Current	External	APEEP	Public Health Costs of Coal Mining, SO2, NOX, PM, VOC, Mercury, Abandoned Land Value, Accidents, GHG	Schwartz *et al.*, 2008	$6,000,000	None	$10-30-100
Muller *et al.*	United States	2011	Coal, Natural Gas	Current	External	APEEP	SO2, NOX, PM, VOC, Ammonia, GHG	Pope *et al.*, 2002	$6,000,000	$265,000	$7.40

Private Cost Studies

Two private cost studies are reviewed in this section: the EIA (2011b) "Levelized Costs of New Generation Resources" and Greenstone and Looney (2012). Each study includes an assessment of the private costs of new U.S. electricity generation, and the Greenstone and Looney analysis estimates the private costs of existing generation as well. The CASES study also analyzes the private costs of new European generation, and values are included in the following results chapter. However, the CASES study was already reviewed in the previous externality studies section and is therefore not included below.

The study reviews are outlined as follows: first the study is contextualized, then the methodology is explained, and finally the results are presented. Additionally, if necessary, the consumer price index adjustment used to convert results to 2010 US$ are included after each study.

Levelized Cost of New Generation Resources—Energy Information Administration

The "Levelized Cost of New Generation Resources" performed by the EIA (2011b) estimates the private costs of new electricity generation capacity installed in the United States. The study is part of the larger *Annual Energy Outlook* which the EIA publishes yearly in accordance with the *Department of Energy Organization Act of 1977* (EIA, 2011b). The levelized cost assessment analyzed in this thesis was published in 2011. The study analyzes the costs in the year 2016, because the implicit lead time required to permit and construct new generation would be at least five years. The generation technologies analyzed include fossil fuel, nuclear, hydro, onshore and offshore wind, and solar PV. The levelized cost analysis includes the capital, O&M, fuel and financing costs over the assumed lifecycle of the generation facility.

Methodology

The EIA private cost analysis uses the National Energy Modeling System (NEMS) to calculate the LCOE (EIA, 2011b). The NEMS was first developed by EIA in 1993 to analyze the future composition of the U.S. grid and assess future economic, environmental or supply issues (EIA, 2009). The private costs of each technology are calculated by first estimating the capital costs and lifetime fuel, financing and O&M costs of a new plant from the market. Then, the costs are converted to NPV and annualized. Accounting for the plant capacity, expected lifetime and capacity factor, the expected annual electricity generation is computed. Finally, the annualized NPV is normalized by the expected annual electricity generation to obtain a LCOE in dollars per megawatt-hour ($/MWh). The analysis includes an estimation of average required transmission upgrades per generation facility. The EIA private cost analysis calculates the levelized cost based solely on capital and labor costs in the absence of any distortionary governmental policies or incentives. That is to say, the EIA LCOE is the ‘real’ private cost, or inherently includes the private costs of electricity and subsidies.

The assumed after-tax cost of capital (COC) in the model is 7.4%, with the exception of fossil fuel plants which have a COC of 10.4% to reflect the difficulty of building new fossil fuel plants due to the knowledge that GHG prices could modify generation plant economics (EIA, 2011b). It is possible that the costs of new fossil fuel plants are overestimated because of the higher COC.

Results

According to the EIA (2011b), the U.S. levelized cost of new coal generation in 2016 varies between 8.56 and 11.10 ¢$_{2009}$/kWh[4] with a central value of 9.51 ¢$_{2009}$/kWh. The majority of the levelized cost of new coal generation is the capital cost (6.55 ¢$_{2009}$/kWh) and the fuel cost (2.45 ¢$_{2009}$/kWh), and the remainder is the O&M cost and the required transmission upgrades. The levelized cost range of new natural gas generation is between 5.69 and 7.33 ¢$_{2009}$/kWh for CCGT[5] and between 8.63 and 14.11 ¢$_{2009}$/kWh for SCGT[6] (EIA, 2011b). The central values are 6.22 ¢$_{2009}$/kWh and 10.21 ¢$_{2009}$/kWh for CCGT and SCGT, respectively. Natural gas has a lower capital cost than coal (between 1.75 and 4.58 ¢$_{2009}$/kWh depending on the technology) but a much higher fuel cost (estimated between 4.12 and 6.99 ¢$_{2009}$/kWh). The private costs of new nuclear plants are estimated to be between 10.98 ¢$_{2009}$/kWh and 12.16 ¢$_{2009}$/kWh, with a central value of 11.40 ¢$_{2009}$/kWh (EIA, 2011b). Almost 80% of the cost of a new nuclear plant is expected to be capital cost (9.02 ¢$_{2009}$/kWh), and, while the nuclear fuel costs are lower than fossil fuel generation (1.17 ¢$_{2009}$/kWh), the O&M costs are higher (1.11 ¢$_{2009}$/kWh).

The levelized cost of new hydro generation is expected to be between 5.68 and 14.90 ¢$_{2009}$/kWh, with a central value of 9.50 ¢$_{2009}$/kWh (EIA, 2011b). Over 85% of the levelized cost is composed by the capital cost of new hydro projects (7.85 ¢$_{2009}$/kWh). The private costs for new wind generation range between 8.23 and 11.51

[4] The EIA (2011b) presents the results in \$2009/MWh which are equivalent to 0.1 ¢2009/kWh.

[5] This range includes both advanced and conventional CCGT. The central value demonstrates the average advanced CCGT cost.

[6] This range includes both advanced and conventional SCGT. The central value presents the average advanced SCGT.

¢$_{2009}$/kWh for onshore wind and an estimated 18.71 and 35.0 ¢$_{2009}$/kWh for offshore wind, depending on the location (EIA, 2011b). The central estimates are 9.61 and 24.37 ¢$_{2009}$/kWh for onshore and offshore wind, respectively. In both cases the O&M (0.96 ¢$_{2009}$/kWh onshore and 2.81 ¢$_{2009}$/kWh offshore) and transmission costs (0.34 and 0.59 ¢$_{2009}$/kWh onshore and offshore, respectively) pale in comparison to the capital cost (8.33 ¢$_{2009}$/kWh onshore and 20.97 ¢$_{2009}$/kWh offshore). The cost of new PV generation in 2016 is expected to be between 15.89 and 32.44 ¢$_{2009}$/kWh—without any government assistance—with a central value of 21.10 ¢$_{2009}$/kWh (EIA, 2011b). The capital cost (19.40 ¢$_{2009}$/kWh) of new solar PV generation accounts for over 90% of the total cost. Overall, renewable energy technologies have higher capital and O&M costs than traditional generation, but compensate because the fuel costs are zero. The results are highly variable depending on the installed location and the advancement of technology, which explains the wide ranges in expected costs.

Conversion

The consumer price index adjustment from 2009 US$ to 2010 US$ is 1.016 (BLS, 2012).

Paying too much for Energy? The True Costs of our Energy Choices—Greenstone & Looney

In an economic policy analysis for the Hamilton Project of the Brookings Institution, Greenstone and Looney (2012) assessed the private costs of both current and future U.S. electricity generation technologies and then added the external costs for coal and natural gas based on the NRC (2010) study. The intention was to understand the entire social cost of electricity for use in policymaking. The study was later published in a peer-reviewed journal. The Greenstone and Looney study is similar to this thesis in that both assess private and external costs of electricity generation. However, the Greenstone and Looney study does not include as comprehensive an analysis of external costs based on multiple sources and furthermore, does not quantify the subsidies provided to current electricity generation.

Methodology

The private costs for new coal, natural gas (both CCGT and SCGT), nuclear, hydro, onshore and offshore wind, and solar PV are estimated based on the capital costs and lifetime fuel, financing and O&M costs of a new plant from market prices. Then, the costs are converted to NPV and annualized. Accounting for the plant capacity, expected lifetime and capacity factor, the expected annual electricity generation is computed. Finally, annualized NPV is normalized by the expected annual electricity generation to obtain a LCOE in dollars per kWh. The Greenstone and Looney model is an extension and update of the widely accepted Du and Parsons (2009) model for nuclear power.

The private costs for existing coal, natural gas, and nuclear generation are calculated assuming that the capital generation costs have already been amortized. Additionally, the O&M costs are assumed to be two-thirds less expensive than a new plant, to account for the cost of a new plant adhering to new environmental regulations, under which the existing plants are grandfathered and need not comply. The fuel costs are assumed to be the same, but, the fuel efficiency of existing capacity is assumed to be less than that for new generation.

Results

The private cost of electricity from existing coal, natural gas and nuclear generation is estimated to be 3.2 $¢_{2010}$/kWh, 4.9 $¢_{2010}$/kWh, and 2.2 $¢_{2010}$/kWh, respectively (Greenstone and Looney, 2012). The cost for new coal generation is estimated to be 6.2 $¢_{2010}$/kWh, new natural gas is estimated to be 5.5 $¢_{2010}$/kWh for CCGT and 10.8 $¢_{2010}$/kWh for SCGT, and new nuclear is estimated to be between 8.2-10.5 $¢_{2010}$/kWh (Greenstone and Looney, 2012). Electricity generated from renewable energy projects range in cost from 6.4 $¢_{2010}$/kWh for hydropower to 19.5 $¢_{2010}$/kWh for solar PV, with wind generation at 8.0 $¢_{2010}$/kWh for onshore and 19.1 $¢_{2010}$/kWh for offshore projects (Greenstone and Looney, 2012).

Subsidy Studies

Two subsidy studies are reviewed in this section: the EIA "Direct Federal Financial Interventions and Subsidies" and Koplow (2011). Both studies assess the federal incentives to electricity generation. However, while the EIA study includes all generation sources, the Koplow study focuses exclusively on nuclear power. The study reviews are outlined as follows: the study is contextualized and summarized and then the results are presented. The EIA subsidy review includes conversions from total subsidy amounts ($) to subsidies per unit energy (¢/kWh) through subsequently discussed methods.

Direct Federal Financial Interventions and Subsidies—Energy Information Administration

At the request of several U.S. Representatives the EIA (2011c) assessed the federal subsidies provided to energy in 2010. The study includes direct federal subsidies as well as tax breaks for each electricity generation technology. However, under the study mandate, to be included, the subsidy must be quantifiable in the fiscal year (FY) 2010 federal budget, and must exclusively benefit energy. Thus, the EIA assessment excludes billions of dollars in subsidies, because it precludes the inclusion of the highly valuable accelerated depreciation schedule, which benefits all manufacturing interests, and the integral *Price-Anderson Act Nuclear Industries Indemnity Act* (henceforth Price-Anderson Act), which caps the damage liability of nuclear generators in the event of a catastrophic failure, but is not a budgetary inclusion (Koplow, 2010). Furthermore, the EIA (2011c) assessment provides a static view of subsidies since it includes only a single year's analysis, and may be skewed because of the release of funds under the ARRA—commonly known as the stimulus package. In fact, the EIA researchers note that "focusing on a single year's data also does not capture the imbedded effects of subsidies that may have occurred over many years across all energy fuels and technologies" (EIA, 2011c, p. xvii). However, the EIA study at least provides a lower-bound estimate of the federal subsidies for electricity generation.

Results

The EIA (2011c) analysis found that U.S. coal generation received $1.19 billion in federal subsidies in 2010, mostly in the form of R&D funding ($575 million) and tax expenditures ($486 million) (EIA, 2011c). Natural gas and oil generation were subsidized $655 million, almost entirely in tax expenditures ($583) (EIA, 2011c). Nuclear power received \$2.50 billion, again mostly in the form of R&D funding (\$1.17 billion) and tax expenditures (\$908 million) (EIA, 2011c). The subsidies for hydro power were an order of magnitude less than nuclear at \$216 million and were primarily composed of tax credits for interest earned on mandated trusts (\$130 million) (EIA, 2011c). Wind power received the largest federal subsidy in 2010 with \$4.99 billion, the majority of which went to support installation of new projects through direct expenditure of the ARRA section 1603 cash grant (\$3.56 billion) and tax expenditure through the ITC (\$1.18 billion) (EIA, 2011c). The federal solar power subsidy was \$1.13 billion, which was primarily composed of direct expenditure (\$496 million), R&D funding (\$348 million) and DOE loan guarantees (\$173 million) (EIA, 2011c).

In order to convert the values into subsidies per unit of electricity (\$/kWh), there are two methods employed. The first method is used for traditional generation technologies (coal, natural gas, and nuclear) which already have substantial capacity installed and thus as a percentage are not growing quickly. For traditional generation, the total subsidies for each generation source are divided by the total electricity generated by that source during 2010 (generation data from EIA, 2011a).

With the first method, the resulting subsidy for coal generation is 0.064 $¢_{2010}$/kWh, natural gas generation is 0.064 $¢_{2010}$/kWh, nuclear power is 0.310 $¢_{2010}$/kWh, and hydro power is 0.083 $¢_{2010}$/kWh. The subsidy for wind power is 5.27 $¢_{2010}$/kWh and the subsidy for solar power is 93.3 $¢_{2010}$/kWh.

The 2010 subsidy values can be compared to the results of a previous EIA study of the FY 2007 federal budget (EIA, 2011c). Following the description outlined in the paragraph above, the FY 2007 values were converted into \$/kWh. The coal power subsidy was found to be 0.197 $¢_{2010}$/kWh, the natural gas subsidy was 0.036 $¢_{2010}$/kWh, the nuclear subsidy was 0.213 $¢_{2010}$/kWh, the hydro subsidy was 0.069 $¢_{2010}$/kWh, the wind subsidy was 1.38 $¢_{2010}$/kWh and the solar subsidy was 29.2 $¢_{2010}$/kWh.

The second method is used for quickly growing renewable energy sources, since the majority of the FY 2010 subsidies for wind and solar incentivized the installation of new projects (EIA, 2011c). Therefore, a more realistic assessment of the subsidy per unit energy would be to calculate the expected lifetime generation of the new projects installed in 2010 and divide into the total FY 2010 subsidy allocation. Through this second method, the subsidy would be amortized over the project lifetime rather than assessing the subsidy designed to encourage new generation based on existing generation. Inherently, this method assumes that all new generation installed in 2010 was subsided by federal allocations in FY 2010. The project lifetime of a wind installation is conservatively assumed to be 20 years with a net capacity factor of 30%, and the lifetime of a solar PV project is assumed to be 25 years with a capacity factor of 15%. In 2010, 5,116 MW of wind capacity (AWEA, 2011) and 918 MW of solar capacity (Bolcar & Ardani, 2011) were installed in the United States. The resulting subsidy is 1.85 $¢_{2010}$/kWh for wind power and 3.75 $¢_{2010}$/kWh for solar power. This analysis does not include any discounting of future electricity generation. An alternate estimate for wind power subsidies would be to use the PTC value of 2.2 $¢_{2010}$/kWh for the first 10 years of operation.

Based on these results it appears that wind and solar power are highly subsidized, however, it is important to remember that they are emerging technologies that only account for small portion of the national electricity generation. Thus, while on a per kWh level the renewable energy subsidy appear to be generous, the dollar value is far from an order of magnitude larger than for traditional energy. In fact, during the early stages of nuclear power development the industry received the equivalent of 7.5 $¢_{2010}$/kWh (Koplow, 2011); at least double what solar or wind power receive now. Furthermore, the data embody a year (2010) that government promoted the installation of new solar and wind generation, but which is not representative of long-term subsidy trends. Indeed, the long term trend is quite the opposite; over the years, fossil fuel and nuclear power has received billions more in federal subsidies than renewable energy (ELI, 2009). According to an Environmental Law Institute study of federal energy subsidies from 2002-2008, fossil fuel energy companies (including oil) received $72 billion, while renewable energy received $29 billion, half of which went to supporting corn-based ethanol (ELI, 2009). These statistics do not include industry wide benefits such as the accelerated depreciation schedule. Due to the non-industry specific nature of the study the subsidies per kWh were not calculated, but it is still vital to understand the magnitude.

It is important to note that state and local subsidies—such as tax rebates, grants, production-based subsidies, low-interest bonds, and generous land swaps—can play an important role in electricity markets. However, due to their diffuse and sporadic nature, state and local subsidies are difficult to assess and thus not quantified in this thesis.

Nuclear Power: Still not competitive without subsidies—Koplow

The Union of Concerned Scientists commissioned an assessment of federal nuclear power subsidies from noted energy subsidy analyst Doug Koplow. The

Koplow (2011) study assesses federal subsidies in the form of direct spending, tax rebates, accelerated depreciation, below-market lending, low-interest loans, liability caps, and socialization of waste disposal; a far larger scope than the EIA (2011c) analysis.

Results

Koplow concludes that the legacy subsidies that nuclear generation received through the 1980's are equivalent to 7.50 $¢_{2010}$/kWh (Koplow, 2011). The legacy subsidies came mainly in the form of investment tax credits and accelerated depreciation to promote technology adoption. The continuing subsidies for existing privately owned generation are smaller than the legacy subsidies but still substantial at 0.74 to 4.16 $¢_{2010}$/kWh (Koplow, 2011). The ongoing subsidies include the socialization of risk through the Price-Anderson Act, the public cost for high-level nuclear waste interment, tax-free interest on waste disposal trusts, cheap—or free—cooling water, and uranium mining and enrichment subsidies. The subsidies for new, privately-owned generation are between 5.01 and 11.42 $¢_{2010}$/kWh (Koplow, 2011). The substantial subsidies for new nuclear generation include federal loan guarantees, accelerated depreciation, PTC, and long-term waste internment. The results from the Koplow study represent a marked increase from the EIA analysis and demonstrate the importance of including the full spectrum of subsidies, not only those accounted for within the annual federal budget.

