The Role of CCS as a Mitigation Technology and Challenges to its Commercialization

by

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ABSTRACT

Greenhouse gases are being emitted at an increasing rate, which may cause irreversible damage to the earth's climate. Considering the magnitude of CO_2 emissions from industrial facilities and power plants, carbon capture and storage (CCS) is expected to play an important role in mitigating climate change. The estimated contribution of CCS to a given emissions reduction target depends on assumptions made about various factors such as the availability of the technology, the availability of substitutes such as nuclear technology, and the stringency of emissions reduction targets. Given that the global energy economy has largely been operating in "business as usual" mode, the effective implementation of a carbon policy is likely to be delayed. In addition, other trends in the energy sector such as the availability of inexpensive gas-based generation and the uncertainty related to nuclear capacity expansion may also have an impact on the role of CCS. Part A of this thesis analyzes the importance of CCS as a mitigation technology under different future policy responses and incorporating these current trends.

Using the Emissions Prediction & Policy Analysis (EPPA) model developed by the Joint Program on the Science & Policy of Global Change at the Massachusetts Institute of Technology (MIT), the study finds that the more stringent the emission caps, the more important the role of CCS becomes. In addition, the role of natural gas based generation is found to be transitional in its contribution to emissions reduction. Consequently, the availability of inexpensive gas-based generation does not eliminate the need for CCS towards the end of the century. Furthermore, advanced nuclear technology and CCS are found to be close substitutes for technologies that serve the needs of a low-carbon economy in the latter half of the century. The role of one technology, therefore, is in part determined by how technological development and cost reduction occurs in the other.

Part B of this thesis focuses on challenges experienced in the current demonstration phase of CCS technology development. Most demonstration projects are typically supported by a combination of policy incentives such as grants, investment tax credits, production tax credits, loan guarantees, or additional sources of revenue. Regardless, many of these demonstration projects have been cancelled in the recent past primarily due to poor project economics. A financial model was developed and used to analyze the impact of each of these policy incentives on project economics. In addition, case studies have been conducted on two major demonstration projects: ZeroGen (Australia) and the Kemper Country (USA).

The study finds that even with the combined impact of all incentives, first-of-a-kind CCS plants are not economical when compared to supercritical pulverized coal plants. CCS and similar low carbon technologies are also facing increasing economic pressure from cheaper natural gas-based electricity. These factors, in addition to endogenous risks associated with first-of-a-kind plants, are likely to deter potential developers. Therefore, CCS demonstration plants may require other policy mechanisms such as a rate-based pay that allow costs to be passed on to consumers. Policymakers may need to consider the distributional impacts of such a mechanism because costs are borne by consumers within a particular jurisdiction whereas the benefits of commercializing CCS accrue to a larger group of consumers. Regardless, incurring costs in the short-term may be inevitable to ensure the availability of CCS as a competitive, longer-term low carbon technology option.

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I dedicate this thesis to my parents and my sister. I would not have made it this far without your support, and I cannot thank you enough for everything that you have done for me. I hope to continue to make you proud.

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LIST OF ACRONYMS & UNITS

List of Acronyms

ABARE	Australian Bureau of Agriculture and Resource Economics
ACALET	Australian Coal Association for Low Emission Technologies Limited
AEO	Annual Energy Outlook
AEP	American Electric Power
ARRA	American Recovery & Reinvestment Act
AU$	Australian Dollar
BAU	Business As Usual
BP	British Petroleum
BSER	Best System of Emissions Reduction
CCPI	Clean Coal Power Initiative
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilization and Storage
CES	Constant Elasticity of Substitution
CGE	Computable General Equilibrium
COE	Cost of Electricity
CP	Carbon Price
CWIP	Construction Work In Progress
DOE	Department of Energy
EGU	Electricity Generating Unit
EIA	Energy Information Administration
EIS	Environment Impact Statement
EOR	Enhanced Oil Recovery
EPA	Environment Protection Agency
EPPA	Emissions Prediction & Policy Analysis
ERCOT	Electric Reliability Council Of Texas
ETA	Emission Trading Allowances
ETP	Energy Technology Perspectives
EUA	Emission Unit Allowances
FEED	Front End Engineering Design

FOAK	First-of-a-kind
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GCCSI	Global CCS Institute
ICCSP	Industrial CCS Projects
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
ITC	Investment Tax Credit
LCOE	Levelized Cost of Electricity
MHI	Mitsubishi Heavy Industries
MPC	Mississippi Power Company
MSPSC	Mississippi State Public Services Commission
NACC	North American Coal Corporation
NDT	Northern Denison Trough
NETL	National Energy Technologies Limited
NGCC	Natural gas Combined Cycle
NOAK	Nth-of-a-kind
NSPS	New source performance standards
OECD	Organization for Economic Cooperation and Development
O&M	Operation & Maintenance
PISC	Post injection site care
PTC	Production Tax Credit
PUC	Public Utilities Commission
R&D	Research & Development
RD&D	Research, Development, & Demonstration
RfP	Request for proposals
RUS	Rural Utilities Service
SAM	Social Accounting Matrix
SBC	Schlumberger Business Consulting
SCC	State Corporate Commission

SCPC	Supercritical Pulverized Coal
SMEPA	South Mississippi Electric Power Association
SOP	Standard Operating Procedure
SPV	Special purpose vehicle
T&D	Transmission & Distribution
TOC	Total Overnight Costs
TRIG	Transport Integrated Gasifier
TS&M	Transport Storage & Monitoring
w/o	without

List of Units

AU$	Australian dollar
bbl	barrel of oil
Btu	British thermal units
$GtCO_2$	gigaton of CO_2
mcf	million cubic feet
MMBtu	Million Btu
Mtpa	Million tons per annum
MW	Megawatt
MWh	Megawatt-hour
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
lb	pound
tCO_2	ton of CO_2
$TgCO_2$	teragrams or million metric tons of CO_2

1. INTRODUCTION

According to estimates by the International Energy Agency (IEA), global CO_2 emissions in 2011 reached a record high of 36.1 gigatons ($GtCO_2$) with coal accounting for 45% of total energy-related emissions followed by oil (35%) and natural gas (20%) (IEA, 2012). This problem is exacerbated by the fact that the countries with the largest emissions also have abundant reserves of fossil fuels such as coal and natural gas. Furthermore, the extraction of fossil fuels is increasing through the application of new technology to resources in the deep sea, shale rock, and oil sands. Therefore, in the absence of regulatory intervention, emitters have no incentive to reduce the consumption of these economically viable fuels. Consequently, greenhouse gases are being emitted at an increasing rate, which may cause irreversible damage to the earth's climate.

Pathways for carbon emissions reduction depend on the source of these emissions; fuel efficiency standards are employed in the transportation sector, energy conservation and efficiency initiatives are common in the commercial and residential sectors, while carbon capture and storage (CCS) technology is targeted at stationary sources such as power plants and industrial facilities using fossil fuels. Considering the magnitude of CO_2 emissions from industrial and power plants, CCS is expected to play an important role in mitigating climate change. In the BLUE Map scenario developed by the IEA, a 50% reduction in emissions by 2050 (compared to 2005) were projected to be delivered by options as illustrated in Figure 1 (Fischedick *et al.*, 2011).

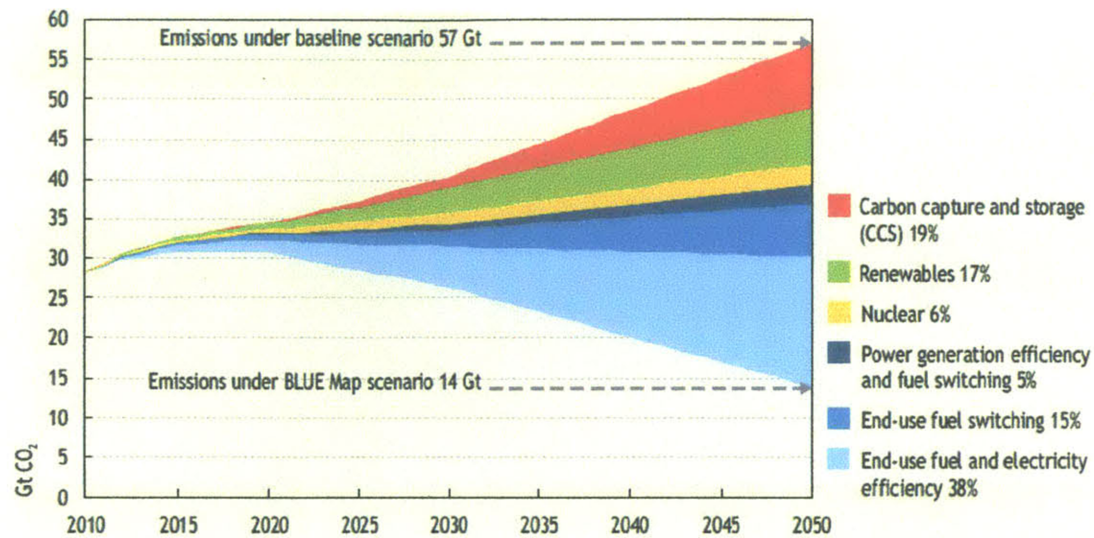

Figure 1: Carbon Emissions Reduction Pathway (IEA, 2011)

The estimated contribution of CCS technology to a given emissions reduction target depends on the assumptions made about various factors such as the availability of the technology, the availability of substitutes such as nuclear technology, the stringency of emissions reduction targets, and the development of renewable energy technologies. In addition, many assumptions used to build scenarios in published studies may not hold true when viewed in the context of current trends in the energy sector. For example, while the results from these studies are predicated on the assumption that countries will establish and enforce emissions reduction targets, only the European Union (EU) has made significant progress to meet its goals under the Kyoto Protocol. Considering that the global energy economy has largely been operating in "business as usual" (BAU) mode, **the focus of this thesis is to ascertain the importance of CCS as a mitigation technology under different policy responses in the future.**

Other trends in the energy sector may also have an impact on the role of CCS. It may be argued that various mitigation technologies such as renewables are becoming uncompetitive due to the availability of inexpensive gas-based electricity. Furthermore, in a post-Fukushima world, industrial economies seem to be proceeding cautiously with their plans to expand their nuclear capacity. The uncertainty related to nuclear capacity expansion and the related costs (increasingly stringent safety standards and consequent cost escalation) may result in a switch to fossil fuel-based plants with CCS for emissions reduction. **In Part A of this thesis, I examine how the role of CCS in a carbon mitigation portfolio changes when current trends in the energy sector are accounted for.**

I use the Emissions Prediction & Policy Analysis (EPPA) model developed by the Joint Program on the Science & Policy of Global Change at the Massachusetts Institute of Technology (MIT) to build on the results of energy economic models while accounting for the aforementioned trends in the energy sector. Chapter 2 highlights relevant results from various top-down models on the importance of CCS technology under different assumptions. Two kinds of policy responses that account for the delay in implementing a comprehensive carbon policy represent the base case scenarios in EPPA, and these are presented in Chapter 3. One scenario has more stringent targets in later years to compensate for the lack of adequate regulatory intervention at present, and in the other scenario no attempt is made to compensate for inadequate action at present, which results in higher atmospheric concentrations of greenhouse gases. The results, including the annual electricity generated from plants with CCS, the carbon price needed to support relevant policy responses, and the technologies constituting the electricity mix are presented in Chapter 4. I also analyze the sensitivity of these results to varying assumptions about the availability of advanced nuclear technology and the cost of gas-based electricity.

In Part B of this thesis, I analyze CCS as a mitigation technology from a bottom-up perspective. Specifically, I examine financing and related challenges for CCS demonstration projects. Many of these demonstration projects, that planned to capture carbon dioxide (CO_2) at the rate of over one million tons per annum (Mtpa), have been cancelled in the recent past. For example, Jänschwalde, a project in Germany, was withdrawn due to local opposition to the project based on environmental concerns. PGE, a proponent of the Belchatow project in Poland, stated that it was in no position to execute the project in the absence of incentives. Considering that the cost of capturing a ton of CO_2 at its pilot plant was approximately €60 – 65 while emission unit allowances (EUAs) were trading at €6.53 per ton of CO_2 (tCO_2), additional support was needed to bridge this gap (BusinessWeek, 2012). ZeroGen, a project in Australia, suffered from escalating costs, with the project cost estimate increasing from AU$4.3 billion to AU$6.93 billion.

Most demonstration projects are typically supported by a combination of grants, investment tax credits, production tax credits, loan guarantees, or additional sources of revenue. **In Part B, I use a financial model to analyze the impact of each of these policy incentives on project economics.** The impact of these policy incentives is first analyzed using data gathered from studies on generic power plants using CCS technology. Then, I use data from specific projects to further investigate policy incentives that contribute positively to the economics of a demonstration project. This section of the thesis, therefore, analyzes specific cases of CCS demonstration projects - ZeroGen (Australia) and the Kemper Country (USA) project are used as case studies.

The costs associated with CCS demonstration projects are catalogued in Chapter 5. The results from studies that attempt to explain why actual costs for plants that use a new technology deviate significantly from initial or generic estimates are also presented in this chapter. These cost estimates, along with other project data are used in the financial model, which is described in Chapter 7. The impact of policy incentives is analyzed and presented in Chapter 8 to delineate the factors that contribute positively to the economics of a project versus the factors that may lead to a project's cancellation. Case studies on ZeroGen and the Kemper County projects are presented in Chapters 6 and 9 respectively.

The results from both the top-down and bottom-up approaches to analyzing CCS technology may answer the following questions: **Under what future carbon policies are CCS integral to an emissions reduction strategy? To develop CCS as a mitigation technology, how should the demonstration phase of CCS technology development be supported?** Relevant policy implications that emerge from the analyses in Part A and Part B, and conclusions are discussed in Chapter 10.

PART A: Analysis of CCS in a Carbon Mitigation Portfolio

2. REVIEW OF RESULTS FROM INTEGRATED ASSESSMENTS

In this chapter, results from integrated assessments on mitigation scenarios are reviewed to estimate the contribution of CCS in achieving carbon emissions reduction targets. Apart from the contribution of CCS relative to other technology options, the costs associated with different mitigation portfolios are also presented. The uncertainty related to the assumptions incorporated in these assessments translates to the uncertainty regarding both the contribution and timing of CCS technology in a carbon mitigation portfolio. A few important assumptions are discussed, and some conditions that may negate their validity are also included in this chapter.

2.1 Role of CCS in a carbon mitigation portfolio

The estimated role of CCS technology in achieving targets of carbon emissions reduction varies based on the assumptions used to build different scenarios. One such assumption is the pace of development of CCS technology. The Australian Bureau of Agriculture and Resource Economics (ABARE) global model[1] that accounts for higher energy prices and CCS opportunities estimates that CCS shall account for 4.4 $GtCO_2$ of greenhouse gas (GHG) emissions avoided in 2030, which represents a 17% reduction from its reference base case (R.E.H. Sims *et al.*, 2007). In contrast, the Energy Technology Perspectives (ETP) report by the IEA estimated a 0.3 – 1.0 $GtCO_2$ contribution by CCS with regard to GHG emissions avoided in 2030. These results are consistent with the idea that the technology is to be demonstrated on a commercial scale before it can be deployed widely (R.E.H. Sims *et al.*, 2007).

Factors such as capital and operating costs for various technology options, perceptions of how these costs are expected to evolve, and the inclusion of externalities associated with carbon emissions (typically through a carbon price) determine the switch to mitigation technology options (R.E.H. Sims *et al.*, 2007). The uncertainty in the contribution of each mitigation technology option to emissions reduction targets is

[1] Based on an original version produced for the Asia Pacific Partnership - US, Australia, Japan, India, Korea

primarily determined by the uncertainty in two factors – the estimated cost of the technology option and the effective carbon price. Table 1 below indicates the mitigation potential, in percentage terms, of various technology options spread over a set of cost ranges. The entries in these cost ranges take into account the estimated range of mitigation costs associated with each option. To illustrate, CCS with coal and CCS with gas are viable technology options for mitigation at cost ranges of \$20 – 50/tCO_2 avoided and \$50 – 100/tCO_2 avoided respectively while nuclear may be viable at \$20/tCO_2 avoided or below. These numbers are based on the results presented in the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) published in 2007. Results from more recent studies are also presented in this chapter.

Table 1: Mitigation potential as a function of costs of CO_2 avoided (R.E.H. Sims et al., 2007)

	Regional groupings	Mitigation potential; total emissions saved in 2030 ($GtCO_2$-eq)	Mitigation potential (%) spread over cost ranges (US$/t$CO_2$-eq avoided)				
			<0	0-20	20-50	50-100	>100
Fuelswitch and plant efficiency	OECD	0.39		100			
	EIT	0.04		100			
	Non-OECD	0.64		100			
	World	**1.07**					
Nuclear	OECD	0.93	50	50			
	EIT	0.23	50	50			
	Non-OECD	0.72	50	50			
	World	**1.88**					
Hydro	OECD	0.39	85	15			
	EIT	0.00					
	Non-OECD	0.48	25	35	40		
	World	**0.87**					
Wind	OECD	0.45	35	40	25		
	EIT	0.06	35	45	20		
	Non-OECD	0.42	35	50	15		
	World	**0.93**					
Bioenergy	OECD	0.20	20	25	40	15	
	EIT	0.07	20	25	40	15	
	Non-OECD	0.95	20	30	45	5	
	World	**1.22**					
Geothermal	OECD	0.09	35	40	25		
	EIT	0.03	35	45	20		
	Non-OECD	0.31	35	50	15		
	World	**0.43**					
Solar PV and CSP	OECD	0.03				20	80
	EIT	0.01				20	80
	Non-OECD	0.21				25	75
	World	**0.25**					
CCS + coal	OECD	0.28			100		
	EIT	0.01			100		
	Non-OECD	0.20			100		
	World	**0.49**					
CCS + gas	OECD	0.09				100	
	EIT	0.04			30	70	
	Non-OECD	0.19				100	
	World	**0.32**					

At this juncture, it is important to note that nuclear technology and CCS are assumed to be close substitutes for base-load electricity generation in many scenarios of integrated assessments, i.e. when one is not available, the majority of generation is provided by the other rather than by renewable energy sources (Fischedick *et al.*, 2011). In a post-Fukushima world, there may be a higher level of uncertainty associated with the costs of nuclear technology due to increasingly higher safety requirements and the acceptability of the technology. It is, therefore, highly likely that the contribution of CCS is sensitive to the assumptions made about the costs and/or availability of nuclear as a mitigation technology option. With reference to Table 1, low-carbon electricity (1.88 $GtCO_2$-equivalent avoided in 2030) may need to be delivered by plants with CCS to meet a given emissions reduction target if there were strong resistance to nuclear technology.

Factors such as capital and operating costs (which may include externality costs as represented by a carbon price) also determine the competitiveness of one technology relative to another. This, in turn, defines the technology mix required to meet specific emissions reduction targets. As mentioned previously, the capital costs associated with relatively new technologies and how these are perceived to evolve over time determine whether investors choose one power generation technology over another. Unless the penalty on carbon emissions is high, the market will not choose power generation technologies with CCS. This is illustrated in a paper published by ExxonMobil for the Society of Petroleum Engineers Conference on CCS (Kheshgi *et al.*, 2010); the attractiveness of various power generation technologies is analyzed for a range of gas prices and carbon prices. With reference to Figure 2 below, systems with CCS become attractive at carbon prices of over \$70/tCO_2. The range of carbon prices prevailing in the market may be determined by the effectiveness with which carbon policies measures are executed.

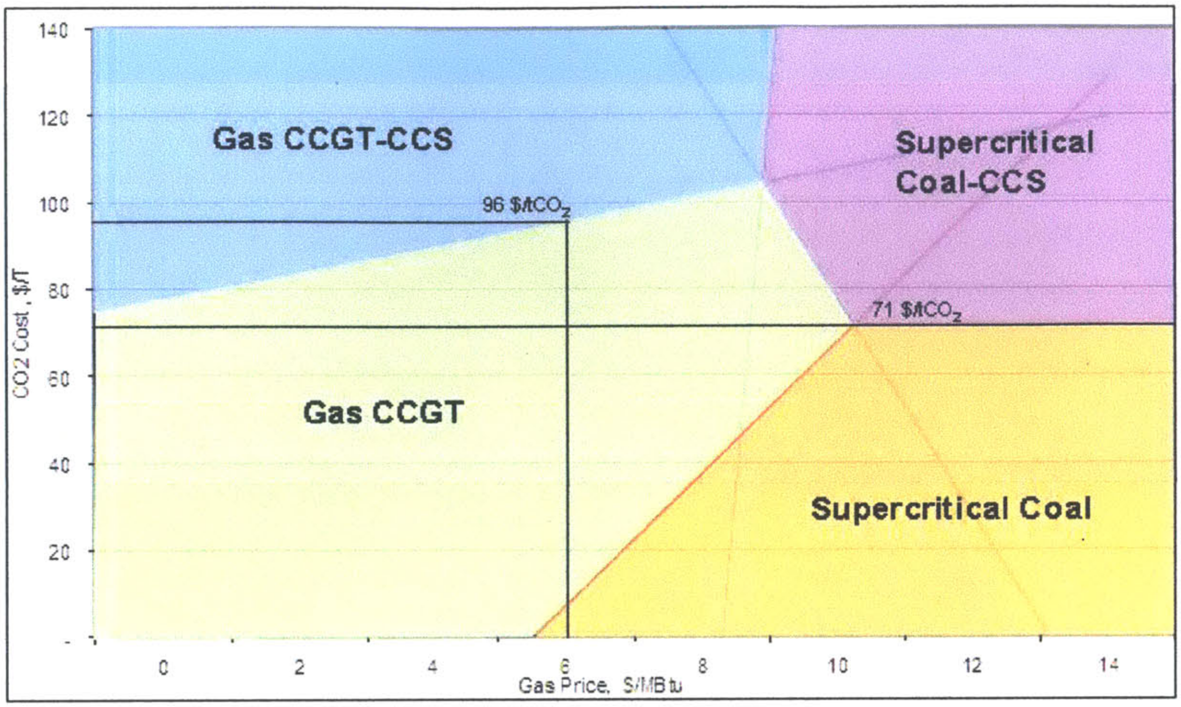

Figure 2: Competitiveness of technologies determined by various costs (Kheshgi et al., 2010)

Low gas prices are likely to generate either or both of these responses – generators choose to run their gas plants at higher capacity factors, and generators invest in gas plants over coal plants. With the shale gas revolution increasing the supply of inexpensive natural gas, both of these effects are observed; for the first time since the Energy Information Administration (EIA) began collecting data, generation from gas was essentially equal to that from coal in the U.S. in April 2012 (EIA, 2012), and no new coal-fired power plants are under development. At low gas prices, gas-based power generation systems (with and without CCS) are the clear choice for a wide range of carbon prices, as illustrated in Figure 2 above. Supercritical coal-fired plants are competitive with gas-based plants at a gas price of over $5 per million British thermal units (MMBtu). If power generation plants are subject to a carbon price, the gas price at which investment decisions tip in favor of supercritical coal-fired power plants increases with an increase in carbon price. Given that the carbon intensity of coal-fired power plants is higher than that of gas-based plants, these results are expected. Supercritical coal-fired power plants with CCS are only competitive at high gas and high carbon prices. There are considerations that complicate the above analysis. For example, gas prices are traditionally volatile while coal prices are stable, which could help coal better compete with gas.

2.2 Costs associated with different mitigation portfolios

The costs associated with different mitigation portfolios are examined in the IPCC's Special Report on Renewable Energy, and the results from various integrated models are compiled and compared in this report (Fischedick *et al.*, 2011). As illustrated in Figure 3 below, to meet a carbon emissions standard of 400 ppm, which is arguably impractical at this stage, the cheapest and most expensive mitigation portfolios are determined by the role that biomass plays in energy supply. Limiting the role of nuclear technology yields the second most expensive mitigation portfolio, but by less than half the costs of a portfolio that limits the role of biomass. In these models, mitigation costs are measured in terms of global gross domestic product (GDP) losses. Here, it is important to note that an emissions standard of 400 ppm cannot be achieved without the use of CCS or renewable energy in a carbon mitigation portfolio at any mitigation or adaption cost. Evidently, the more stringent the emission caps, the more important the role of CCS in a carbon mitigation portfolio.

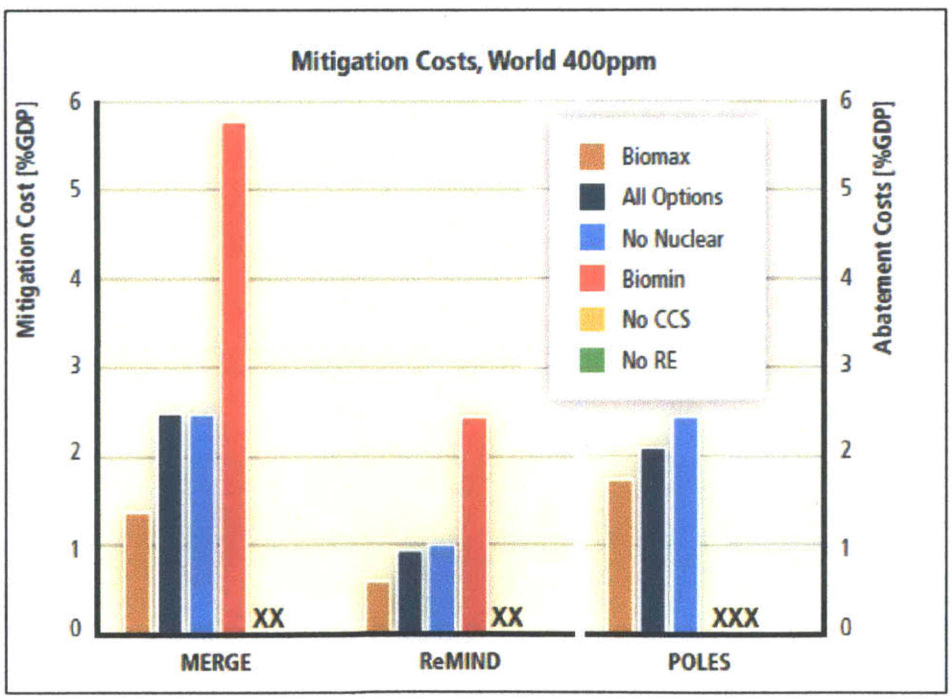

Figure 3: Mitigation/Abatement costs as a proportion of global GDP (for 400 ppm) (Fischedick et al., 2011)

Figure 4 below shows that a carbon emissions cap of 550 ppm can be achieved without CCS. However, mitigation costs associated with a portfolio that excludes CCS is the second most expensive portfolio after one that excludes renewable energy. In one integrated model (MERGE) these costs are estimated at more than twice the costs of portfolios that i) consider all options, ii) limit the role of nuclear technology, and iii) limit the role of energy from biomass. In another model (POLES), a technology mix that excludes CCS constitutes the most expensive portfolio; these abatement costs are measured in terms of the percentage of global GDP needed to deliver a given target. In these scenarios, mitigation is more expensive if CCS is not available.

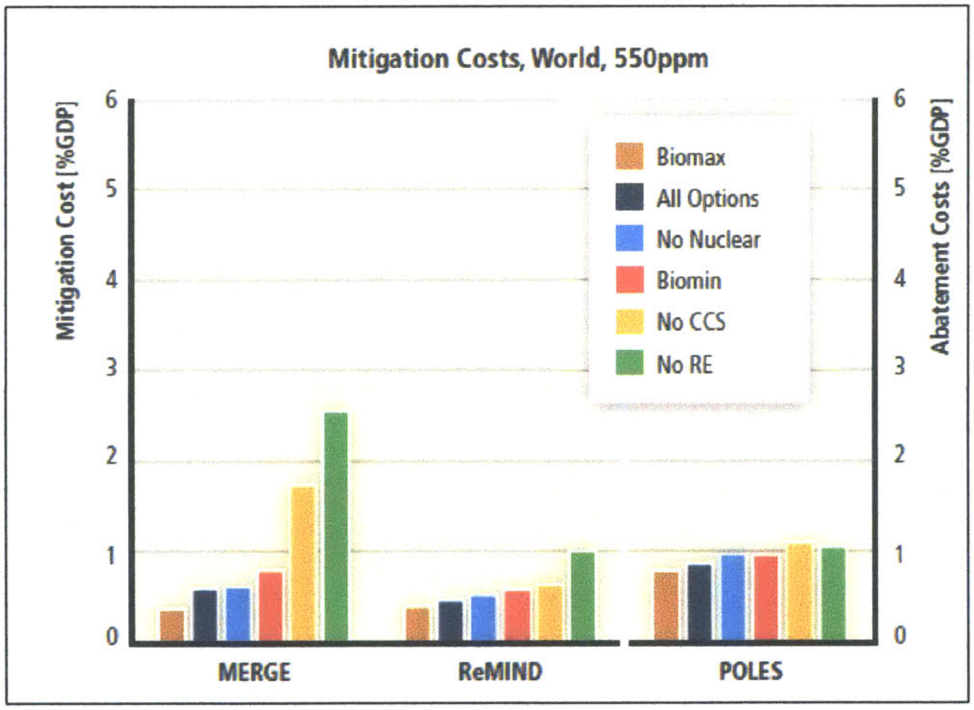

Figure 4: Mitigation/Abatement costs as a proportion of global GDP (for 550 ppm) (Fischedick et al., 2011)

2.3 Timing of CCS technology

Renewable energy technologies are expected to be the mainstay of the future supply of energy enabled by significant advancements in the conversion efficiencies of these technologies and in storage technology. In comparison, CCS is generally viewed as a transitional technology; it was expected that CCS technology will be deployed commercially from 2015 onwards, total capacity utilizing the technology will peak after

2050 as existing heat and power-plant stock is replenished, and deployment will decline thereafter (R.E.H. Sims *et al.*, 2007). In comparison, renewable energy is expected to become the dominant low-carbon energy supply option by 2050 in the majority of scenarios reviewed (164 scenarios from 16 different large-scale integrated models) in the IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation (Fischedick *et al.*, 2011). Some studies, however, suggest that there would be continued expansion of CCS capacity even towards the end of the century after deployment starting from 2015, and yet other studies suggest that there would be no significant use of CCS technology until 2050 (R.E.H. Sims *et al.*, 2007).

