DISCUSSION PAPER

March 2012 ■ RFF DP 12-14

Flexible Mandates for Investment in New Technology

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RESOURCES FOR THE FUTURE

Flexible Mandates for Investment in New Technology

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Abstract

Regulators often seek to promote the use of improved, cleaner technology when new investments occur; however, technology mandates are suspected of raising costs and delaying investment. We examine investment choices for electricity generation under a strict emissions rate performance standard requiring the installation of carbon capture and storage (CCS) on fossil-fired plants. We compare the strict standard with a flexible one that imposes a surcharge for emissions in excess of the standard. A third policy allows the surcharge revenue to fund later CCS retrofits. Analytical results indicate that increasing flexibility leads to earlier introduction of CCS, lower aggregate emissions and higher profits. We test this using multi-stage stochastic optimization, with uncertain future natural gas and emissions allowance prices. Under perfect foresight, the analytical predictions hold. With uncertainty, these predictions hold most often but we find outcomes that contradict the theory. In some cases, investments are delayed to enable the decisionmaker to learn additional information.

Key Words: technology standards, innovation, climate change, uncertainty, carbon capture and storage

JEL Classification Numbers: Q52, Q55, Q58

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Flexible Mandates for Investment in New Technology

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1. Introduction

Environmental regulators often impose technology standards on new investments that require better performance than the incumbent technology. For example, corporate average fuel efficiency standards require efficiency that exceeds the average of the existing vehicle fleet and which are made more stringent over time. New Source Performance Standards impose a benchmark for stationary sources that is typically more stringent than for existing facilities. The process of New Source Review requires an ongoing evaluation of best achievable control technology that is ratcheted up over time.

The intuition for such policy is straight forward —it should be less expensive to achieve emissions reductions at new emissions sources than at existing sources, and those emissions reductions will continue over the entire life of the facility. Unfortunately, technology standards are likely to raise the cost of investment and thus may delay new investment, causing existing vehicles or stationary sources to continue in operation at a dirtier level of performance than would their replacement. This may be true even if their replacement did not face a technology standard because a new facility is likely to take advantage of newer vintage technology and certainly perform better than aged facilities. Hence, regulators face a dilemma in the design of policies to promote new technology—technology mandates might have the unintended result of increasing pollution.

This dilemma is especially acute in the context of investments in the electricity sector because many existing facilities have aged technology that is in use beyond its anticipated useful

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The authors are grateful to Rich Sweeney, Susie Chung, Margaret Goulder, Varun Kumar, Erica Myers, Matthew Woerman and Anthony Paul for technical assistance, and to Catherine Wolfram and participants in seminars at Carnegie Mellon University and North Carolina State University for helpful comments. This study received support from the BigCCS Centre, formed under the Norwegian research program Centres for Environment-friendly Energy Research (FME), with contributions from the following partners: Aker Solutions, ConocoPhilips, Det Norske Veritas AS, Gassco AS, Hydro Aluminium AS, Shell Technology AS, Statkraft Development AS, Statoil Petroleum AS, TOTAL E&P Norge AS, GDF SUEZ E&P Norge AS, and the Research Council of Norway (193816/S60). Patino-Echeverri received financial support from the Center for Climate and Energy Decision Making funded by the National Science Foundation (SES-0949710).Model development was supported by EPA STAR grant RD-83099001, Mistra's Climate Policy Research Forum (Clipore) and the Joyce Foundation.

life. New investments are likely to be more efficient with lower emissions rates even in the absence of technology standards. However, because new investments also are likely to have a long operating life and effectively lock in their technology design for decades, there is a motivation to make those investments as modern as possible.

The long-term nature of investment in the electricity sector triggers special concern about the long-term problem of climate change. The electricity sector contributes roughly 40 percent of the U.S. domestic carbon dioxide (CO_2) emissions. Despite state and federal policies to encourage development of renewable generating technologies, such as wind, biomass and solar, and emerging federal policies to promote new development of nuclear power, over 70 percent of the electricity produced in this country is generated with fossil fuels and, according to the Energy Information Administration (EIA) it is expected to remain above 60 percent for the next 25 years (U.S. EIA 2010a). This continued reliance on fossil fuels, particularly coal, makes the challenge of reducing emissions of CO_2 a substantial one. Currently there is no national binding restriction on CO_2 emissions, thus the electricity industry is uncertain what to assume about future carbon regulation when evaluating investment opportunities. Investment decisions in the near term also could increase the potential exposure of electricity rate payers in regulated regions to higher electricity rates in the future, when a federal climate policy comes into force.