Chapter 5

RESULTS

This chapter presents the results computed as described in the calculations chapter, including appropriate figures, graphs and tables. The chapter is broken into four sections: external costs, private costs, subsidies and social costs. Within the social cost section, the results of the previous three sections are combined using different summary measure methods. The social cost summary measures include: median, best estimate, and low- and high-GHG related damage. The use of best estimates are justified and all values are presented in 2010 US$ equivalent. The results are interpreted and discussed in the subsequent chapter 6.

External Costs

The results of the six external cost studies analyzed in chapter 4 are presented as summary statistics below in Table 2. Columns distinguish generation technologies, as well as differentiate between studies which focus on existing generation and those which focus on new technologies. Evidently, not every study quantifies the externalities of each of the three existing technologies—coal, natural gas, and nuclear—and eight new generation types—coal, CCGT, SCGT, nuclear, hydro, onshore wind, offshore wind, solar PV. The number of studies (*N*) included in the analysis is presented along with the relevant descriptive statistics: minimum, maximum, mean, median and standard deviation (SD) of the quantified externalities.

The external cost results in Table 2 are displayed graphically in Figure 5. The entire external cost range is presented along with the median and mean.

Table 2 *Descriptive statistics for externality values of the analyzed studies, separated by generation technology. Results are in ¢$_{2010}$/kWh, with the exception of 'N' which represents the number of studies included in the analysis.*

(¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
Min	1.25	0.30	0.29	2.68	0.99	2.16	0.12	0.04	0.15	0.14	0.59
Max	27.23	5.84	1.01	14.53	6.80	2.71	1.01	1.44	0.43	0.42	1.61
Mean	11.92	2.55	0.65	5.64	2.73	2.44	0.38	0.51	0.26	0.23	1.00
Median	7.73	1.44	0.65	3.75	1.55	2.44	0.27	0.05	0.18	0.18	0.86
SD	10.40	2.56	0.51	5.00	2.74	0.39	0.36	0.80	0.15	0.12	0.40
N	4	3	1	3	3	2	2	2	2	3	3

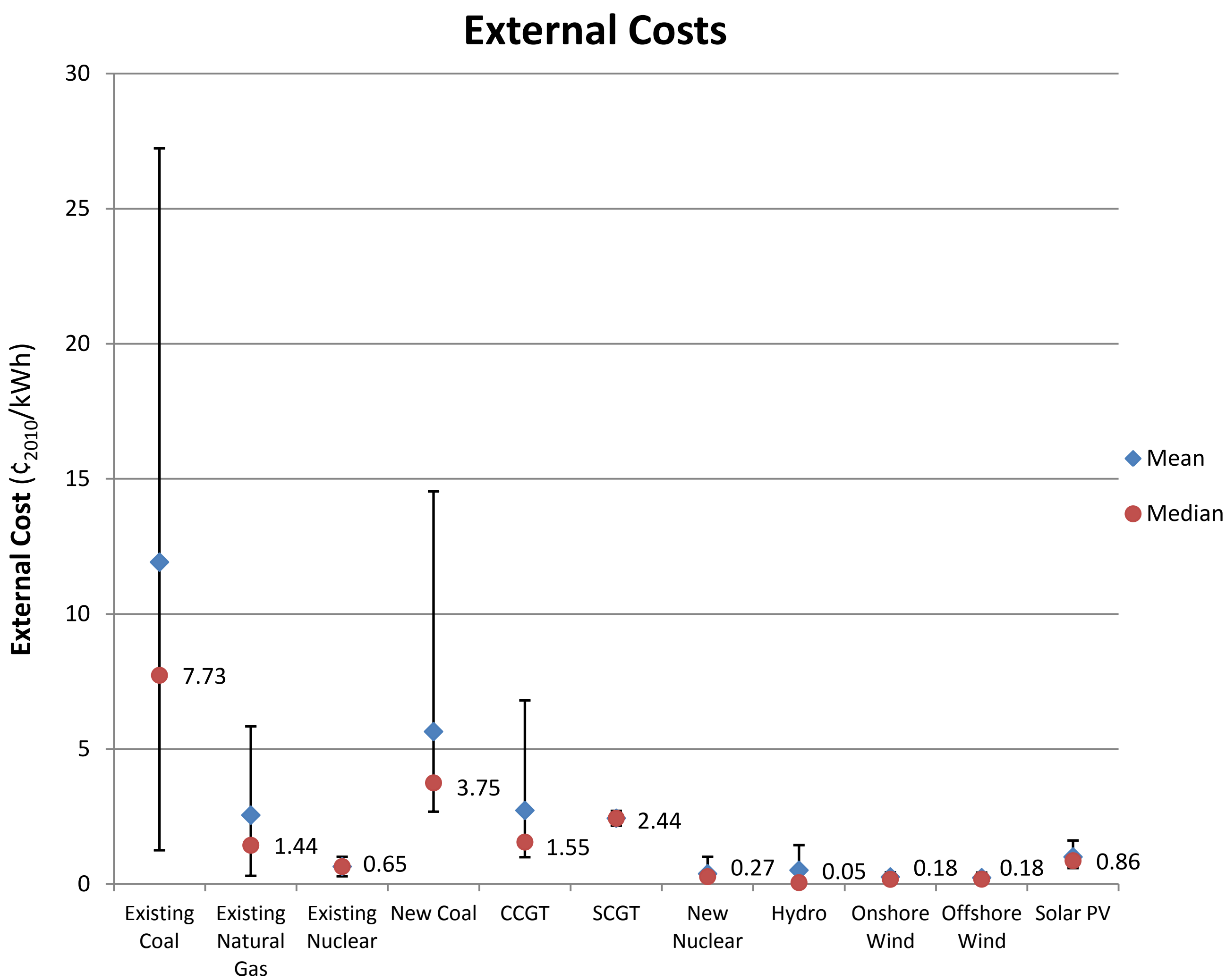

Figure 5 **The mean, median and range of the analyzed external cost studies. The bars span the minimum and maximum values for each generation technology. The median values are labeled on the graph. Results are in ¢$_{2010}$/kWh.**

According to the studies reviewed, existing coal generation has the highest external cost with a median of 7.73 ¢$_{2010}$/kWh. New coal generation has the second highest external cost with a median of 3.75 ¢$_{2010}$/kWh followed by new natural gas generation (median of 2.44 ¢$_{2010}$/kWh for SCGT and 1.55 ¢$_{2010}$/kWh for CCGT) and existing natural gas generation with a median of 1.44 ¢$_{2010}$/kWh. Existing and new nuclear generation, as well as the renewable energy technologies, all have median external costs of less than 1 ¢$_{2010}$/kWh. The external costs of onshore and offshore wind include the environmental cost estimation of avian and bat mortality. It is important to note that because of the small number of studies available and the wide range of external values, mainly pertaining to uncertainty surrounding the cost of GHG emissions, the standard deviation is often larger than the median (Table 2 and Figure 5).

The studies reviewed in this thesis all contain a 'best estimate' or central estimate of the external costs. The central estimate usually includes a mid-range value for the cost of GHG emissions of between 27 and 33 \$$_{2010}$/t$CO_2$-eq. The central estimates for each study are presented in Table 3 and displayed graphically in Figure 6.

Table 3 Central values or best estimates of the external costs of various electricity generation technologies. Values are in ¢$_{2010}$/kWh.

Study (¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
ExternE (2003 & 2005)	5.83	1.44	0.29	3.17	1.30	2.16		0.07	0.20	0.23	0.59
NEEDS (2010)				4.35	1.89		0.12			0.18	0.91
CASES (2010)				4.09	1.81	2.71	0.27	0.05	0.20	0.18	1.16
NRC (2010)	6.52	1.75									
Epstein *et al.* (2011)	18.07										
Muller *et al.* (2011)	4.55	0.71									

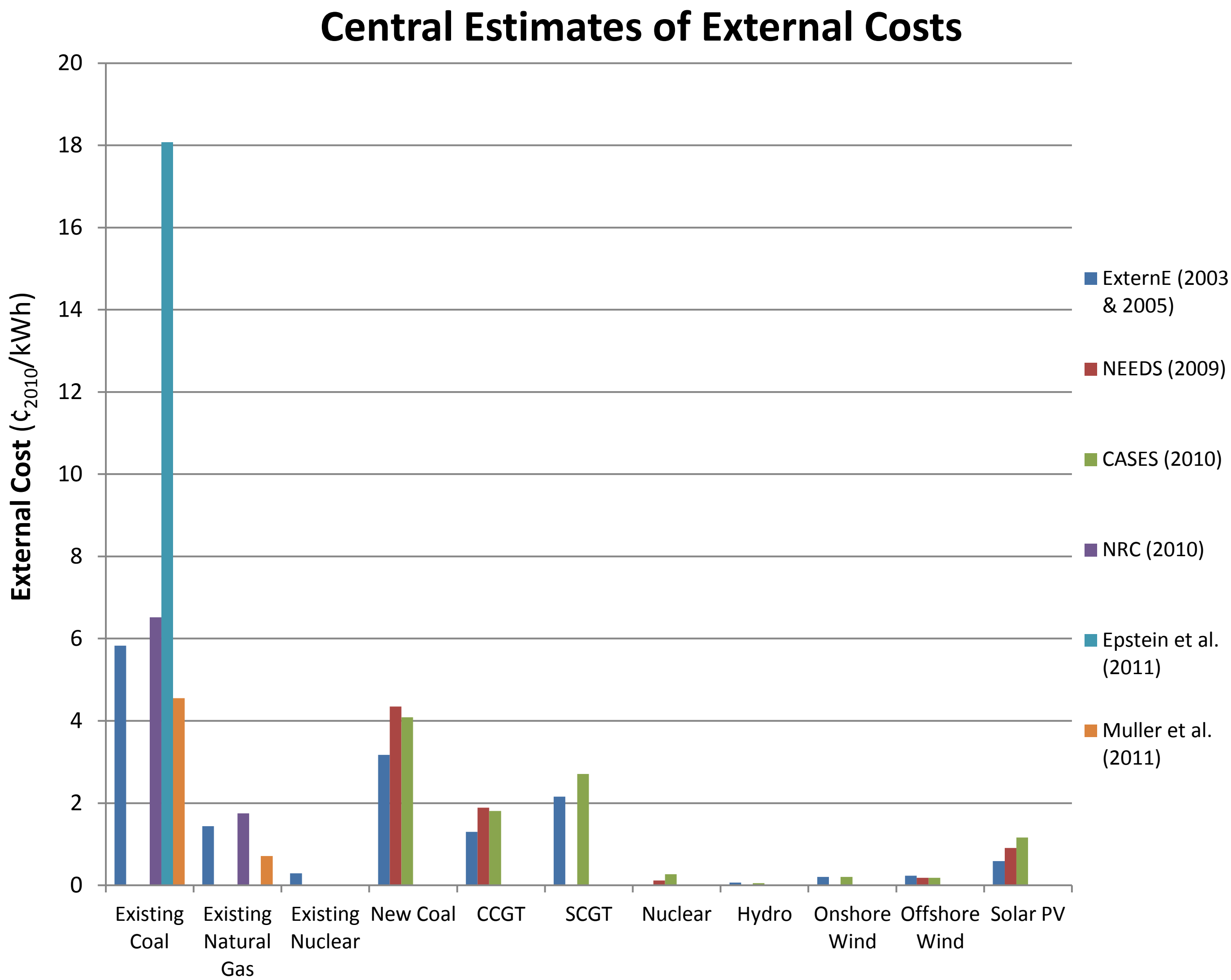

Figure 6 **Central values or best estimates of the analyzed externality studies of various electricity generation technologies. Values are in ¢$_{2010}$/kWh.**

The central external cost estimates are highest for existing coal generation, followed by new coal generation, new natural gas generation, existing natural gas generation, solar PV, existing nuclear, new nuclear generation and then the remaining renewable energy sources (Figure 6).

Private Costs

The results of the three private cost studies—CASES (Markandya et al., 2010), EIA (2011b) and Greenstone and Looney (2012)—are presented below in Table 4. A differentiation is made between studies which focus on existing generation and those which focus on new technologies. Only the Greenstone and Looney study includes private cost estimates for existing coal, natural gas and nuclear generation; while all three studies include estimates for the eight new generation types—coal, CCGT, SCGT, nuclear, hydro, onshore wind, offshore wind, solar PV. The number of studies (*N*) included in the analysis is shown along with the relevant descriptive statistics: minimum, maximum, mean, median and standard deviation (SD) of the private costs. For the two U.S. studies included in Table 4, both new nuclear and offshore wind are necessarily based on incomplete data, since neither generation technology has been built in the United States and initial contracts or price estimates are probably not going to be representative of an industry in serial production. The Table 4 results are displayed graphically in Figure 7. To highlight the broad nature of the estimates, the entire private cost range is presented along with the median and mean.

Table 4 Descriptive private cots of the analyzed studies, separated by generation technology. Results are in ¢$_{2010}$/kWh, with the exception of 'N' which denotes the number of studies included in the analysis.

(¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
Min	3.20	4.90	2.20	4.34	5.50	8.57	4.04	5.77	7.96	8.29	16.15
Max	3.20	4.90	2.20	11.28	7.45	14.34	12.36	15.14	11.70	35.57	46.78
Mean	3.20	4.90	2.20	7.63	6.25	10.62	9.25	9.05	9.01	20.49	28.85
Median	3.20	4.90	2.20	7.45	6.03	9.79	10.50	7.64	8.18	19.06	26.24
SD	0.00	0.00	0.00	3.02	0.86	2.68	3.28	4.28	1.80	11.26	13.99
N	1	1	1	3	3	3	3	3	3	3	3

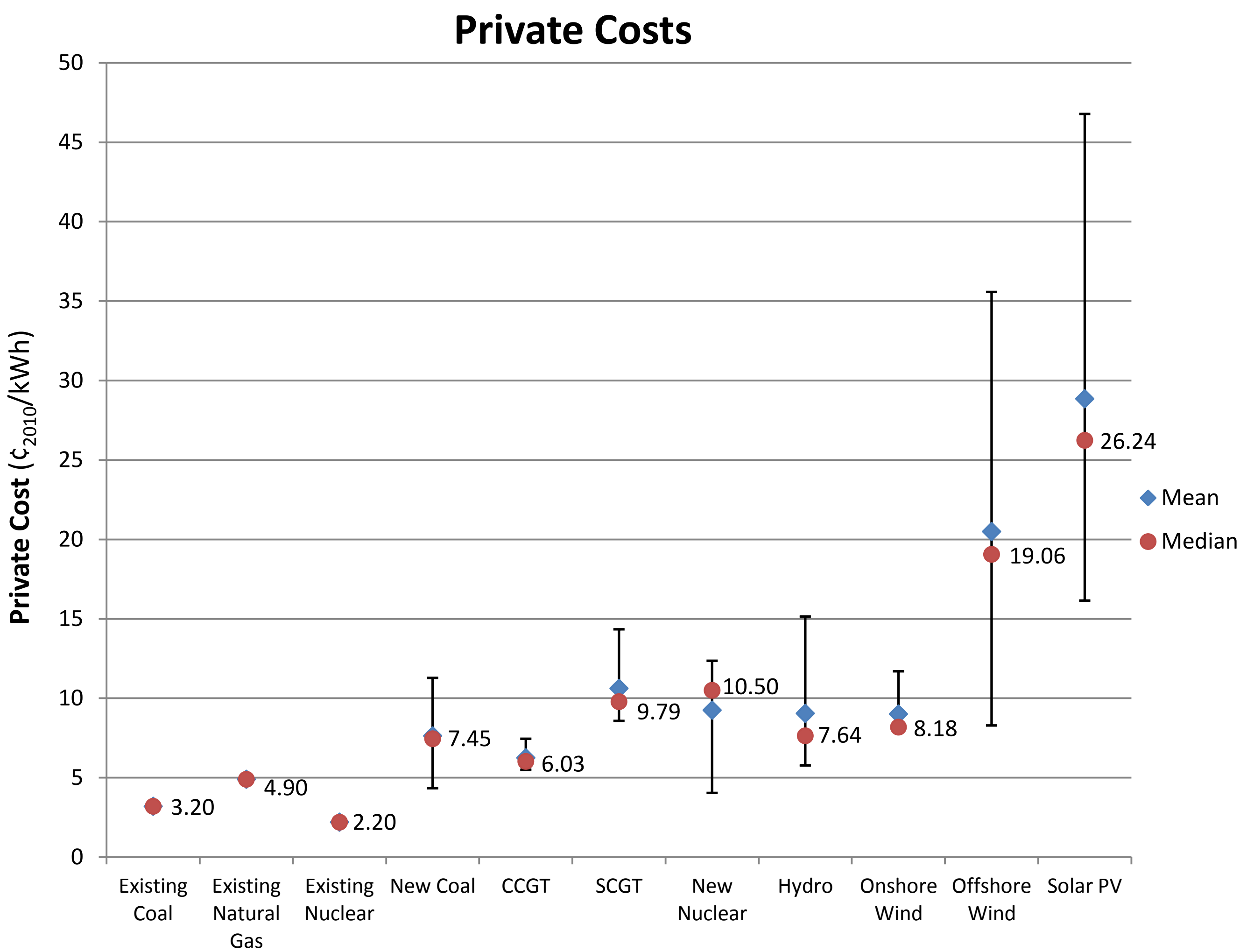

Figure 7 **The mean, median and range of the analyzed private cost studies. The bars span the minimum and maximum values for each generation technology. The median values are labeled on the graph. When only one study is available, only the median is shown. Results are in ¢$_{2010}$/kWh.**

According to the studies reviewed, existing generation has the lowest private cost because the capital cost has already been amortized (see Chapter 4). Existing nuclear generation has the lowest private cost with a median of 2.20 ¢$_{2010}$/kWh followed by existing coal generation (median of 3.75 ¢$_{2010}$/kWh) and existing natural gas generation (median of 4.90 ¢$_{2010}$/kWh).