Differences in such results across studies may be attributed to differences in the assumptions about interrelated factors such as the costs of CCS relative to other technologies, how these costs evolve over time, the commercial availability of the technology, the policy incentives established by various governments, and the emissions reduction requirements that are imposed. To the latter point, it has been suggested that the use of CCS technology could result in negative emissions (net removal of carbon-dioxide from the atmosphere) when applied to biomass sources (R.E.H. Sims *et al.*, 2007), and therefore increase the attainability of low emission standards. As we continue operating on BAU mode, CCS may arguably become increasingly relevant to attain even less than ideal emission standards (550 ppm over 400 ppm for example).

The role of CCS may also be determined by how the fuel-mix of electricity is expected to evolve in regions with the largest emissions. For example, coal-based capacity is expected to play an increasing and significant role in supplying electricity in non-OECD Asia through 2035 (refer Appendix A). Considering that coal-fired power plants have a useful life of at least 40 years, the new capacity that will be added in 2035 may serve the region's needs until 2075. Assuming that reducing carbon emissions will continue to be important towards the end of the century, development of CCS technology is essential to ensure continued growth in this region. Therefore, it may be argued that the role of CCS is likely to be more than just transitional.

3. DESCRIPTION OF THE EPPA MODEL

In this chapter, the EPPA Model, which is a computable general equilibrium model (CGE), is described in detail. A description of how mitigation technologies available to the electric power sector are modeled is included in this chapter, which explains the factors that determine the competitiveness of one mitigation technology relative to another. The construction of the base case scenarios that represent two kinds of policy responses is explained in the latter half of this chapter.

3.1 Emissions Prediction & Policy Analysis (EPPA) Model (Palstev *et al.*, 2005)

The EPPA model is a recursive-dynamic multi-regional general equilibrium model of the world economy. It is designed to estimate economic growth and anthropogenic emissions of GHG under BAU assumptions and under specific carbon policies such as an emissions cap or carbon tax. Similar to other economic simulation models that are categorized as CGE models, EPPA represents the circular flow of goods and services in the economy. Capital and labor inputs flow from consumers to producers, who, in turn, provide goods and services to consumers. Consumers make payments for goods and services to producers, who, in turn, use revenues to provide returns to labor (in the form of wages) and capital to consumers. The government acts as a passive entity to ensure that savings by consumers are invested in producers, and that taxes collected by the government are used for the consumers' benefit.

The circular and closed nature of the model implies that all revenues generated in each production sector are allocated to consumers as their return on capital or wages, to intermediate producers, and/or to the government as taxes. Similarly, the costs of all inputs, capital, and labor are reflected in the price of the good produced by a specific sector. A basic feature of the EPPA model is the elasticities of substitution between various inputs of production that allow producers to make tradeoffs between these inputs in response to changes in price of these inputs, the availability of cheaper technology etc. Similarly, consumers can substitute between goods and services when there are exogenous shocks to the economy. For example, considering that a carbon policy increases the price of fossil fuels, the degree to which the cost of production increases depends on the share of energy as an input to production, the carbon content of energy used, and the ability to substitute to less carbon-intensive inputs or technology. The degree to which consumers' are able to substitute goods or services that are more carbon intensive to goods that are not, also depends on the elasticities of substitution between the two goods and how the prices of these goods change as a result of the carbon policy. Therefore, these elasticities of substitution are important determinants of the cost of carbon policies such as a carbon price or emission caps.

Data that describe the economy of each region in the base year 1997 (refer Appendix B for regions and sector represented in EPPA), including national income and product accounts and data on inter-industry flows of goods and services, are used to create Social Accounting Matrices (SAMs). These SAMs determine the structure of the EPPA model. To capture the dynamics of the economy through time, EPPA assumes that savings and investment are based only on the current period, and these are optimized within a given period. The model also contains data on calorific values of various fuels and their carbon emissions to determine which sectors are most affected by carbon policies. Further, technological change, which is an important source of growth of any given economy, is modeled in three ways: i) there is an exogenous augmentation of supplies of capital and labor, ii) the energy use per unit output decreases exogenously over time, and iii) the model includes a class of technologies referred to as backstop technologies which are available for use when fossil fuel resources begin to deplete or when a carbon policy increases the price of energy from fossil fuels. The solution to the EPPA model is one that maximizes consumer welfare and producer profits subject to the technologies of production, the availability of factors of production, and other constraints imposed by policies such as a carbon price.

3.2 Mitigation & other technologies for electricity generation (Ereira, 2010)

Mitigation technologies (or backstop technologies) are available for use when fossil fuel resources are depleted and/or when a carbon policy increases the cost of existing technologies relative to mitigation technologies. The share of factor endowments of capital, labor, land, fuel, and other factors that are required for production defines these existing and mitigation technologies. In addition, mitigation technologies are also defined by their mark-up, which are defined as the ratio of the levelized cost of electricity (LCOE) for a given mitigation technology to the LCOE of traditional coal-fired generation. The mark-up factors for mitigation technologies used in electricity production are given in subsequent section. Together, the shares of various factor endowments and the mark-up factors determine the competitiveness of one technology relative to another as the price of inputs change.

Various production sectors including the electricity sector are described using nested constant elasticity of substitution (CES) functions (see Figure 5). Vertical lines in the input nest imply that the elasticity of substitution between these inputs is zero. Terminal nests with '…' indicate the same aggregation structure for imported goods as detailed in the energy intensive (EINT) sector. Conventional crude oil (OIL) is modeled as an internationally homogenous good i.e. the OIL produced in each region is a perfect substitute for OIL produced in other regions. As illustrated in the figure below, conventional fossil, nuclear, hydro, and mitigation technologies (expect wind and solar) are perfect substitutes for each other subject to the constraint of resource availability. Solar and wind are treated as imperfect substitutes (defined by the elasticity of substitution σ_{EWS}) on account of their intermittent nature. Fossil fuel generation technologies are represented as one technology with fuel substitution between coal, oil, and gas. Such a representation takes into account the value of each of these technologies for base load, intermediate, and peak generation.

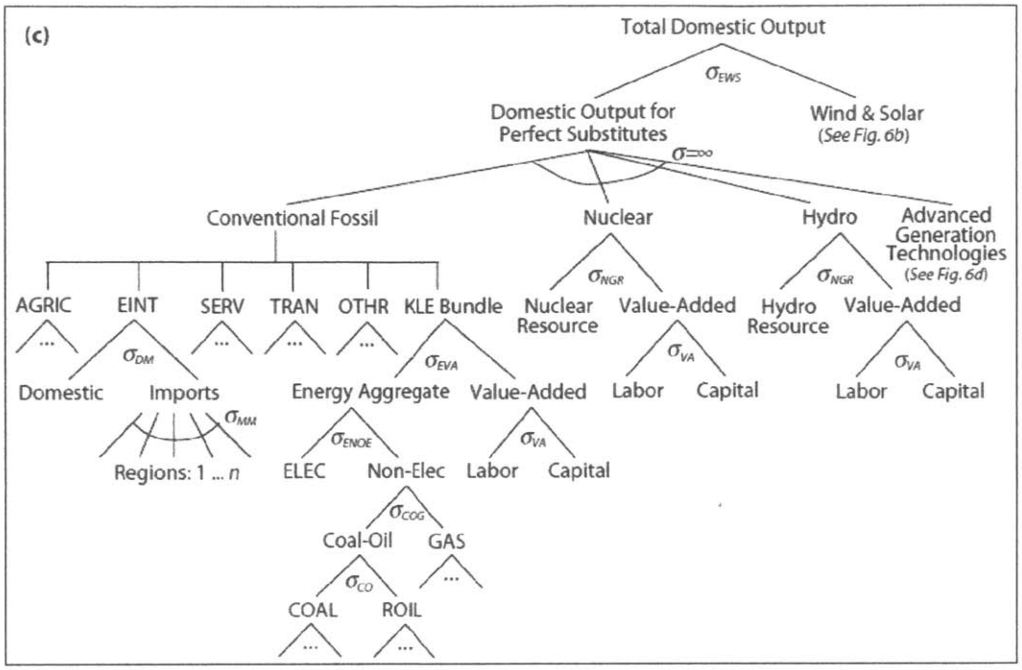

Figure 5: Structure of electricity sector in EPPA (Palstev et al., 2005)

Mitigation technologies such as bioelectric, wind, and solar include an additional fixed factor to slow penetration of these technologies in the marketplace (Figure 6); this is added to simulate the slow capacity addition of a new technology as it competes with incumbent technologies. Transmission and distribution (T&D) costs are implicitly included in the capital cost of these technologies. In practice, however, the entire cost of extending transmission and distribution to remote wind and solar farms is seldom passed on to the developer because these costs are likely to be prohibitive. Therefore, T&D costs that are included in capital costs most likely account for extensions to the substation closest to the wind farm or solar power plant.

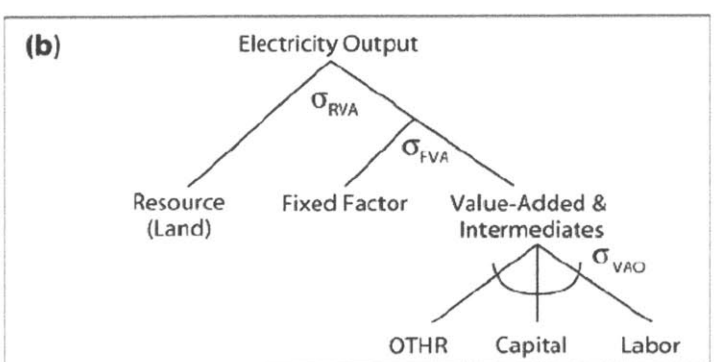

Figure 6: Structure of bioelectric, wind, and solar technologies (Palstev et al., 2005)

Mitigation technologies that store carbon are described using the nested structure in Figure 7. As mentioned earlier, the vertical lines for T&D and generation & storage imply that the elasticity of substitution between theses inputs is zero. Similarly, the share of inputs for fuel, generation, and storage cannot be substituted for one another. Carbon permits and generation & storage are defined by elasticity of substitution σ_{PT}. The capture rate, which is defined at 90% in the base year, is a variable. Together, these two factors imply that the capture rate increases when the price of carbon permits increases relative to the price of electricity because it becomes economical to capture more carbon. This structure of the electricity sector and that of various mitigation technologies define how the electricity mix changes in response to a carbon policy.

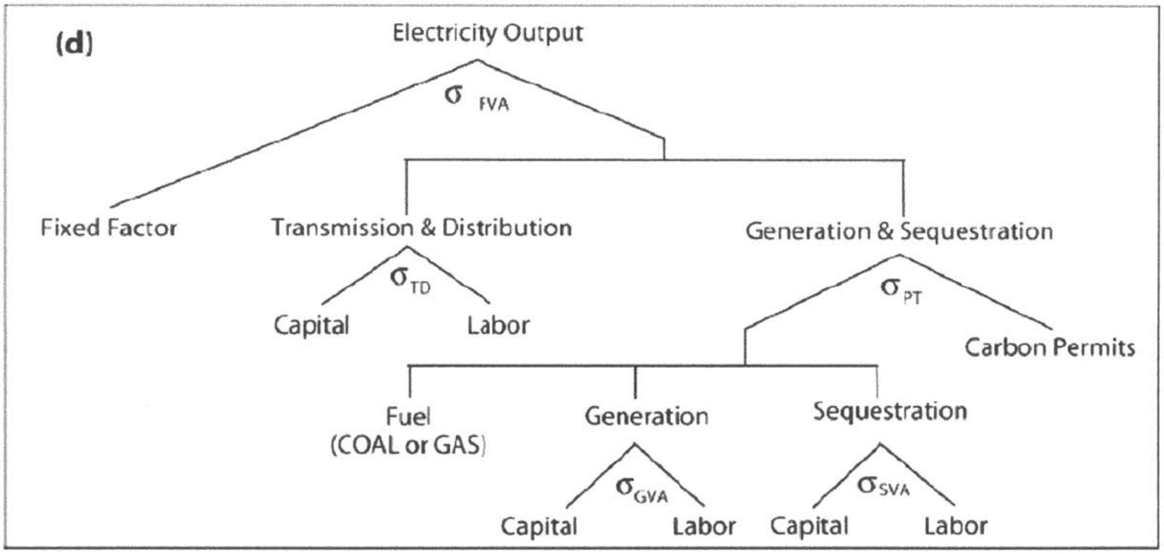

Figure 7: Structure of storage technologies (Palstev et al., 2005)

3.3 Updating markup factors

The methodology used to calculate the markup factors for mitigation or backstop technologies is consistent with that in Morris *et al.* (2010). Data from the EIA's Annual Energy Outlook (AEO) 2013 Early Release (AEO, 2013) is used to derive these markup factors. Data on overnight capital cost, fixed operation and maintenance (O&M) costs, variable O&M, and heat rate are sourced from the AEO 2013 and presented in Table 2 below. The total capital requirement is estimated by accounting for escalation during the period of construction. Assuming a discount rate of 8.5% and a project life of 20 years, a capital recovery rate is calculated. This recovery rate is used to estimate the amount of capital that is to be recovered annually. The assumptions of capacity factors are consistent with those used in Morris *et al.* (2010). Fuel costs are also sourced from the EIA; a 6-year average for the price of coal and natural gas is considered (EIA, 2012a). The markup factors for natural gas based technologies are also calculated when the 3-year average price is considered, which yields a value of \$4.85/MMBtu versus \$6.27/MMBtu in the 6-year average case. The prices for uranium and biomass are consistent with data in Morris *et al.* (2010).

The cost of CO_2 transport, storage, and monitoring (TS&M) for CCS is technologies estimated at \$10/tCO_2 in Hamilton (2009). This data is compared to a study published by the DOE (2010), wherein CO_2 TS&M costs are estimated, and presented in terms of mills per kilowatt-hour (mills/kWh). When the DOE estimates were converted to yield CO_2 costs in \$/tCO_2 terms, the values were lower than \$10/tCO_2. Considering that TS&M costs are subject to high variability on account of site-specific factors, the higher value of \$10/tCO_2 is maintained for calculation of markup factors. Relevant escalation factors were applied to reflect prices in 2011-dollar terms (BEA, 2013). The costs of capital recovery, fixed and variable O&M, fuel, and TS&M are then calculated in \$/kWh terms, and added up to give total levelized costs. The ratio of the LCOE of each technology in the table below to that of Pulverized Coal is calculated to determine the markup factor associated with each technology.

Table 2: Markup factors used for analysis

	Pulverized Coal	*NGCC*	*NGCC with CCS*	*NGCC*	*NGCC with CCS*	*IGCC with CCS*	*Advanced Nuclear*	*Wind*	*Biomass*
"Overnight" Capital Cost (\$/kilowatt (kW))	**2883**	**1006**	**2059**	**1006**	**2059**	**3718**	**5429**	**2175**	**4041**
Construction time (years)	4	3	3	3	3	5	5	2	4
Total Capital Requirement (\$/kW)	3344	1127	2306	1127	2306	4462	7601	2349	4688
Fixed (f) O&M (\$/kW)	**30.6**	**15.1**	**31.2**	**15**	**31**	**50.5**	**91.7**	**38.9**	**103.8**

Variable (v) O&M ($/kWh)	**0.004**	**0.003**	**0.007**	**0**	**0**	**0.007**	**0.002**	**0.000**	**0.006**
Project Life (years)	20	20	20	20	20	20	20	20	20
Capital Recovery Charge Rate (%)	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%
Capacity Factor (%)	85%	85%	80%	85%	80%	80%	85%	35%	80%
Operating Hours (hours)	7446	7446	7008	7446	7008	7008	7446	3066	7008
Capital Recovery Required ($/kWh)	0.047	0.016	0.035	0.016	0.0348	0.07	0.11	0.08	0.0707
Fixed O&M Recovery Required ($/kWh)	0.004	0.002	0.004	0.002	0.004	0.007	0.01	0.01	0.01
Heat Rate (Btu/kWh)	**8740**	**6333**	**7493**	**6333**	**7493**	**7450**	**10452**	**0**	**13500**
Fuel Cost ($/MMBtu)	1.94	6.27	6.27	4.85	4.85	1.94	0.72	0.00	1.17
Fuel Cost ($/kWh)	0.017	0.040	0.047	0.031	0.036	0.015	0.008	0.000	0.016
Cost of CO_2 TS&M ($/kWh)			0.004		0.004		0.007		
LCOE	**0.073**	**0.061**	**0.097**	**0.052**	**0.086**	**0.103**	**0.130**	**0.094**	**0.107**
Markup Over Coal	**1.00**	**0.84**	**1.33**	**0.71**	**1.18**	**1.42**	**1.78**	**1.28**	**1.47**

The base year in the EPPA model used for analysis is 1997. Therefore, all costs were represented in 1997-dollar terms, and the markup factors were recalculated. They were estimated to be the same as those indicated in Table 2.

3.4 Construction of base case scenarios

Despite efforts to mitigate climate change through the ratification of the Kyoto Protocol, carbon emissions have been on the rise. It is, therefore, arguable that carbon policy implementation is likely to be delayed i.e. countries shall continue to operate in BAU mode and delay the effective implementation of carbon emission caps. Therefore, to analyze the role of CCS in reducing carbon emissions, the current state of carbon policy implementation needs to be accounted for. A representative emissions reduction scenario is considered wherein emissions caps are implemented from the year 2010 onwards. To incorporate delay in policy implementation, two cases are considered – implementation of emission caps are delayed by 10 years and 20 years i.e. they are only implemented from the year 2020 or 2030 onwards. From these points of implementation, two kinds of policy responses are considered:

***Floating emission caps*:** Operating in BAU mode for 10 or 20 additional years implies higher emissions in those periods when compared to emissions under the representative scenario, which is defined as a 'No Delay' scenario. The first kind of policy response does not attempt to compensate for inadequate action at present i.e. policymakers do not attempt to reduce the impact of higher emissions in earlier periods by imposing stricter caps in later periods. The 10-year or 20-year delayed emissions pathway represents a fairly fixed deviation from the representative pathway starting from the point of implementation. The emission caps under delays are constructed such that the ratio of the emission cap in year 't+1' to that in year 't' is the same as that in the 'No Delay' scenario. The representative emissions pathway along with the ones representing a 10-year or 20-year delay in implementing emissions caps are illustrated in Figure 8 below.

Under floating emission caps, emissions increase as the policy implementation is delayed. This is apparent in Figure 8 below given that the area under the emissions curve increases as the delay in implementation of emission caps increases from 10 years to 20 years. The costs associated with increasing emissions and related impacts, however, are beyond the scope of the results presented in this thesis.

Figure 8: Policy response I - Floating Emissions Caps

Strict emission caps: In this policy response, an attempt is made to compensate for higher emissions in earlier periods by imposing stricter emission caps in later periods. The delayed emission pathways are constructed such that the total emissions under the curve are the same for all emission pathways i.e. total emissions under all three curves from 1997 to 2100 is the same. In order to ensure that i) total emissions remain the same, and ii) the emissions pathways represent a reasonable version of a carbon policy, the emission caps allow for initial increases and become progressively more stringent. It may be argued that such a pathway accounts for the development of low carbon technologies to make them more competitive with existing technologies. The representative emissions pathway, along with those that pertain to 10 and 20-year delays in this policy response, are illustrated in Figure 9 below.

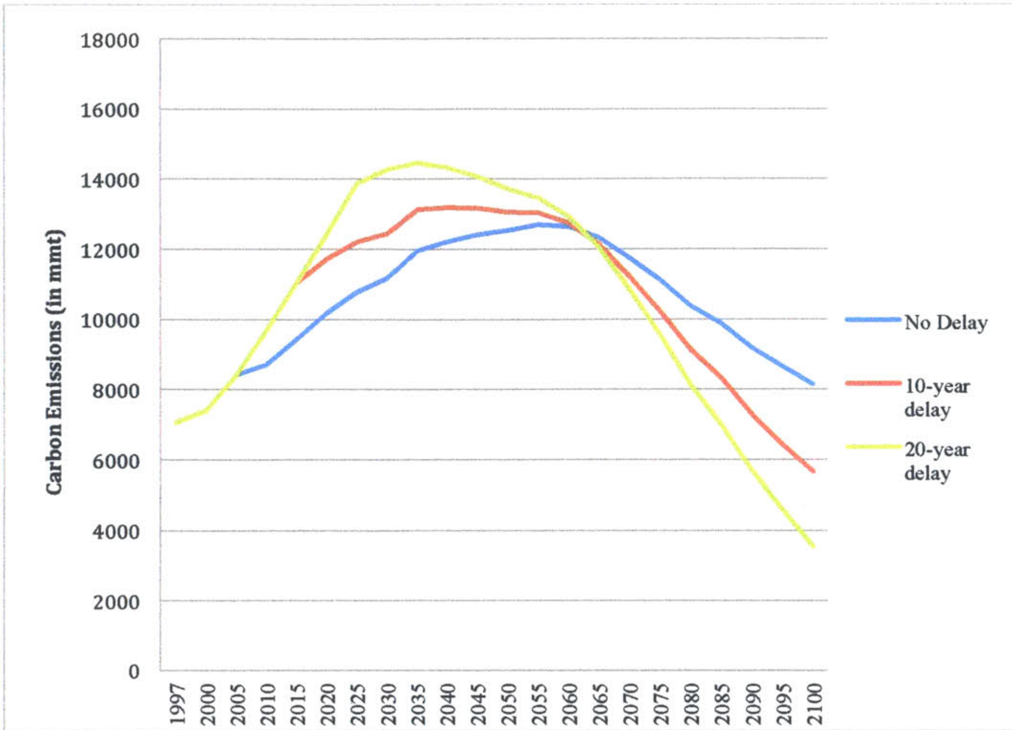

Figure 9: Policy Response II - Strict Emission Caps

4. RESULTS FROM ANALYSIS USING EPPA

The expected generation from CCS and shadow carbon prices under base case policy scenarios (Case 1a and 1b), cases with the exclusion of advanced nuclear technology (Case 2a and 2b), and cases with inexpensive generation from natural gas in addition to the exclusion of advanced nuclear technology (Case 3a and 3b) are discussed in this chapter. The conditions in cases 2 and 3 are created by rendering advanced nuclear technology a non-viable option and by reducing the mark-up factors associated with natural gas-based electricity to reflect 3-year average cost, see Table 2. All cases are outlined in Table 3 below. Then, the global electricity-mix and its evolution are analyzed for specific cases. The latter section of this chapter includes a discussion on limitations of results and policy implications.

Table 3: Differences between cases analyzed

Assumptions built into case (Across)	Base Case	No Advanced Nuclear	Inexpensive Gas-based Generation	Floating Emission Caps	Strict Emission Caps
Case 1a	✔			✔	
Case 1b	✔				✔
Case 2a		✔		✔	
Case 2b		✔			✔
Case 3a		✔	✔	✔	
Case 3b		✔	✔		✔

The initial hypothesis of the role of CCS under these policy responses is – i) the role of CCS is diminished when emissions caps are allowed to be less stringent, and ii) is enhanced when any attempt is made to compensate for higher emissions in early periods. This hypothesis is tested in the base case and under conditions of non-availability of advanced nuclear technology and inexpensive electricity from natural gas.

4.1 Base case policy scenarios

In Case 1a, the amount of generation that needs to come from plants with CCS reduces as policy implementation is delayed, see Figure 10. The generation reduces from approximately 0.8 trillion kWh in 2100 in the 'No Delay' scenario to less than 0.5 trillion kWh in the same year in the '20-year Delay' scenario, which is a nearly 40% reduction.

The stringency of emission caps determines whether the market will substitute towards clean energy technology options such as CCS. Therefore, the above result is expected given that the emission caps become less stringent as implementation is delayed. CCS enters the electricity mix in the latter half of the century, and therefore, may not play a transitional role in an emission reduction strategy.

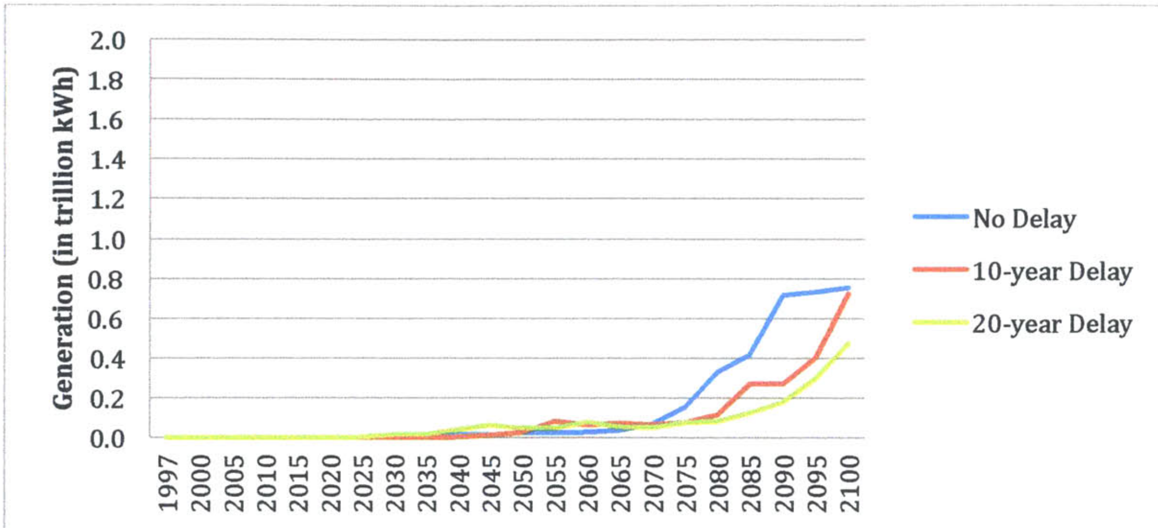

Figure 10: Generation from CCS – Case 1a

Given that the emission caps become less stringent, the shadow carbon price needed to support these caps also reduces from the 'No delay' to the '20-year delay scenario' in Case 1a. With reference to Figure 11, the shadow carbon price is approximately \$340 and \$220/tCO_2 in 2100 in the 'No delay' and '20-year delay' scenarios respectively. This represents a nearly 35% decrease in the shadow carbon price, which renders CCS less competitive when compared to other mitigation technologies.

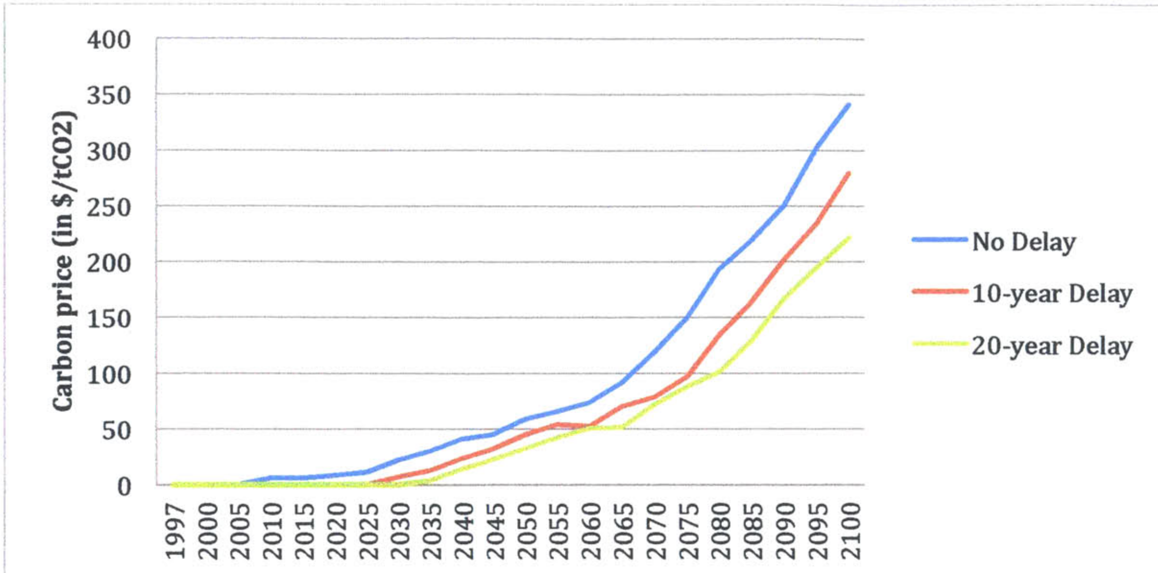

Figure 11: Shadow Carbon Price – Case 1a

In Case 1b, the amount of generation that needs to come from CCS increases as policy implementation is delayed. The generation from CCS in 2090 in the '20-year delay' scenario is more than double the generation in 2100 in the 'No delay' scenario. The generation in the '20-year delay scenario' then reduces in the last decade because emission caps in 2095 and 2100 are stringent enough to necessitate the shutdown of some plants with CCS, refer Figure 12. The generation in the '10-year delay' and '20-year delay' scenario are, therefore, nearly the same in 2100. Even in the case of strict emission caps, CCS enters the electricity mix in the latter half of the century. In addition, with each 10-year delay in policy implementation, significant generation from CCS is advanced. To elaborate, the generation from CCS crosses the 0.2 trillion kWh mark earlier as the delay in implementation increases. Evidently, the generation from CCS becomes more relevant under stricter emission caps.