For new generation, combined-cycle natural gas has the lowest median private cost of 6.03 ¢$_{2010}$/kWh, followed by new coal generation at 7.45 ¢$_{2010}$/kWh. Renewable hydro and onshore wind generation have median private costs of 7.64 ¢$_{2010}$/kWh and 8.18 ¢$_{2010}$/kWh, respectively, while traditional generation in the form of SCGT and new nuclear have private costs of 9.79 ¢$_{2010}$/kWh and 10.50 ¢$_{2010}$/kWh, respectively. Offshore wind power and solar PV have the highest median private costs of 19.06 ¢$_{2010}$/kWh and 26.24 ¢$_{2010}$/kWh, respectively. Again, given the small number of studies available and the wide range of possible private costs, the standard deviation can be more than half the median (Table 4). With only one to three studies, the use of the mean and median are not as robust as in a larger sample.

The private cost studies all contain a best estimate or central estimate. The central estimates for each study are presented in Table 5 and displayed graphically in Figure 8. Because the economics of electricity generation change daily, as the oldest study, the CASES analysis may be the least applicable, since private costs have likely changed since its release.

Table 5 Central values or best estimates of the private costs of various electricity generation technologies. Values are in ¢$_{2010}$/kWh.

Study (¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
CASES (2010)				4.34	6.27	8.57	4.04	8.87	7.96	8.29	46.78
EIA (2011)				9.67	6.32	10.37	11.59	9.20	9.78	24.77	21.45
Greenstone & Looney (2012)	3.2	4.9	2.2	6.2	5.5	10.8	10.5	6.4	8	19.1	19.5

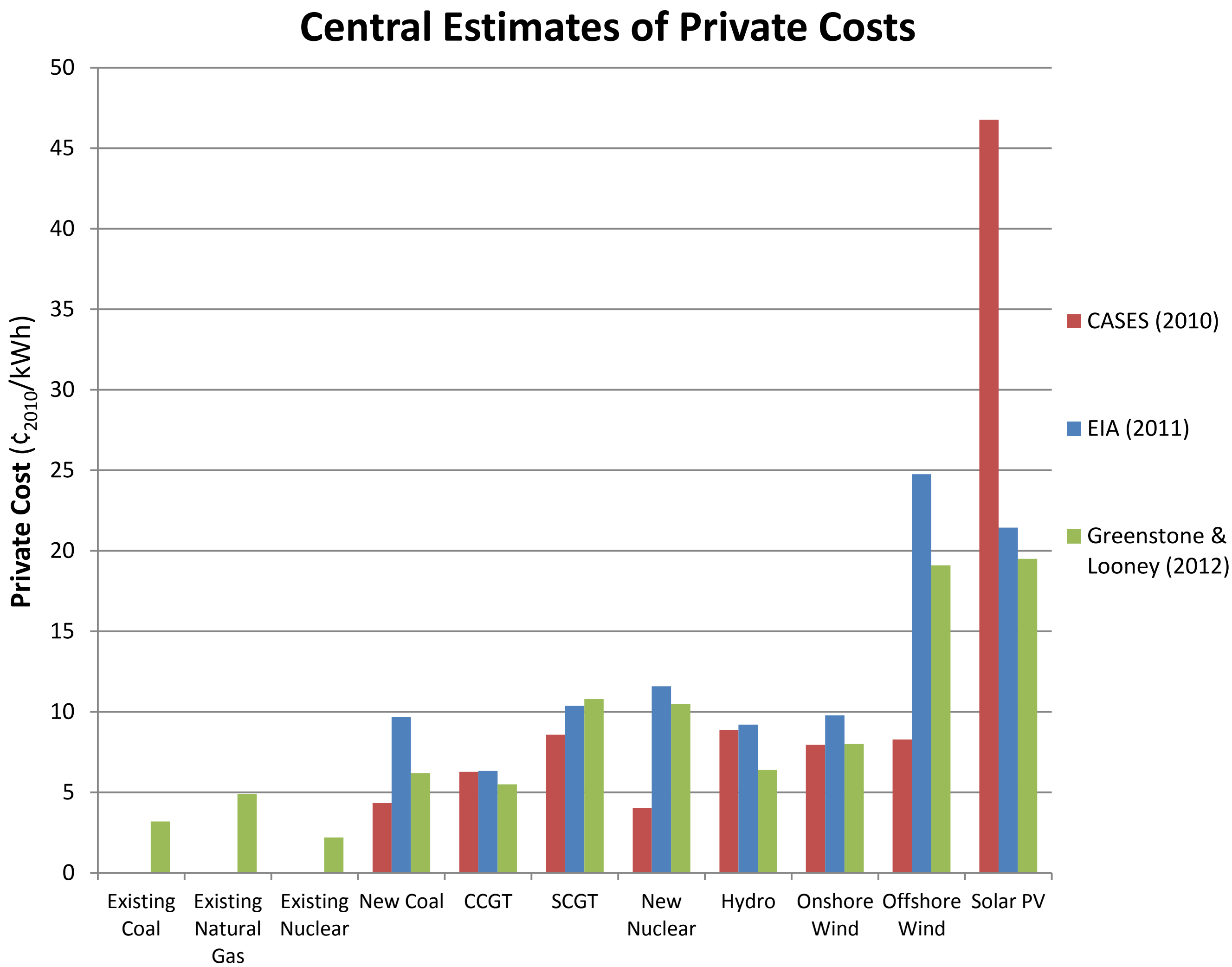

Figure 8 **Central values or best estimates of the analyzed private cost studies of various electricity generation technologies. Values are in ¢$_{2010}$/kWh.**

The central private cost estimates are lowest for existing nuclear, coal and natural gas generation. The central estimates vary for new coal, new natural gas, hydro, and especially for new nuclear, offshore wind and solar PV generation. The technology with the lowest private costs depends on the study. Overall, offshore wind and solar PV have the highest private costs (Figure 8).

Subsidies

The results of the two U.S. subsidy studies—EIA (2011c) and Koplow (2011)—are presented below in Table 6. The Production Tax Credits for nuclear, onshore and offshore wind are also included as a frame of reference. The EIA subsidy study includes information about federal subsidies for all energy technologies in both FY 2007 and FY 2010, while the Koplow study focuses exclusively on nuclear power. Due to the limited number of subsidies studies, it is possible to present the entire results below in Table 6. The results are displayed graphically in Figure 9. To highlight the broad nature of the estimates, the entire private cost range is presented along with the median and mean.

Table 6 *Complete results of the two subsidy studies. The nuclear and wind PTCs are included as a frame of reference. Values are in ¢$_{2010}$/kWh.*

Study (¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
EIA (2011c)*	0.06	0.06	0.31					0.08	1.85		3.75
	0.20	0.04	0.21					0.07	1.38		1.68
Koplow (2011)			0.74-4.16				5.01-11.42				
Production Tax Credit							1.8†		2.2†	2.2†	

The data for the top row of EIA (2011c) is from FY 2010 and the data for the second row is from FY 2007.

† *The nuclear PTC only applies to the first eight years of production and the wind PTC only applies for the first ten years of production*

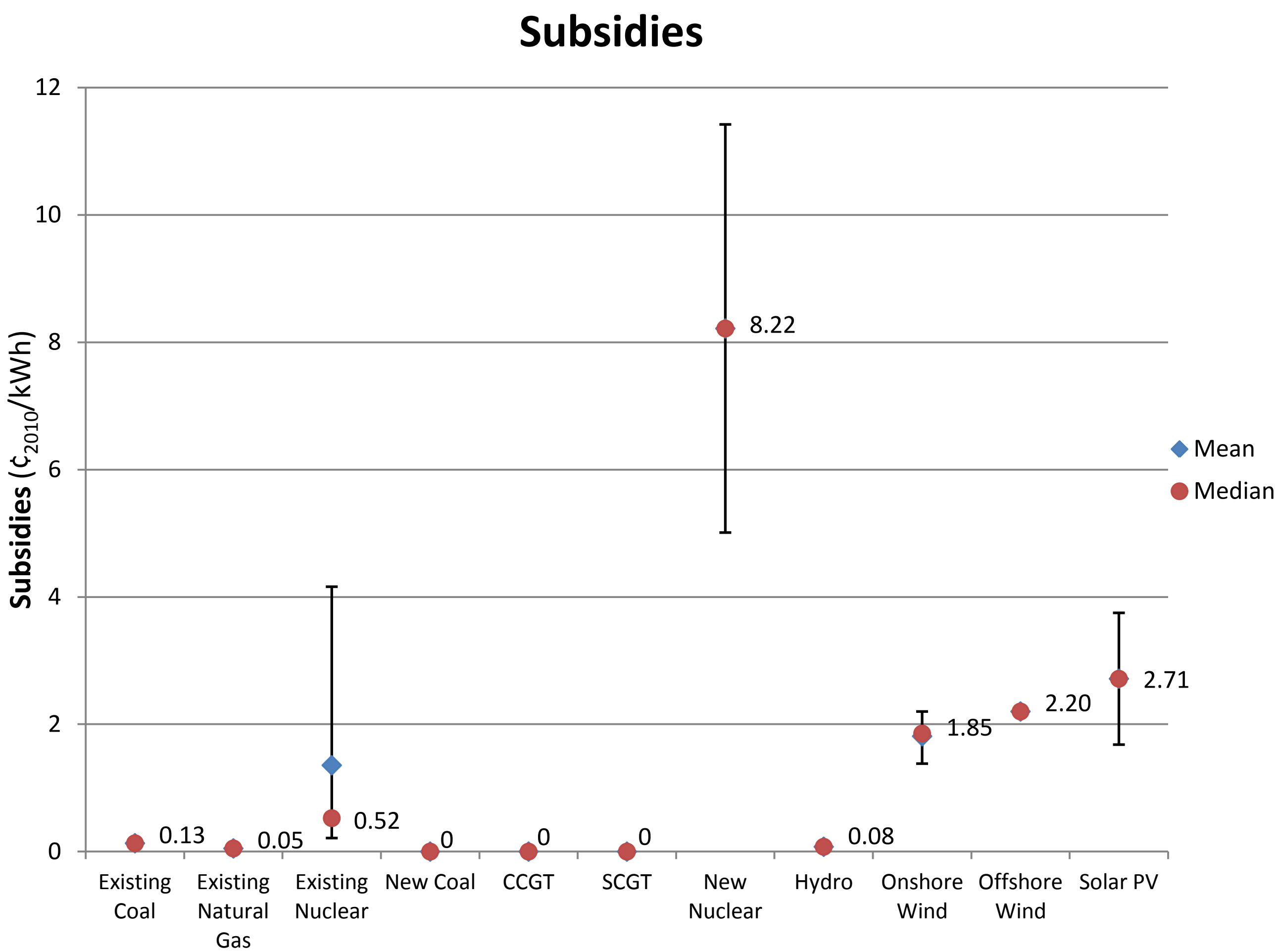

Figure 9 **The mean, median and range of the analyzed subsidy studies. The bars span the minimum and maximum values for each generation technology. The median values are labeled on the graph. Results are in ¢$_{2010}$/kWh.**

Based on the reviewed studies, fossil fuel and hydro generation receive low subsidies on a per kWh basis, while nuclear, wind and solar generation receive higher subsidies (Figure 9). Using the EIA (2011c) data and the methods outlined in Chapter 4, the subsidy for coal is calculated to be between 0.06-0.20 ¢$_{2010}$/kWh, natural gas between 0.04-0.06 ¢$_{2010}$/kWh, nuclear between 0.21-0.31 ¢$_{2010}$/kWh and hydro between 0.07-0.08 ¢$_{2010}$/kWh, depending on the year analyzed. The subsidy for onshore wind is between 1.38-1.85 ¢$_{2010}$/kWh—less than the ten year PTC of 2.2 ¢$_{2010}$/kWh—and between 1.68-3.75 ¢$_{2010}$/kWh for solar PV. Of course, as was already discussed, the EIA study only includes incentives in the federal budget which are unique to energy; thus excluding subsidies such as accelerated depreciation which is important to coal and natural gas power, and liability caps which are paramount to nuclear power (Koplow, 2010). The thorough nuclear power subsidy study found that the incentive for existing nuclear generation is between 0.74-4.16 ¢$_{2010}$/kWh and for new nuclear generation is between 5.01-11.42 ¢$_{2010}$/kWh (Koplow 2011).

In addition to the subsidy per kWh, the total subsidies to each generation technology are presented in Table 7 and Figure 10. Results from the EIA (2011c) and Koplow (2011) studies are presented as well as those from ELI (2009). The EIA analysis includes the amounts for both FY 2007 and FY 2010. The ELI study takes place over multiple fiscal years and only differentiates between fossil fuel and renewable energy subsidies. The Koplow analysis includes a high and low estimate of the nuclear subsides in 2010. No distinction is made between existing and new coal, natural gas and nuclear generation, because for the most part, no such distinction was made in the studies. The total subsidies offer a different perspective into the federal support of energy generation technologies.

Table 7 Total subsidy amounts for each electricity generation technology over various years. Results are presented in Million US$.

Study (Million 2010 $)	Year	Fossil Fuel		Nuclear	Renewable Energy			
		Coal	Natural Gas		Hydro	Onshore Wind	Offshore Wind	Solar PV
ELI (2009)	2002-08	73427*			12356			
EIA (2011c)	2010	1189	630	2499	216	4986		1134
	2007	3981	317	1714	170	476		179
Koplow (2011)	2010 (Low Estimate)			5972†				
	2010 (High Estimate)			33570†				

* *The fossil fuel subsidy calculated by ELI (2009) includes the federal subsidy for oil.*

† *The high and low Koplow (2011) estimates are calculated by multiplying the per kWh subsidy by the amount of electricity generated by nuclear power in 2010 from EIA (2011a).*

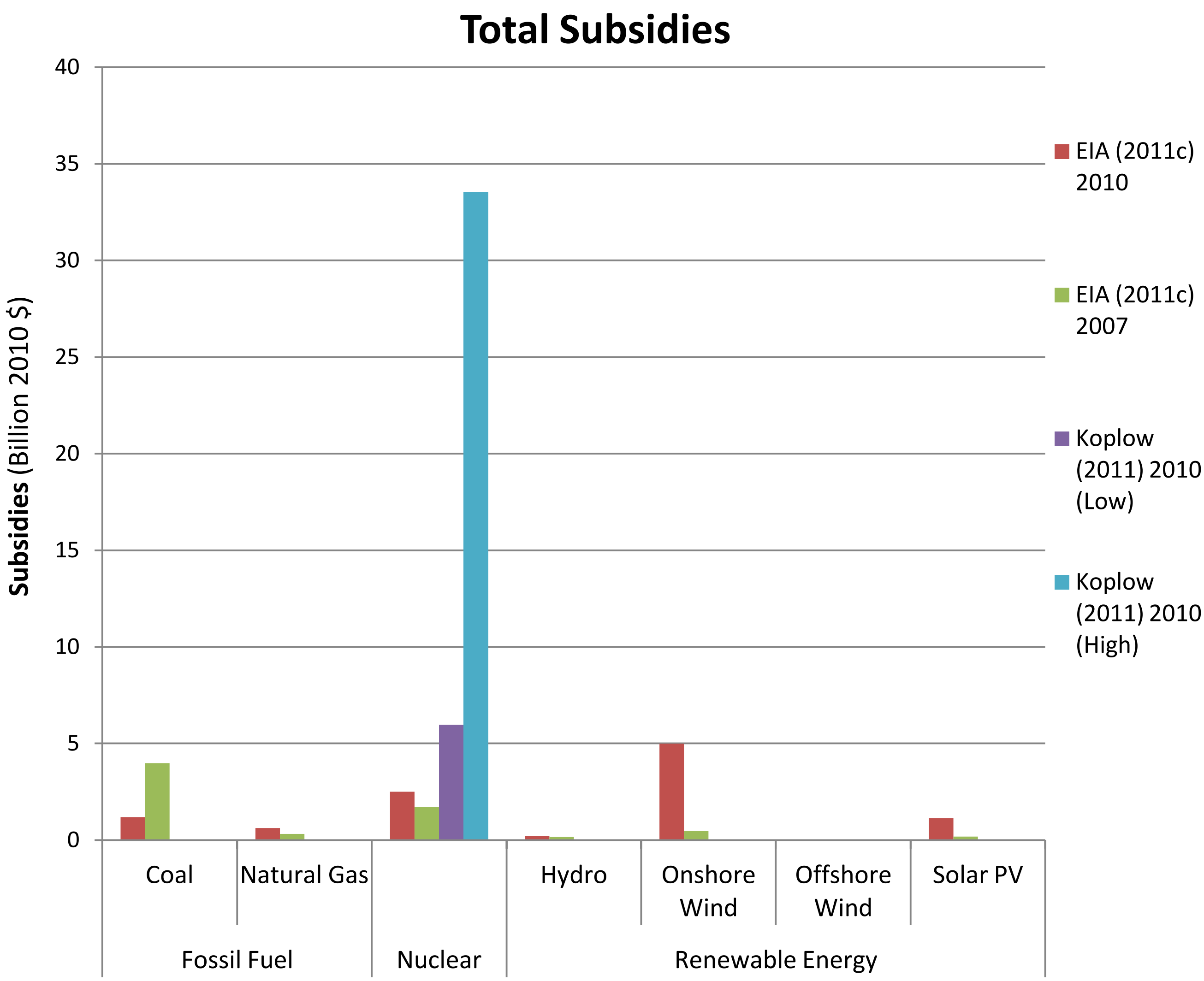

Figure 10 The total subsidy values by technology. Results are presented in Billion US$.

It is difficult to draw any conclusions about the total subsidy amounts because they vary by study and year. The ELI (2009) study finds that from 2002-08 fossil fuel received six-times more federal subsidies than renewable energy (Table 7). However, in general, nuclear subsidies are among the highest of the electricity generation technologies, as well as, depending on the year, coal and onshore wind. Solar PV subsidies have increased nearly ten-fold from about $180 million in 2007 to $1.1 billion in 2010 (EIA, 2011c). Natural gas and hydropower subsidies fall in the smaller, $100 million range, and offshore wind has not received any subsidies since there is no installed generation in the United States.

Subsidies distort the private costs of electricity by either artificially decreasing the price of electricity through liability caps or reduced cost of lending, or by transferring costs to the general tax base instead of the electricity consumers. Some private cost studies include the transferred costs as part of the LCOE calculations; while others calculate only the net cost to generators, and thus subsidies fall outside the scope of those studies. The manner in which these two cases are addressed is subsequently discussed in the best estimate section.

Social Costs

The social costs of electricity are the total cost to society, defined as the sum of the private cost of generation, externalities and subsidies. The social costs are presented in various measures including a minimum, a maximum, and a median cost summary method, to signify the uncertainty and various assumptions embodied in the estimates. In addition, there is a 'best estimate' summary measure based on the author's evaluation of the various studies and methodologies. The 'best estimate' summary measure includes an analysis of low, medium and high external costs of GHG to understand how carbon cost sensitivity affects the social costs of electricity.

The summary measures represent the marginal cost of adding an additional kWh of electricity to the PJM grid, and are meant to serve as a guide when comparing different electricity generation technologies. The results are displayed as marginal cost comparisons.

Median Cost Summary Measure

In the median cost summary measure, the median external cost, private cost and subsidy values are calculated separately from the studies reviewed, and then combined to obtain the total social cost. The results are displayed in Table 8 and Figure 11. Subsidies are shown separately in Table 8 only for existing generation, because the private cost studies of new generation reviewed in this thesis calculate the LCOE irrespective of federal incentives. Subsidies are included as part of the median private cost values in Figure 11.

Table 8 The median social costs of electricity generation technologies. The median social costs values are the sum of the median private cost, external cost and subsidy values. Subsidies are only shown as separate values in this table if the base study did not include them in the private cost. Results are in ¢$_{2010}$/kWh.

(¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
Private Costs	3.20	4.90	2.20	7.45	6.03	9.79	10.50	7.64	8.18	19.06	26.24
Subsidies	0.13	0.05	0.52								
External Costs	7.73	1.44	0.65	3.75	1.55	2.44	0.27	0.05	0.18	0.18	0.86
Total	**11.06**	**6.39**	**3.37**	**11.20**	**7.58**	**12.22**	**10.77**	**7.69**	**8.36**	**19.24**	**27.10**

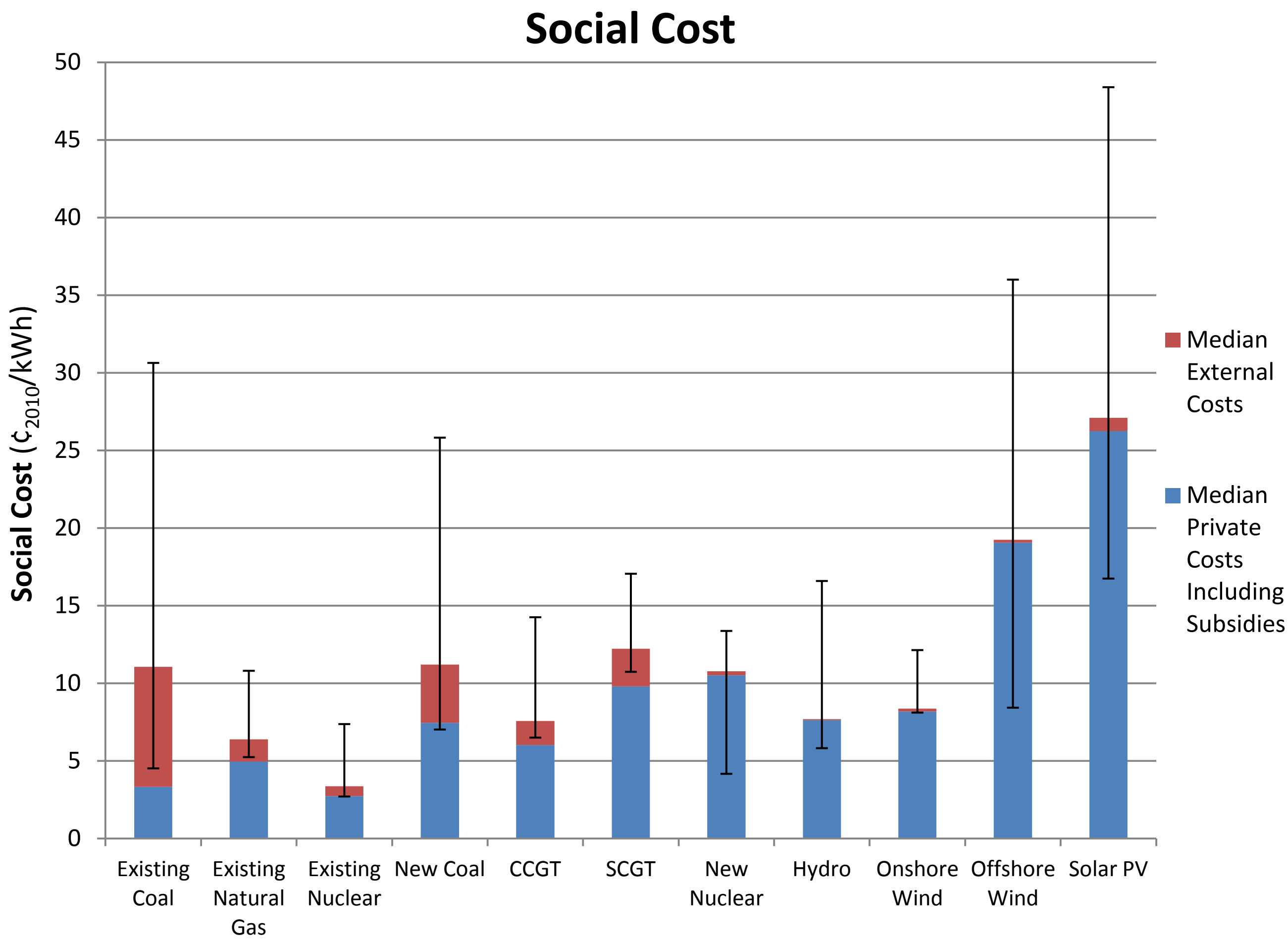

Figure 11 **The median social costs of electricity generation technologies according to the reviewed studies. The values are composed of the median private costs, including subsidies, and the median external costs. The bars represent the minimum and maximum social cost values. Results are in ¢$_{2010}$/kWh.**

The generation with the lowest median social cost is existing nuclear (3.37 ¢$_{2010}$/kWh), followed by existing natural gas (6.37 ¢$_{2010}$/kWh). The low private cost of these two sources coupled with the middle-of-the-range external costs combine for the lowest social cost. In comparison, existing coal also has a low private cost but its external costs are the highest of all the sources surveyed, which means that the social costs, at 11.06 ¢$_{2010}$/kWh, are higher than new combined cycle natural gas (7.58 ¢$_{2010}$/kWh), hydro (7.69 ¢$_{2010}$/kWh), and nuclear (10.77 ¢$_{2010}$/kWh) generation. Furthermore the social costs of existing coal generation are almost as high as those of new coal generation (11.20 ¢$_{2010}$/kWh). The median social costs of SCGT are 12.22 ¢$_{2010}$/kWh. Due to high private costs, offshore wind and solar PV have the highest median social costs at 19.24 ¢$_{2010}$/kWh and 27.10 ¢$_{2010}$/kWh, respectively. The bars represent the substantial range between the minimum and maximum social cost values.

The minimum and maximum social costs summary measures are represented by the error bars shown in Figure 11. The ranges are included to illuminate the uncertainty surrounding the median number.

The maximum social cost summary measure changes the order of technologies. Existing nuclear generation is still the least expensive, followed by existing natural gas, however onshore wind is the least costly new generation, followed by new nuclear, CCGT, SCGT, and new coal. Existing coal generation is the third most expensive source in the maximum social cost case, after solar PV and offshore wind.

Likewise, the minimum social cost modifies the order of technologies. Existing nuclear power is still the least expensive generation because of the low private costs. However, in the minimum social cost summary measure, new nuclear is the second cheapest source of electricity, followed by existing coal, existing natural gas, hydro, CCGT, and new coal. Renewable onshore wind and offshore wind are about half as expensive as solar PV, with SCGT social costs between wind and solar.

Best Estimate Summary Measure

The best estimate summary measure combines external cost, private cost and subsidy values chosen based on the author's judgment about the reviewed studies and methodologies. Use of the values is justified below. The results are subsequently presented in Table 9 and Figure 12.

Private Costs

The private costs for existing technologies come from Greenstone and Looney (2012). The values were chosen because the authors adapt the well established Du and Parsons (2009) economic model for nuclear power, and because the values were the best available estimates for technologies with amortized capital costs. The private cost values for new generation are taken from the EIA (2011b). The private cost values were selected due to the expertise of the EIA. Furthermore, the EIA study specifically analyzes U.S. generation and was recently updated in 2011. The central EIA private cost values represent the midpoint in the range of possibilities nationally and within PJM, due to variance in terms of generating plant size and efficiency, resource quality and required infrastructure upgrades. However, as previously noted, there have not been any new nuclear plant designs commissioned, nor offshore wind generation built in the United States. In particular, the EIA has no experience with offshore wind. By contrast, analysis by Levitt *et al.* (2011) suggests that, based on best examples on Europe and assuming a U.S. industrial ramp-up, but without any major technological change, LCOE from offshore wind could drop by more than half. Thus, after the first few projects, the EIA estimate for offshore wind is probably misleadingly high.

External Costs

Study Methodology & Assumptions

Analysis of the externality studies illuminates several key assumptions and methodological choices which have a great deal of bearing on the result. The most important methodological considerations are: comprehensive assessment of human health, environmental and climate change related damages across the entire electricity generation lifecycle; the particulate matter dose-response function; the computation of the mortality cost due to pollution through either VSL or VSLY (Schleisner, 2000; Sundqvist, 2004); and the marginal cost of greenhouse gas emissions. These assumptions have the largest impact on the results; higher than the location of the study (although the VSL varies by location) or the analysis model employed.

Comprehensive methodologies which monetize the entire human health, environmental and climate change related lifecycle damages find the highest external costs and are the most valid. When compared to the NRC (2010) study, the most important consideration of the Epstein *et al.* (2011) study is the inclusion of the entire coal lifecycle externalities in the calculation. Even the Epstein *et al.* low-range external cost calculation (9.2 $¢_{2008}$/kWh) is almost 1.5 times larger than the NRC best estimate (6.2 $¢_{2007}$/kWh) simply because the Epstein *et al.* study includes several externalities which are not monetized in the NRC study. By not monetizing these damages, the NRC study assumes no external costs of issues such as human health damages to communities surrounding coal mines. It is important to account for and monetize all externalities in order to properly inform the public and policymakers.

The $PM_{2.5}$ dose-response rate is an area of continued research and discussion within the epidemiological community. Most studies—including ExternE (European

Commission, 2003), NEEDS (2009), CASES (2009), NRC (2010), and Muller *et al.* (2011)—use the Pope *et al.* (2002) dose-response function. The Pope *et al.* dose-response rate is supported by the similar results of the Chen *et al.* (2008) meta-analysis which reviewed epidemiological studies of $PM_{2.5}$ related mortality from 1950-2007. However, the Epstein *et al.* (2011) analysis uses the Schwartz *et al.* (2008) dose-response rate for $PM_{2.5}$ which leads to two to three times the health impacts when compared to Pope *et al.* (NRC, 2010; Muller et al., 2011). The Epstein *et al.* authors insist that the Schwartz *et al.* uses "elaborate statistical techniques" to calculate the dose-response rate and that the rate is now commonly accepted, as several recent studies—Roman *et al.* (2008) and Levy *et al.* (2009)—support the Schwartz *et al.* findings (Epstein et al., 2011, p.86). Given the evolving nature of the field, and the fact that the author is not an epidemiologist, neither position is favored in this thesis.

Another methodological point which remains unsettled is the treatment of pollution-related mortality, or VSL versus VSLY. The European externality studies all use the Value of Life per Year Lost or VSLY to value mortality caused by pollution, which typically finds lower external costs than the Total Value of Life or VSL method preferred by most of the American studies (Sundqvist, 2004). American researchers contend that the literature is not settled as to the effect of age on the VSL, and therefore the use of VSL is justified (NRC, 2010). However, as shown in Rabl (2003), the number of individual mortalities cannot be determined from externality studies, only the aggregate number of years of life lost. Therefore VSLY is the appropriate method. It is worth noting that in some cases the difference between methods is minor. As previously discussed, without climate change damages, the NRC (2010) study, which uses VSL, and Muller *et al.* (2011) study, which uses

VSLY, calculated the external costs of coal to be 3.37 $¢_{2010}$/kWh versus 3.55 $¢_{2010}$/kWh, respectively. All else equal, studies that use the VSLY method are favored in the best estimate summary measure.

The valuation of climate change related damage from GHG, or what is commonly referred to as the 'social cost of carbon'—to avoid confusion, in this thesis it is called 'cost of carbon'—greatly affects the externality result. For instance, the cost of carbon range in the NRC (2010) study of \$10-100/tCO_2-eq varies the external cost of coal by 9 $¢_{2010}$/kWh (from 4.4 $¢_{2010}$/kWh to 13.4 $¢_{2010}$/kWh). The cost of carbon is far from certain due to uncertainty surrounding climate modeling, climate change scenarios, future population and economic growth, discount rates, and equity weighting of damages (NRC, 2010).

A meta-analysis of 211 cost of carbon estimates from 50 studies found the range of estimates to be between \$0 and \$105/tCO_2-eq with a mean value of \$29/tCO_2-eq (Tol, 2008). Additionally, as part of the analysis for the promulgation of carbon dioxide regulation of light vehicles under the *Clean Air Act*, the U.S. Environmental Protection Agency estimated the cost of carbon. The analysis concluded that the 2010 cost of carbon is somewhere between \$4.7 and \$35.1/tCO_2-eq, depending on the assumed social discount rate, with a mean value of \$21.4/tCO_2-eq (IWGSCC, 2010). As was mentioned in the previous chapter, the NRC (2010) performed an estimation of the cost of carbon using the FUND, RICE and DICE climate models. According to the NRC, the social cost of GHG emissions is likely between \$10-\$100/tCO_2-eq, with a mid-range, best estimate value is \$30/tCO_2-eq using a discount rate of future damages of 3%. In fact, with the exception of Muller *et al.*, the externality studies reviewed all use a best estimate cost of carbon of about

$\$30/tCO_2$-eq in 2010 US\$. Likewise, this thesis uses the mid-range carbon value of the NRC study of $\$30/tCO_2$-eq which is larger than the EPA value but corresponds to the mean from the Tol (2008) meta-analysis. The next section shows how the cost of carbon range modifies the best estimate results with a low-end estimate of $\$10/tCO_2$-eq and a high-end estimate of $\$100/tCO_2$-eq.

Studies Chosen for Best Estimate

The external costs are drawn from a variety of sources. In general, deference is paid to the most recent U.S.-centric studies, and those with the most comprehensive assessment of external costs. Moreover, studies that assume the cost of carbon to be about $\$30/tCO_2$-eq and use the VSLY to calculate public health impacts are preferred.