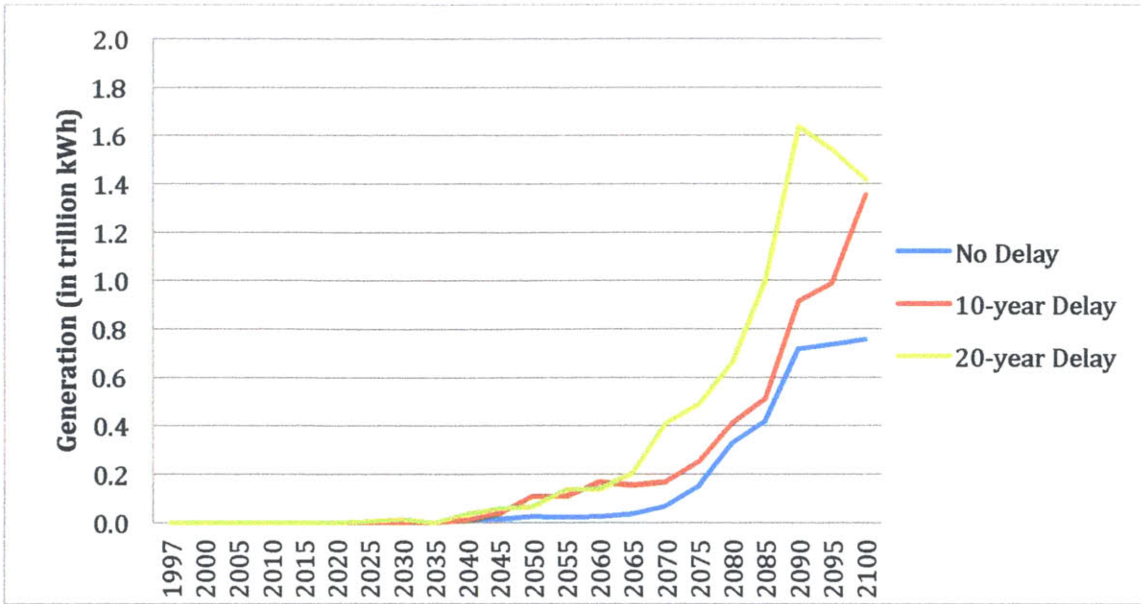

Figure 12: Generation from CCS – Case 1b

The shadow carbon price needed to support emission caps that get progressively more stringent increases exponentially, as illustrated in Figure 13. This effect is observed both in the '10-year delay' and the '20-year delay' scenarios. Here, it is important to note that in the '20-year delay' scenario, the emission cap in 2100 results in emissions that are approximately half those in base year 1997. Therefore, the shadow carbon price needed to support such a steep cut in emissions is likely to be high, about \$8960/tCO_2 in 2100. In the '10-year delay' scenario, the carbon price rises to about \$1050/tCO_2 in 2100. While it is unlikely that such a steep cut in emissions is enforced, it is evident that compensating for higher emissions in periods of no or ineffective policy becomes more expensive the longer the delay in implementing a carbon policy.

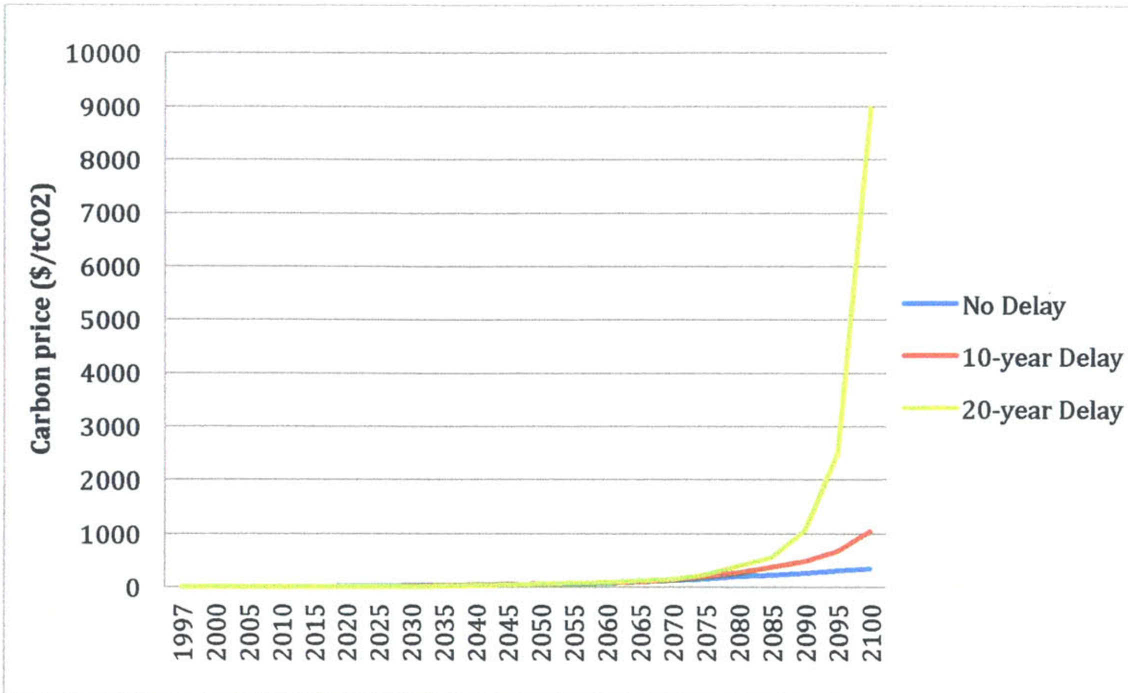

Figure 13: Shadow Carbon Price – Case 1b

4.2 Exclusion of advanced nuclear as a mitigation technology

When advanced nuclear technology is excluded from a portfolio of mitigation technologies, the generation from plants with CCS typically substitutes for generation that would have come from advanced nuclear power plants. With reference to Figure 14, the amount of generation that comes from plants with CCS increases by an order of magnitude when advanced nuclear technology is excluded. In Case 2a, the generation from CCS increases to nearly 30 trillion kWh in 2100 in the 'No delay' scenario. In the 'No delay' scenario in Case 1a, advanced nuclear supplies approximately 40 trillion kWh in 2100. Therefore, CCS substitutes for a significant proportion of the generation that would have come from advanced nuclear power plants. Furthermore, when deployment of advanced nuclear capacity is curtailed, CCS technology enters the electricity mix earlier than it does in Case 1a.

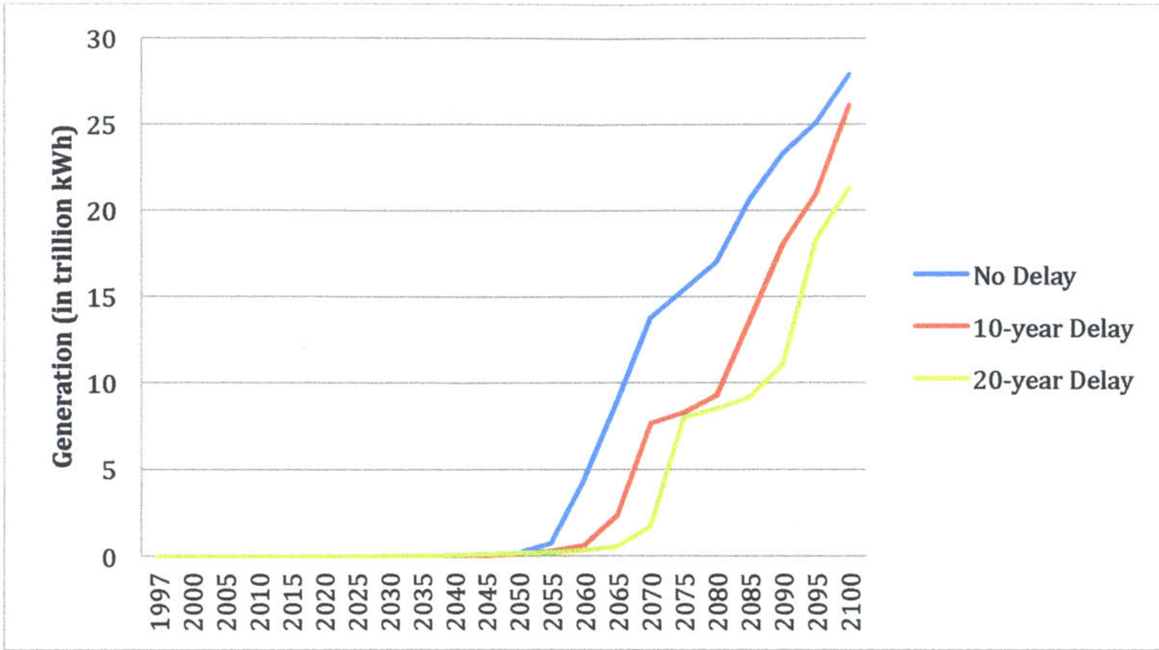

Figure 14: Generation from CCS – Case 2a

In Case 2b, the generation from CCS in all three scenarios is nearly the same at 25 trillion kWh by 2095. This implies that even though the entry of CCS in the electricity mix is delayed in the '10-year delay' and '20-year delay' scenarios, plants with CCS may need to contribute significantly to the electricity mix by the end of the century. In this case, therefore, delaying implementation of policy implies that CCS capacity may need to be ramped up faster to meet the prescribed emission caps. In addition, it is important to note that when the generation from nuclear is curtailed, CCS needs to contribute at least 20 trillion kWh in 2100 regardless of whether policymakers choose strict or floating emission caps, see Figure 14 and Figure 15.

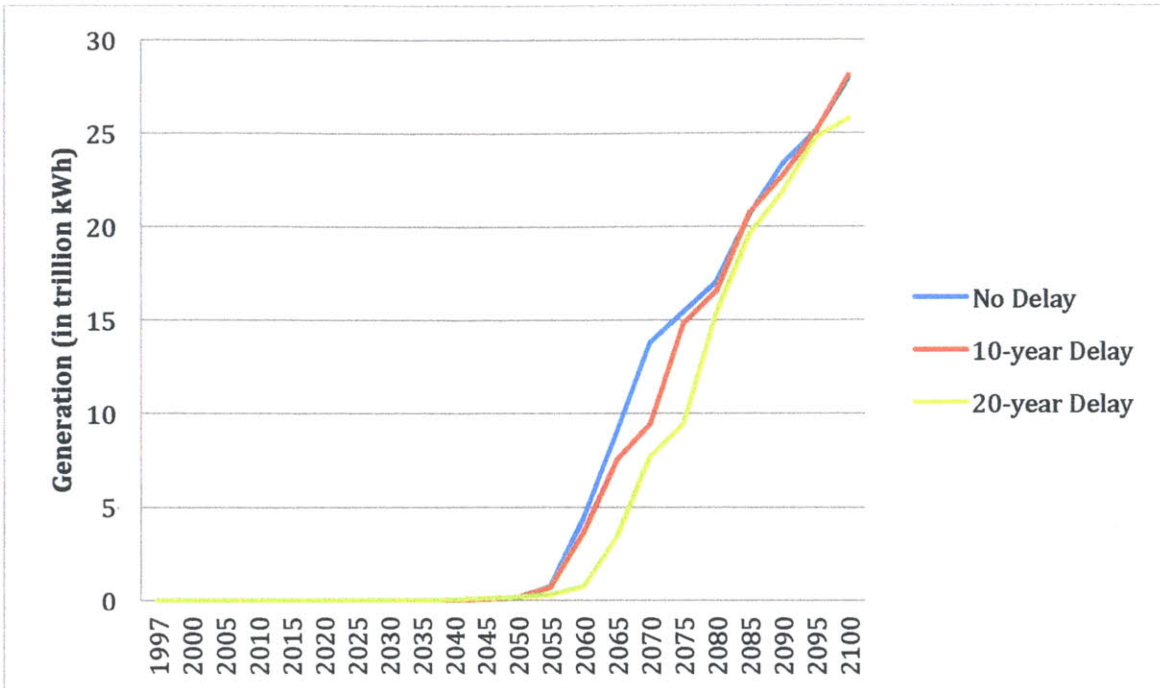

Figure 15: Generation from CCS – Case 2b

With reference Figure 16 and Figure 17, the carbon prices needed to support caps in Case 2a and 2b are very similar to those in the Case 1a and 1b respectively, with prices being slightly higher when advanced nuclear technology is excluded. From these results, the following inferences are made – i) emissions reduction is more expensive when there are fewer low carbon technologies available and ii) advanced nuclear and CCS are close substitutes for technologies that can meet the demands of low carbon energy economy. Considering that endogenous factors that determine the competitiveness of one technology vis-à-vis another are uncertain at this stage, it is difficult to make an argument for investment in one technology over another. However, the availability of either as a low carbon technology in the latter half of the century is contingent on investment in both technologies in the present.

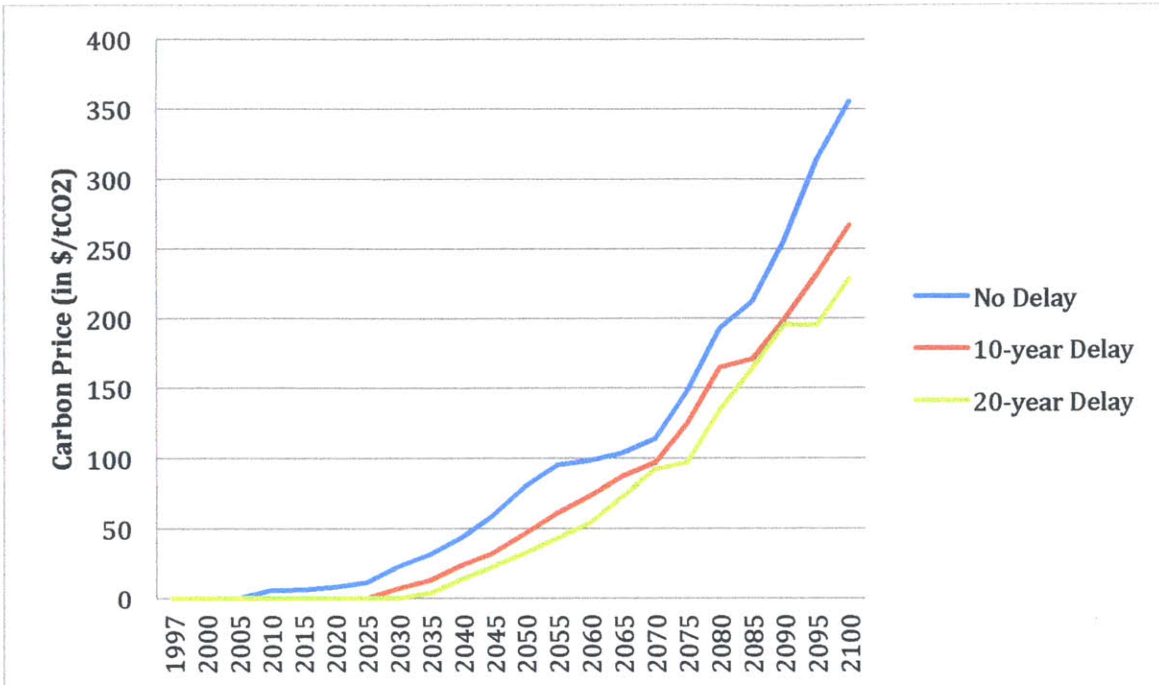

Figure 16: Shadow Carbon Price – Case 2a

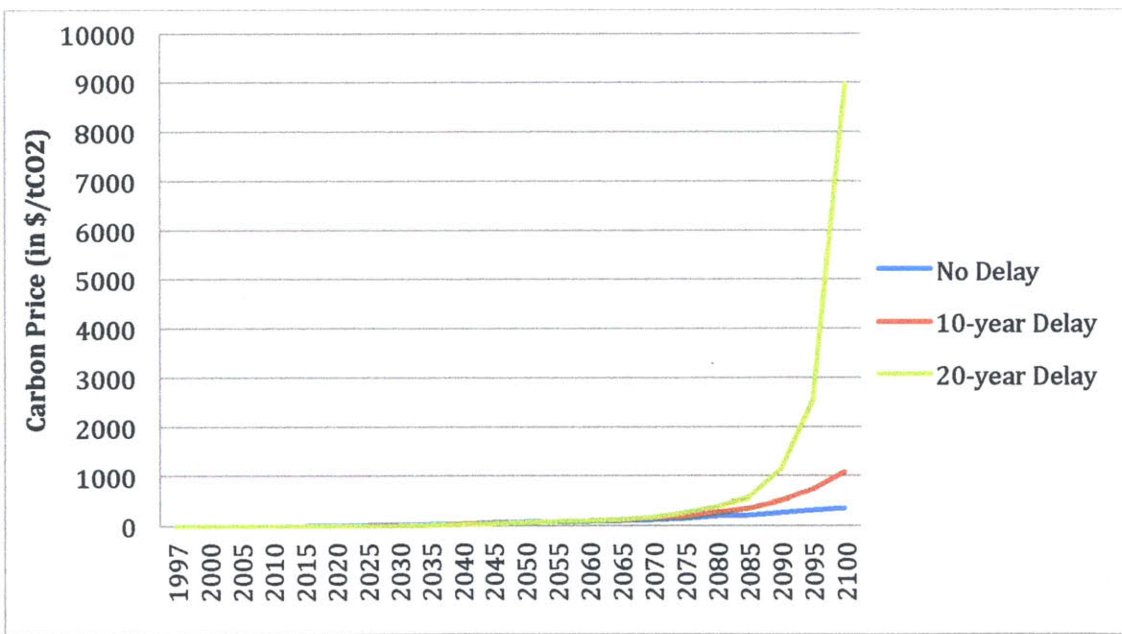

Figure 17: Shadow Carbon Price – Case 2b

4.3 Exclusion of advanced nuclear and inexpensive gas-based generation

The generation from CCS in all scenarios in case 3a compared with those in case 2a is lower (see Figure 18 and Figure 14, respectively). Similar trends are observed when

Figure 19 and Figure 15 are compared for analysis on case 3b and case 2b. However, it is important to note that i) the reduction across scenarios is no more than 20%, and ii) CCS needs to contribute at least 20 trillion kWh in 2100 under most policy responses. Therefore, while the use of inexpensive gas-based generation reduces the burden on CCS technology, it does not eliminate the need for CCS in the latter half of the century.

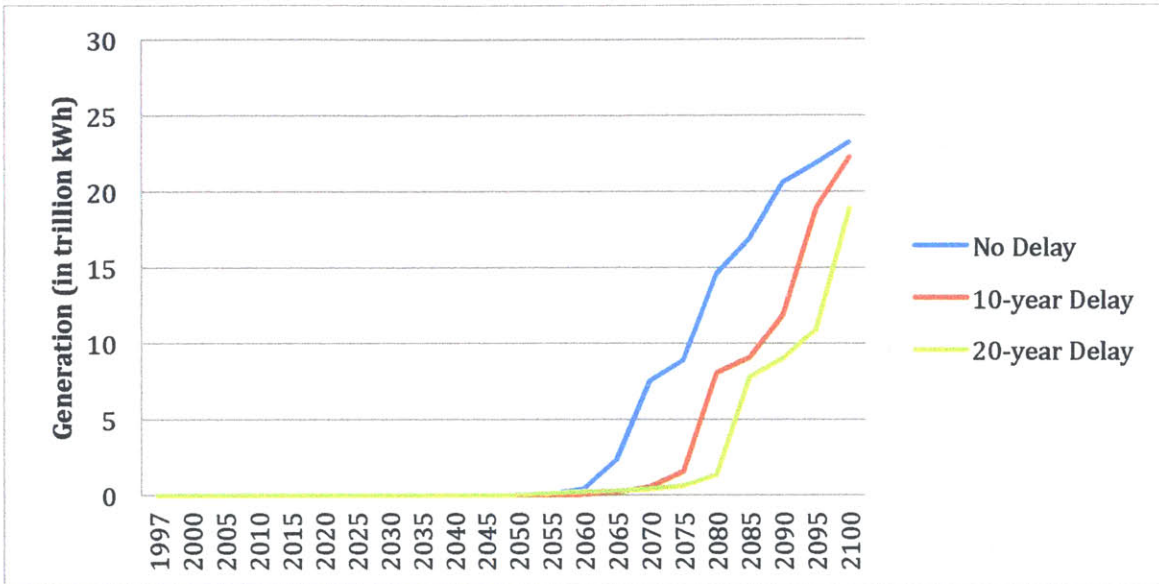

Figure 18: Generation from CCS – Case 3a

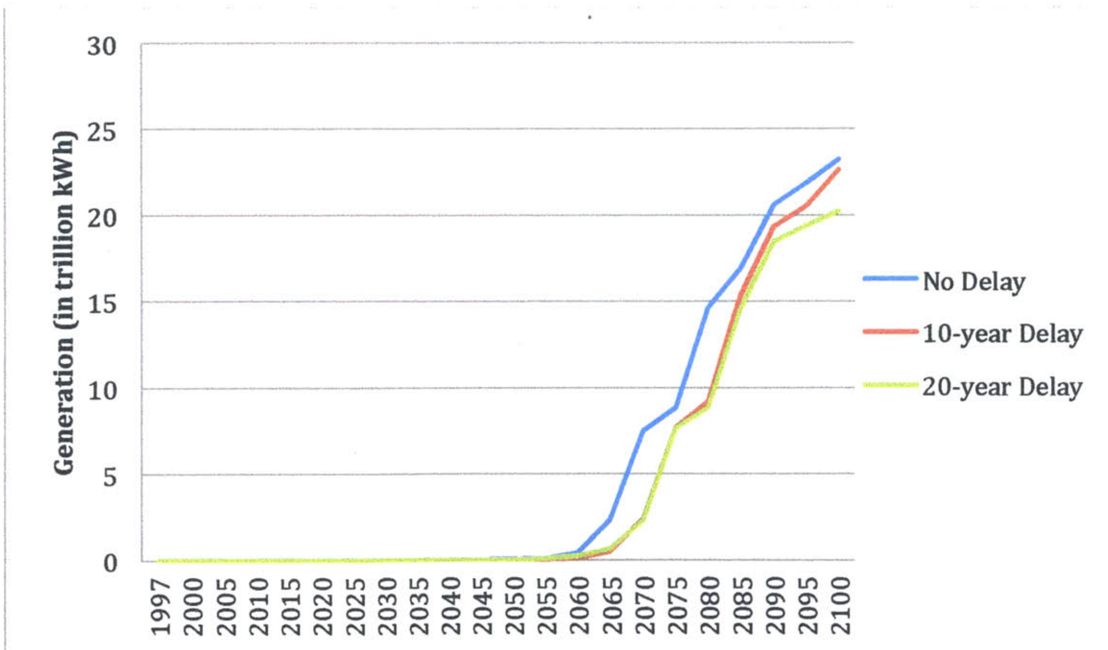

Figure 19: Generation from CCS – Case 3b

When gas-based generation becomes inexpensive, the overall cost of emissions reduction is expected to reduce because lower shadow carbon prices are needed to enable deployment of natural gas combined cycle (NGCC) plants. However, when the transitional gains in emission reduction from fuel switching delay the entry of other low carbon technologies, the cost of reducing emissions may be higher. There is some evidence of this effect when results on shadow carbon prices in Cases 2a and 3a (see Figure 16 and Figure 20, respectively) are analyzed. The carbon prices in 2100 in the 'No Delay' scenario and '10-year delay' scenario are higher for a portfolio wherein gas-based generation is cheaper. A similar trend is observed in cases 2b and 3b i.e. the carbon prices in the same year in the 'No delay' and '10-year' scenarios are higher in case 3b when compared to case 2b (see Figure 17 and Figure 21, respectively).

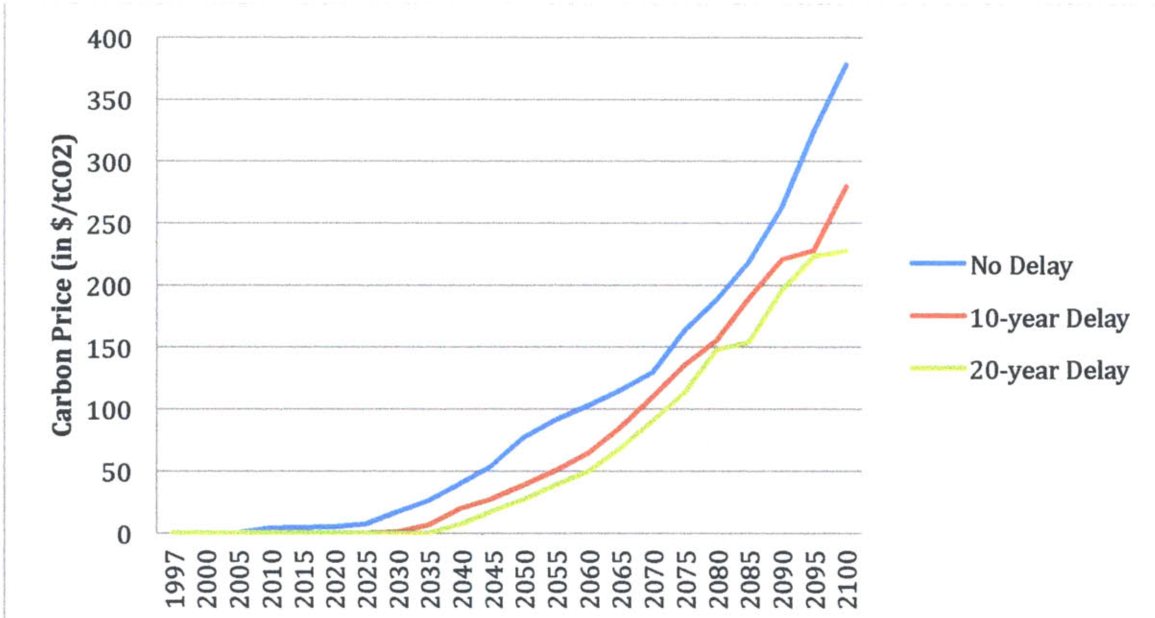

Figure 20: Shadow Carbon Price – Case 3a

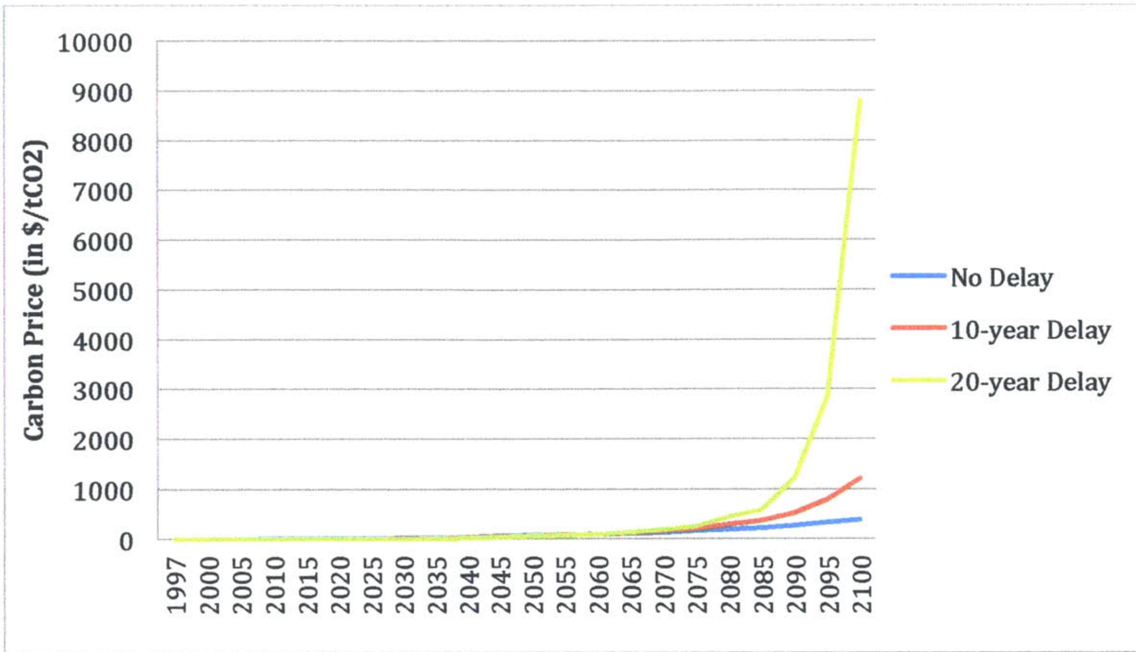

Figure 21: Shadow Carbon Price – Case 3b

4.4 Global electricity-mix and its evolution

With reference to the markup factors derived using data in the AEO (2013) and presented in Table 2, it is evident that NGCC is more economical when compared to pulverized coal-based generation. Therefore, NGCC may displace fossil based generation to become the dominant technology in a low carbon energy economy. This is supported by trends observed the U.S. energy sector today – significant gas-based capacity is being added and existing gas plants are being operated for longer hours. Analyzing the global electricity mix and its evolution in the cases above may also help determine the role of NGCC vis-à-vis other low carbon technologies.

The global electricity mix for the 'No delay' scenario (same for cases 2a and 2b), and the '10-year delay' scenario in cases 2a and 2b are presented in Figure 38, Figure 39, and Figure 41 in Appendix C. The following trends emerge – i) inexpensive gas-based generation is likely to displace fossil-fuel based generation, which is primarily coal-based, and the degree of displacement is determined by the stringency of emission caps, and ii) the role of inexpensive gas-based generation is likely to be transitional, and the magnitude of its contribution is determined by the stringency of emission caps.

Therefore, even with the availability of inexpensive gas-based generation, a low carbon technology such as CCS or advanced nuclear is required to meet the demands of a low carbon economy in the latter half of the century.

4.5 Policy implications

With reference to Appendix C, the contribution of one low carbon technology compared to another in a low carbon electricity mix is sensitive to the markup factors associated with these technologies. The uncertainty related to technology-specific factors that determine a low carbon technology's competitiveness translate into the uncertainty related to its contribution to emissions reduction. Policymakers, therefore, have the challenging task of making decisions under uncertainty to impact outcomes in the long-term. By incorporating the most current information on costs and performance of various low carbon technologies, an attempt has been made to better estimate the role of CCS vis-à-vis other technology options.