For existing coal generation, the results from the Epstein *et al.* (2011) study are used. A significant part of the decision was that the study includes the most human health and environmental impacts in the external cost calculation. The Epstein *et al.* study expands upon the NRC (2010) methodology, including an analysis of health impacts to communities surrounding Appalachian coal extraction regions. Furthermore, the NRC analysis explicitly notes that coal generation within the Ohio River Valley and Mid-Atlantic have some of the highest external heath damages in the United States (NRC, 2010, p. 341), which suggests that the health costs within PJM are higher than the national average; supporting the use of the Epstein *et al.* value. The Epstein *et al.* study is the only to use the Schwartz *et al.* dose-response rate for $PM_{2.5}$, which leads higher public health costs than Pope *et al.* (NRC, 2010; Muller et al., 2011). However, as previously discussed, the literature is not settled as to the preferred dose-response rate. It is true that the Epstein *et al.* study only uses the Total Value of Life or VSL, as opposed to the preferred Value of Life per Year Lost or

VSLY. But overall, given that the Epstein *et al*. has the most inclusive assessment of external costs and that NRC study notes that the externalities within PJM are higher than the national average, the Epstein *et al*. central value is chosen as the best estimate of coal external costs for this thesis.

The NRC (2010) and the Muller *et al.* (2011) studies employ similar methodologies to compute the external costs of existing natural gas generation (see Chapter 4). The major difference is that when valuing health externalities, the NRC uses VSL while the Muller *et al.* uses a variant of VSLY, and thus, the NRC study finds a larger externality; although the difference is only a fraction of cent—0.17 $¢_{2010}$/kWh versus 0.11 $¢_{2010}$/kWh, respectively. Given that the NRC study was commissioned by Congress, performed by a multidisciplinary team across several universities and was reviewed by a distinguished panel, whereas the peer-reviewed Muller *et al.* was performed by three—albeit highly-esteemed—economists, the central NRC value is chosen as the best estimate for this thesis. In addition, regarding externalities of GHGs, the central value in NRC study uses an estimate of \$30/tCO_2-eq while the Muller *et al.* uses the low valuation of \$7.4/tCO_2-eq for GHG related damages. It is worth noting that, as is the case for existing coal generation, the NRC (2010) study states the some of the highest external damages for natural gas power plants occur within PJM along the Eastern Seaboard. Therefore, although the central value is used, the health related external costs may be closer to the NRC high-end estimate of 0.53 $¢_{2010}$/kWh.

The ExternE study is the only available estimate for the external costs of existing nuclear generation. Therefore the ExternE estimate of 0.29 $¢_{2010}$/kWh for European generation is used in this thesis.

Unfortunately, for new generation all the externality studies are performed for power plants in Europe. As such, all the values for new generation used in this thesis come from either the NEEDS or CASES studies. The goal of the NEEDS study is to assess the external cost of new generation, but not all technologies are analyzed. The CASES study assesses the social costs of electricity in Europe. While the two studies employ the same methodology—both extensions of the ExternE study—the CASES study includes the external cost of backup generation for renewable technologies. Therefore, whenever NEEDS values are available, those are used; otherwise the values come from the CASES assessment. Thus, the externalities of new coal, CCGT, new nuclear, offshore wind and solar PV are the central estimates of the NEEDS study, while the externalities of SCGT, hydro and onshore wind are the central estimates of the CASES study. When external costs for a technology are available in both studies, the results are very similar: the largest difference is 0.26 $¢_{2010}$/kWh for the external costs of new coal generation (Table 3).

Subsidies

In the best estimate summary measure, subsidies need to be added only for some technologies. The EIA (2011b) private cost analysis of new generation includes subsidies as part of the private cost. However, the Greenstone and Looney (2012) calculation does not include subsidies, and thus they must be added as is done in Table 9. In addition, the Price-Anderson Act subsidy must be added for new nuclear power because the EIA did not account for it in the private cost study. Without the socialized risk provided by the Price-Anderson Act, the nuclear industry would have to purchase additional private insurance to cover the risk of a nuclear catastrophe.

Subsides for existing coal and natural gas come from the most recent estimate from FY 2010 (EIA, 2011c), and the subsidy values for existing and new nuclear generation are from Koplow (2011). For the remaining electricity generation technologies, the subsidy values are not shown in Table 9 but are displayed in subsequent figures as portion of the private costs, although the total costs are not changed. Presenting subsidies as part of private costs illuminates how federal subsidies modify the cost comparison between technologies.

The subsidy values for renewable technologies come from the best available estimate, the EIA study of FY 2010 (EIA, 2011c). When subsidy values are not available—i.e. for new coal and natural gas generation—it is assumed that new generation will have the same access to continuing incentives as existing generation, and thus, subsidy values of existing generation are used. Additionally, offshore wind is assumed to have the same subsidy as onshore wind.

Best Estimate

The best estimate values described above are displayed in Table 9.

Table 9 Best estimate private costs, subsidy values, external costs, and combined social costs. Results are in ¢$_{2010}$/kWh.

(¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
Private Costs	3.2 [a]	4.9 [a]	2.2 [a]	9.67 [b]	6.32 [b]	10.37 [b]	11.59 [b]	9.20 [b]	9.78 [b]	24.77 [b]	21.45 [b]
Subsidies	0.06 [c]	0.06 [c]	4.16 [d]				2.5 [d]				
External Costs	18.07 [e]	1.75 [f]	0.29 [g]	4.35 [h]	1.89 [h]	2.71 [i]	0.12 [h]	0.05 [i]	0.20 [i]	0.18 [h]	0.91 [h]
Total	**21.33**	**6.71**	**6.65**	**14.02**	**8.21**	**13.08**	**14.21**	**9.25**	**9.98**	**24.95**	**22.36**

Sources for Table 9:

[a] *Greenstone & Looney, 2012*
[b] *EIA, 2011b*
[c] *EIA, 2011c*
[d] *Koplow, 2011*
[e] *Epstein et al., 2011*
[f] *NRC, 2010*
[g] *ExternE, 2003*
[h] *NEEDS, 2009*
[i] *Markandya et al., 2010*

Based on the best estimates from the existing studies, and assuming a cost of carbon of \$30/tCO_2-eq, the electricity generation technologies compare as follows: the electricity generation technology with the lowest social cost is existing nuclear generation (6.65 ¢$_{2010}$/kWh), closely followed by existing natural gas generation (6.71 ¢$_{2010}$/kWh). Despite the high subsidies to nuclear power and the moderate externalities of natural gas, the low private costs of the existing generation technologies—assuming as before that the capital investment for existing generation has already been amortized—leads to the lowest social costs. For new generation, combined cycle natural gas is the least expensive at 8.21 ¢$_{2010}$/kWh and is less than half as much as existing coal generation, which has a social cost of 21.33 ¢$_{2010}$/kWh. In fact, most technologies have lower social costs than existing coal, including renewable hydropower (9.25 ¢$_{2010}$/kWh) and onshore wind generation (9.98 ¢$_{2010}$/kWh), as well as SCGT (13.08 ¢$_{2010}$/kWh), new coal (14.02 ¢$_{2010}$/kWh) and new nuclear (14.21 ¢$_{2010}$/kWh). Solar PV and offshore wind have the highest social costs at 22.36 ¢$_{2010}$/kWh and 24.95 ¢$_{2010}$/kWh, respectively, due to high private costs.

The results of Table 9 are presented graphically in Figure 12 and shown in order of lowest to highest social costs in the ranking of average costs in Figure 13.

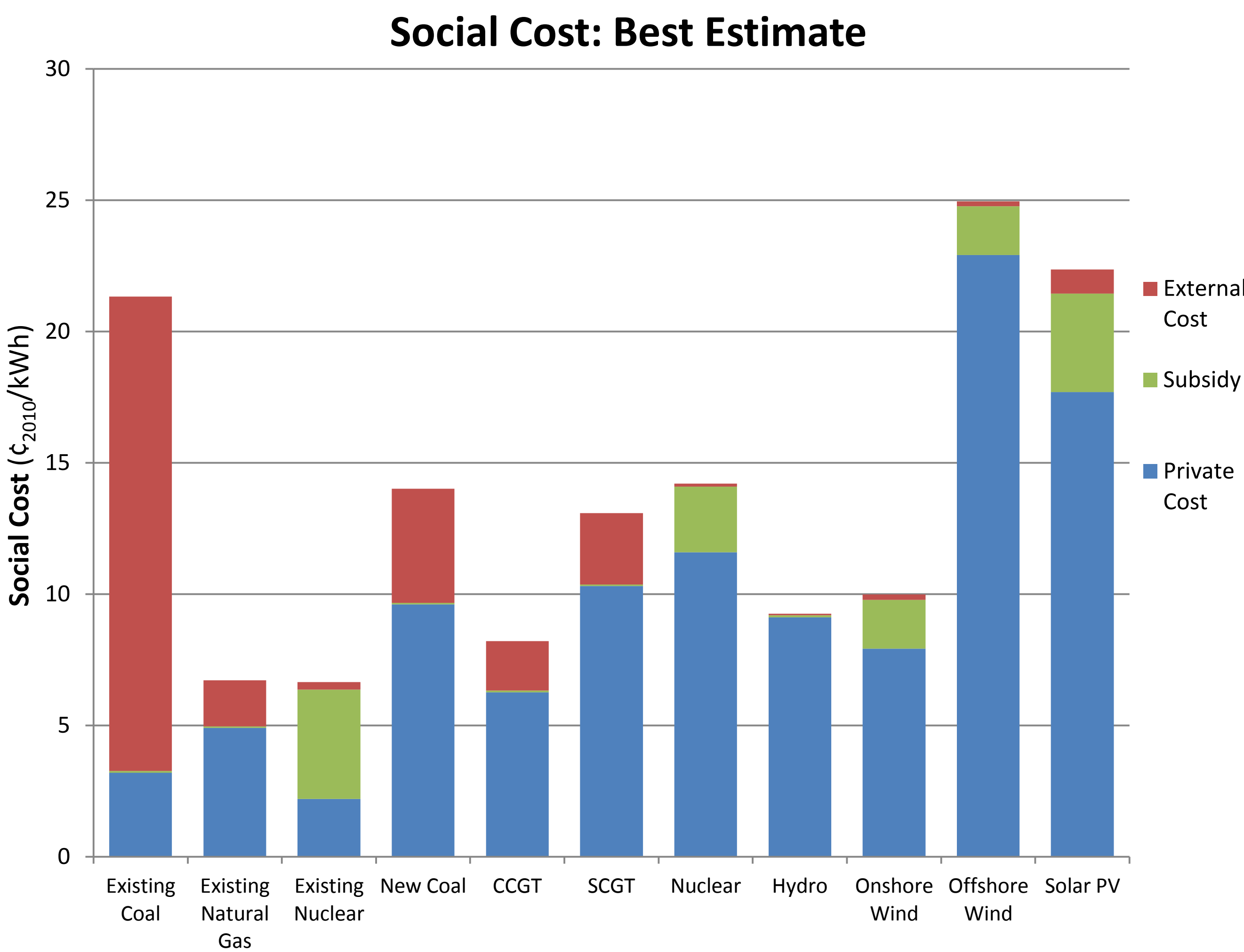

Figure 12 **Best estimate of social costs. The results are in ¢$_{2010}$/kWh.**

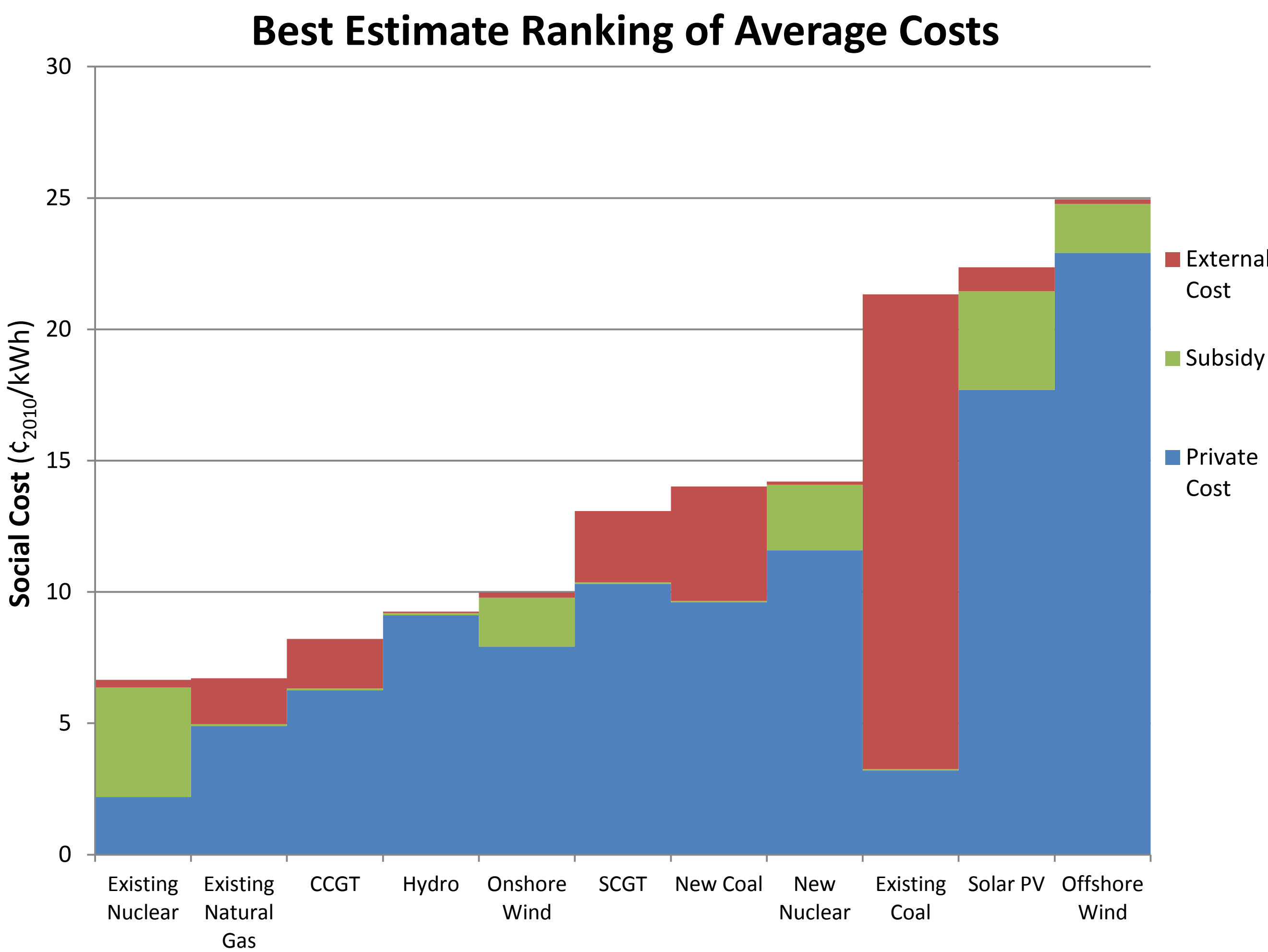

Figure 13 **Best estimate of social costs. The technologies are presented in order of social costs, from lowest to highest. The results are in ¢$_{2010}$/kWh.**

Low & High Cost of Carbon

In the best estimate of social costs, the external costs are calculated with a GHG-related damage cost of \$30/tCO_2-eq. Given the uncertainty surrounding the cost of carbon due to the use of long-term climate models and equity weighting of damages, a low social cost and a high cost of carbon summary measure are analyzed in addition to the best estimate. In the low cost of carbon summary measure, the external costs are calculated with a GHG-related damage value of \$10/tCO_2-eq. In the high cost of carbon summary measure, the cost of GHG-related damage is valued at \$100/tCO_2-eq. The low- and the high-end estimates of the cost of carbon in this thesis correspond with those suggested in the 'Hidden Costs of Energy' performed by the NRC (2010).

The external costs calculated with the various social costs of carbon are shown in Table 10.

Table 10 The external costs of each electricity generation technology calculated at the low, high, and best estimate social costs of carbon. The results are shown in ¢2010/kWh.

Cost of Carbon (¢$_{2010}$/kWh)	Existing Coal	Existing Natural Gas	Existing Nuclear	New Coal	CCGT	SCGT	New Nuclear	Hydro	Onshore Wind	Offshore Wind	Solar PV
Low (\$10/tCO2-eq)	15.96	0.69	0.29	2.68	0.99	1.43	0.12	0.05	0.19	0.16	0.79
Best (\$30/tCO2-eq)	18.07	1.75	0.29	4.35	1.89	2.71	0.12	0.05	0.20	0.18	0.91
High (\$100/tCO2-eq)	25.72	5.43	0.37	10.48	4.83	6.94	0.16	0.07	0.26	0.23	1.30

Since GHG-related damages compose a substantial portion of natural gas and coal externalities, the social cost of those technologies are most affected by the change in the cost of carbon. Nuclear and renewable generation, which emit few GHG gases, are less affected.

Low Cost of Carbon

Under the low cost of carbon of \$10/tCO_2-eq, coal and natural gas generation become more attractive (Figure 14). Existing natural gas generation swaps with existing nuclear generation as the least expensive technology. The order of all the other technologies remains the same; however the social cost decreases for all technologies (Figure 15).