On a related note, large-scale penetration of renewables is concomitant with intermittency and related issues. While, contending with these challenges effectively may require significant advancements in storage technology and grid operation, current levels of penetration are managed through the use of significant reserve capacity. It is yet to be determined how the regulations pertaining to electricity markets allocate these imposed costs. Consequently, additional costs may be imposed on renewable capacity even if the technology becomes competitive with technologies that can be dispatched. The true costs of renewable generation, therefore, are difficult to estimate. Considering that the EPPA model does not account for grid-level effects of adding renewable capacity, the penetration of renewables is limited. Furthermore, it may be argued that the limited role of renewables is consistent with the idea that technologies such as advanced nuclear or CCS are more compatible with the electric power system without requiring many significant changes to the way it is operated. While the impact of potentially disruptive technologies cannot be ruled out, the analysis presented in this chapter incorporates information available today.

As discussed earlier, the role of inexpensive gas-based generation is likely to be transitional with a technology such as CCS or advanced nuclear meeting the demands of low carbon economy in the latter half of the century. Therefore, it may be imperative that the gains from fuel-switching are managed effectively, and resources be allocated to the development of other low carbon technologies. Notwithstanding the limitations discussed above, the role of CCS is estimated to be i) more important when emission caps become more stringent, and ii) dominant in the latter half of the century if advanced nuclear technology cannot be deployed on a large-scale. To ensure that a technology like CCS is available as a viable option in the future, resources need to be allocated for its development in the present.

PART B: Analysis of CCS Project Economics

5. STATUS & COSTS OF CCS DEMONSTRATION PROJECTS

Considering that the development of CCS may be essential to meeting the demands of a low carbon economy, especially in the latter half of the century, it is imperative that the factors contributing to the success or cancellation of a demonstration project be examined. This chapter is designed to provide sufficient background on the analysis of the economics of demonstration projects through a case study-based approach. First, the state of CCS development in various industrial countries or regions in the world is outlined. Then, project cost estimates for power plants with CCS are collated from various studies and compared to the estimates of ongoing demonstration projects. Insights from a RAND study, which outlines the reasons for cost escalation in demonstration projects using new technologies, may be applicable to CCS because the integration and subsequent application of capture and storage technologies is yet to be demonstrated. As cost escalation leading to poor project economics has been cited as an important reason why projects were cancelled, a discussion on relevant results from the RAND study is also included in this chapter.

5.1 State of CCS technology development

CCS is currently in the demonstration phase of technology development with several projects under development and construction. The demonstration phase of technology development typically is the most expensive stage of the innovation pipeline. Apart from the capital-intensive nature of these projects, generators are limited by what they are willing to invest at this stage because of the uncertainty in climate policy. Therefore, government assistance to facilitate further development of the technology is required. To that end, the United States Congress appropriated nearly $6 billion dollars since FY'08 for CCS research, development, and demonstration (RD&D) at the Department of Energy's (DOE) Office of Fossil Energy; approximately $3.4 billion of the above amount comes from the American Recovery & Reinvestment Act (ARRA) of 2009, and nearly all of the ARRA funds are allocated to demonstration projects as indicated in Table 4 below (Folger, 2012). Projects are developed under three programs:

i) FutureGen, which is a large-scale demonstration project developed by a consortium of leading power generators, ii) Clean Coal Power Initiative (CCPI), a DOE program that supports large-scale power projects, and iii) Industrial CCS Projects (ICCSP) which deploys CCS technology on industrial plants.

Table 4: Funding of demonstration projects in the U.S. (Folger 2012)

(funding in $ thousands, FY2008-FY2013)

Program	FY2008	FY2009	Recovery Act	FY2010	Restructured Program after FY2010a	FY2011	FY2012 (enacted)	Totals (FY2008-FY2012)	FY2013 (request)
FutureGen	72,262	0	1,000,000	0	FutureGen 2.0	0	0	1,072,262	0
Clean Coal Power Initiative (CCPI)	67,444	288,174	800,000	0	CCS Demonstrations	0	0	1,155,618	0
Industrial Carbon Capture and Storage Projects			1,520,000	0		0	0	1,520,000	0

The experience from demonstrating CCS on power plants is more valuable because power plants account for a significant proportion of CO_2 emissions. In the US alone, emissions from electricity generation accounted for over 40% of total emissions of 5439.3 teragrams ($TgCO_2$) equivalent in 2010 (EPA, 2012). This, in turn, justifies greater support for demonstration projects in the power sector. However, power projects are more complex and therefore more expensive. Consequently, the projects developed under CCPI encountered more challenges than the industrial projects under the ICCSP. Table 5 below provides a list of power projects developed under Round 3 of CCPI that used CCS technology (Folger 2012). Three out of the six projects listed below were withdrawn.

Table 5: DOE's CCPI Round III Projects (Folger 2012)

CCPI Round 3 Project	Location	DOE Share of Funding ($ millions)	Total Project Cost ($ millions)	Percent DOE Share	Metric Tons of CO_2 Captured Annually (millions)	Project Status
Texas Clean Energy Project	Penwell, TX	450	1,727	26%	2.7	Active
Hydrogen Energy California Project	Kern County, CA	408	4,008	10%	1.8 or 2.5	Active
NRG Energy Project	Thompsons, TX	167	334	50%	0.4	Active
AEP Mountaineer Project	New Haven, WV	334	668	50%	1.5	Withdrawn
Southern Company Project	Mobile, AL	295	665	44%	1	Withdrawn
Basin Electric Power Project	Beulah, ND	100	387	26%	0.9	Withdrawn
Total		**1,541**	**7,789**	**19.8%**	**8.3**	
Total, Active Projects[a]		**812**	**6,069**	**13.4%**	**4.9**	

a. Total include amounts that were reallocated from withdrawn projects to active projects.

Similar outcomes are observed with CCS projects in the EU. On 9th November 2010, the European Commission announced the allocation of 300 million emission unit allowances (EUA) to large-scale demonstration projects using CCS technology and innovative renewable energy projects (NER300) (Bellona, 2010). At the time, these EUAs were valued at €4.5 billion or at the floor price of €15/EUA. However, with the establishment of new rules for EUAs, the floor price of €15/EUA no longer applies (Commodities Now 2012). The quantum of total funding has, therefore, reduced from €4.5 billion to less than half that amount with EUAs currently trading at approximately €6 in the spot market (European Energy Exchange, 2013). In addition to a reduction in the total quantum of funding (Lupion and Herzog, 2013), many of the projects that applied for the NER300 funding mechanism faced other hurdles to execution, which resulted in their inevitable cancellation.

5.2 Factors contributing to economics of CCS demonstration projects

Many CCS demonstration projects supported by governments in industrialized nations have been withdrawn or cancelled in the recent past. Figure 22 provides a small sample of projects that are being developed under policies such as the ARRA 2009, NER300 etc., and their current statuses. As illustrated in Figure 22, there is correlation between the type of storage proposed for the project and its cancellation. Projects using enhanced oil recovery (EOR) for storage are less likely to be cancelled when compared to power projects that do not have a secondary source of revenue.

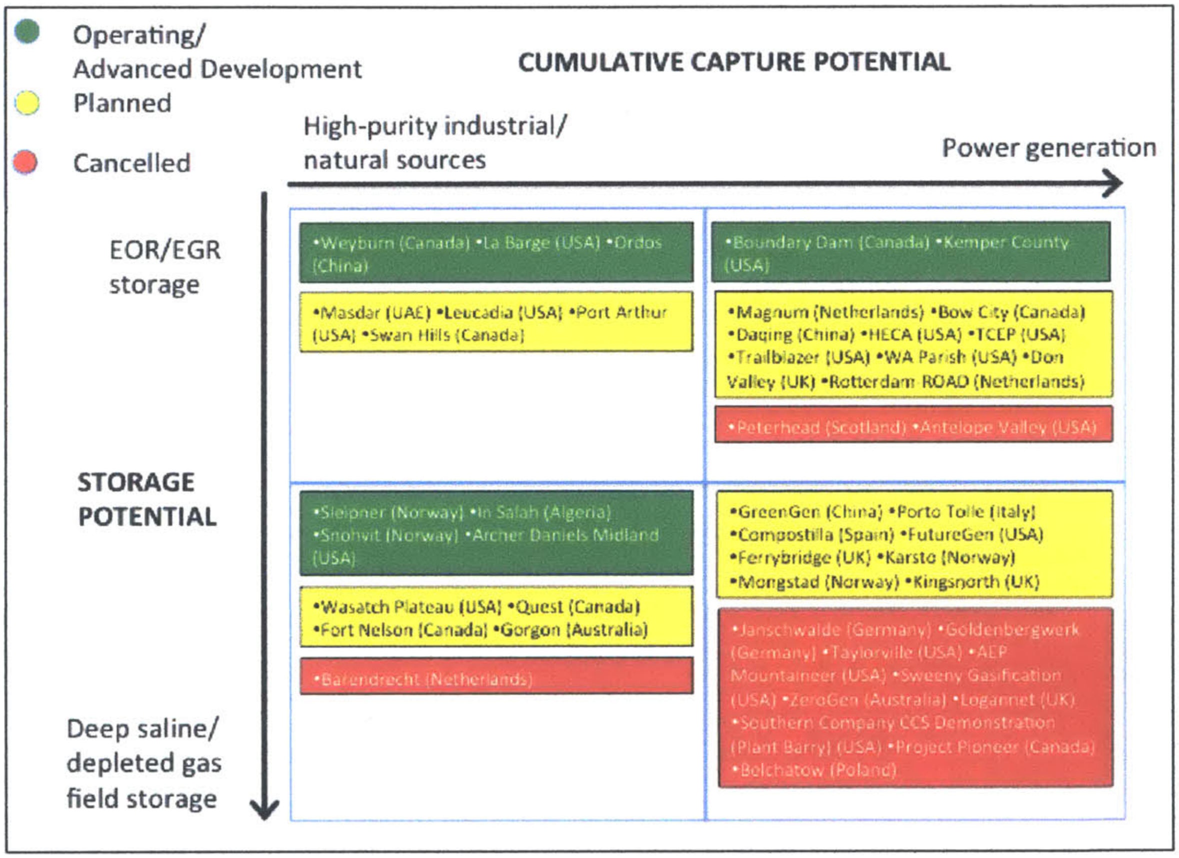

Figure 22: Sample of CCS demonstration projects and their statuses (MIT, 2013)

Factors contributing to the cancellation of or to the uncertainty associated with a sample of projects surveyed in Figure 22 (refer Appendix D) may be categorized into monetary and non-monetary. Monetary reasons include escalating project costs, the lack of monetary support from the federal and/or state governments, the lack of an overarching climate policy, and the lack of additional revenue streams such as EOR. In general, the projects that relied on solely one revenue stream such as a rate-based pay or assumed that a carbon price would be a second revenue stream have tended not to progress beyond the stage of a feasibility study. Non-monetary reasons include the lack of political will (which may manifest itself as lack of funding), inadequate legal or regulatory framework, local opposition to the project, opposition from environmental groups, existing risk exposure through involvement in similar projects, disagreements between companies forming the project company, and the general economic climate. The Schlumberger Business Consulting (SBC) Energy Institute conducted a survey of private developers of CCS projects and found that 89% of respondents believed that most projects suffered from poor economics because there was no existing market for the technology and that federal grants were insufficient to support these capital-intensive projects (SBC, 2012). On a related note, 73% of respondents said that the uncertainty arising from the lack of a climate mitigation policy, an unclear framework for storage, and the tendency to substitute towards natural gas-based capacity were also significant challenges to the development of projects.

5.3 Nth-of-a-kind (NOAK) & first-of-a-kind (FOAK) estimates of project costs

Given the stage of development of CCS technology, the cost estimates for projects that are currently under development (first-of-a-kind) are significantly higher than the estimates for projects that will be developed once the technology is commercially demonstrated (nth-of-a-kind). Typically, FOAK estimates are derived from NOAK estimates; costs that are likely to be unique to demonstration projects such as higher design and engineering costs, higher contingencies etc. are accounted for to arrive at FOAK estimates. As inferred from Table 6, the estimates of NOAK costs for plants with and without CCS do not differ significantly across studies for most technologies. The biggest difference is observed in the estimates for an integrated gasification combined cycle (IGCC) plant with CCS. Considering that IGCC is a relatively new technology, there is a higher degree of uncertainty with regard to cost estimates for a plant that uses IGCC technology with CCS.

Table 6: Nth-of-a-kind costs of power plants with and without CCS

Parameter (Unit)	*IGCC w/o*	*IGCC*	*SCPC w/o*	*SCPC*	*NGCC w/o*	*NGCC*
DOE Baseline Studies (DOE, 2010)						
Total overnight cost TOC ($/kW)	2716	3904	2024	3570	718	1497
O&M - (f) - $/kW p.a.	85	117	59	97	22	42
O&M - (v) mills/kWh	7.8	9.9	5.0	8.7	1.3	2.6
Global CCS Institute (GCCSI, 2011)						
Total overnight cost TOC ($/kW)	2618	3413	1921	3440	711	1447

The Global CCS Institute (GCCSI) estimates the investment costs for a large-scale CCS demonstration project to be in the range of at least $5000 - $6000/kW (GCCSI, 2012). A study conducted by the Belfer Center at the Harvard Kennedy School provides a cost estimate in terms of the impact of adding CCS on the cost of electricity (COE), which is estimated at a premium of least $0.08/kWh. The details of both studies are presented in Appendix E. The implied impact of the premium on the capital cost, to yield FOAK estimates, is presented in Chapter 8. Deriving generic FOAK cost estimates from relevant NOAK estimates in a manner such that these estimates are useful for decision makers is challenging for the following reasons – The costs associated with i) conditions that are specific to the project site such as remoteness, the infrastructure at the site, the compensation for local inhabitants, the availability/proximity of resources such as fuel and water, and the ambient environmental conditions, ii) the owners' requirements such as office buildings and compliance with local regulations, and iii) other soft costs such as legal and financing costs cannot be accounted for accurately in studies of this nature. Furthermore, projects under execution are subject to volatility in the inflation and exchange rates, and geological risk associated with storage. These factors, in turn, make it more likely that the project costs are underestimated at the early stages of project execution leading up to the start of construction. Therefore, a margin of error of +/- 40% is typically given to the estimates provided in such studies.

The project costs of various CCS demonstration projects, sourced from government websites, Front End Engineering Design (FEED) studies, news sources, and various databases, are catalogued in Appendix F. The estimated project cost for projects listed in Appendix F is plotted as a function of their capacities in Figure 23 below.

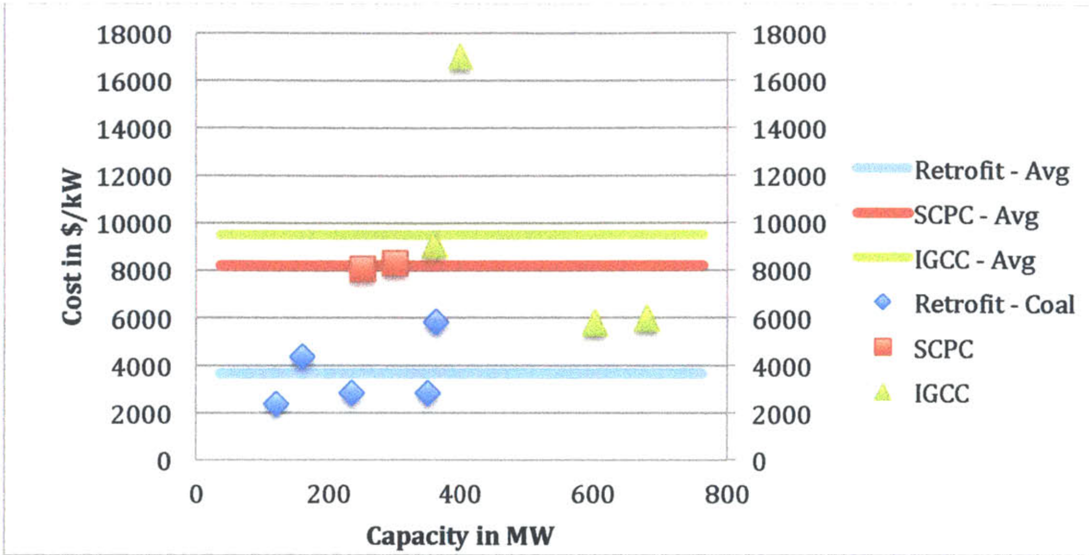

Figure 23: Estimated cost of demonstration projects as a function of capacity

With reference to Figure 23, while new supercritical pulverized coal-fired (SCPC) power plants appear to be cheaper than IGCC power plants, it is important to note that the cost of the cancelled project, ZeroGen, is an outlier that is increasing the average cost of IGCC plants. The costs of SCPC plants and IGCC plants would be approximately the same (between \$7000 - \$8000/kW) when the ZeroGen project is not considered. In addition, the project cost of retrofit plants is about less than half that of new SCPC plants (\$4000/kW).

5.4 RAND study & relevant results (Merrow *et al.*, 1981)

The objective of a study conducted by the RAND Corporation on synthetic fuel plants was to examine the factors that adversely affect cost estimations and plant performance. This section focuses on the results pertaining to cost estimations, and draws parallels to CCS demonstration projects wherever relevant. The hypothesis of the paper is that the greater the deviation from previously established or existing commercial systems, the larger the cost growth or escalation. A plant's technology deviates from the norm in the following ways: i) new chemical conversion steps, ii) new equipment, iii) new feedstock, and iv) large scale-up of previously used equipment. The paper also hypothesizes that cost growth declines as the completeness of plant definition increases.

Data on cost estimates at different stages of project development, the physical character of the plant, various measures of technological change, and measures of project development are collected from 44 different synthetic fuel plants. The dependent variable, cost growth, is defined as the ratio of an estimate of project cost to the actual project cost. The study defines five classes of estimates depending on which stage of development the estimate was provided at; Class 0 is provided at the R&D stage, class 1 at the stage of project definition, class 2 when 30% of detailed engineering is completed, class 3 at the end of detailed engineering, and class 4 is provided during construction.

Various independent variables are tested first for correlation with cost growth, the dependent variable, and then for statistical significance. The equation given below was found to be the most robust model to estimate variation in cost growth. PCTNEW is defined as a measure of the percentage of capital investment made in technology unproven in commercial use. COMPLEXITY is a count of the number of continuously linked process steps or block units used in the plant. INCLUSIVENESS is a measure of the percentage of the following three items included while making an estimate – i) land purchase/leases/property rentals, ii) initial plant inventory/warehouse parts/catalysts, and iii) pre-operating personnel costs. The variable, PROJECT DEFINITION, was constructed using the average of the site information variables and adding a level-of-engineering variable to it. PROJECT DEFINITION ranged from 2 (maximum definition) to 8 (no definition). For each estimate in the dataset, PROCESS INFORMATION was measured in the following manner – if most of the process information is obtained from small-scale laboratory experiments or literature, or if a coordinated R&D program is underway, the assigned value was 1. If either a demonstration unit or sufficient data to start the design on a commercial scale were available, or if the major process uncertainties were resolved, the assigned value was 0. The variable IMPURITIES ranged from 0 to 5, and is a measure of the extent to which impurity buildup was a significant source of design problems in the early stages of project development; 0 indicated that no problems occurred and 5 indicated impurities were a major source of problems during the early design stage.

COST GROWTH = A – B1*PCTNEW – B2*IMPURITIES – B3*COMPLEXITY + B4*INCLUSIVENESS – B5*PROJECT DEFINITION – B6*PROJECT DEFINITION*PROCESS INFORMATION

COST GROWTH = 1.12196 – 0.00297*PCTNEW – 0.02125*IMPURITIES – 0.01137*COMPLEXITY + 0.00111*INCLUSIVENESS – 0.04011*PROJECT DEFINITION – 0.02350*PROJECT DEFINITION*PROCESS INFORMATION

All the coefficients of the independent variables listed in the above model are statistically significant, and interpreted in the following manner. Each 10% of the capital cost invested in new technology reduces the cost growth ratio by approximately 3% i.e. the higher the percentage of investment in new technology, the less accurate the project cost estimate is likely to be. For every unit increase in the count of process steps, the cost growth ratio (and therefore the accuracy of the estimate) decreases by approximately 1.14%. If accurate measures of cost elements such as land lease cost, pre-operating personnel cost, and inventory/warehouse costs are included in the cost estimate, the cost growth ratio increases by 0.1% i.e. the estimate is more accurate because it is closer to the actual project cost. With a decrease in the degree of project definition (value of variable increases from 2 to 8), the cost growth decreases by approximately 4% i.e. the estimate of cost is lower or less accurate. Further, if the process information for the plant is sourced from lab experiments or early R&D, the lack of project definition reduces the accuracy of the cost estimate by an additional 2.35%. The basic conclusion of the study, therefore, is that the greater the degree of uncertainty associated with the technology in use in a project, the higher the likelihood that the early estimates for project cost are biased toward underestimation.

All the variables discussed above are relevant for a demonstration plant that uses CCS. Prior to FEED studies, the project definition for a CCS demonstration plant is likely to be lower compared to plants that use commercially available technology because many aspects of the technical design and site-specific data can only be included during the FEED study. In addition, the process information for an integrated CCS plant is derived from smaller demonstration plants, which adds to the degree of inaccuracy of the project cost estimate when the project definition is low. Further, in most demonstration projects using CCS, upwards of 50% of the capital cost is invested in new technology. These factors, in turn, may lead to grossly inaccurate pre-FEED estimates of the project cost.

Financial support from governing bodies, however, is typically announced on the basis of early project cost estimates. As seen in the case of both Longannet and the ZeroGen project, governing bodies were compelled to withdraw support for the project because the estimates of project cost post a FEED study (or pre-feasibility study in the case of ZeroGen) were significantly higher than the initial estimates. Therefore, it may be recommended that governing bodies set aside a fund to support FEED studies for projects that are applying for financial support, and grant the financial awards on the basis of the results of the FEED study. This may reduce the likelihood that demonstration projects get cancelled due to escalating project costs.

6. ZEROGEN – A CASE STUDY IN COST ESCALATION

6.1 Project history (Ashworth *et al.*, 2011)

In March 2006, ZeroGen Proprietary Limited (ZeroGen) was incorporated as a subsidiary of Stanwell Corporation Limited, a company that had conducted extensive research on low-emission electricity generation. In March 2007, the ownership of ZeroGen was then transferred to the Queensland State government, and it allocated funds of over AU$100 million for the pre-feasibility study and the operational expenses of the company. Through this project, the Queensland government expected to further its strategic intent to preserve Queensland's competitive advantage as a power generator and to ensure the continued mining, use, and export of Australian black coal. In response to the Clean Coal Council's recommendation that the development of a commercial-scale IGCC plant with CCS be accelerated, ZeroGen was reconfigured into a two-stage project – 120 megawatt (MW) (gross) IGCC plant with CCS in 2012, and a plant of 450 MW (gross) using the same technology in 2017. A pre-feasibility study and an Environmental Impact Statement (EIS) were initiated for Stage I of the project.

During the development of Stage I, Mitsubishi Heavy Industries (MHI) proposed the construction of a 550 MW (gross) IGCC plant with CCS to accelerate development of the technology for commercial scale while addressing technical challenges. ZeroGen subsequently issued Requests for Proposals (RfP) to various technology providers to account for the possibility that their offers might be competitive with the MHI proposal; ZeroGen received offers from General Electric and Shell. In October 2008, ZeroGen initiated a scoping study, and the report generated at the end of that study and supporting documentation was submitted to the Queensland government, the Australian Coal Association Low Emission Technologies Limited (ACALET), and the Clean Coal Council. After these several changes in the configuration, the project configuration of 530 MW (gross) IGCC plant with CCS was approved in June 2009, thus obviating the need for a Stage I.

6.2 Results of the pre-feasibility study (Garnett *et al.*, 2011)

The scoping study initiated in October 2008 generated a total project cost estimate of AU$4.3 billion. Thereafter, the project configuration was finalized, and a pre-feasibility study was initiated. The pre-feasibility study involved extensive engineering and cost estimation studies, CO_2 storage exploration, and detailed financial analysis. The total cost of the pre-feasibility study was AU$138 million, and over 70% of this amount was spent on exploration, drilling, and testing of the allotted CO_2 storage sites. The exploration of potential storage resources and the pre-feasibility study were conducted concurrently rather than sequentially to meet the requirements and timelines for the Commonwealth Government CCS Flagship grants. Furthermore, as the project was of an FOAK nature, the technology providers were involved in the pre-feasibility stage to ensure that the project configurations were aligned with their capabilities. At the end of the pre-feasibility study, the estimate of total project cost increased to AU$6.93 billion. The factors that resulted in cost escalation and the magnitude of their impact are illustrated in Figure 24 below.

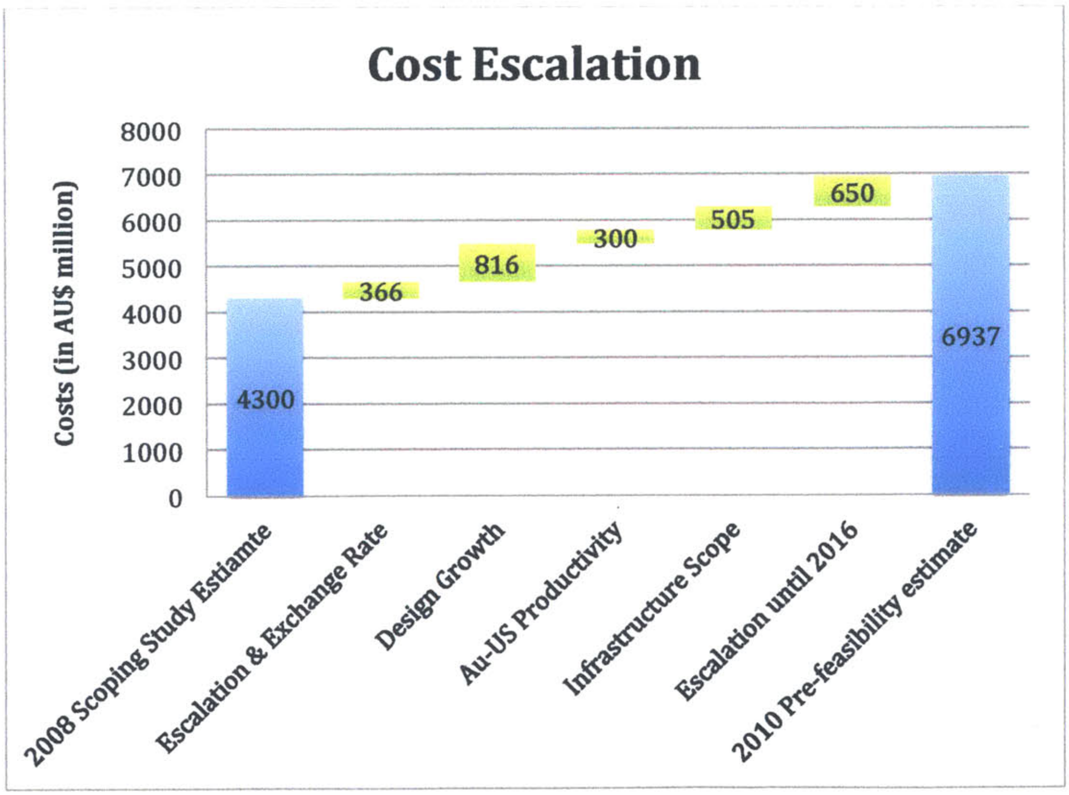

Figure 24: Escalation of Capital Costs (Greig, 2012)

The factors that contributed to cost escalation in ZeroGen are analyzed below:

a. ***Escalation & Exchange Rate:*** Given that approximately 34% of the total project cost relied on non-Australian currency (US Dollar and Yen), escalation and changes in relevant exchange rates resulted in a nearly 9% increase in the project cost estimate.
b. ***Design Growth:*** In projects of this nature, wherein several technology providers are working together, battery limits of each provider are not likely to be defined clearly before the FEED study stage of execution. Better definition of the MHI scope (IGCC plant with capture) led to design growth, which resulted in a 19% increase in total project cost.
c. ***Au-US Productivity:*** There is a lack of skilled labor to execute this project in Australia. A 7% increase in total project cost is on account of lower productivity levels relative to skilled labor in the U.S.
d. ***Infrastructure Scope:*** Changes in the infrastructure scope to include enabling infrastructure such as roads, buildings etc., in a remote area accounted for approximately a 12% increase.
e. ***Forward Escalation:*** Escalation of the project cost over the construction period accounted for approximately a 15% increase.

In effect, the project cost increased by over 60% from its scoping study levels.

The expected electricity price during the life of the project was AU$38 per megawatt-hour (MWh) in 2014 rising linearly to AU$75/MWh in 2030. Similarly, the expected carbon price during the life of the project was AU$28.3/t$CO_2$ in 2014 rising linearly to AU$56.6/t$CO_2$ in 2030. Given the high capital cost and the expected market price for electricity and the carbon price, the project was not expected to generate sufficient revenues to cover its operating costs even without accounting for the capital recovery requirement. In order for the project to be viable, the team concluded that the project would require i) a capital subsidy, ii) an operating subsidy, iii) a CO_2 storage incentive, iv) must-run status by the Australian Energy Market Operator, and v) some risk underwriting, perhaps in the form of a loan guarantee.

6.3 Storage uncertainty & related cost implications (Garnett *et al.*, 2011)

In an internal risk assessment workshop for ZeroGen, three risks were identified as "Extreme" i.e. risks that could not be resolved within a reasonable timeframe. Two of these "Extreme" risks were related to storage. This subsection details ZeroGen's experience with storage exploration.