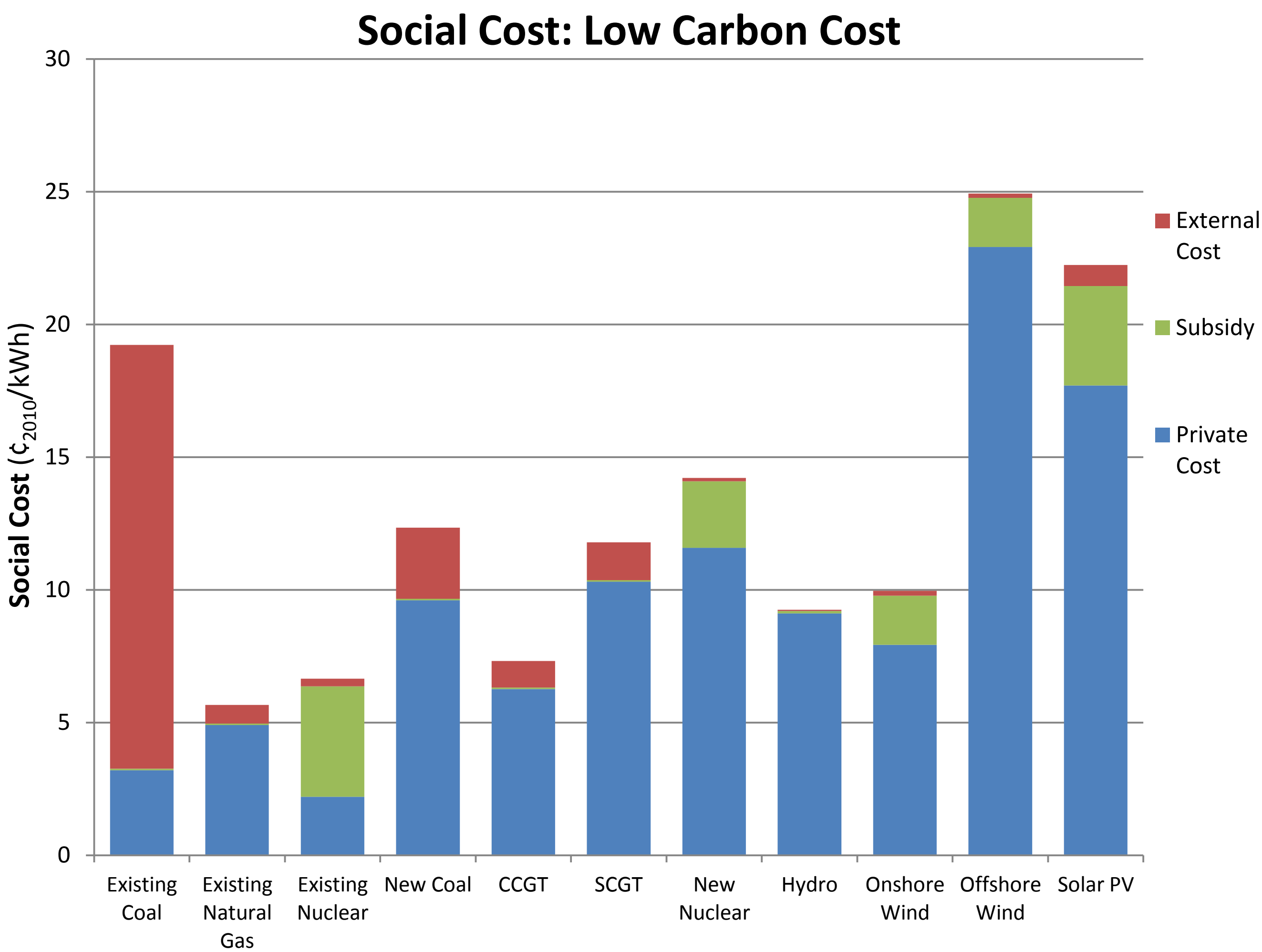

Figure 14 **Social costs of each electricity generation technology in the low cost of carbon of \$10/tCO_2-eq. The results are in ¢$_{2010}$/kWh.**

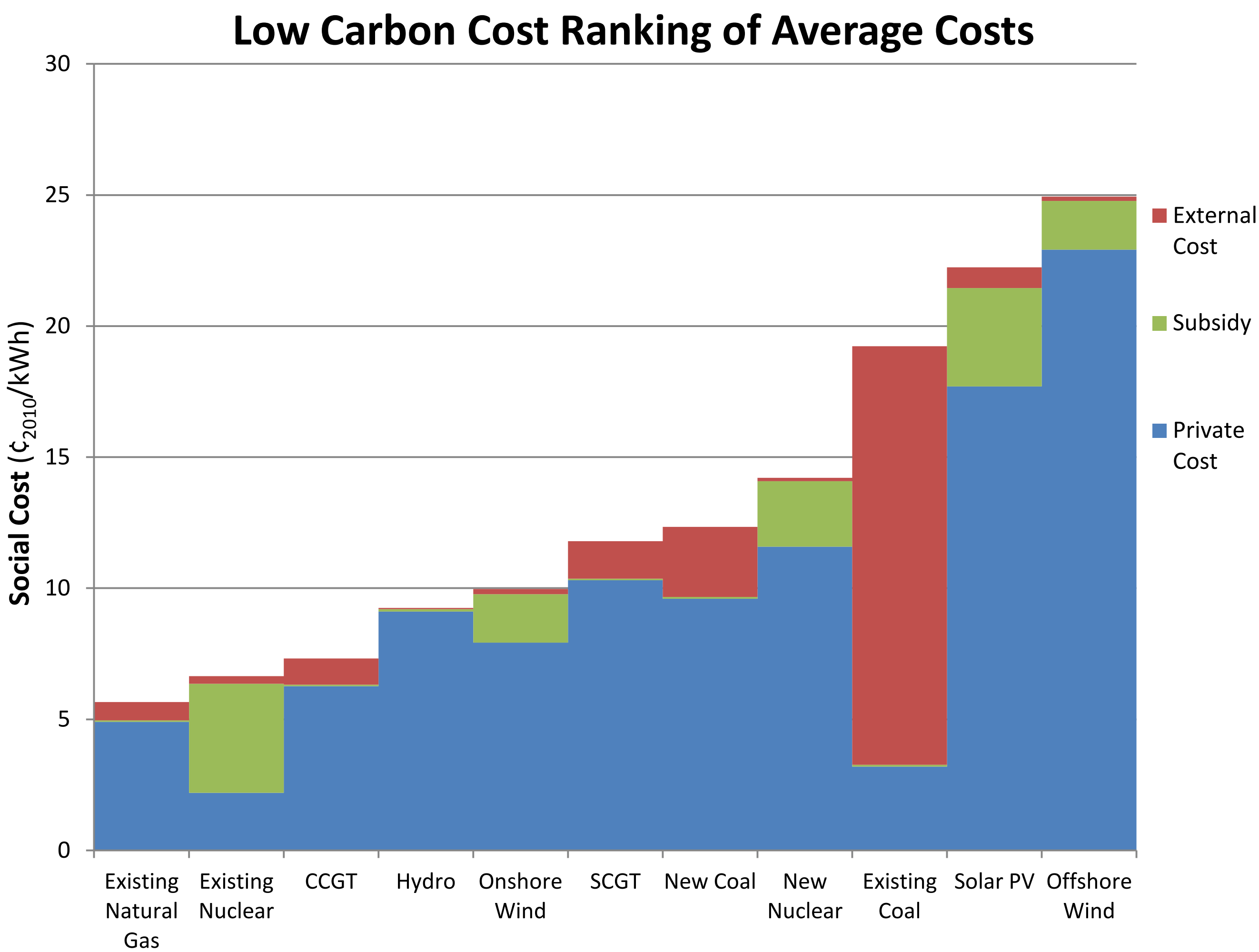

Figure 15 **The social costs under the low cost of carbon. The technologies are presented in order of social costs, from lowest to highest. The results are in ¢$_{2010}$/kWh.**

High Cost of Carbon Scenario

Under the high cost of carbon summary measure of \$100/tCO_2-eq, coal and natural gas generation are far less attractive than in the best estimate (Figure 16). Existing nuclear generation is still the least expensive generation; however existing natural gas is usurped by hydro and onshore wind (Figure 17). Existing natural gas is followed by, in order: CCGT, new nuclear, SCGT, new coal, solar PV and offshore wind power. Existing coal has the highest social costs of any technology. Overall, the social cost increases for all technologies, but most significantly for fossil fuel generation.

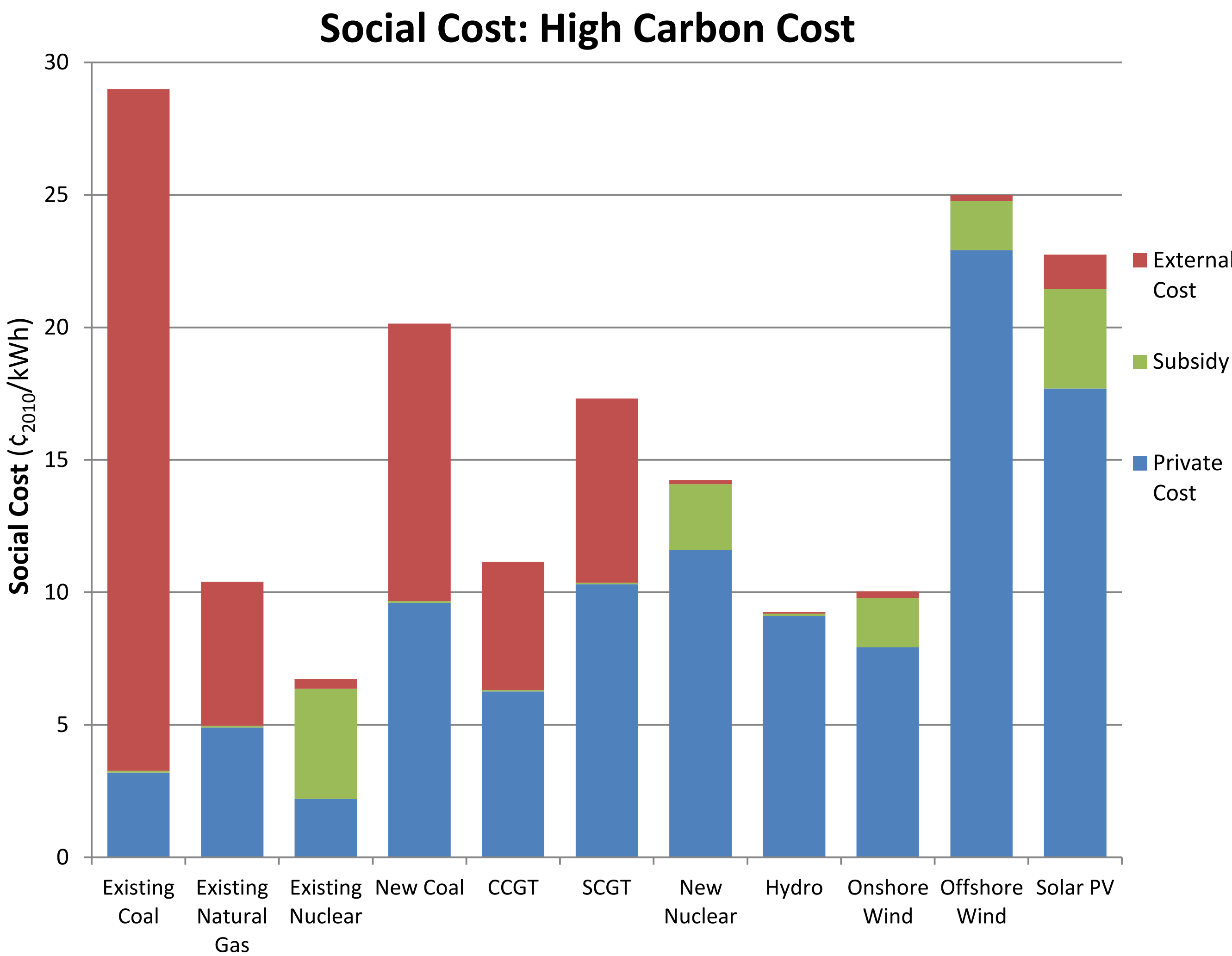

Figure 16 **Social costs of each electricity generation technology under the high cost of carbon of \$100/tCO_2-eq. The results are in ¢$_{2010}$/kWh.**

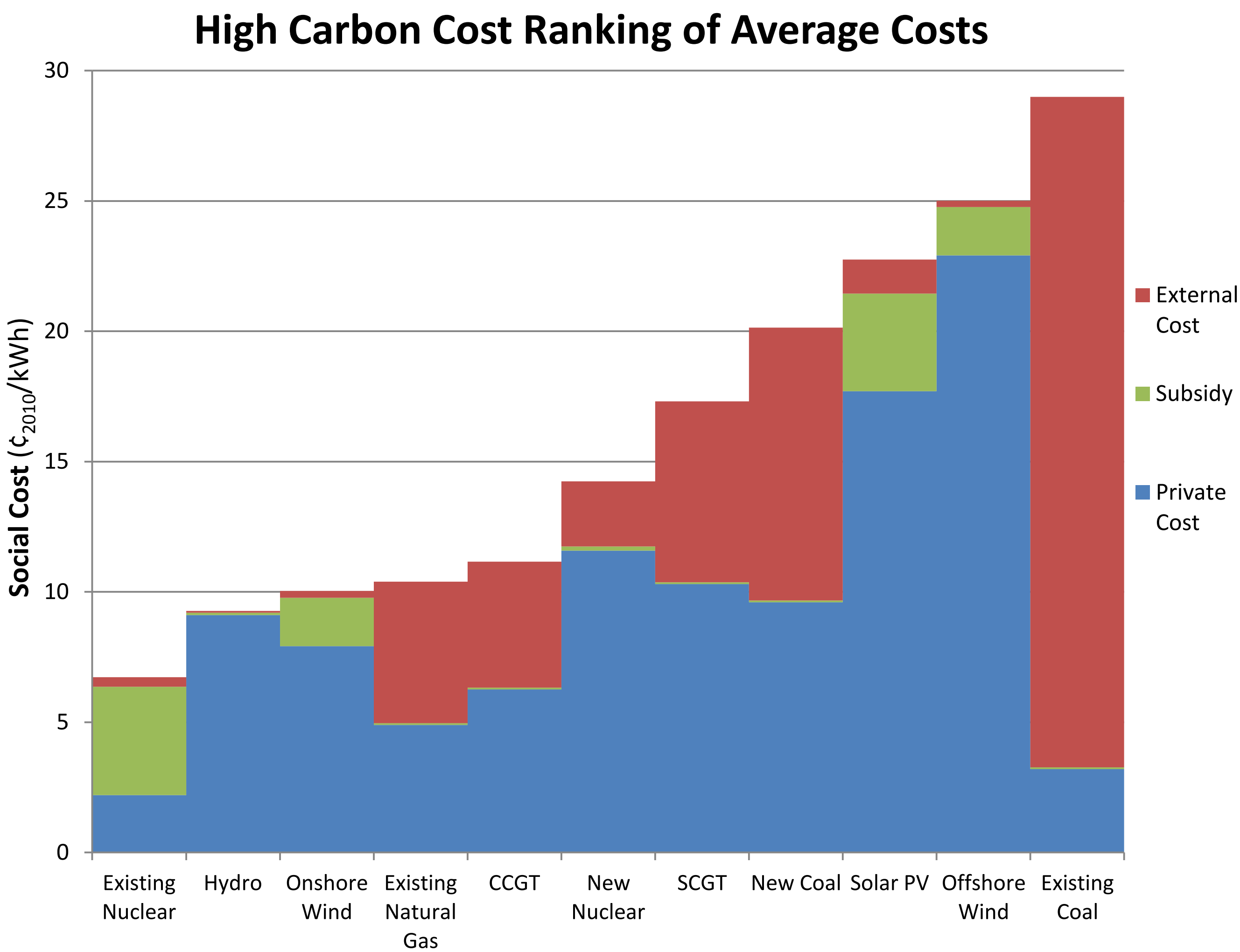

Figure 17 **The social costs under the high cost of carbon. The technologies are presented in order of social costs, from lowest to highest. The results are in ¢$_{2010}$/kWh.**

The next chapter considers the importance of these results and discusses how they can be interpreted. Additionally, policy measures to incorporate the results are analyzed.

Chapter 6

DISCUSSION

The previous chapter affirms that when government subsidies and externalities are included with private costs, the economics of electricity generation change. The extent that the social cost deviates from the private cost of electricity depends on the assumptions and the studies considered, but simply including the subsidies and externalities—as evidenced by the minimum cost summary measure—alters the order of least-cost generation. This chapter considers the importance of the social cost results, including: a comparison of electricity generation sources, a discussion of resources and future costs, and a re-evaluation of policy options given the results.

Comparison of Electricity Sources

There are several ways that this type of analysis can be interpreted and applied. A first application would be to use the social cost approach to compare new sources of generation. Existing generation is excluded from this discussion. A federal, state or local agency or public service commission could use the social costs as a guide in evaluating the choice of new generation technologies. If required, utilities or independent generators could use the results to evaluate the true costs of their power plants. Secondly, the social cost approach could inform policymaking and the positions of advocacy groups in a more systematic and quantitative way than considering some technologies good and others bad.

Additionally, with some slight modifications, the social cost approach can be used operationally, as a guide for a power dispatcher. In this case, the external cost would be included with generators' marginal private cost bids for the day-ahead electricity market. As the PJM market currently operates, independent generation owners bid into the PJM day-ahead and real-time wholesale energy markets in order to sell electricity to the grid. PJM then accepts the cheapest bids until the required demand is met; it is therefore within the interest of the generators to keep bid prices low. However, generators must recoup their variable costs, such as fuel and O&M, through wholesale electricity prices, while fixed costs are paid-off through the separate capacity market. In this thesis, the private costs include both fixed and variable costs, but if two costs were separated then it is possible that the external costs could be included with the variable costs for dispatch decisions. The lowest social cost technologies should be dispatched first, followed by the next lowest costs, and so on. Any on-line generation, new or old technologies, can be dispatched in this manner.

Because this thesis necessarily relied on existing externality and price data, and that data (as noted in the prior chapter and below) is incomplete or not comparable in some cases, the above recommendations of use are for this *type of analysis*, not necessarily the specific numeric results. This thesis demonstrates the need for more comparable data across generation types. As such data becomes more complete and comparable, applications like those suggested above could be valuable. Also, the results show clearly that policy or non-market values are important inputs from which the conclusions cannot be isolated—for example, the projected cost of fuel and chosen cost of CO_2 both affect the ranking of generation options.

Existing Generation

In the social cost best estimate, existing nuclear and natural gas generation have the lowest social costs at 6.65 $¢_{2010}$/kWh and 6.71 $¢_{2010}$/kWh, respectively (see Table 9 and Figure 13). Given that the private cost calculation for existing generation assumes that the capital cost of power plant has already been amortized, there is little surprise that these technologies have the lowest social costs. Indeed, the surprising conclusion is that due to high external costs—more than 5.5-times greater than the private costs—existing coal generation is more expensive than new coal generation, and overall it has the third highest social cost.

There are several stipulations attached to the appraisal that existing nuclear and natural gas generation have the lowest overall social costs. First of all, only one national study was available for the private costs of existing generation. Additionally, neither the NRC (2010) nor the Muller *et al.*(2011) externality studies consider the environmental and public health impacts related to the extraction and transport of natural gas. Only the impacts from the combustion, or generation, phase are considered. Moreover, no comprehensive subsidy study similar to the Koplow (2011) study is available for fossil fuels and thus the less inclusive EIA (2011c) analysis was used.

In the low cost of carbon summary measure, a decrease in the assumed cost of carbon from \$30/tCO_2-eq to \$10/tCO_2-eq reduces the social costs of all technologies. Additionally, existing natural gas usurps existing nuclear as the generation with the lowest social cost (Figure 15). Otherwise the social cost order remains the same as the best estimate.

In the high cost of carbon summary measure, with a high cost of carbon of \$100/tCO_2-eq, the social costs of all technologies increase, but most significantly for fossil fuel generation. In this case, existing nuclear is still the least expensive, but the social costs of existing natural gas exceed those of hydro and onshore wind (Figure 17). Also, existing coal surpasses solar PV and offshore wind as the most expensive technology.

New Generation Technologies

In the social cost best estimate, Natural gas (CCGT) is the lowest social cost new generation at 8.21 $¢_{2010}$/kWh at today's natural gas prices. After the historic high price of natural gas in the mid to late 2000's, decreased demand due to the global economic downturn and increased domestic production through hydraulic fracturing and horizontal drilling have meant a 50% drop in the wellhead commodity price since the 2008 peak (EIA, 2012c). In fact, the wellhead price for the month of March 2012 was $2.25 per thousand cubic feet, a nearly 75% drop from March 2008 and a level not seen since ten years prior (EIA, 2012c). Of course the fuel cost composes only a portion of the private cost, but it does represent almost 70% of the LCOE from a new combined cycle natural gas power plant according to the EIA (2011b). Thus, with the precipitous drop in the natural gas prices, it is no wonder that CCGT has the lowest social cost for new generation. Furthermore, natural gas health externalities are an order of magnitude less than coal and the carbon emissions are half as large (NRC, 2010).

The assessment that natural gas has the lowest social cost of new generation within the PJM region comes with the assumptions of the social cost best estimate, explained in Chapter 4. The lifecycle emissions estimates used in the European NEEDS assessment, and this analysis, do not include pollutant emissions from hydraulic fracturing extraction, which is prevalent in the PJM region. As previously mentioned, the fracking process increases fugitive methane emissions an estimated 30-200% over traditional extraction methods (Howarth et al., 2011), which would substantially increase the GHG related externalities of natural gas emissions. The hydraulic fracturing process also raises local air and water pollution concerns. Unfortunately no comprehensive external cost estimates of natural gas extracted through fracking exist, so consequently the best available natural gas externality assessment was used.

The advent of hydraulic fracturing and horizontal drilling has greatly increased the technically recoverable natural gas reserves in the United States. The US Geological Survey estimates that the technically recoverable natural gas resource in the Marcellus shale—most of which is within the PJM region—is between 43-144 trillion cubic feet (Tcf) with a best estimate of 84 Tcf; a substantial increase over the estimate of 2 Tcf in 2002 (EIA, 2012d). The current EIA national natural gas reserve estimate is 2,214 Tcf (EIA, 2012d), while the proven reserve is much smaller at 284 Tcf (EIA, 2010a). At the current annual US rate of consumption of 24.1 Tcf (EIA, 2011b) the technically recoverable reserve would provide over 91 years of natural gas supply, while the proven domestic reserves would supply only 11 years of demand. If the technically recoverable reserves are to be believed then the United States has ample supply of natural gas for the foreseeable future. Indeed, the EIA estimates that the United States will become a net exporter of gas within the next decade, reversing current trend (EIA, 2012d). However, the current proven reserves suggest that the supply could be exhausted in the near term, especially given the expected increase in natural gas use during the next decade (EIA, 2011d). This range of possible supply futures makes it difficult to project natural gas prices over the life of new generation facilities.

The lowest social cost renewable generation is hydropower at 9.25 ¢$_{2010}$/kWh, followed by onshore wind at 9.98 ¢$_{2010}$/kWh. In 2010, the almost 8 GW of hydroelectric capacity within PJM generated 2% of the total electricity (MMU, 2011). Although hydropower is an attractive proposition because it has a moderate private cost and very low external cost, it is minimally available within PJM because most of the hydropower resource has already been tapped. A recent national study by the DOE suggests that existing navigation locks and dams maintained by the US Army Corps of Engineers could be retrofitted to generate electricity (Hadjerioua et al., 2012). Many of un-powered locks are on the Ohio River and about an estimated additional 1.5 GW of capacity is available within the PJM region (data from Hadjerioua et al., 2012, Table 4 and Figure 11). The low LCOE from hydropower (9.20 ¢$_{2010}$/kWh)—second lowest for new generation according to the EIA (2011b)—could make the retrofitting existing hydro infrastructure economically appealing. The low costs for hydropower are partially because once a dam or a lock have been constructed the private and social costs or retrofitting to include electricity generation capacity are much lower. Nevertheless, a total resource of 1.5 GW is very small in comparison to PJM's need for new generation.

Similar to hydropower, the private cost of onshore wind is less than 10 ¢$_{2010}$/kWh and the external cost are less than 2.5% of the total social costs (externalities compose 2% of the social costs of onshore wind and 0.5% of hydropower). As noted previously, the cost of onshore wind power is directly related to the wind speed, transmission access and other site-specific factors, so a calculation of the price of installed projects will be a mix of lower- and higher-cost sites. Therefore, the existing subsidies enable developing some of the less-favorable sites to the benefit of industry development (see learning curve discussion below) but consequently showing a higher price per kWh of installed capacity. Unlike hydro, onshore wind is a vast potential resource in PJM (NREL, 2010), both in the western region in Ohio, Indiana and Illinois and on ridge tops along the Appalachian Range. The National Renewable Energy Laboratory estimates the wind potential to be 92.6 GW of capacity within the PJM states (data from NREL, 2011). Assuming a 27.4% capacity factor (the average capacity factor for wind projects in PJM in 2010) for the wind projects, this equates to 33% of the 2010 average PJM load (MMU, 2011). Indeed, driven by strong wind resource and state and federal policy, onshore wind accounts for 50% of the new generation in PJM queue (MMU, 2011). Considering the precipitous growth in the capacity—almost a 1 GW, or a 20% increase, in PJM during 2010 (MMU, 2012)—it is no surprise to see that onshore wind has the second lowest social costs of any renewable energy. Furthermore, despite the impending sunset of the wind PTC at the end of 2013, onshore wind still appears poised to be a large-scale source of new generation, now and in the future.

Dispatchable generation in the form of SCGT has a social cost of 13.08 $¢_{2010}$/kWh. External costs account for about 21% of the social costs, mostly from GHG emissions. SCGT operate at lower efficiencies than their CCGT counterparts, since they are well suited to satisfy load matching or peaking demand and therefore are generally called upon less frequently. The cycling of the power plants increases the private costs and carbon emissions. However, as is the case with the CCGT plants, the current depressed price of natural gas makes SCGT more economically attractive.

New coal generation has a social cost of 14.02 ¢$_{2010}$/kWh. The external costs account for 31% of the coal social costs, mostly from GHG emissions. While the private costs of coal generation are often thought of as low, the EIA (2011b) study suggests that they are actually 50% higher than combined cycle natural gas and about on par with onshore wind. Additionally, the fuel costs of coal generation have been increasing. According to the EIA, 2010 bituminous and sub-bituminous coal commodity prices were $54.73 per short ton and $12.64 per short ton, respectively (EIA, 2011a). In adjusted US$ these are the highest prices since the early 1990's and represent a more than 20% increase since 2007, even during an economic downturn (EIA, 2011a). During this same time period, natural gas prices decreased 28% (EIA, 2012c). New coal capacity accounts for less than 5% of the new capacity in the PJM queue, while natural gas accounts for 37% (MMU, 2012). Of course the important metric is what actually gets constructed, but this stark contrast between proposed generation types illustrates the future of new coal generation within PJM.

Existing coal generation has a social cost of 21.33 ¢$_{2010}$/kWh. Only including the private costs and ongoing subsidies of existing coal power makes it appear very competitive against other electricity generation technologies (Table 9). However, existing coal generation has the largest external costs of any technology reviewed and the externalities account for almost 85% of the social costs. Only offshore wind and solar PV are adjudged to have higher social costs than existing coal generation.

Existing coal generation within PJM faces a tenuous future because of low natural gas prices and promulgation of new government regulations. Indeed, the EPA seeks to reduce coal externalities through promulgation of new standards under the *Clean Air Act* regarding mercury and other hazardous air toxics and fine particulate matter ($PM_{2.5}$), as well as the possible reprisal of cross-state SO_2 and NO_x pollution rules (EPA, 2012a-c). In fact, due to enhanced EPA enforcement of the *Clean Air Act*, PJM forecasts that 11 GW of coal power plants, which on average are over 50 years old and less than 200 MW in size, are likely at risk of retirement (PJM, 2011). Another 14 GW of coal power plants, which on average are 37 years old and about 400 MW in size, are at some risk of retirement due to additional costs required to comply with EPA regulations. Despite the potential retirement of over 24 GW of coal capacity, PJM does not predict a regional problem meeting electricity demand, although the ISO acknowledges that localized issues may arise (PJM, 2011). Some of the 'at-risk' coal generation could be switched to natural gas as demonstrated by Calpine's purchase and subsequent conversion of Conectiv's PJM coal generation (Business Wire, 2010).

One positive for coal is the extensive reserves in the United States. Often referred to as "the Saudi Arabia of coal", the EIA estimates that the technically recoverable US coal reserves are 259 billion short tons (EIA, 2012e). At the 2010 US coal consumption of 1.085 billion short tons (EIA, 2011a); the national coal reserves would last for over 230 years. However, further analysis portrays a different situation. A US Geological Survey review which assesses the substantial Wyoming Powder River Basin reserves based not only on technological constraints but also economic and logistical considerations finds that the economical recoverable coal to be only about 6% of the original reserve (Luppens et al., 2008). Additionally, looking only at production raises doubts about the future of coal in the United States. Coal production in Appalachia peaked in the 1990's (McIlmoil & Hansen, 2010) and, according to one peer-reviewed multi-Hubbert cycle analysis, the US coal production is expected to peak in 2015 (Patzek & Croft, 2010). Certainly, the United States has extensive coal reserves, but the extent that those reserves are economically recoverable—or more importantly will be developed—is unclear.

New nuclear power, which has social costs of 14.21 $¢_{2010}$/kWh, is slightly more expensive than new coal power and less than existing coal generation. If only comparing private costs, new nuclear power is the third most expensive source, but because of existing coal generation's high external costs, based on social costs it is the fourth most expensive technology. Externalities compose less than one percent of the overall social cost, while subsidies compose about 17%. Both domestically produced and imported nuclear fuel prices have more than tripled since 2000 and, adjusted for inflation, are at their highest prices since the 1980's (data from EIA, 2011a, Table 9.3).

According to the EIA (2010b), the United States has reserves of 1,227 million pounds of nuclear fuel (uranium oxide, U_3O_8) that are economically recoverable at \$100 per pound of U_3O_8—more than twice the current price of about \$45 per pound of U_3O_8. At near current prices of \$50 per pound of U_3O_8, the economically extractable US reserves are 539 million pounds of U_3O_8 (EIA, 2010b). At the average consumption of 1999-2008, the US has only 23 years worth of reserves at \$100 per pound of U_3O_8, and 10 years at \$50 per pound of U_3O_8 (EIA, 2010b). It is important to note that, on average, domestically produced nuclear fuel accounts for only 10% of the US demand (EIA, 2010b). According to the International Atomic Energy Association (IAEA), at current international fuel consumption and prices there are about 80 years worth of economically recoverable reserves (IAEA, 2010). The aforementioned calculation was performed assuming once-through fuel cycle and that there is no growth in the global nuclear capacity, which given the vigorous installation rate in India and China seems unlikely. The country with the largest percentage of the global reserves is Australia (31%), while the US has only 4% (IAEA, 2010). In short, at over 14 ¢$_{2010}$/kWh new nuclear is more expensive than onshore wind or natural gas and to remain economically competitive the US nuclear industry requires continued access to the global nuclear fuel market or proliferation of breeder reactors.

There are over 6 GW of new nuclear capacity within the PJM queue, which amounts to 7% of the total queue (MMU, 2012). Combined License applications have been submitted to the US Nuclear Regulatory Commission (NRC) for expansions to the existing Calvert Cliffs generator in Maryland and Bell Bend generator in Pennsylvania (NRC, 2012). If the NRC approves the Combined License applications then new reactors could be constructed and allowed to generate for 40 years. Additionally, an Early Site Permit was submitted for an additional nuclear reactor at the Salem generating facility in New Jersey (NRC, 2012). The Calvert Cliffs and Salem applications are currently under review by the NRC, while the Bell Bend application was suspended at the request of the applicant (NRC, 2012). Even if the licenses are approved it is not guaranteed that new reactors would be constructed, as the projects would still have to prove economic viability and secure financing.

Solar PV is the second most expensive technology with social costs of 22.36 ¢$_{2010}$/kWh. External costs compose only 4% of the social cost, but the private costs alone of 21.45 ¢$_{2010}$/kWh make solar the second most expensive technology. Solar panel prices have fallen precipitously over the past decade; almost 60% since 2002 (data from Solarbuzz, 2012). Private costs are expected to further decrease during the next decade; a recent analysis estimates that LCOE for solar PV could fall to between

6 ¢/kWh and 10 ¢/kWh by 2020 (Fthenakis et al., 2009). Moreover, prices vary depending on whether the project is a retrofit of an existing structure, or whether the PV panels can be used in lieu of another building material in a new construction. Within PJM, North Carolina, Virginia and the Delmarva Peninsula have the best solar PV resource, but in general the PJM resource is among the worst in the United States (NREL, 2008). However, given that solar can be roof or ground mounted, many obstruction-less, south-facing sites are potential locations for PV. Solar capacity within PJM almost doubled between 2010 and 2011, from 64 MW to 124 MW, and there are another 3.6 GW proposed in the queue (MMU, 2012).

Offshore wind is the most expensive electricity generation technology with a social cost of almost 25 $¢_{2010}$/kWh. The private costs alone of 24.77 $¢_{2010}$/kWh makes offshore wind the most expensive technology. The high private cost of offshore wind is partially due to the absence of installed projects in United States. The first-of-a-kind projects (FOAC) installed in 2016 are assumed to have capital costs of $5,822/kW (EIA, 2011d). This is slightly higher than the assumed first-of-a-kind capital cost of $5,750/kW in Levitt *et al.* (2011). The Levitt *et al.* study uses higher financing rates and therefore finds that without government incentives, the first US projects will have private costs between 26.50-26.80 $¢_{2010}$/kWh—slightly higher than the EIA (2011b) analysis. Both EIA and Levitt *et al*. FOAC estimates are consistent with the Cape Wind Power Purchase Agreement prices, validating those estimates for the actual FOAC in the United States. On the other hand, European offshore wind projects report a capital cost of about $4250/kW, which yield a private cost of 18.9-19.2 $¢_{2010}$/kWh without incentives (Levitt et al., 2011). In the longer term, the Levitt *et al.* analysis illustrates that experience with construction and industry development both decrease project costs, even without any technology breakthroughs, as discussed below.

Offshore wind is an enormous resource in the Atlantic Ocean adjacent to the PJM service territory. For example, only including commercially-proven monopile and gravity-based foundation technologies in up to 35-meters depth, and excluding areas for environmental and social conflicts (as outlined in Dhanju et al., 2008 and Sheridan et al., 2012), offshore wind could satisfy over 35% of the average 2010 PJM load (Baker, 2011). Including jacket foundations in up to 60-meter depth, the amount increases to 72% (Baker, 2011). And if future floating technologies are included up to 1000-meter depth, then offshore wind could provide 123% of the average PJM load (Baker, 2011). There are currently at least seven offshore wind projects in various states of planning within the PJM queue (PJM, 2012b).