ZeroGen was awarded exploration permits (land tenements wherein exploration may be conducted) in the Northern Denison Trough (NDT). At the time, these were the only exploration permits allotted in Queensland (or even in mainland Australia) to any project for the purposes of CO_2 storage. The purpose of the exploration was to examine if – i) the storage resource has a total capacity of at least 60 million tons, ii) the storage resource can sustain an injection rate of 2 Mtpa, and iii) the storage costs are less than \$50/tCO_2 (including the cost of capital and O&M of both transport and storage). The capture rate for the project was initially fixed at 65% with plans to increase it to 90%. Therefore, the storage capacity would also have to be able to support an injection rate of 3 Mtpa for a 90% capture plant.

After extensive exploration activities, the project team concluded that it was unlikely that NDT's storage resource could sustain an injection rate of 2 Mtpa even though the storage resource had a capacity of 60 million tons. Further, it was considered highly unlikely that NDT could sustain an injection rate of 3 Mtpa as required for 90% capture. A cost estimate for the storage resource yielded the result that there was a greater than 95% likelihood that total cost of TS&M will exceed AU\$50/tCO_2. ZeroGen then actively advocated with the regulatory bodies and the funders to release exploration permits in different areas. To this end, ZeroGen submitted a proposal to the Queensland Government and ACALET to create a multi-user "hub" storage development, which involved the exploration of many potential resources (prioritizing Surat Basin) while seeking low cost and low commitment permits in Eromanga and/or Galilee Basins. The desktop studies for storage resources in these basins yielded cost estimates of AU\$8 - AU\$20/tCO_2 excluding transport costs, which primarily depends on the new plant site.

When ZeroGen decided to close the project, the team was still waiting for new permits to be released by the relevant authorities.

6.4 Conclusions from the case study

Based on an investigation of the ZeroGen case, the following reasons for why cost escalation resulting in poor financial viability is observed in CCS demonstration projects are outlined:

a. ***Conflicting political and economic goals resulting in scope changes*** – At the very least scope changes result in sunk costs because the process of engineering design needs to be repeated with every significant change in the scope of the project. At most, these changes may result in uncertain battery limits of each technology provider, which are likely to be resolved only in the later stages of execution. As discussed in the RAND study, in most cases, the clarification of said limits result in improvements in the project definition, and therefore cost escalation.

b. ***Costs that cannot be accounted for until site is identified*** – There are certain cost elements that cannot be accurately estimated until the project site is identified and a pre-feasibility or feasibility study is conducted. Examples of these are the costs of supply to site, the costs of CO_2 TS&M, the infrastructure at site, the owner's costs, local labor productivity, and compliance with the local regulations. As the RAND study indicates, the inclusiveness of the project cost estimate improves when these cost items are accounted for, which results in cost escalation.

c. ***Volatility in financial parameters*** – Given that CCS technology is still under development, no single technology provider has the experience of executing a turnkey project. Therefore, there is a heavy reliance on imported technology and expertise for project execution, the costs of which are subject to interest and exchange rate volatility. While these risks are usually mitigated at the financing stage of project development, cost increases during various feasibility studies cannot be avoided. Furthermore, the risks associated with these parameters may be greater for a project that invests a significant amount of capital in a new technology. This is supported by results from the RAND study, which indicate that the percentage invested in a new technology determines, in part, the extent of cost escalation.

d. ***Storage exploration*** – While the global storage potential has been assessed, individual storage sites have not been assessed for their capacity and threshold injection rates, the two primary parameters that determine whether a particular storage site is viable. The costs of storage exploration, therefore, are typically borne by project developers. These costs can run into several hundreds of million dollars depending on how many sites are assessed. Unless relevant governing bodies support the storage exploration and feasibility studies for a project, developers typically attempt to capitalize these costs, which, in turn, increase the capital recovery requirements during the life of the project. These factors result in higher than the initially estimated project costs. Furthermore, the storage related uncertainty contributes to the lack of both project definition and process information.

7. DEVELOPING THE FINANCIAL MODEL

A financial model was developed to conduct analysis on the economics of CCS demonstration projects. The model was then calibrated using data on NOAK plants with and without CCS that use three different kinds of technologies – i) SCPC, ii) IGCC, and iii) NGCC. In this chapter, the financial model is described along with the assumptions and data that are used to test and verify the model.

7.1 Construction of the financial model

The financial model is a discounted cash flow model in which the annual cash flows of investment, revenue, costs, debt, equity etc. are estimated for the life of the plant, and it incorporates a detailed method of risk accounting and risk weighting that is described below. The model is used to estimate the COE in the first year of operation of the plant that is needed to ensure that equity holders receive their expected rate of return. The inputs into the model include detailed information on plant characteristics such as its capacity, heat rate, capital costs, O&M costs, fuel requirement and prices, and carbon emissions. In addition, financing assumptions on the cost of capital, depreciation, inflation and escalation rates are included. A snapshot of the input sheet of the financial model is provided in Table 7 below.

Table 7: Input Sheet - Model

PLANT CHARACTERISTICS		
[1]	Capacity	MW (gross)
	Capacity	MW (net)
[2]	Capacity Factor	%
	Aux Consumption	%
[3]	Generation	MWh
[4]	Heat rate	Btu/kWh
[5a]	Total Overnight Cost	$
[5b]	Overnight Cost (less grant)	$/kW
[5c]	Overnight Cost (total)	$/kW
[6]	Incremental capital costs	$/kW/year
[7a]	Price of electricity - no incentives	$/MWh
[7b]	Price of electricity - with incentives	$/MWh
[8]	Plant Life	years
[9]	Construction Schedule	%
OPERATION & MAINTENANCE		

[10]	Fixed O&M Costs	$/kW/year
	Fixed O&M Costs	$
[11]	Variable O&M Costs	mills/kWh
FUEL & BYPRODUCTS		
[12]	Fuel Costs	$/MMBtu
[13a]	Carbon intensity	kg-C/MWh
[13b]	Carbon intensity	kg-CO2/MWh
INFLATION & ESCALATION		
[14]	Inflation Rate	%
[15]	O&M real escalation	%
[16]	Fuel real escalation	%
TAX & DEPRECIATION		
[17]	Tax Rate	%
[18]	Depreciation Schedule	%
	Max Depr. Tax Shield	% of Pro-forma taxes
COST OF CAPITAL		
[19]	Debt fraction	%
[20]	Interest rate	%
[21]	Debt Tenure	years
[21]	Risk-free interest rate	%
[22]	Equity rate	%
[23]	WACC (weighted avg cost of capital)	%
INCENTIVES		
[24]	Additional Source of Revenue	List
[25a]	Carbon Price	$/tCO_2$
[25b]	EOR Price	$/tCO_2$
	Price of Oil (for EOR)	$/bbl
	% of Price of Oil (for EOR)	%
	Price of CO2 (for EOR)	$/mcf CO2
[26]	% carbon utilized or stored	%
	% carbon for EOR	
	% carbon for CP	
[27]	Production Tax Credit	% of revenue
[28]	Grant	$/kW
[29]	Investment Tax Credit	% of total investment

Sheets indicating the investment schedule, the debt repayment schedule, and the income statement associated with a given set of input parameters are constructed in this Microsoft Excel-based model.

Investment schedule: The investment schedule is calculated using two factors – the percentage of the total capital expended in a given year during construction and the total capital investment. An escalation rate of 3.6%, as defined in the DOE study (DOE, 2010) is applied to account for the escalation of costs during construction.

Debt repayment schedule: A certain percentage of the capital investment, 45% or 50% in the DOE baseline study, is expected to come from financial institutions as debt. This percentage is multiplied by the required capital expenditure in each year of construction to estimate the new debt issued each year. The interest accrued during construction is also calculated to determine the total amount to be repaid once the plant is operational. This amount is divided equally during the repayment period, which is 15 years in DOE baseline study. In addition to the repayment of the principal, the interest that is paid each year is calculated and shown on the sheet.

Income: The annual revenue is calculated using a price of electricity that is estimated in the model. The method by which this price is calculated is described subsequently. From this revenue, the O&M costs, fuel costs, and CO_2 emission costs, if any, are deducted. The depreciation is calculated using the depreciation schedule defined in the input sheet, and deducted from gross revenue. The interest paid, as calculated on the debt repayment schedule, is also deducted from the gross revenue, and the taxable income is calculated as the amount remaining after these deductions are accounted for. The net income is calculated as the income after tax.

The risk assumed by various agents (debtors, government, and equity holders) contributing to the total value of the project is estimated by the discount rate used to calculate the value of their contribution. These contributions can either be additions to or subtractions from the project cash flows. For example, when debt is issued, it adds to project cash flows, and subtracts from it when debt is repaid. The model then incorporates a method of risk accounting and risk weighting that follows these basic principles:

a. The equity cash flows are equal to the project cash flows minus the tax payments and debt payments. The project cash flows are calculated as the difference between total revenue and the sum of the operating costs such as O&M costs, fuel costs etc. The equity holders, therefore, are residual claimants of project cash flows.
b. Accordingly, the risk or discount rate associated with the equity cash flows in each year is calculated as the weighted discount rate of the project cash flows minus that of the tax payments and debt payments. These discount rates are weighted by the year-on-year amounts of these cash flows.
c. The relevant discount rates are then used to calculate the value of each of these cash flows. Based on the principles outlined above, the value of the equity payments in each year must equal the value of the project cash flows minus the value of the tax payments and debt payments.
d. The discount rate associated with the project cash flows is the weighted average cost of capital, and that associated with debt payments is the rate of debt. The discount rate associated with the tax payments are calculated using the principles outlined below.
e. The cash flows of actual taxes should be equal to cash flows of pro-forma taxes (tax liability if no tax shields were available to the project) minus that of tax shields. Accordingly, the value of the actual taxes is equal to the value of the pro-forma taxes minus the value of the tax shields.
f. It is important to note that the value of the tax shields cannot exceed the value of the pro-forma taxes because the project can only use its tax shields to the extent that it covers its liabilities. Therefore, adjustments may be made to the discount rates associated with the various tax shields.
g. As in the case of the equity payments, the discount rate associated with tax payments in each year is calculated as the difference between the weighted discount rate of the pro-forma taxes minus that for the sum of all the tax shields. This method of calculating the discount rates ensures that the value of the actual taxes equals the value of the pro-forma taxes minus the value of the sum of all the tax shields.

These principles are built into the model because the risk assumed by the equity holders is not the same in each year of construction or plant operation. Availability and timing of the contributions, positive or negative, by other agents changes the risk that the equity holders assume. This method of risk accounting becomes especially important when incentives become available to the project.

7.2 Incentives built into the model

The model is designed to analyze the individual and collective impact of a production tax credit, a grant, an investment tax credit, a loan guarantee, a carbon price, and an additional source of revenue such as EOR.

a. ***Production tax credit (PTC):*** In the base version of the model, a production tax credit is defined as a fixed percentage of annual revenue that is exempt from taxation. This amount is deducted from the gross revenue before the taxes are calculated, and added back to the revenue after tax to estimate the net revenue. The model can be adapted to include variations in the form of the production tax credit such as a fixed amount per MWh or a fixed amount annually.

b. ***Investment tax credit (ITC):*** Considering that the project is not generating revenues during construction, the investment tax credit is available to the project once the plant is operational. The quantum of the investment tax credit is calculated as a percentage of the total investment. This tax credit is then distributed in a manner as defined in the terms of the investment tax credit i.e. during the first 5 years of operation or the first 10 years of operation etc. Variations to an ITC such as an R&D tax credit i.e. a tax credit for the amount invested in R&D etc. can be built into the model.

c. ***Carbon price:*** A carbon price is a penalty for emissions from a plant, and therefore, adds to its operating costs. For a plant with CCS and 90% capture, there is a penalty for 10% of the emissions and an avoided cost for 90% of CO_2 that is captured. For a plant without CCS, the impact of a carbon price is much higher at 100% of the emissions from the plant. Therefore, unlike other incentives, a carbon price adds to the COE for all plants, but adds more to the COE for a plant without CCS.

d. ***Additional source of revenue:*** In the base version of the model, the additional revenue is assumed to come from EOR. The EOR price is defined in terms of $/t$CO_2$, and the revenue is calculated using the emissions data. This model can be adapted to account for other sources of revenue such as ammonia or any other chemical production that requires CO_2. The relevant price can be converted into a $/t$CO_2$ measure, if not measured in those units.
e. ***Grants:*** Many CCS demonstration project receive grants from the DOE to help developers bridge the capital cost gap between a plant with and without CCS. Grants reduce the required capital investment during construction, and its impact is calculated in terms of its contribution to the value of gross project cash flows.
f. ***Loan guarantee:*** For capital intensive and technologically risky projects, the DOE may provide loan guarantees. In other words, in the event the project is unable to make its debt payments, the DOE will protect financial institutions by bridging the gap between the payments made by the project and the required debt payments. The extent of the DOE's contribution is usually defined in the terms of the loan guarantee. A loan guarantee may allow financial institutions to provide more debt, to provide cheaper debt, or both. The model can incorporate any of the above.

The principles outlined in the preceding section continue to apply even when these incentives become available to the project. The impact of the incentives is accounted for in the following manner – i) the value of both the PTC and ITC adds to the value of the total tax shields, ii) the value of the grants, the additional sources of revenue, and a carbon price adds to the value of the project cash flows, and iii) the loan guarantees change the value of debt payments. In the analysis presented in the next chapter, the impact of these incentives is analyzed in terms of the ability to charge a lower price of electricity to consumers while ensuring that the project continues to be financially viable. In other words, the user of the model can calculate the rate of electricity in year 1 of operation (assumed to escalate at 3% per annum) that needs to be charged to consumers to ensure that the equity holders receive their expected rate of return.

7.3 Base case assumptions

The base cases for the financial model are constructed using data from the 2010 DOE baseline studies (DOE, 2010). The study includes the estimates of cost and performance data for NOAK plants that use the following generation technologies – i) SCPC, ii) IGCC, and iii) NGCC. Data from six cases i.e. systems that use each of the abovementioned technologies with and without CCS are used for base cases in the financial model. These data are given in Table 8 below.

Table 8: Base case data sourced from DOE baseline study (DOE, 2010)

Parameter	*Case 11 SCPC w/o*	*Case 12 SCPC*	*Case 5 IGCC w/o*	*Case 6 IGCC*	*Case 13 NGCC w/o*	*Case 14 NGCC*
Gross MW	580	662	737	673	565	512
Net MW	550	550	629	497	555	474
TOC ($/kW)	2024	3570	2716	3904	718	1497
Heat Rate	8687	12002	8099	10924	6798	7968
Fuel ($/MMBtu)	1.64	1.64	1.64	1.64	6.55	6.55
Fuel real escl.	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Capacity Factor	85%	85%	80%	80%	85%	85%
O&M (f) - $/kW pa	59	97	85	117	22	42
O&M (v) mills/kWh	5.0	8.7	7.8	9.9	1.3	2.6
O&M (f) – real escl	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Depreciation	150% declining balance	150% declining balance	150% declining balance	150% declining balance	150% declining balance	150% declining balance
% of total overnight capital (TOC) that is depreciated	100%	100%	100%	100%	100%	100%
Debt repayment	15 years	15 years	15 years	15 years	15 years	15 years
Percentage Debt	50%	45%	45%	45%	50%	45%
Rate of Debt	4.5%	5.5%	5.5%	5.5%	4.5%	5.5%

Rate of Equity	12%	12%	12%	12%	12%	12%
Tax Rate	38%	38%	38%	38%	38%	38%
Capital Expenditure Period	5 years	5 years	5 years	5 years	3 years	3 years
Escalation of costs during construction	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
Distribution of capital costs	10%, 30%, 25%, 20%, 15%	10%, 30%, 25%, 20%, 15%	10%, 30%, 25%, 20%, 15%	10%, 30%, 25%, 20%, 15%	10%, 60%, 30%	10%, 60%, 30%
Escalation of O&M and Fuel Costs	3%	3%	3%	3%	3%	3%
Working Capital	0	0	0	0	0	0
CO_2 Generated Kg-CO_2/MWh	804	1111	724	976	364	426
CO_2 Captured Kg-CO_2/MWh	0	1000	0	879	0	384
CO_2 Emitted Kg-CO_2/MWh	804	111	724	98	364	43
CO_2 TS&M mills/kWh	0	5.6	0	5.6	0	3.2

As expected, the heat rate for plants that include CCS is higher on account of the energy penalty. Given that IGCC technology is not as mature as SCPC and NGCC, the capacity factor is quoted at a lower rate of 80% compared to 85% for SCPC and NGCC plants. Considering that IGCC and SCPC plants are more capital-intensive, the construction period is longer for these plants at 5 years compared to 3 years for NGCC plants. While the debt is repaid over 15 years for all plants, riskier plants (plants with CCS and IGCC plants) have a lower debt percentage (45%) and a higher rate of debt (5.5%) compared to plants that use existing technologies without CCS (50% debt and 4.5% rate of debt). The carbon emissions generated, and therefore captured, are highest for SCPC plants and lowest for NGCC plants. This is a function of the fuel and technology used in these plants. The depreciation schedule, percentage of the total overnight costs (TOC) that are depreciated, escalation of costs during construction, and escalation of O&M and fuel costs are the same across cases. Any working capital requirements are assumed to be included in the fixed and variable O&M costs.

7.4 Verification of the model

The model is tested and verified using the data in Table 8; COE in year 1 which is assumed to escalate at rate of 3% per annum as calculated using the financial model is compared to the same cost as given in the DOE baseline study. The results are provided in Table 9 below.

Table 9: Verification of the model

Parameter	*Case 11 SCPC w/o*	*Case 12 SCPC*	*Case 5 IGCC w/o*	*Case 6 IGCC*	*Case 13 NGCC w/o*	*Case 14 NGCC*
COE (DOE Study)	59	110	81	119	59	86
COE (Model Verification)	**58**	**105**	**79**	**116**	**62**	**88**

As indicated in the table, the difference in the results obtained from the financial model and the results of the study ranges from \$1 - \$5/MWh. These differences may be attributed to the method of calculating COE in year 1 in the DOE study versus that in the model developed for this study. The DOE study applies a capacity charge to the TOC to account for capital costs that need to be recovered in year 1. The capacity charge is multiplied by the TOC, and divided by the total generation to yield the capital recovery component of the COE. To this value, the costs of all variable components such as fuel costs and fixed and variable O&M costs in year 1 are added to estimate the total COE in year 1. Our financial model calculates a COE such that the equity holders get their expected rate of return after payments to the contractors and the debtors have been made. Given that the capital charge is an approximate value that takes into account the expected return on equity, tax rates etc. these small differences in the results obtained in the financial model versus those in the study are expected. The next chapter describes how the model is used to analyze the economics of FOAK CCS demonstration projects.

8. RESULTS FROM ANALYSIS ON PROJECT ECONOMICS

This chapter focuses on the impact of various incentives on the economics of demonstration projects, which are FOAK plants. Using the financial model described in the previous chapter, an analysis of the economics of generic demonstration plants follows the steps given below:

a. ***Updating economic parameters in the model:*** The economic parameters sourced from the DOE baseline studies (DOE, 2010) are updated to reflect the current fuel prices and reasonable escalation rates for certain costs.

b. ***Analyzing generic FOAK costs:*** In addition, the NOAK costs in the DOE baseline studies are updated to reflect FOAK costs.

c. ***Analyzing the impact of incentives:*** The impact of a set of policy incentives on generic FOAK plant costs is estimated. This impact is measured in terms of the reduction on COE compared to a project without any incentives.

8.1 Updating economic parameters

Certain economic parameters from the DOE baseline studies (see Table 8) are updated to reflect the current conditions (see Table 10). The fuel cost and real escalation on the fuel costs are updated to reflect values in the AEO (2012). The O&M costs, both fixed and variable, are expected to escalate by a nominal 1% per annum because the DOE baseline study did not assume any real escalation these costs. The tax rate is updated to reflect the increase in corporate taxes (USA Today, 2013). Updated results on the COE are given in the table below.

Table 10: Updating Economic Parameters

Parameter	*Case 11 SCPC w/o*	*Case 12 SCPC*	*Case 5 IGCC w/o*	*Case 6 IGCC*	*Case 13 NGCC w/o*	*Case 14 NGCC*
	Economic Parameters (DOE, 2010)					
Fuel ($/MMBtu)	1.64	1.64	1.64	1.64	6.55	6.55
Fuel real escl.	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O&M (f) – real escl	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Rate	38%	38%	38%	38%	38%	38%
COE (Model – Verification)	58	105	79	116	62	88

	Updated Economic Parameters					
Fuel ($/MMBtu)	2.22	2.22	2.22	2.22	4.85	4.85
Fuel real escl.	0.90%	0.90%	0.90%	0.90%	1.40%	1.40%
O&M (f) – real escl	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Tax Rate	39.2%	39.2%	39.2%	39.2%	39.2%	39.2%
COE (Model – Updated Economic Parameters)	**70**	**123**	**92**	**134**	**58**	**84**

The COE for both SCPC and IGCC increased to reflect increases in all the updated parameters. However, the COE for NGCC decreased to reflect a significant decrease in the fuel cost from $6.55/MMBtu to $4.85/MMBtu despite the increases in other parameters.

8.2 Analyzing generic estimates of FOAK costs

The NOAK costs in the DOE baseline studies are updated to reflect FOAK costs, which are sources from two studies – GCCSI and Belfer Center (see Appendix E). The GCCSI estimates that a demonstration plant costs $5000 - $6000/kW for an SCPC or an IGCC plant, and the analysis uses an average value of $5500/kW. The Belfer Center study concludes that adding CCS to a plant results in a premium of $85/MWh. Considering that the analysis focuses on the impact on COE, results from the Belfer Center study are chosen. FOAK costs are then estimated for each of the three technologies, and presented in Table 11 below.

i) ***FOAK SCPC Plants:*** The first set of cases analyzed is an SCPC plant with and without CCS. Notwithstanding the switch from coal-based to gas-based fleet, an SCPC plant without CCS is assumed to be the reference plant against which all other plants are compared in terms of their COE. As indicated in Table 11, FOAK costs for an SCPC plant with CCS are estimated at $4909/kW, which is the capital cost that yields a premium of $85/MWh.

ii) ***FOAK IGCC Plants:*** IGCC is a relatively new power generation technology when compared to SCPC and NGCC. Therefore, the costs of IGCC plants without CCS are also likely to be FOAK costs, which are derived from a GCCSI study (GCCSI, 2011). In this study, the capital cost of an FOAK IGCC plants is expected to be over 30% higher than its NOAK costs. Therefore, the capital cost assumption for an IGCC plant without CCS is also updated. Then, FOAK costs for an IGCC plant with CCS are estimated at \$6364/kW, which is the capital cost that yields a premium of \$85/MWh.

iii) ***FOAK NGCC Plants:*** In general, NGCC plants have the lowest COE when compared to IGCC and SCPC plants on account of its lower capital costs and now lower fuel costs. Insights from the Belfer Center study cannot be applied to NGCC plants because the results are only applicable to plants that use solid fuels. However, NGCC plants are similar to SCPC plants because both are post-combustion plants. Therefore, to estimate FOAK NGCC plant costs with CCS, the following ratio is used:

$$\frac{FOAK\ SCPC\ plant\ with\ CCS\ -\ NOAK\ SCPC\ plant\ without\ CCS}{NOAK\ SCPC\ plant\ with\ CCS -\ NOAK\ SCPC\ plant\ without\ CCS}$$

The value of this ratio is assumed to be the same for NGCC plants as well. Therefore, using NOAK costs of an NGCC plant with and without CCS, the calculation yields an estimate of \$2172/kW for an FOAK NGCC plant with CCS.

Table 11: FOAK Costs for plants with CCS

Parameter	*Case 11 SCPC w/o*	*Case 12 SCPC*	*Case 5 IGCC w/o*	*Case 6 IGCC*	*Case 13 NGCC w/o*	*Case 14 NGCC*
	FOAK – Belfer Center (+\$85/MWh)		***FOAK – Belfer Center (+\$85/MWh)***		***FOAK – Belfer Center***	
			NOAK Costs			
TOC (\$/kW)	2024	3570	2716	3904	718	1497
O&M (f) - \$/kW pa	59	97	85	117	22	42
O&M (v) mills/kWh	5.0	8.7	7.8	9.9	1.3	2.6
CO_2 TS&M mills/kWh	0	5.6	0	5.6	0	3.2
COE - (Model – Updated Economic Parameters)	70	123	92	134	58	84
			Updated FOAK Costs			
TOC (\$/kW)	2024	4909	3631	6364	718	2172
O&M (f) - \$/kW pa	59	133	114	191	22	61
O&M (v) mills/kWh	5.0	12.0	10.4	16.2	1.3	3.7
CO_2 TS&M mills/kWh	0	7.7	0	9.1	0	4.6
COE (Model - FOAK added to above)	**70**	**155**	**114**	**199**	**58**	**98**

Notwithstanding the differences between the technologies analyzed in Table 11, the COE in year 1 is estimated to be in the range of \$84 to \$199/MWh, which represents an increase of 40% to 180% over the COE of an SCPC plant without CCS. To consider another measure of comparison, the average price of electricity in the Electricity Reliability Council of Texas (ERCOT) Houston market in 2011 was approximately \$61/MWh (EIA, 2011). About 12% of the time, the price in the market averaged at approximately \$200/MWh. Such high prices were realized mostly during peak times of the year in that market. Evidently, plants with CCS may need other incentives to be competitive.

8.3 Analyzing the impact of incentives

The impact of a grant of \$500 million, a PTC of 10%, an additional source of revenue from using the captured CO_2 for EOR at \$20/tCO_2, and a loan guarantee are analyzed. With a loan guarantee, it is assumed that the project has access to more debt (from 45% to 50%) at a lower rate (from 4.5% to 5.0%) because the government is underwriting a certain portion of the total debt. With these changes, a project with CCS is assumed to be able to raise debt on terms that are similar to those for established technologies, as defined in the DOE baseline study. The cumulative impact of all these incentives on the generic FOAK demonstration plants is presented below.

8.3.1 Impact of incentives on SCPC plants

The cumulative impact of a grant, PTC, EOR revenue, and loan guarantee on the COE of an SCPC plant with CCS is illustrated in Figure 25. The EOR revenue has the largest impact in reducing the COE, which is estimated at nearly 20% when you exclude the savings from not having to pay TS&M costs. Including those savings, the impact exceeds a 25% reduction in the COE. A \$500 million grant reduces the COE by approximately 8%. When the impact of all of these incentives is considered cumulatively, the COE of an SCPC plant with CCS is still over 30% higher than an SCPC without CCS.

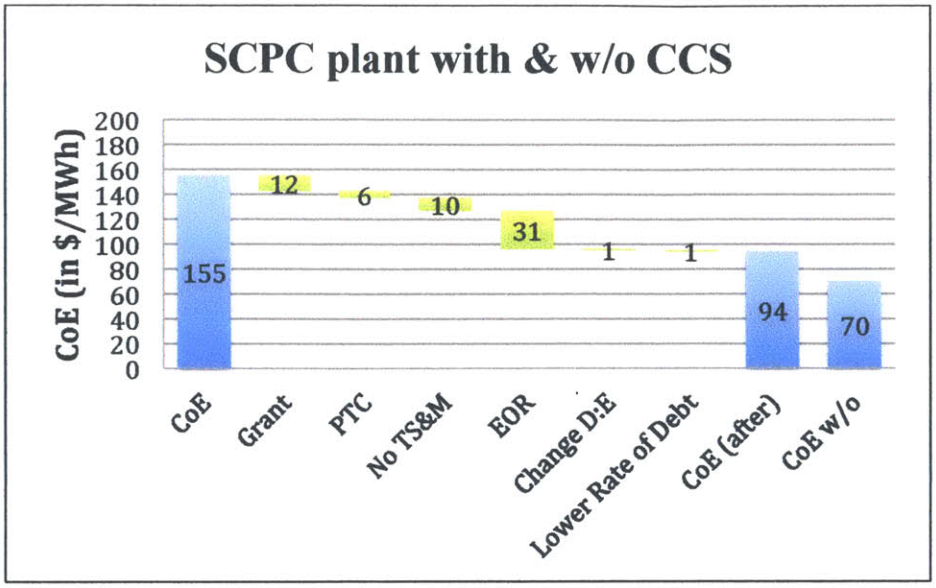

Figure 25: Cumulative Impact of Incentives on FOAK SCPC plants with CCS

8.3.2 Impact of incentives on IGCC plants

The estimate for FOAK costs for an IGCC plant with CCS yields a COE of nearly \$200/MWh. This COE is higher than a similar estimate for an SCPC plant with CCS, and the difference is attributed to the lower capital and operating costs for SCPC plants with CCS and higher performance as measured by their capacity factors. The differences in maturation of the technology contribute to the differences in these parameters.

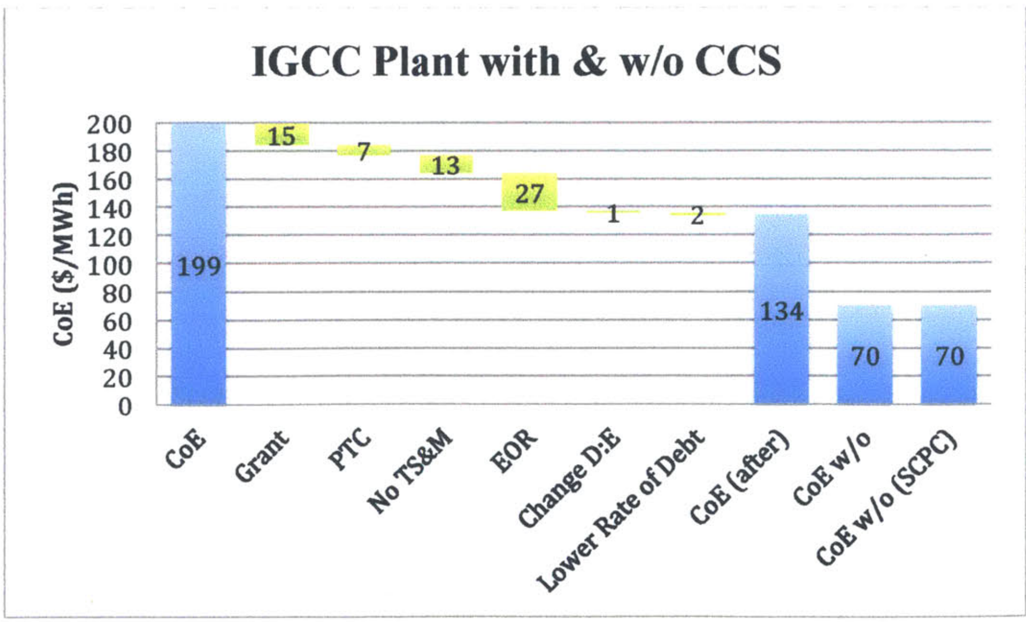

Figure 26: Cumulative Impact of Incentives on FOAK IGCC plants with CCS

The cumulative impact of a grant, PTC, EOR revenue, and loan guarantee on the COE of an IGCC plant with CCS is illustrated in Figure 26. Adding an additional source of revenue has the highest impact in reducing the COE of an IGCC plant with CCS by approximately 13%. The impact, in terms of percentage reduction on the base COE, is lower than that in an SCPC plant with CCS because IGCC plants are more expensive. The impact in an IGCC plant with CCS is even higher (~20%) when the TS&M costs are eliminated. A grant of $500 million has the second highest impact on reducing the COE, a 7% reduction. The impact of a loan guarantee is nominal because both the debt-to-equity ratio and the rate of debt are assumed not to change significantly on account of the loan being guaranteed. If the loan guarantee covers a significant proportion of total debt, say 80% as proposed in some cases, the impact is expected to be higher.

8.3.3 Impact of incentives on NGCC plants

The COE of an NGCC plant is primarily driven by its operating costs. Therefore, as increase in capital cost to reflect FOAK costs increases the COE by only about 17% i.e. from $84/MWh to about $98/MWh.

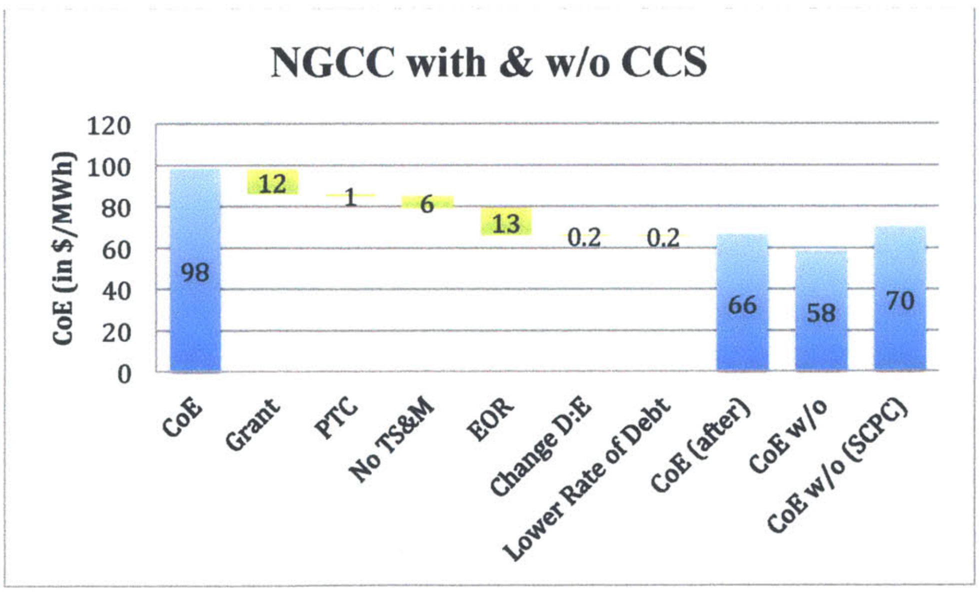

Figure 27: Cumulative Impact of Incentives on FOAK NGCC plants with CCS

The cumulative impact of all incentives on COE is illustrated in Figure 27. The EOR revenue and a $500 million grant have similar impacts on the COE, an approximately 12 - 13% reduction in the COE. This is on account of the fact that a $500 million dollar grant is a much higher percentage of the total capital cost in an NGCC plant when compared to IGCC or SCPC plants. Furthermore, NGCC plants are the least carbon-intensive resulting in lower EOR revenues. When the TS&M savings are included, EOR revenue contributes to an approximately 19% reduction in the COE. The case of parity with an SCPC plant without CCS is considered in Figure 28. Parity is achieved by varying the gas price such that the COE of an NGCC plant without CCS is the same as the COE of an SCPC plant without CCS at $70/MWh. The results in the case of parity with an SCPC plant are similar to those in Figure 27.

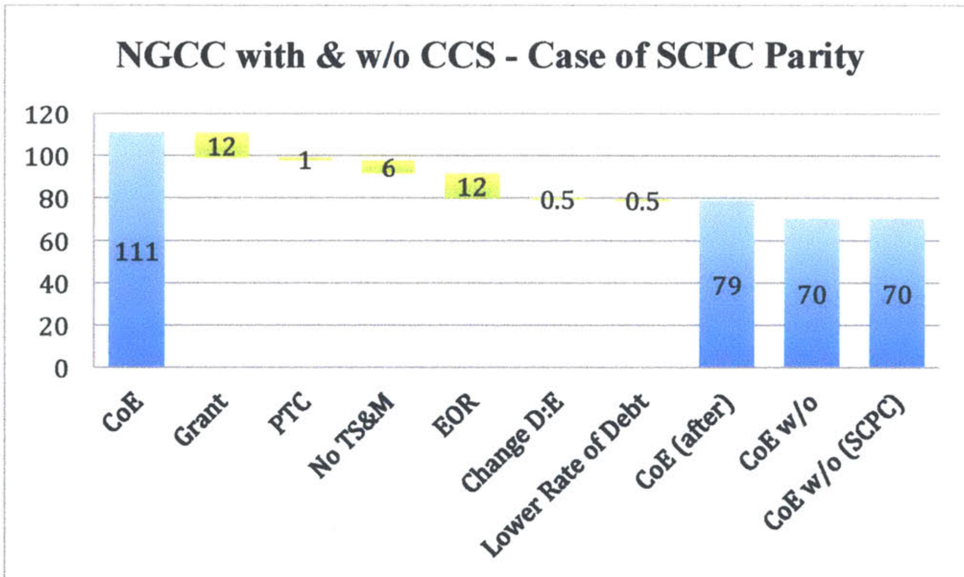

Figure 28: Cumulative Impact of Incentives for FOAK NGCC Plants (Case of gas price = $6.10/MMBtu)

8.4 Discussion & policy implications

CCS adds to the total capital and operating costs of a power plant and has a negative impact on its performance due to the energy penalty. While a grant helps compensate for the increase in capital costs, EOR compensates for the loss of revenue. Therefore, these incentives are found to have the most impact in terms of reducing the base COE. A feed-in-tariff that is not market determined may have a similar impact on the COE as EOR depending on the value of these incentives on a per MWh basis. However, the added benefit of excluding the TS&M costs is not applicable for these other incentives.

In all cases, the cumulative impact of the set of incentives analyzed above does not bridge the gap in the COE between a plant with and without CCS. In addition, in most cases, the COE of a plant with CCS including the impact of all incentives is not lower than $70/MWh, which is the COE of an SCPC plant without CCS. Furthermore, plants with CCS become less competitive when inexpensive gas-based generation becomes available. This places a high economic pressure on technologies like CCS because investors are more likely to favor NGCC technology over other power generation technologies even before the additional costs and the energy penalty on power plants with CCS are considered. To elaborate, the cost of CO_2 avoided is estimated using the following equation for all FOAK plants before and after the impact of incentives is considered:

$$Avoided\ Cost = \frac{\{COE_{with\ removal} - COE_{reference}\}\ \$/MWh}{\{CO_2\ Emissions_{reference} - CO_2\ Emissions_{with\ removal}\}\ tons/MWh}$$

The cost of CO_2 avoided is calculated, and presented in Table 12 below. Both an SCPC and NGCC plant without CCS are considered as reference plants for this calculation.

Table 12: Cost of CO_2 avoided (in $/t$CO_2$)

FOAK CCS plant technology	*Cost of CO_2 avoided (Impact of incentives not considered)*		*Cost of CO_2 avoided (Impact of incentives included)*	
Reference Plant (across)	SCPC w/o CCS	NGCC w/o CCS	SCPC w/o CCS	NGCC w/o CCS
SCPC	123	383	35	142
IGCC	183	530	91	286
NGCC		125		25

Adding the impact of various incentives to an FOAK plant helps reduce the avoided cost by at least approximately half in most cases; the impact is highest in cases wherein the technology of reference plant and the specific FOAK plant with CCS is the same. When an NGCC plant without CCS is chosen as the reference plant, the cost of

CO_2 avoided is higher in all cases by at least three times when compared to the estimated avoided costs when an SCPC plant without CCS is the reference plant. This result is expected considering that NGCC plants have lower emissions and a lower COE. This result explains the increasing economic pressure on low carbon technologies arising from the availability of inexpensive gas-based generation.

As evidenced by the experience of the developers of demonstration projects, plants with CCS are not competitive with a reference plant even when the impact of various incentives is considered. If developers cannot pass their costs on to the ratepayers, it becomes exceedingly difficult to make a case for why a plant with CCS is financially viable. The appropriate strategy, therefore, may be to increase the quantum of incentives with the most impact and offer it to fewer projects and/or allow project developers to recover their costs by passing them on to the ratepayers. As an investigation of the Kemper County project in Chapter 9 reveals, the mechanism by which the costs are passed on to the ratepayers can also be challenging.

9. KEMPER COUNTY – A CASE OF A SUCCESSFUL PROJECT

9.1 Project description (MPC, 2013)

Located in Kemper County, Mississippi, this 582 MW project is arguably the most advanced CCS demonstration project in the U.S. The proposed plant uses IGCC technology and is designed to capture at least 65% of its CO_2 emissions. Owned by the Mississippi Power Company (MPC, a subsidiary of Southern Company), the project uses a technology that was developed jointly by the Southern Company, KBR, and the DOE, the air-blown Transport Integrated Gasifier (TRIG) technology (NETL, 2013). This technology enables MPC to capitalize on the abundant reserves of lignite in the state,[2] while simultaneously reducing the environmental impact of power plants that use coal (MPC, 2013a). Furthermore, MPC's experience with CCS is likely to prepare the company for emission standards that are expected to become increasingly stringent. The plant is scheduled to be operational in May 2014.

The plant is located next to a lignite mine site that spans an area of approximately 31,000 acres. These mines are owned by MPC, and developed by Liberty Fuels, a subsidiary of North American Coal Corporation (NACC) (NETL, 2013). In June 2012, the mine obtained a permit approval from the Mississippi Department of Environmental Quality, thus securing a cheap source of fuel for the plant (World Fuels, 2012). The fuel sourced from the mine has an average heat content of 5290 Btu/lb (as received) and moisture content of at least 40% (NETL, 2011). Once operational, the plant will have a heat rate of 11,708 Btu/kWh and generate approximately 3 million tons of CO_2 annually for EOR. Other by-products include 135,000 tons of sulphuric acid and 20,000 tons of ammonia (NETL, 2011). Revenues generated from the sale of these by-products are not estimated to be significant when compared to that generated from selling the CO_2 for EOR (Esposito, 2012).

Several benefits are expected to accrue to the state of Mississippi from the construction and operation of this power plant (MPC, 2013a). The plant helps the state diversify its electricity mix, which, in turn, protects consumers from short-term fuel price

[2] Lignite accounts for approximately half of the world's coal supply (MPC, 2013)

shocks. In terms of tax revenue, the plant will generate approximately $75 million during construction and nearly $30 million annually once the plant is commissioned. As per MPC, the project employs 3500 workers on site, and will generate nearly 12,000 direct and indirect jobs during the construction phase. Once operational, the plant is expected to generate over a 1000 permanent jobs. The project is also expected to increase the oil production of Mississippi and therefore the U.S. by 2 million barrels annually.

9.2 Regulatory support – federal and state-level

The Kemper County project qualified for Round 2 of the DOE's CCPI. Through this initiative, the project qualified for a $270 million grant, which is nearly 10% of the then estimated project cost of $2.8 billion (NETL, 2013). The project is also receiving support in the form of federal investment tax credits to the tune of $133 million (GHG News, 2012). After initially approving a cost of $2.4 billion, the Mississippi State Public Service Commission (MSPSC) approved a 20% increase in capital costs (Arnold & Porter LLP, 2010). The Sierra Club appealed the validity of this decision at the Mississippi Supreme Court; details of the case and implications on the project are provided in the next section.

With costs escalating during construction on account of factors such as switching between contractors and related delays (Washington Examiner, 2012), the project looks for any additional support that it can obtain. In 2012, the project was already nearing its $2.88 billion project cost cap as approved by the MSPSC, and MPC requested a $55 million rate increase in June which was subsequently denied by the Mississippi court (Reuters, 2012). The DOE is also considering providing a loan guarantee to the project that will cover up to 80% of its costs (Mitchell Williams, 2012). Under these conditions, a federal loan guarantee may help alleviate the impact of escalating costs on the financial viability of the project. However, MPC has since withdrawn its request for a $1.5 billion federal loan guarantee after the MSPSC approved a settlement that allowed the company to pursue legislation to issue securitized bonds of up to $1 billion to recover costs over the $2.8 billion cap (Reuters, 2013). Apart from the direct financial support, federal agencies are considering supporting organizations that have a stake in the project. The

Rural Utilities Service (RUS) may provide a $480 million loan guarantee to South Mississippi Electric Power Association (SMEPA) to support their acquisition of 15% in the project (Federal Register, 2012).

For a power plant that uses commercially available technology, potential financiers consider the regulatory risk associated with delays in approvals. Therefore, securing early environmental approvals for the plant's lignite mine contributes positively to regulatory risk mitigation. The potential financiers of the project are also likely to be concerned with the cost and performance related uncertainty, especially with the use of a new technology. Therefore, strong support from federal and state government agencies helps mitigate some of these risks perceived by potential financiers.

9.3 MSPUC V. Sierra Club (Arnold & Porter LLP, 2010)

In January 2009, MPC filed a petition with the MSPSC to seek permission to build the proposed plant in Kemper County. MPC argued that as per Mississippi statute, this power plant was required to serve the present and future "public convenience and necessity". MPC also argued that the MSPSC should either approve the proposed plant right away for continued access to federal subsidies or rely on natural gas-based generation that may be subject to price volatility. In its petition, MPC also indicated that some risk needs to be shifted to the ratepayers during the construction phase of the project through the construction work in progress (CWIP) mechanism. The CWIP mechanism allows the project to recover costs during construction itself i.e. even before the plant is operational, a certain portion of construction costs are recovered by increasing the rate that consumers have to pay. This is to ensure that the company can maintain the credit rating needed to raise the significant amount of capital needed for the project. When MPC applied to the MSPSC for a Certificate to build the plant, the estimated cost was indicated as $2.5 billion.

The MSPSC divided the hearing into two schedules - the first to determine a reasonable range of forecasts for electricity demand and a consensus on the existing and likely sources of supply. In Phase I, MPC showed that in 2014, the state could need additional capacity ranging from 304 to 1276 MW. The second phase was to determine what sources of supply were available to meet the forecasted demand, and the Kemper County project was evaluated as source of supply. The MSPSC requested interested parties to submit their bids, and the Boston Pacific Corporation was used as an independent evaluator. During the second phase hearing in February 2010, MPC requested that the company be allowed to exceed its cost estimate by as much as 33% to avoid the risk of a downgrading credit rating and requested full CWIP financing on the project. However, MPC maintained that the risk of rising capital costs was a manageable one for consumers. The Sierra Club submitted that a hard cap must be imposed on MPC if a certificate is granted, and that even a 20% cost overrun implies that the Kemper Plant would be more expensive than natural gas-fired plants in the majority of the scenarios presented. The order dated April 29, 2010 found that the Kemper plant did not serve the "public convenience and necessity". MPC was given 20 days to accept the conditions proposed by the MSPSC – i) $2.4 billion cap and, ii) no CWIP.

MPC filed a Motion for Rehearing, in which it requested permission for a 20% cost overrun and 100% CWIP. In an order dated May 26, 2010, the MSPSC reversed its previous decision and stated that the project would be approved if MPC agreed to cap any cost overruns at 20%. The MSPSC supported its decision by stating that the Boston Pacific Corporation's testimony indicated that 20% cost cap would be on the high end of the acceptable range of cost caps that would still make the Kemper plant the best overall choice for customers. MPC agreed to the conditions set out in this order, and a Certificate to build the Kemper plant was issued to MPC on June 3, 2010. The Sierra Club filed a petition within 30 days stating that i) nothing in the Boston Pacific Corporation's testimony supported the MSPSC's decision, ii) the majority's action was not supported by record and was contradictory to its previous decision thus rendering it "arbitrary and capricious", and consequently, iii) the MSPSC's decision to grant MPC a Certificate to build the Kemper plant must be vacated.

In response to the Sierra Club's petition, the MSPSC entered an order in favor of MPC. The Sierra Club appealed to the Chancery Court of Harrison County, which affirmed the MSPSC's decision on the matter. The Sierra Club then appealed with the Supreme Court of Mississippi, which stated that the MSPSC's findings must be "supported by substantial evidence presented," which "shall be in sufficient detail to enable [this] court on appeal to determine the controverted questions presented, and the basis of the commission's conclusion." In a judgment delivered on February 28, 2011, the Supreme Court found that the MSPSC's approval of the project failed to satisfy the abovementioned requirement, and reversed the Chancery Court's judgment and the MSPSC's order, and remanded to the MSPSC for further proceedings. In response, the MSPSC issued a more detailed order on 24 April 2012 authorizing MPC to continue the project (HighBeam Business, 2012). The Sierra Club has contested this order.

Legal challenges to projects of this nature add to the risks perceived by potential financiers of the project. It took three years from the time that MPC applied for a Certificate to build the plant for the MSPSC to issue a detailed order authorizing MPC to continue the project. MPC was able to mitigate some of the risks associated with project delays and related escalation because the company chose to continue with plant construction. Notwithstanding the debate surrounding cost overruns, MPC also requested a 13% rate increase that would have generated $58 million (Reuters reported this as $55 million (Reuters, 2012)) in CWIP money (Mississippi Business Journal, 2013). When this petition was denied by the MSPSC, MPC appealed to the Mississippi Supreme Court. In a settlement between the MSPSC and MPC, it was decided that i) the hard cap on project costs would be lowered from $2.88 billion to $2.4 billion, ii) the ratepayers would get 10% royalty share in the plant's TRIG technology, and iii) if CWIP were granted to the company, it cannot exceed $172 million, and the money would be held in an escrow and only flow to the company if the Mississippi Supreme Court allows MPC to continue with the project (Mississippi Business Journal, 2013). Subsequently, MPC filed for CWIP for the project to recover $172 million, which may represent a 21% increase in the price of electricity for retail customers. If approved, the typical residential customer using 1,000 kWh a month will see an increase of less than a $1 a day on bills in 2013 (MPC, 2013b).

9.4 Financial analysis & details on EOR arrangement

The assumptions used for the financial analysis in this section are given in Table 13 below. The parameters highlighted in blue most closely reflect project parameters, and those highlighted in black are consistent with assumptions in the DOE study.

Table 13: Kemper County - Assumptions for Economic Analysis

Parameter	*Kemper County*	*Remarks*
PLANT CHARACTERISTICS		
Net MW	582	
Capacity Factor (CF)	85%	To generate ~3 Mtpa, CF = ~85%
COSTS		
Total Overnight Cost	$2.88 billion	Hard-cap provided by PUC; MPC is allowed to pass through costs to consumers to the extent of the cap
Overnight Cost	~5000/kW	
Working Capital	0	Zero for all parameters
FUEL & BY-PRODUCTS		
Heat Rate	11708 Btu/kWh	Source: National Energy Technologies Laboratory (NETL)
Fuel Price	$1.77/MMBtu	EIA: 2010 price
Fuel Price escl. (real)	0.5%	EIA: Avg real escl from 1980 - 2011
CO_2 Generated Kg-CO_2/MWh	1046	Carbon intensity assumed to be the same as Shell-IGCC = 197 lb/MMBtu
CO_2 Captured Kg-CO_2/MWh	680	65% Capture considered
CO_2 Emitted Kg-CO_2/MWh	366	
O&M		
O&M (fixed)	$150 / kW / year	Adding 25% to O&M Costs of DoE Base Case
O&M (variable)	12.4 mills/kWh	Adding 25% to O&M Costs of DoE Base Case
TS&M costs	0	No TS&M costs assumed as CO_2 is used for EOR
TAX & DEPRECIATION		
Tax rate	39.2%	Corporate Tax rate increased to 39.2%
Depreciation	150% declining balance	Depreciation over 20 years

% of total overnight capital that is depreciated	100%	Even if a substantial amount of TOC is non-depreciable, it introduces a small error
FINANCING		
Debt repayment		
Percentage Debt	45%	Lower % debt because of higher risk
Rate of Debt	5.5%	Higher debt rate because of higher risk
Rate of Equity	12%	
CAPITAL EXPENDITURE		
Capital Expenditure Period	5 years	
Escalation of costs during construction	3.60%	
Distribution of capital costs	10%, 30%, 25%, 20%, 15%	Distribution of costs during construction Construction began in 2010, commissioning end 2014 – typical S-curve distribution assumed

For the purposes of this analysis, it is assumed that the MSPSC has authorized MPC to pass on capital costs of up to $2.88 billion to the ratepayers, it has not granted CWIP, and that MPC is still considering a loan guarantee. These assumptions are chosen considering that the $172 million increase to ratepayers was reduced to a maximum of $156 million by the MSPSC on March 22, 2013 (MSPSC, 2013). Further, the MSPSC specified that the annualized CWIP amount shall be staggered as follows – i) beginning from the first billing cycle in April 2013 to the last billing cycle in December 2013, the annualized CWIP amount will be $125 million, and ii) beginning from the first billing cycle in January 2014 to the last billing cycle in April 2014, MPC's annualized CWIP retail revenue requirement shall be escalated to $156 million. These revenue adjustments represent increases of 15% for 2013 and 3% for 2014. It remains to be seen if MPC accepts the abovementioned amounts or files a motion for rehearing considering that the maximum amount agreed upon in the court settlement was $172 million, and that the cost cap has been lowered from $2.88 billion to $2.4 billion.

As mentioned previously, the Kemper County project has access to a grant of $270 million, investment tax credits of up to $133 million, and EOR revenue amounting to approximately $50 million annually (MPC, 2012). Although this revenue is assumed to be the total from the sale of all by-products, EOR is assumed to account for a significant percentage of this revenue (Esposito, 2012). Therefore, it is assumed that all the captured CO_2 is used for EOR. The impact of the loan guarantee is assumed to be two-fold - the project has access to more debt (from 45% to 80%), and half of the total debt has a lower rate (from 5.5% to 4.5%) because the government is underwriting a certain portion of the total debt.

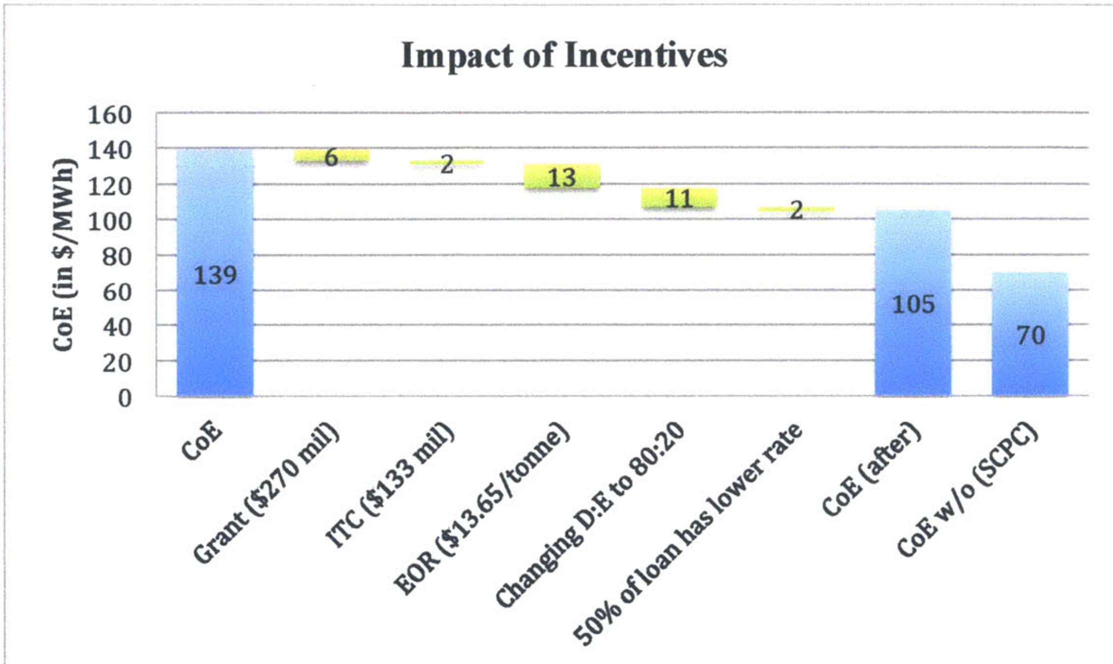

Figure 29: Impact of Incentives on COE of Kemper County

Similar to analyses presented before, the cost with and without accounting for the impact of various incentives is presented in Figure 29. The revenue from EOR adding up to approximately $50 million in annual revenues has the most impact in reducing the COE borne by the ratepayers. The reduction is approximately 9% from the base COE of $139/MWh. The cumulative impact of a loan guarantee ($11/MWh + $2/MWh) is as effective as the EOR revenue in terms of reducing the COE. The impact of the grant is the next largest at an approximately 4% reduction from the base COE. The ITC protects net revenue (total revenue minus operating costs) from taxation to the extent of the credit. The value of this tax credit is then added to the revenue after tax. When the net revenue before tax is not very high, the impact of a tax credit is minimal. A tax credit is most effective for a company that has a lot of spare cash. For example, if the Kemper County project were funded on the balance sheet of Southern Company, the parent company of MPC, the impact of the ITC may be higher. However, technologically risky and capital-intensive projects such as Kemper County are typically developed in a special purpose vehicle (SPV) i.e. a separate project company to insure shareholders from the risks associated with the project.

Denbury Resources Inc. entered into a purchase contract with MPC to purchase 70% of the CO_2 captured from the Kemper County plant (Business Wire, 2011). As part of the arrangement between MPC and Denbury, MPC agreed to build a portion of the pipeline leading to the field in exchange for an EOR price that would have been higher that the price that Denbury was willing to offer if it had to build that portion of the pipeline instead (Esposito, 2012). Evidently, it was more economical for MPC to have incurred the cost and received an estimated \$13.65/tCO_2, than not incurring the cost of the pipeline and accepting a lower EOR price. Based on an analysis conducted using the financial model, for every percentage of the total project cost (\$2.88 billion) that MPC spent on building the pipeline, it should have received an additional \$0.50/tCO_2, (see Figure 30. The fact that MPC chose to build the pipeline implies that \$13.65/tCO_2 was higher than the base price that Denbury was offering. By making the choice to build a portion of the pipeline, MPC has attempted to reduce the burden on the ratepayers.

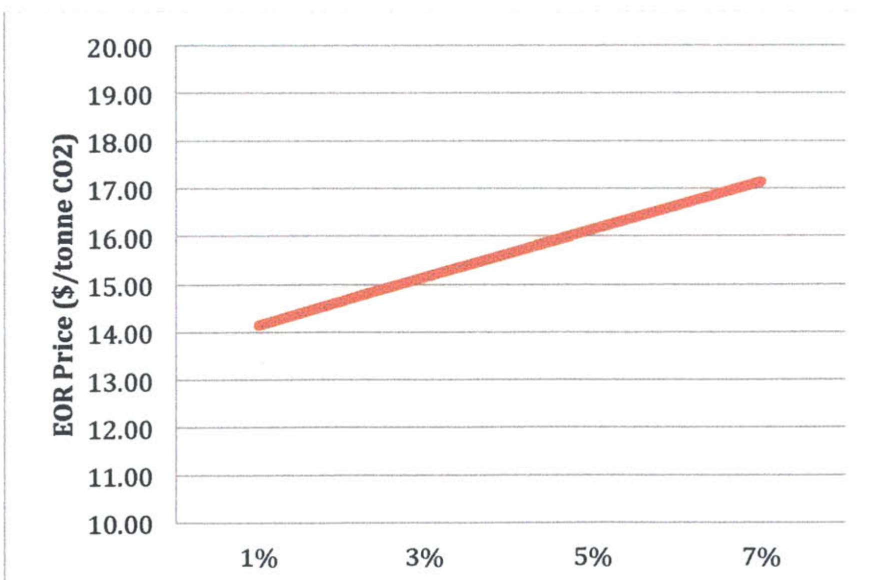

Figure 30: Parity between EOR Price & Capital Cost of Pipeline (in % of Kemper Costs)

9.5 Conclusions of this case study

Based on an investigation of the Kemper County case, factors that have contributed to the success of the project are outlined below:

a. ***Passing costs on to the ratepayers*** – As is established previously, a demonstration plant with CCS cannot compete with a reference plant without CCS (typically SCPC) in terms of the COE. Therefore, other mechanisms of cost recovery are needed for a demonstration plant to be economical. In the Kemper County case, this mechanism is a rate-based pay i.e. the COE of the Kemper plant, an estimated $105/MWh (see Figure 29) in its first year of operation, are passed on to the ratepayers. MPC claims that the above price represents an average retail rate increase of 20 – 25%, which implies that retailers on an average pay an estimated $79 – $84/MWh plus transmission and distribution charges. Given the uncertainties in this analysis, this seems consistent with the data on average retail prices in Mississippi, which was approximately $85/MWh in January 2012 (EIA, 2013).

b. ***Additional government support*** – As part of a settlement between the MSPSC and MPC, it was agreed that the price cap would be lowered from $2.88 billion to $2.4 billion in exchange for CWIP financing to the extent of $172 million, and legislative support to issue bonds worth up to $1 billion to recover costs over and above the cap. Notwithstanding the legal challenges, this is indicative of the willingness of relevant government authorities to support the project, and ensure that the plant is commissioned. This helps inspire confidence in potential financiers that the risks associated with the project can be mitigated.

c. ***Decision to continue construction*** – Despite all the legal and regulatory challenges, MPC decided to continue construction at site. This may have been critical in terms of avoiding cost escalation related to construction delays, delays in contractor payments, and other related factors. The additional government support, as described above, may have given the developers the confidence needed to continue construction at site.

d. ***Storage related risks*** – Considering that projects of this nature are subject to technological and regulatory risk, adding on the geological risk for projects that only store the CO_2 may be a strong deterrent for developers. Unless a clear policy on storage is executed and a source of revenue is made available for CO_2 that is stored in deep saline aquifers, the developers of CCS demonstration projects may only engage in projects that include revenue generation through EOR. The strong focus on EOR by the DOE (DOE, 2012), and consequent efforts to rebrand CCS as CCUS (carbon capture utilization & storage) only reinforces a potential developer's inclination towards projects with EOR.