Future Electricity Prices

As noted, the social costs of electricity are not static. The results chapter only provides a snapshot in time of the economic situation of electricity generation technologies. Technology advancement, learning-by-doing and the closely related economies of scale can reduce the costs of electricity and drastically modify the results of this thesis, especially for developing technologies like offshore wind power and solar PV.

Historically in the electricity sector, as technologies are deployed en mass, the price of deployment decreases. The theory behind price reductions garnered from 'learning-by-doing', or technological learning, is a logarithmic relationship between production or deployment of a technology and price. Thus, for every magnitude increase in production there is a demonstrated 'progress ratio' or decrease in price

(IEA, 2000). Learning curves are especially important for developing technologies where production scales rapidly and the price drops as a consequence (Jamasb, 2007; Jamasb & Kohler, 2008). Consequently, traditional technologies such as coal and natural gas do not see much reduction in price from experiential learning, except for decreased costs of environmental control technology (Rubin et al., 2004). On the other hand, renewable technologies which are rapidly scaling up, profit from high learning rates and the associated price reductions (Jamasb & Kohler, 2008). Examples of this relationship between price and installed capacity include wind power in Denmark (Ibenholt, 2002), Spain and the United Kingdom (Junginger et al., 2005) and global solar PV, which benefits from 24% cost reductions each time capacity doubles (Bloomberg New Energy Finance, 2012).

Whereas technology curves are assumed to be permanent cost reduction based on units produced, the closely related economies of scale varies directly with production. Small batch production, manufacturing or installation is expensive due to high overhead and sunk costs. Scaling up manufacturing and production allows for capital investments and streamlined processes when dealing with many units rather than a few. Based on the European experience, US offshore wind stands to benefit from economies of scale through streamlined project development, volume turbine and foundation production and installation price reductions for large-scale projects (Garrard Hassan, 2003).

Even without any disruptive technology advancement, renewable electricity technology prices are expected to reduce substantially over the next decade due to technological learning. One prediction based on historical technological learning rates expects the private costs of electricity from onshore wind, offshore wind and solar PV to drop to 4.2 ¢$_{2010}$/kWh, 8.4-13.7 ¢$_{2010}$/kWh and 10.5 ¢$_{2010}$/kWh, respectively (Delucchi & Jacobson, 2011). Predicted cost reductions would make the social cost of onshore wind electricity, the least expensive generation technology; 33% cheaper than existing nuclear and natural gas generation. Solar PV would be less expensive than SGCT, and at the low end estimate, offshore wind would be on par with CCGT.[7]

Policies

In order to level the economic playing field between technologies, external costs should be internalized and existing subsidies for traditional, developed technologies should be removed. From a policy standpoint there are many methods to achieve this goal, each with benefits and drawbacks as well as political likelihood. Since these methods are well developed components of the political discussion (e.g., Stavins & Whitehead, 1992; Eyre, 1997; Owen, 2006; Stern, 2007; Kolstad, 2010), they will not be reviewed in detail here.

Utilities beholden to public service commissions reliably provide electricity at a calculated minimum cost to the rate base. As illuminated in the results chapter, least-cost from a purely private cost standpoint includes a number of technologies with high externalities. Historically, federal agencies overcome this issue through top-down regulation of pollutants. Under the directive of the *Clean Air Act* (2008), the EPA regulates the emission of criteria pollutants—SO_2, NO_x, particulate matter ($PM_{2.5}$ & PM_{10}), ozone, carbon monoxide and lead—through national ambient air quality

[7] Electricity prices calculated by replacing the EIA (2011b) private costs with the future private costs (year 2020 and beyond) from Delucchi and Jacobson (2011) for renewable electricity generation in the social cost best estimate from Chapter 5, otherwise all costs remain the same.

standards, mandates for new plants, and best available technology requirements; among other programs. Additionally, the agency regulates the release of mercury (EPA, 2012b) and the proposed GHG emission rules for new generation (EPA, 2011d) were upheld by the federal appeals court and final rules could be forthcoming.

In order to fully internalize the external costs of electricity generation, one option is to expand these programs and tighten the regulations. Indeed, this is already occurring. As previously mentioned, on December 14, 2012, the EPA finalized the new allowable national ambient air quality standard for fine particulate matter of 12 micrograms per cubic meter (EPA, 2012c). Furthermore, new rules regarding the emissions of mercury and other hazardous air toxics are forthcoming (EPA, 2012b). Additionally, the EPA promulgated more stringent regulations for cross-state SO_2 and NO_x pollution in June 2011, and while the rule was vacated in August 2012 by the US Court of Appeals for the District of Columbia Circuit, the EPA has requested a hearing *en banc* and new rules are possible at some point (EPA, 2012a). The new regulations are reshaping the PJM generation layout as nearly 14 GW of old coal power plants which require cost-prohibitive upgrades have asked to be retired and removed from the market (DiSavino, 2012). The common argument against top-down mandates is their expense due to lack of flexibility for implementation or economic incentive for innovation (Kostad, 2010; Hsu, 2011).

A market-based policy option which internalizes external costs while allowing for innovation and least-cost implementation is a cap-and-trade system or an emission trading scheme (Kolstad, 2010). There are several examples of this mechanism in the United States, including the EPA's regional SO_2 and NO_x emission trading scheme, the Regional Greenhouse Gas Initiative, the Western Climate Initiative, California's

Global Warming Solutions Act (AB 32), and the proposed national GHG emission trading scheme in the *American Clean Energy and Security Act of 2009*—commonly referred to as Waxman-Markey—which passed the House of Representatives but was not brought to a vote in the Senate due to lack of support. Much has been written about the caveats of the cap-and-trade mechanism (Kolstad, 2010; Hsu 2011), especially related to the European Union's emission trading scheme (Demailly & Quirion, 2006; Hintermann, 2010) which will not be repeated here, but suffice to say that the number and allocation of permits is of paramount importance.

Another market-based solution to internalize externalities is a Pigouvian tax on damages. In this case, the pricing of external costs is crucial in order to send the correct price signals. The tax can be implemented at the any point of the generation stream: the extraction, generation, use, etc. Through the tax, an economic incentive is placed on reducing negative impacts by abatement, reduction or substitution. Often favored by economists due to its simplicity, it is avoided in political circles, reportedly because of the political risk of being on record supporting a new tax. However, a GHG emissions tax could be made revenue-neutral to the Federal Government by using the revenue to reduce corporate or personal income taxes as is the practice in Australia and British Columbia (Hsu, 2011; Bauman & Hsu, 2012).

Ideally from the perspective of economic theory, the United States would introduce either a cap-and-trade system or a Pigouvian tax to internalize externalities; however, in the absence of such policies, there are other corrective mechanisms which recognize the environmental benefits of renewable electricity technologies. State policies which serve this role are Renewable Portfolio Standards (RPS) or Clean Energy Standards (CES), which in effect separate the markets for developing renewables and traditional technologies as a measure to compensate renewable for competitors' un-priced externalities. A similar policy for renewable generation is being discussed at the national level through the *Clean Energy Standard Act of 2012* introduced by former Senator Jeff Bingaman (D-NM).

State RPSs mandate state-regulated utilities to purchase a minimum percentage of their electricity from renewable sources. These have been implemented through tradable Renewable Energy Credits (REC) or the like, and have proven to be successful mechanisms to spur development as demonstrated by New Jersey's solar market (Kisker & McKillop, 2011). Indeed, RPSs even allow special technology-specific carve-outs such as SRECs for solar PV or ORECs for offshore wind. However, linking renewable energy growth to an electricity percentage subjects the industry to boom-bust cycles. The RECs provide sufficient incentive for initial development, but in practice, REC prices—and therefore developments—plummet as targets are reached, unless the REC level is raised before deployment reaches that percent, as Texas and California have done. Furthermore, since no two RPSs are alike, adapting to state-specific program intricacies can prove onerous for developers. A national CES, or better state coordination within each region, could potentially solve the diversity of state requirements. Although, the proposed national CES includes natural gas generation, which, while cleaner than coal, is certainly not carbon-free and does not qualify as a developing technology (Clean Energy Standard Act, 2012).

States can also mandate public service commissions, or the like, to consider externalities in planning decisions. This can be in addition to an RPS or as an alternative. For example, Delaware mandates the public utility to consider the external costs of electricity generation related to the environment and public health in the two-year integrated resource plan (IRP) when choosing generation contracts (Delaware Administrative Code, 2010). The most recent Delaware IRP estimates that between 2013 and 2022, increased demand side management, natural gas and renewable generation along with reduced coal generation and increased emissions control technology on remaining coal plants, will yield $981 million to $2,151 million in human health benefits from reduced $PM_{2.5}$ and ozone levels (Delmarva Power, 2012).

Similarly, arid Arizona requires water demand to be considered by the utility regulatory body—the Arizona Corporation Commission—when issuing a certificate of environmental compatibility for any new generation facility (Arizona Revised Statutes, 2007). As part of the IRPs, Arizona and New Mexico also require regulated utilities to report water consumption rates and emissions of criteria air pollutants—either as rate per unit energy or total amounts—for contracted generation, when possible (Arizona Administrative Code, 2011; New Mexico Administrative Code, 2007). I have not found other states that impose comparable requirements, although an exhaustive search was not conducted for this thesis. There are 28 states with require regulated utilities to submit IRPs (Wilson & Peterson, 2011, Figure 2) and measures similar to the Delaware IRP process could be implemented in other states to level the economic playing field.

A corrective mechanism that does not internalize externalities but can—at least over the short term—compensate for them, are government subsidies. Rather than taxing externalities government can provide subsidies to cleaner generation as a way to reward low external costs or carbon-free generation, or to nurture developing technologies until they gain market presence against traditional, entrenched ones. Both externalities and technology development have been used to justify subsidies to renewable energy (Obama, 2012; Revesz, 2012). Subsidies can come in the form of federal tax credits (PTC, ITC), direct benefit transfers (section 1603 cash grant), accelerated depreciation of assets (MACRS), fixed-price offerings (feed-in tariffs), or provision of low-interest capital through federal loans or loan guarantees (section 1705 loan program), among others.

Subsidies to renewable energy in the United States have focused primarily around temporary tax credits such as the PTC and ITC and low interest loans, while the Europeans have employed feed-in tariffs (FiT) with great success (Butler & Neuhoff, 2008; Cory et al., 2009). The uncertainty caused by the temporary nature of the PTC and ITC has made it difficult for renewable energy developers and manufactures to make long-term investment decisions. The absence of the wind PTC causes bust cycles, while its renewal creates booms (AWEA, 2011b). These boom-bust cycles have largely been avoided through consistent FiTs in Europe. While not market-based, a recent ruling by the Federal Electricity Regulatory Commission opens the door to European-style FiTs at the state-level in the United States under the *Public Utility Regulatory Policies Act of 1978*, with certain qualifying project size restrictions (FERC, 2010).

Another possibility to avoid the boom-bust cycles would be to allow renewable energy generation to take advantage of Master Limited Partnerships (MLPs) and Real Estate Investment Trusts (REITs). MLPs and REITs are corporate structures codified in the U.S. Internal Revenue Code (IRC) that provide tax benefits to investors because the corporation revenue is passed through and only taxed at the individual level. By avoiding ‘double taxation’, MLPs and REITs are able to secure capital at a lower rate, which could reduce the cost of renewable energy generation. Currently, MLPs only benefit qualified ‘depletable’ resources as defined under Section 613 of the IRC—such as coal, oil or natural gas extraction or pipelines—but the *Master Limited Partnerships Parity Act* introduced by Sen. Chris Coons (D-DE) and Sen. Jerry Moran (R-KS) would extend the corporate structure to renewable energy companies (GPO, 2012). Under IRC Section 856, REITs only apply to companies that derive at least 75% of their revenue from real estate rent, but the Internal Revenue Service has been asked to clarify if payment for electricity from distributed solar PV projects would qualify as rent (Rampton, 2012).

In economic theory, the pricing of externalities is preferable to compensatory subsidies, because over time subsidies can change economic models as industries become reliant upon them (Kolstad, 2010) and subsequently expend great resources lobbying politicians for their continuation. A perfect example of this behavior is the traditional energy industries which caused uproar and successfully avoided the removal of age-old subsidies to coal, oil and natural gas proposed by President Barack Obama and the 112th Congress (Obama, 2011). Indeed, the removal of subsides for established energy technologies would offset some unwarranted advantage they now enjoy over renewable energy technologies.

Separate from the previous discussion is the federal R&D budget. The potential cost reductions from technological learning highlight the importance of R&D funding for electricity. However, the private electricity sector spends only 0.4% of revenue on basic research (Margolis & Kammen, 1999), while the innovative pharmaceutical and information technology sectors typically spend 10-20% of turnover (Neuhoff, 2005). The improved public health and security that is offered by clean, domestic power production is a basic public good, which is why it is paramount that the federal government continues to support R&D. Federal government funding of basic R&D is vital to innovation and development of clean energy, as the industry lacks the ability to fund it alone (Jamasb & Kohler, 2008). Indeed, the federal energy R&D budget in 2009 amounts to one-fourth of the expenditure in the in the late 1970s and 80s, or less than one-tenth as much as a percentage of gross domestic product (OMB, 2011). Greatly expanding the energy research budget will provide the support that the industry requires to reduce costs and advance. Programs such as the DOE's Advanced Research Projects in Energy (ARPA-E) have proven successful with limited budgets and similar competitive research grant programs should be expanded. The DOE has provided grant funding for targeted technology development, typically for shorter-term advances than ARPA-E. The increases in such funding could come from a carbon tax or cap-and-trade system or even from sale of RECs through a federal RPS/CES. Or as an alternative to new mechanisms for additional revenue, removing the generous tax subsidies for established electricity generation technologies could offset the program costs.

The ideal policy mix to internalize externalities and support developing technologies through the learning curve would depend on a wider analysis as well as value decisions by elected leaders and thus is beyond the scope of this thesis. Nevertheless, this thesis presents arguments for a combination of environmental regulation, a Pigouvian tax or a cap-and-trade system for GHG emissions, and an increased federal R&D budget.

Areas of Future Research

A chief shortcoming of this thesis and an area for future research is the availability of cost data. Private cost of electricity is highly dependent on technology, location, size of project and cost of capital, and thus it is therefore extremely difficult to assess as a single figure. Furthermore, private costs—especially those of developing technologies such as solar PV and offshore wind—are not static, as they are subject to market forces and technological advancement. It is therefore important PJM specific market data or use many more studies that are updated more frequently than those used in this thesis.

Initially, it was hoped that market data could be used to assess the private economic costs of electricity generation within the PJM service territory. As previously mentioned, generators often look to recoup their variable costs through their bids into the PJM day-ahead electricity market, while fixed costs are paid-off through the capacity and, depending on the type of plant, the ancillary reserves market. PJM publishes the annual market data, including an annual average energy cost within the service territory (MMU, 2011). PJM also compiles capacity and transmission charges, which are separate from energy costs but included in the wholesale cost of electricity. These combined values—energy plus capacity and transmission costs—represent the average private cost of generating electricity. Unfortunately, PJM does not publicly supply annual average energy costs broken down by technology. Therefore it was necessary to use figures from the peer-reviewed literature, many of which assessed electricity costs across the entire United States. Therefore, while the study focuses on the PJM region, many of the results are applicable to the entire United States.

Another shortcoming is the dearth of external cost data specific to the United States. Most the external costs data available is from European studies for European power plants and conditions, which is not necessarily applicable to the United States. European population densities, health preferences, environmental and agricultural conditions, are very different than in America, and, therefore, even with a PPP conversion it is possible that the external costs are not comparable. Furthermore, European health care costs are very different than in the United States and thus a more comprehensive analysis between the difference in public health costs is necessary, because a simple PPP conversion would likely undervalue the real U.S. public health external costs.

More specific U.S. external costs studies are needed for policymaking. While the NRC (2010) report assessed only coal and natural gas externalities, the most widely-cited, comprehensive U.S. external cost paper—based on the author's analysis with Scopus—is Matthews & Lave (2000), but the external cost values change as technology, regulations and population change over time. A new comprehensive PJM-specific analysis would be required to for external costs to be implemented into policy.

Likewise, there is no commonly accepted methodology or study that assesses energy subsidies within the United States. This is complicated by the lack of a commonly accepted definition of government subsidies (e.g. whether subsidies only includes annual federal outlays, or historic assistance, R&D, insurance provisions, etc.), as well as the fact that many tax provisions which benefit electricity generation technologies are also available to the larger manufacturing or extraction industry (e.g., accelerated depreciation of assets or depreciation, depletion and amortization for properties, for example). Furthermore, this analysis did not assess state subsidies. One method to rectify this gap, could be to quantify the benefit of state RPSs in PJM to various technologies based on the value of RECs.

In conclusion, this thesis is intended to emphasize the importance of subsidies and external costs in the discussion of electricity prices, which in policy circles are often over-simplified to the Levelized Cost of Electricity from various technologies, only including the private costs. The social cost values included in the results chapter are not intended to be the definitive values of electricity, but the hope is that the type of analysis in this thesis help revisit the dialogue about the best methods for incorporating external costs into private electricity costs as well as frame the discussion about energy subsidies in the current policy environment.

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