10. POLICY DISCUSSION

In this chapter, the policy implications of the results presented in this thesis are discussed. Then, the factors that make the execution of these policy goals challenging are investigated. These factors include the current policy environment for the development of low-carbon technologies in addition to the factors that are specific to CCS technology. Considering that there exists a need to deploy CCS technology in the long-term, recommendations for policies that may better support the technology development of CCS are presented.

10.1 Analysis of the state of CCS development

CCS technology development appears to have slowed recently. The analysis presented thus far supports the following conclusions regarding the demonstration phase of CCS, and the need to develop this technology:

a. ***Higher than expected costs of demonstration projects:*** There is a high degree of uncertainty associated with both the project definition and the process information in FOAK plants. As an investigation of the ZeroGen project reveals, the resolution of these uncertainties at different stages of project execution results in higher than the initially estimated costs. In the ZeroGen project, the resolution of these uncertainties is estimated to have added 40% to the initial project cost of AU$4.3 billion. In addition, FOAK plants are more vulnerable to interest and exchange rate volatility, which also increases costs. Such high costs necessitate policy support through various incentives for demonstration projects.

b. ***Current incentives are inadequate:*** CCS demonstration projects are not economical in a market-based system, even when the impact of currently available incentives is considered. The gap between the COE of an FOAK plant and an SCPC plant without CCS ranges from $9 - $64/MWh depending on which technology the FOAK plant uses. This gap increases when an NGCC plant without CCS becomes the reference plant, thus increasing the economic pressure on CCS demonstration projects.

c. ***Long-term need for CCS:*** A technology like CCS is essential in meeting the demands of a low-carbon economy in the long-term. As emission caps get more stringent, the role of CCS becomes more important. Further, its role is not expected to diminish even with the availability of inexpensive gas-based generation. To ensure that CCS technology is available for deployment in the long-term, resources need to be allocated for its development in the short-term.

10.2 Short-term outlook

The short-term outlook for CCS technology is not encouraging given the results discussed above. In this section, the factors that may contribute to a challenging environment for the development of CCS technology are investigated. While some of these factors are endogenous to the technology, external conditions also impact a potential developer's decision to build a demonstration plant.

10.2.1 RD&D spending & other policy drivers

The financial crisis of 2008, which led to a recession, changed the U.S. administration's priorities. Just as the U.S. economy was beginning to recover, the deepening European debt crisis slowed progress. Cutting government spending and reducing unemployment, therefore, are now the major concerns in these key administrations. Even the ARRA, which provided significant financial support for CCS demonstration projects, was sold to the American public as an initiative for employment generation. As a result of tighter national budgets, discretionary spending including R&D funding could be reduced, which is likely to impact funding for demonstration projects in the future. If government support for CCS RD&D is expected to reduce, potential developers of are less likely to invest their own funds while assuming the already high risks associated with demonstration projects.

Under current economic conditions, other policy drivers such as a carbon policy have not been very effective either. The economic downturn decreased demand for Emission Trading Allowances (ETAs) resulting in lower than expected prices for these allowances in the EU. In April 2013, after the European Parliament opposed a scheme that could have helped boost carbon prices by extracting allowances from the market and selling them later, prices reached €3/ETA (Lupion and Herzog, 2013). As mentioned previously, the low ETA prices also reduced the total quantum of funding under the

NER300, which was initially estimated at €4.5 billion, by more than half. Therefore, a carbon policy alone may not provide the requisite policy support for the developers of demonstration projects.

10.2.2 Current trends in the energy sector

The current trends in the energy sector combined with policies that reinforce these trends may also render technologies like CCS uneconomical. To elaborate, on 27th March 2012, the Environmental Protection Agency (EPA) released its proposal for "new source performance standards" (NSPS) of 1000 lb/MWh for carbon emissions from new electricity generating units (EGUs). As the EPA outlined in its notice for these standards (EPA, 2012a), the rule does not impose any additional costs on the electric power sector because i) NGCC is likely to be the predominant choice for new fossil fuel-based generation, ii) NGCC is deemed the "best system of emission reduction" (BSER) for the purposes of NSPS because these plants emit CO_2 at a rate lower than 1000 lb/MWh without requiring CCS, and iii) projections for the electric power sector estimate that few, if any, new coal-fired power plants are likely to be built (see Figure 31), for which the EPA estimates that CCS shall become available within the first 10 years of the plant's operation or by 2020. Therefore, the EPA's emission standards may reinforce the trend of fuel-switching from coal to natural gas for fossil fuel-based generation and arguably delay the need for CCS development in the short term.

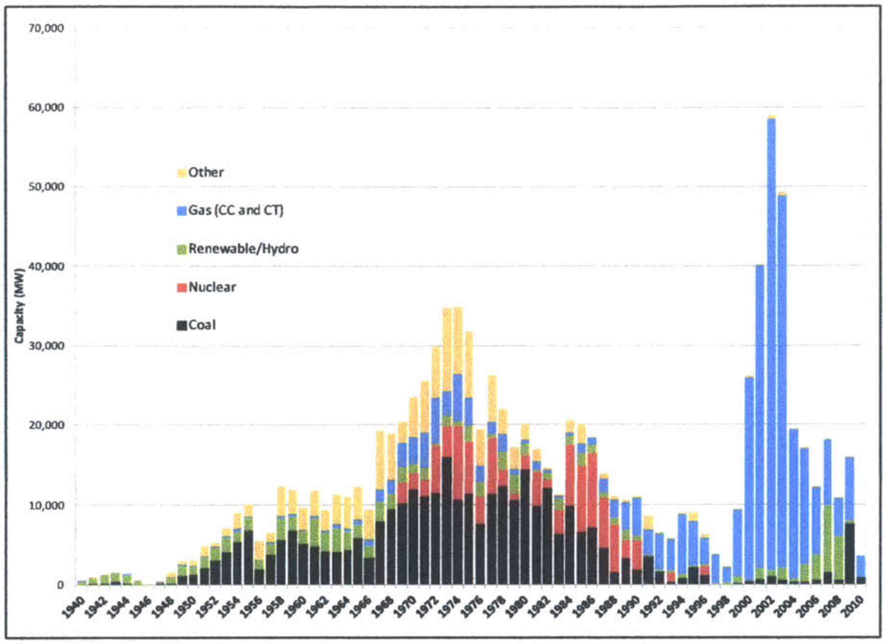

Figure 31: Historical capacity additions - By technology type (EPA, 2012b)

Low carbon technologies are facing increasing economic pressure from inexpensive gas-based generation. This is supported by the analysis on avoided costs (see Table 12); when the reference plant is switched from an SCPC plant to an NGCC plant, the avoided costs of a CCS demonstration plant increase almost threefold. Furthermore, fuel-switching from coal to natural gas results in emissions reduction in the short-term. Under these circumstances, it becomes increasingly difficult for an administration with tight budgets to continue justifying support for CCS technology. As discussed in Chapter 4, however, contribution from fuel-switching is likely to be transitional to emissions reduction targets. Therefore, relying only on inexpensive gas-based generation may not suffice.

10.2.3 Technology-specific risk factors

CCS demonstration projects are subject to regulatory risk in various forms. Demonstration projects, especially those that do not rely on EOR for storage, are subject to regulatory risk related to storage. The costs associated with storage resource development and potential liabilities during the operation and maintenance of said resource can be uncertain. Therefore, policies related to storage, that outline the division of responsibility between developers and the relevant state are critical for demonstration projects. As seen in the case of projects based in Germany, the evolution of the Carbon

Storage Law contributed to developers' decisions to withdraw. In the U.S., applying permitting rules pertaining to Class VI wells to CCS demonstration projects with storage may have increased the regulatory risks associated with these projects. The length of time for obtaining permits and for post-injection site care (PISC), and the long-term liability presumptions inherent in Class VI rules may not be aligned with what potential developers are comfortable assuming (Van Voorhees, 2013).

In a market-based regime in which the cheapest plants are dispatched first, developers are subject to dispatch risk i.e. the risk that power from a CCS demonstration plant is too expensive to be dispatched. This risk may be partly mitigated if a carbon price were applied to fossil fuel-based generation to reflect its true costs. However, with higher than anticipated costs and the lack of a strong carbon policy, projects such as Kemper County and American Electric Power (AEP) Mountaineer requested relevant Public Utilities Commissions (PUCs) for permission to pass their costs on to the ratepayers. As an investigation of the Kemper County project reveals, even when the process results in an approval, it can be subject to legal hurdles and resulting delays.

10.2.4 Passing costs onto consumers

In the face of the challenges described above, seeking regulatory approval to pass the costs of a demonstration project onto the ratepayers seems to be the strategy that potential developers are adopting. As described in Chapter 9, members of organizations internal and external to the regulatory process opposed the project at various stages. The reasons for their opposition included i) escalating project costs, ii) the availability of inexpensive gas-based generation, and iii) MPC consumers assuming the cost burden for developing a technology benefits the company. To address the latter concern, MPC and the MSPSC agreed to a royalty-sharing model in a recent settlement i.e. MPC agreed to share royalties from TRIG technology with consumers that are assuming the cost burden. Considering that the development of the TRIG technology enables the state to use its abundant lignite reserves and to produce CO_2 for EOR, regulatory bodies in Mississippi seem keen to support the project. Similar conditions may not be available to other projects for such a model to be replicable. This is evident from the decision delivered by regulators for the AEP Mountaineer project; the PUC in Virginia declined AEP's request for a $74 million rate increase to support its demonstration project (Bloomberg, 2011).

The Virginia State Corporation Commission (SCC) focused on the distributional impacts if AEP's request to pass costs on to its ratepayers were approved. To elaborate, while the SCC agreed that it is reasonable for AEP to evaluate options for emissions reduction, the regulator considered it unreasonable for AEP to incur high project costs and recover them from its ratepayers (SCC, 2010). This request was deemed unreasonable especially considering that the beneficiaries of the technology such as consumers of AEP and of other U.S. utilities, shareholders of AEP etc. constituted a larger group than the group of ratepayers shouldering the financial burden. Therefore, such distributional impacts may necessitate different strategies to recover the costs of demonstration projects.

10.3 Policy recommendations

The costs of CCS technology development may be recovered from sources such as – i) markets created by comprehensive policies on carbon or by the need for EOR, ii) ratepayers, iii) taxpayers, and iv) potential investors or equity holders of companies developing the technology. As the administration's priorities change under challenging economic conditions and support for CCS technology wanes, equity holders are discouraged from investing in the technology. Furthermore, in the U.S. context, developers may be disinclined to allocate their resources into CCS RD&D because there exists no comprehensive policy on carbon that they need to prepare for. EOR markets are specific to particular regions, and therefore limited. The taxpayers indirectly support CCS technology development through grants from federal organizations such as the DOE. As national budgets become more constrained, indirect support from taxpayers may reduce in magnitude. Therefore, the continued development of CCS technology may require support from the ratepayers as well. In addition, recovering costs from the ratepayers may need to be executed at the federal level to mitigate adverse distributional impacts, as described above in relationship to the AEP Mountaineer Project.

An example of such a policy is a carbon surcharge of \$0.001/kWh levied on all electricity generated from fossil fuels. This policy may help spread the high costs of demonstration projects across the potential beneficiaries of CCS technology. Considering the fact that electricity generation from fossil fuel sources in 2010 totaled to approximately 2880 billion kWh (EIA, 2012b), this surcharge could accumulate nearly \$3 billion annually for all climate change related initiatives. Assuming that an average household in the country consumes about 11500 kWh annually and pays approximately \$0.12/kWh (EIA, 2011a), the household spends about \$1380 on electricity annually. The proposed surcharge would add approximately \$12 to an average household's annual expenditure on electricity, which represents an increase of less than 1% compared to the estimated 20 – 25% increase on the ratepayers of MPC. Legal barriers arising out of conflicting state and federal mandates may prevent the federal government from establishing such a policy. Allison supports this idea by suggesting that broad changes in standard operating procedures (SOPs) are difficult to enforce (Allison, 1969). These SOPs, therefore, become institutional barriers to instituting policies that are designed to address an issue such as climate change. A discussion on these barriers, however, is not in the scope of this chapter.

It is important to understand the impact of such a surcharge on utilities in addition to considering how consumers are affected. Olson suggests that regulated entities in a concentrated industry have an incentive to capture the regulatory process because the benefits that could accrue to them are distributed among a few entities (Olson, 1984). Therefore, in the electric power sector, utilities have an incentive to weaken any policy that may impose additional costs on them. A suggested mitigation measure is to compensate utilities in order to disincentivize them from weakening any policy that affects them. The recommended surcharge may be an efficient way to do so because the collected funds are likely to serve as adequate compensation for the utilities developing CCS technology. Further, industrial nations such as the U.S. may have an interest in supporting policies for technology transfer to create a global market for CCS, which serves as an added incentive for technology developers in the country. In conclusion, to ensure the availability of CCS technology in the long-term, the high costs of demonstration projects need to be incurred in the short-term. Distributing these costs among a large number of ratepayers may be the most practical way forward given the current economic and policy environment.

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12. APPENDICES

APPENDIX A: Evolution of fuel-mix in energy in various regions of the world

Figures below represent the evolving fuel-mix for electricity generation in major regions of the world during the period 2008 – 2035 as depicted in the International Energy Outlook (IEA, 2011a). As illustrated in ***Figure 32*** to Figure 37 below, coal is expected to play a diminishing role in most countries in the North & South American continents and OECD Europe, and the Middle East. In non-OECD Asia and Africa, however, coal-based capacity is expected to increase through 2035.

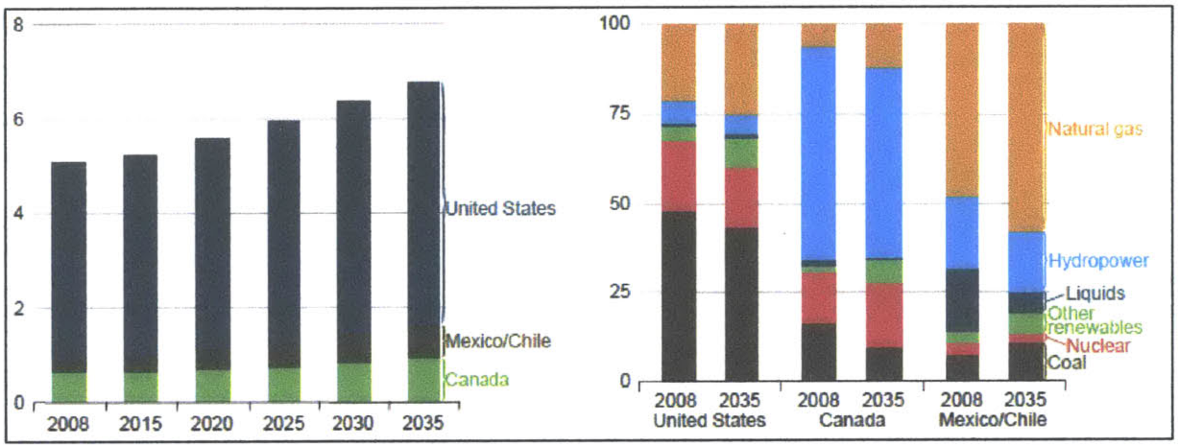

Figure 32: Electricity Generation (left, in trillion kWh) and fuel-mix (right, in %) in North America (IEA, 2011a)

In North and South America, primarily natural gas based capacity is expected to displace coal-based capacity, with hydro making contributions in regions with high resource availability. Notwithstanding that natural gas has lower carbon intensity when compared to that of coal, CCS may need to be added to gas-based systems as well to achieve requisite emissions reduction targets.

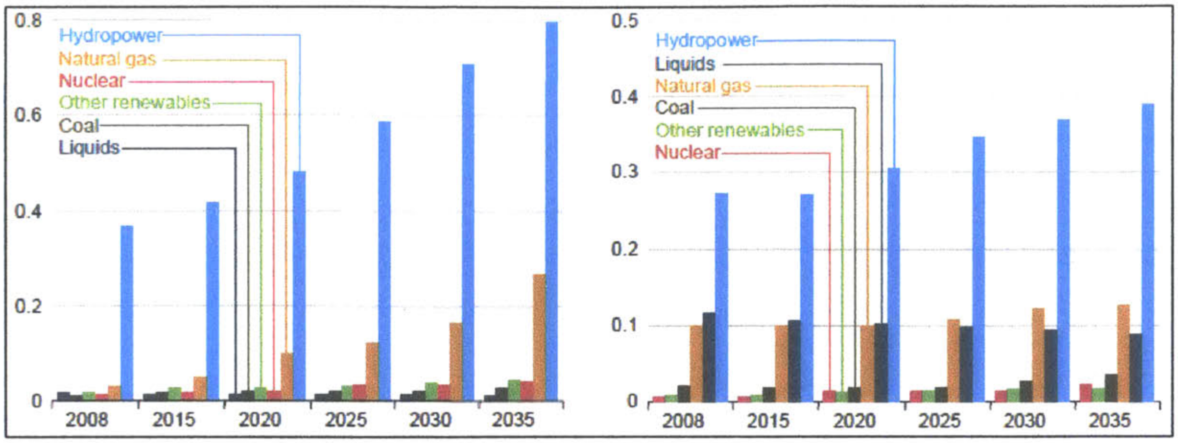

Figure 33: Electricity generation (in trillion kWh) & fuel-mix in Brazil (left) and other Central and South American countries (right) (IEA, 2011a)

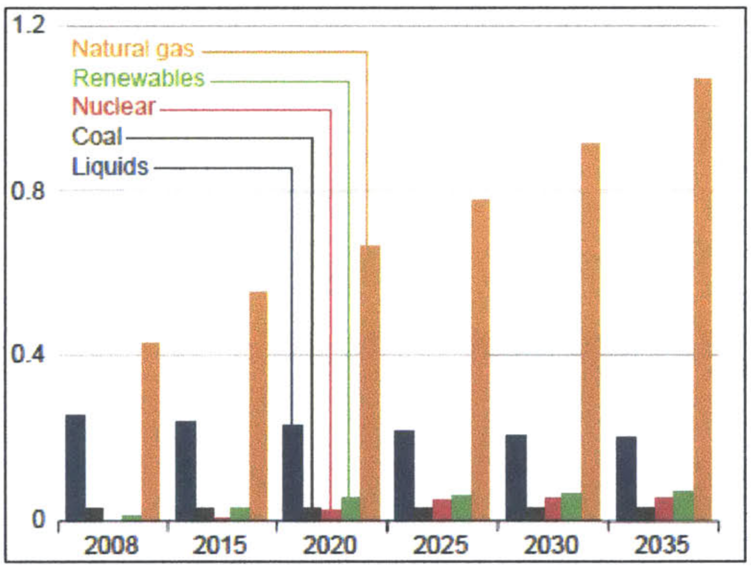

Figure 34: Electricity generation (in trillion kWh) & fuel-mix in the Middle East (IEA, 2011a)

Petroleum fuel-based generation capacity is expected to supply a remainder of the requirement not served by natural gas in the Middle East. In OECD Europe, which is the only region that has surpassed its targets under the Kyoto Protocol, is expected to continue relying on expanding its renewable capacity, which is expected to displace coal in the region. Nuclear and gas-based capacity is expected to contribute nearly equally to the region's generation requirements.

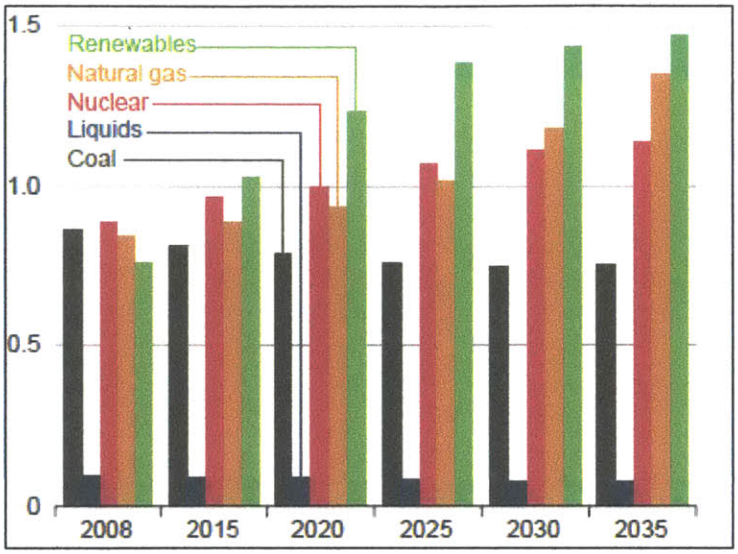

Figure 35: Electricity generation (in trillion kWh) & fuel-mix in OECD Europe (IEA, 2011a)

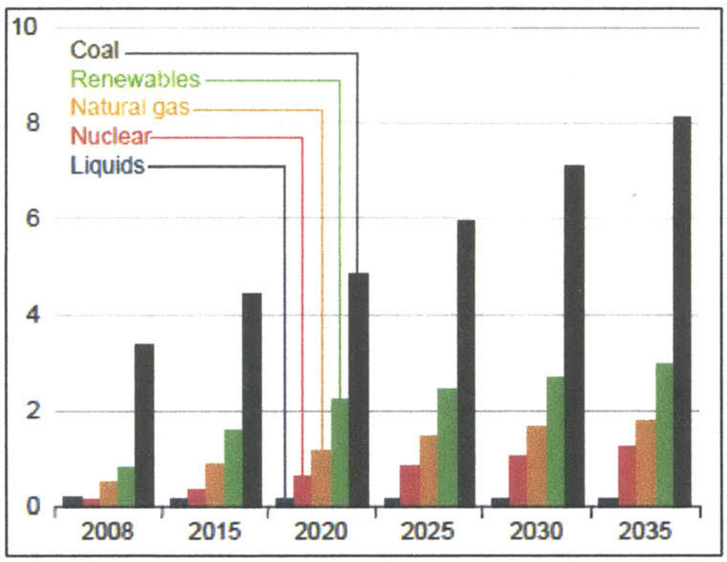

Figure 36: Electricity generation (in trillion kWh) & fuel-mix in Non-OECD Asia (IEA, 2011a)

In both non-OECD Asia and the African continent, coal is expected to play a significant and increasing role in meeting the regions' electricity needs. Considering that coal-fired power plants are expected to have a useful life of at least 40 years, new capacity that is added in 2035 may serve the region's needs until 2075. Assuming that reducing carbon emissions will continue to be important towards the end of the century, development of CCS technology is essential to ensure continued growth in this region.

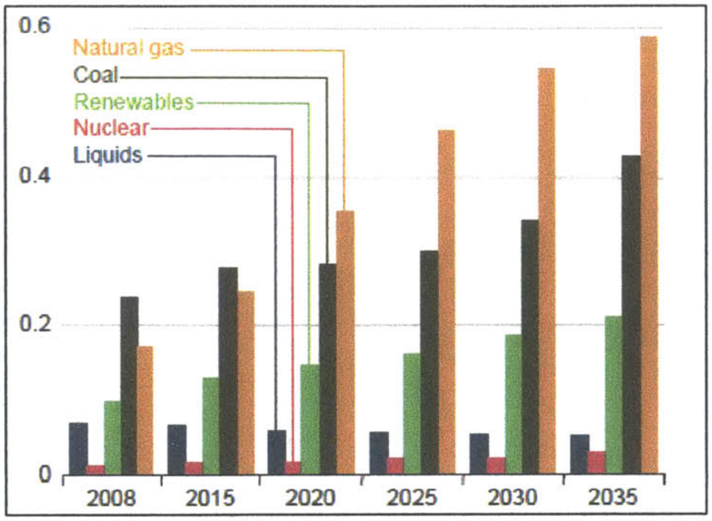

Figure 37: Electricity generation (in trillion kWh) & fuel-mix in Africa (IEA, 2011a)

APPENDIX B: EPPA Model – Details

Table 14: Structure of the EPPA Model (Paltsev et al., 2005)

Countries/Regions	*Sectors*	*Technologies for Electric Power Sector*
United States (USA)	Agriculture (AGRI)	Conventional Fossil
European Union (EUR)	Energy Intensive (EINT)	Hydro
Eastern Europe (EET)	Transportation (TRANS)	Conventional Nuclear
Japan (JPN)	Other Industry (OTHR)	Advanced Nuclear
Former Soviet Union (FSU)	Services (SERV)	Wind, Solar
Australia & New Zealand (ANZ)	Electricity (ELEC)	Biomass
Canada (CAN)	Conventional Crude Oil (OIL)	NGCC
China (CHN)	Oil from Shale (SOIL)	NGCC with CCS (NGCap)
India (IND)	Liquid Fuel from Biomass (BOIL)	IGCC with CCS (IGCap)
Higher Income East Asia (ASI)	Refined Oil (ROIL)	
Middle East (MES)	Coal (COAL)	
Indonesia (IDZ)	Natural Gas (GAS)	
Mexico (MEX)	Gas from Coal (CGAS)	
Central & South America (LAM)		
Africa (AFR)		
Rest of World (ROW)		

APPENDIX C: Global Electricity Mix

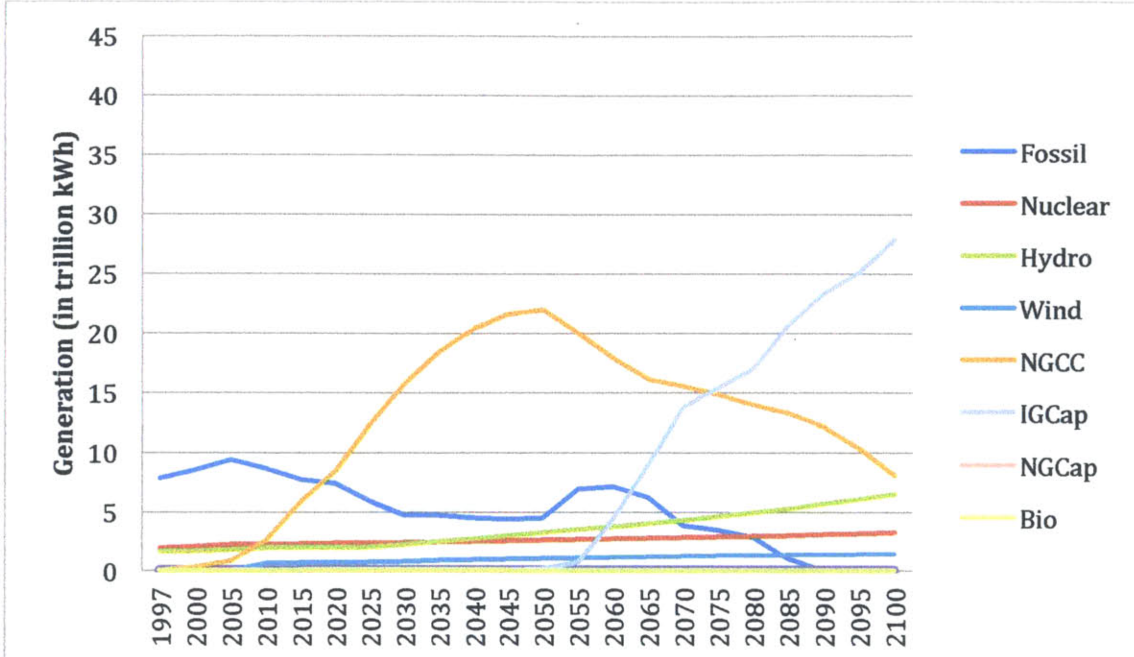

Figure 38: Global Electricity Mix - No Delay - Case 2a & 2b

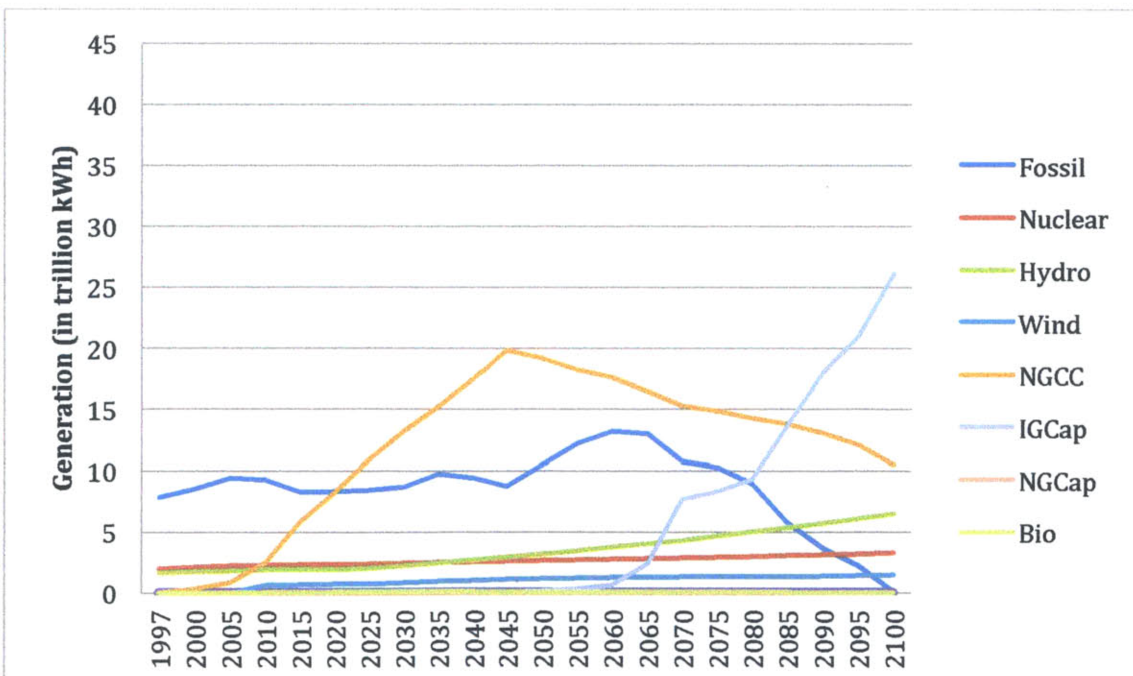

Figure 39: Global Electricity Mix - 10-year Delay - Case 2a

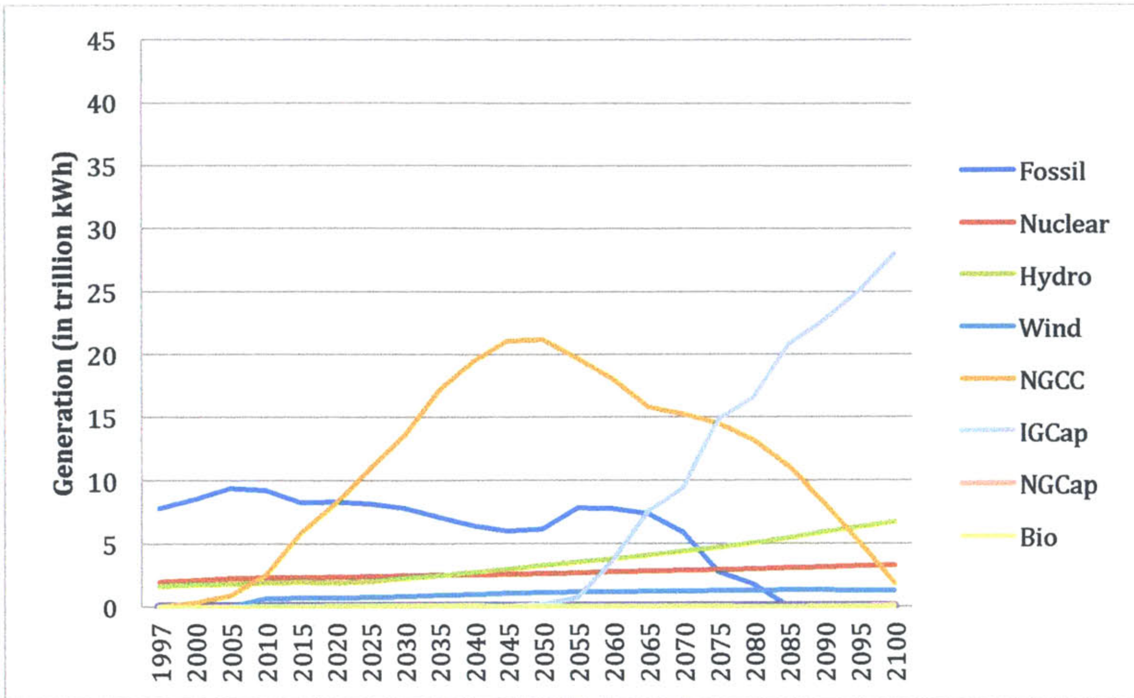

Figure 40: Global Electricity Mix - 10-year delay - Case 2b

Changing the markup factors

Table 15: Changing markup factors

	Pulverized Coal	*NGCC*	*NGCC with CCS*	*NGCC*	*NGCC with CCS*	*IGCC with CCS*	*Advanced Nuclear*	*Wind*	*Biomass*
				For case 3a & 3b	*For case 3a & 3b*				
Markup Over Coal	1.00	0.84	1.33	0.71	1.18	1.42	1.78	1.28	1.47
Markup Over Coal (New)	1.00	1.01	1.42	0.91	1.28	1.52	1.77	1.10	1.50

New markup factors are similar to that in Ereira (2010), and data was sourced from AEO, 2009 to estimate these factors.

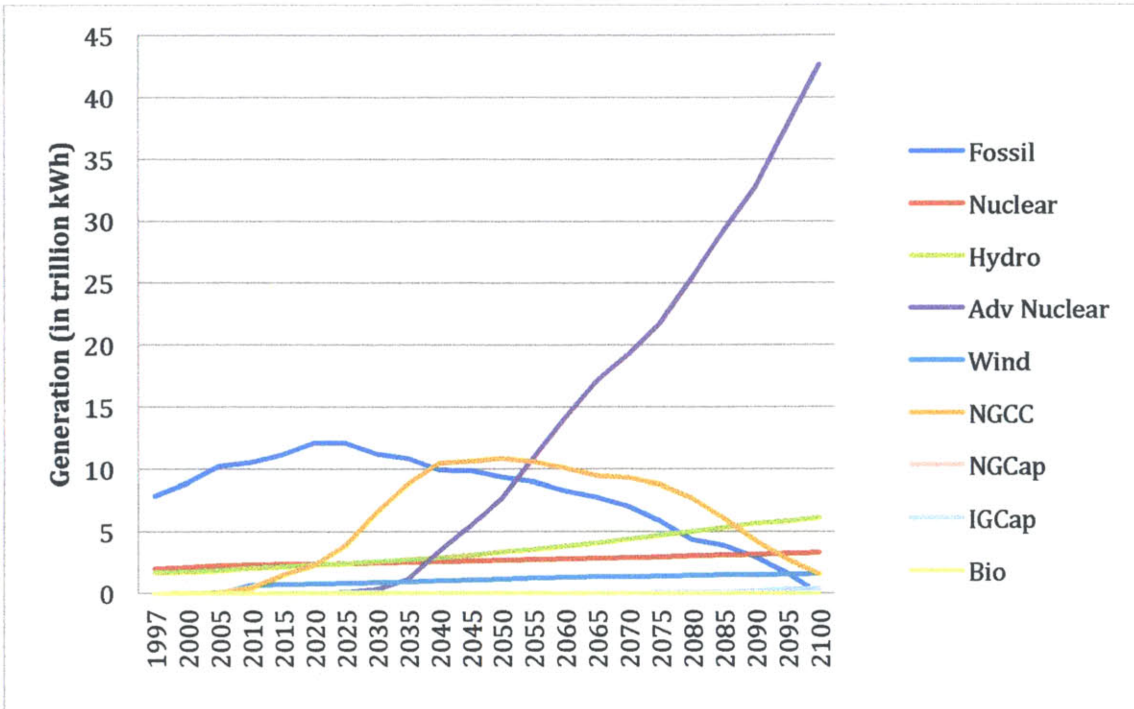

Figure 41: Global Electricity Mix - No Delay

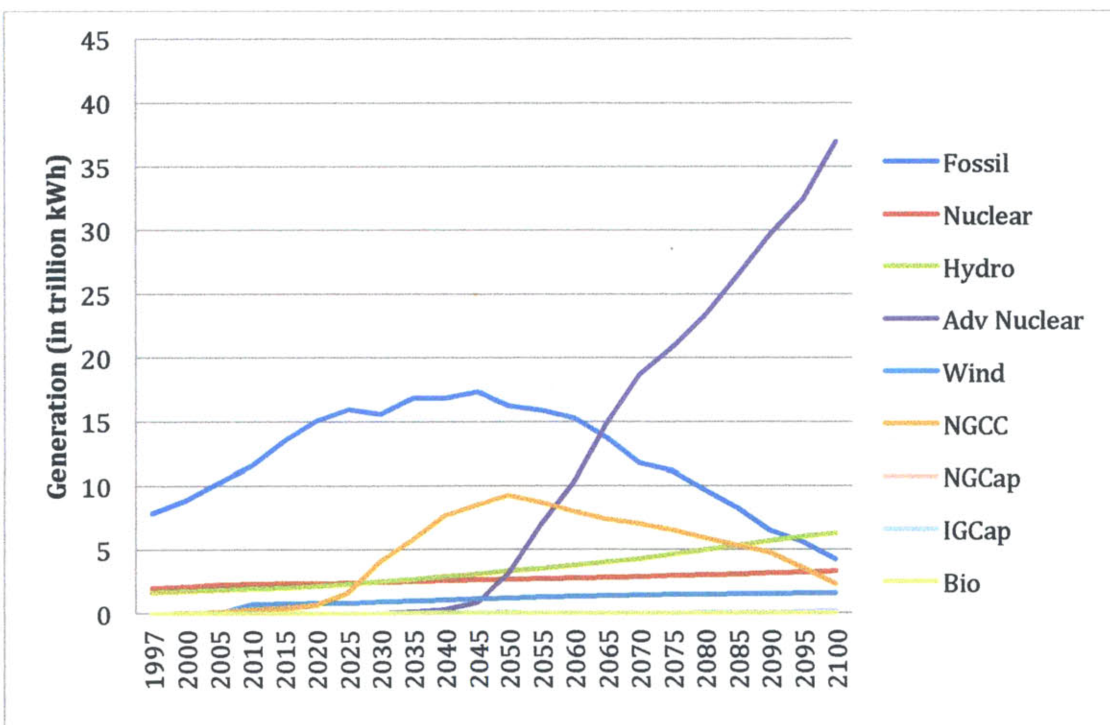

Figure 42: Global Electricity Mix - 10-year delay – Case 1a

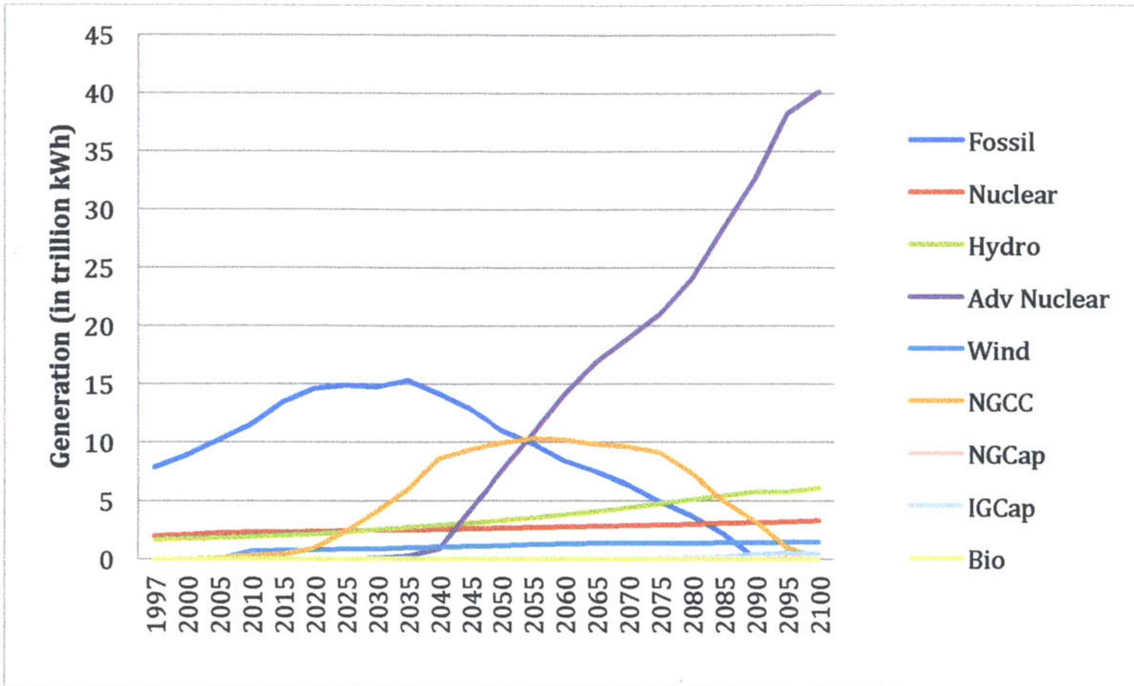

Figure 43: Global Electricity Mix - 10-year delay – Case 1b

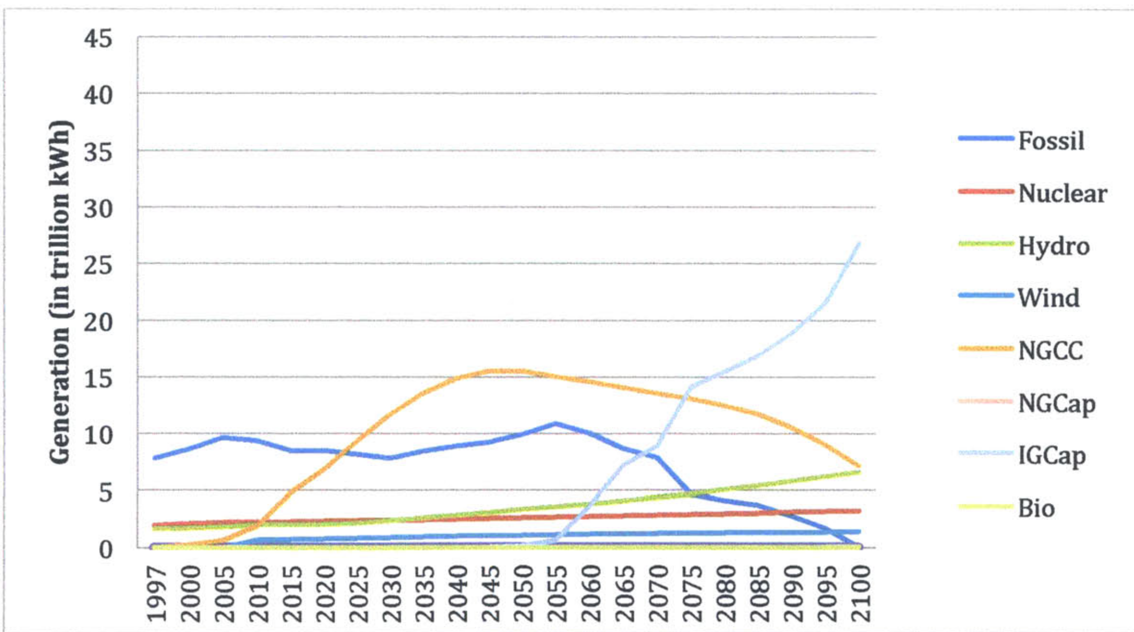

Figure 44: Global Electricity Mix - No Delay – Case 3a & 3b

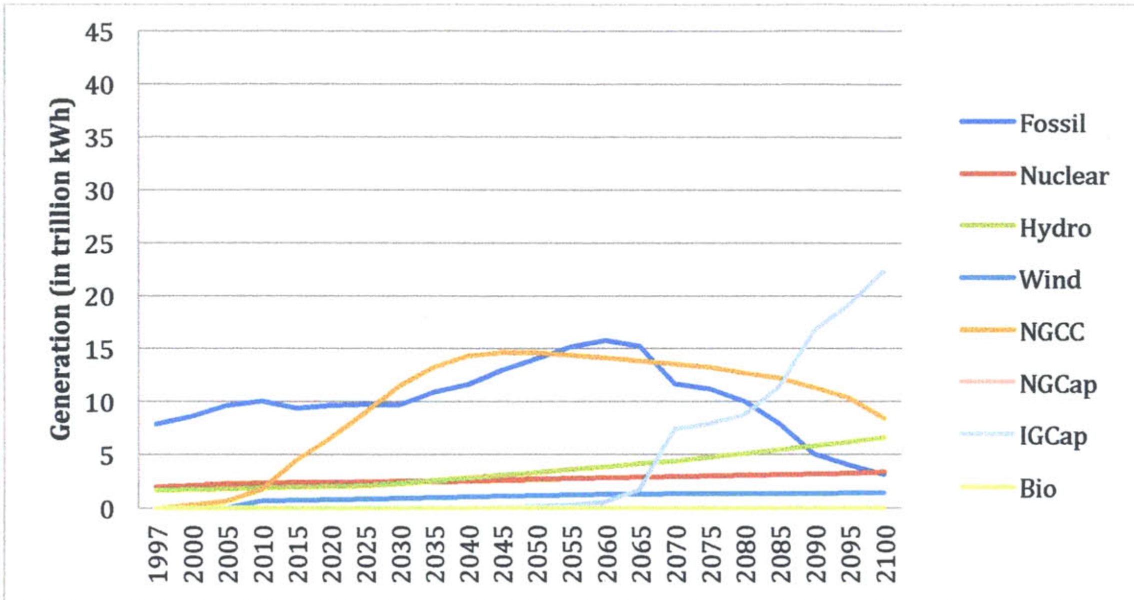

Figure 45: Global Electricity Mix - 10-year delay – Case 3a

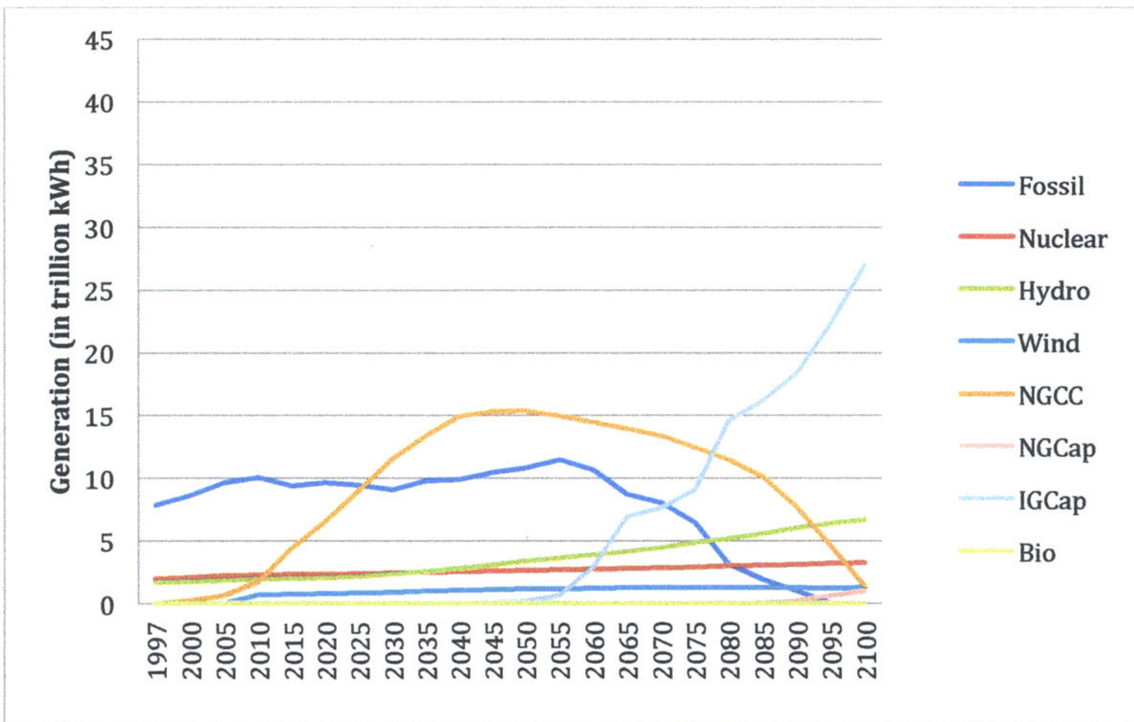

Figure 46: Global Electricity Mix - 10-year delay – Case 3b

APPENDIX D: Monetary & non-monetary reasons for cancellation/uncertainty

The reasons for cancellation or uncertainty associated with a sample of demonstration projects are outlined below in the table below. Information is gathered from news sources, databases, company websites, and similar sources.

Table 16: Reasons for cancellation/uncertainty of Demonstration Projects

Project	Location	Factors	Details	Remarks
Peterhead (Power)	Scotland	Lack of govt. support – ***funds*** **Monetary**	**May 2007:** BP scraps project as the UK government delays announcement of £1 billion prize. BP spends $25 million on project before scrapping it. (Carbon Capture Journal, 2007)	**November 2011:** Shell and Scottish & Southern Energy agree to work together to develop the project contingent on funding (BBC, 2011) Recent development: In the second round of the UK £1 billion CCS competition, this project has been named as the "Preferred Bidder" (UK Government, 2013)
Antelope Valley (Power)	USA	High costs **Monetary**	**December 2010:** FEED Study coupled with assessment of necessary additions, financing, and storage costs led to an estimate of $500 million (Basin Electric, 2011)	Other factors included nascent market for EOR, uncertainty in environmental regulation, and lack of long-term energy strategy in the US.
Janschwalde (Power)	Germany	Lack of govt. support – ***political will*** **Non-monetary**	**December 2011:** Vattenfall scrapped €1.5 billion project due to political opposition based on environmental concerns (Power, 2011)	Local citizens protested against the project citing that leaks could impair quality of water. The Carbon Storage Law passed by the German Federal Cabinet in April 2011 shifts decision on storage from federal to state govt.

Goldenberg werk (Power)	Germany	Lack of govt. support – ***political will*** **Non-monetary**	**November 2009:** Inadequate legal basis and lack of political will were cited as reasons. (RWE, 2009)	
Taylorville	USA	Lack of govt. support – ***funds*** **Monetary**	**January 2011:** Project was cancelled after Senate 33-18 to deny authorization to build the plant. (iStockAnalyst, 2011)	Bill to procure $3.5 billion from ratepayers was rejected by the Senate. (Power, 2011a)
AEP Mountaineer	USA	Lack of govt. support – ***funds*** **Monetary**	**July 2011:** Request to Virginia PUC to recover some costs through $74 million increase for ratepayers rejected (Bloomberg, 2011)	Uncertain climate policy also cited as a reason. (Daily Mail, 2011)
Sweeny Gasification	USA	High costs **Monetary**	**August 2011:** Large financial commitment to be made before federal climate change regulation became certain.	In 2009, the project was selected by DOE to be awarded $3 million Cooperative Agreement to share development of cost. ConocoPhillips did not apply for Phase 2 of DOE funding. (MIT, 2013)
ZeroGen	Australia	Lack of govt. support – ***funds*** **Monetary**	**December 2010:** Queensland state govt scrapped project after study found it unviable.	State writes off AU$96.3 million as a loss while the remaining AU$6.3 million was received as a grant. Federal govt contribution of AU$47.5 million for feasibility study. (Courier Mail, 2010)

Longannet	UK	High costs **Monetary**	**October 2011:** Developers believed that they required £1.5 billion from the govt that was only offering £1 billion. (Guardian, 2011)	Partners' falling out over funding is also cited as a reason.
Kingsnorth	UK	State of the economy **Non-monetary**	**October 2010:** E.ON UK pulled out of the competition for £1 billion for CCS projects on the grounds that the project was uneconomic (Business Green, 2010)	Market conditions were unsuitable for investments in coal, and estimates of project cost were high.
Plant Barry	USA	High costs **Monetary**	**March 2010:** Southern Company withdrew from the project expressing concern regarding the financial requirements. (E&E Publishing LLC, 2010)	Tight timeline to secure funding and involvement in other CCS projects (already have high exposure to risk) were cited as other reasons. (Alabama Media Group, 2010)
Barendrecht	Netherlands	Lack of local support **Non-monetary**	Cancelled due to local opposition to the project (Carbon Capture Journal, 2010)	Project delays were also cited as reasons.

APPENDIX E: Studies on generic FOAK estimates

GCCSI estimates that the capital cost of a demonstration project will fall in the range of \$5000 - \$6000/kW based on their analysis of data in the Longannet FEED study. For this analysis, it is assumed that a generic FOAK plant will cost \$5500/kW.

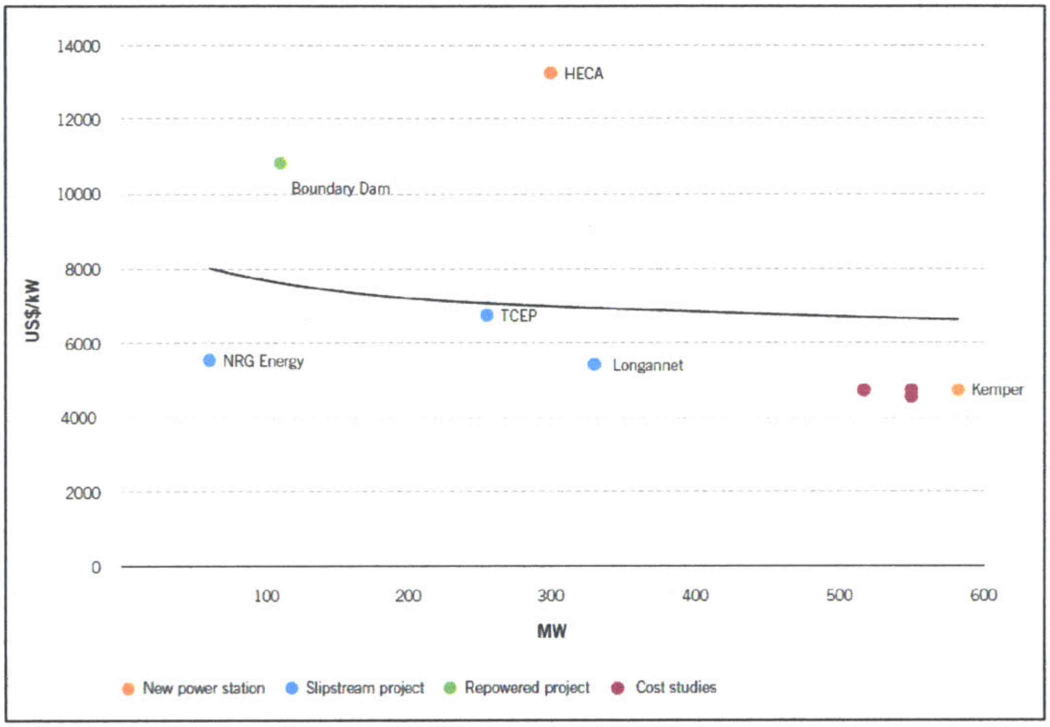

Figure 47: Estimates of FOAK costs

COE in year 1 is calculated using the GCCSI estimates for FOAK Costs. Here, it is important to note that the GCCSI estimates are only applicable to SCPC and IGCC technologies. Further, an IGCC plant without CCS is considered to be an FOAK plant.

Table 17: Analysis on FOAK Costs using GCCSI Estimates

Parameter	*Case 11 SCPC w/o*	*Case 12 SCPC*	*Case 5 IGCC w/o*	*Case 6 IGCC*
	FOAK – GCCSI		***FOAK – GCCSI***	
	NOAK Costs			
TOC (\$/kW)	2024	3570	2716	3904
O&M (f) - \$/kW pa	59	97	85	117
O&M (v) mills/kWh	5.0	8.7	7.8	9.9
CO_2 TS&M mills/kWh	0	5.6	0	5.6
COE - (Model – Updated Economic Parameters)	70	123	92	134

	Updated FOAK Costs			
TOC ($/kW)	2024	5500	3631	5500
O&M (f) - $/kW pa	59	149	114	165
O&M (v) mills/kWh	5.0	13.5	10.4	14.0
CO_2 TS&M mills/kWh	0	8.6	0	7.9
COE (Model - FOAK added to above)	**70**	**170**	**114**	**176**

Results from the Belfer Center study: The impact of the addition of CCS is estimated at 7 – 10 c/kWh, as indicated in the table below. For the analysis in Chapter 8, an average value or 8.5 c/kWh is used, and the capital cost that will yield an 8.5 c/kWh difference between a system with and without CCS is estimated.

Table 18: Estimated impact of the addition of CCS on COE

Year	FOAK cost premium c/kWh	FOAK $/ton	NOAK cost premium c/kWh	NOAK $/ton
2008 * End of period of sustained escalation is costs of large capital intensive projects	8 – 12	120 – 180	2 – 5	35 – 70
2005/06 **Lower than 2008 levels, but significant cost escalation from levels prior to that	6 – 9	90 – 135	1.5 – 4	25 – 50
Estimates of likely representative range ***Data chosen for financial analysis	7 – 10	100 – 150	2 – 4	30 – 50

APPENDIX F: Estimated Costs of Demonstration Projects

Table 19: Estimated Costs for a Sample of Demonstration Projects (MIT, 2013)

PROJECT	EOR	MW gross	MW net	Cost \$/kW	\$/kW Capture	\$/kW Storage	CO_2 Pipeline Length (km)	Pipeline Length km/MW
Peterhead (R)	Y		350	2840			*240*	*0.51*
Antelope Valley (R)	Y		120	2392			*330*	*2.75*
Janschwalde	N		250	8065	6452	1613	150	0.50
Goldenberg werk	N	450	360	9091	7273	1818	530	1.18
Taylorville	N	716	602	5814			50	0.07
AEP Mountaineer (R)	N		235	2843			20	0.08
Sweeny Gasification	N		680	6003			50	0.07
ZeroGen	N	530	400	10616			220	0.42
Longannet (R)	N		363	5835	3344	2491	260	0.79
Kingsnorth	N		300	8330	4165	3832	270	0.90
Plant Barry (R)	N		160	4375			16	0.10

* Pipeline lengths in italics are existing pipelines