Ultimately the U.S. may adopt a comprehensive national climate policy. However, the timing of that action and the stringency of the restrictions that will be adopted remain very uncertain. It appears that if federal policy takes the form of a national cap and trade program, initially that policy will likely impose a relatively modest price on CO_2 emissions and that price may not be sufficient to overcome incentives to invest in uncontrolled coal facilities.

One way to force investors in new facilities to control their CO_2 emissions would be to impose an emission rate standard on new fossil-fired capacity in the same way that such standards are imposed to specify maximum emission rates (or minimum emissions reductions) for criteria pollutants like sulfur dioxide (SO_2) and nitrogen oxides (NO_x). In fact, such a standard is likely to be part of the suite of Clean Air Act regulations of CO_2 emissions under development at the Environmental Protection Agency (EPA, 2010). Initial regulations are likely to impose standards to promote operational efficiency or the greater use of natural gas, but to achieve substantial emissions reductions while enabling the continued use of fossil fuel is likely to require an emissions rate standard that can only be met with carbon capture and storage (CCS) technology. Currently the high costs of carbon capture and the uncertainty surrounding the performance of the technology, plus the largely undeveloped nature of both the physical and regulatory infrastructure for carbon transport and storage, all contribute to a reluctance to make major investments in this technology. In the presence of a technology standard, even if coupled with a moderate CO_2 price, investors might hold off on investing in new facilities and extend the lives of existing units until costs come down and experience with the new technology builds.

The delay in new investment has several potentially deleterious effects. The path of technology costs over time depends on an infusion of investment capital and learning by doing and this learning will be delayed if investment is delayed. Second, in regions of the country with abundant coal resources the possibility of hastening the development of CCS offers the prospect of regional economic development. Further, the need to meet growing electricity demand will lead to increases in electricity prices, which could erode political support for climate policy. In addition, the nation may turn increasingly to natural gas-fired generation, which will push up the price of natural gas and thereby affect the economy on a broader scale. All these factors suggest that an inflexible policy to slow development of uncontrolled coal plants may have unanticipated consequences and policymakers may want to couple this strategy with policy aimed at accelerating the deployment of CCS.

Flexible compliance opportunities may be able to overcome this predicament by providing alternative ways to achieve comparable emissions reductions as if new technology were installed. One approach to introducing flexibility might be lifetime emissions rate averaging that required a facility to achieve an emissions rate equivalent to a performance standard over its lifetime, rather than at each point in time, to allow for subsequent retrofit of facilities with new technology when it becomes less expensive. This approach is similar to the mechanism used for the phase-out of nuclear power. In 2000 in Germany, Italy and elsewhere the phase-outs were mandated based on a budget of remaining hours that the fleet of existing plants could generate based on fixed total lifetime but let the industry allocate those hours in a cost effective way. The disadvantage of such an approach is that it may not be dynamically consistent. As the date of reckoning in these countries came closer the political debate began to revisit the commitment, which could easily be reversed. Moreover, all costs of the phase-out were back loaded, meaning that they would not really be felt until plant closings actually occurred, making policy reversal plausible.[1]

A different approach would be to provide endogenous incentives to allow for technology mandates to be dynamically consistent and incentive compatible. The challenge, which motivates this investigation, is how to provide incentives to accelerate the adoption of new technology.

In this paper we investigate the dilemma associated with mandates for the use of new technology in the electricity sector. We examine investment choices for electricity generation under a strict emissions rate performance standard for CO_2 that would require the installation of CCS on new or modified fossil-fired power plants. We compare the strict standard with a flexible one that provides for the opportunity to pay an emissions surcharge for investments that fail to meet the maximum CO_2 emission rate standard. Third, we look at a policy that allows revenue from the surcharge to be held in an escrow account and to be used to fund later retrofit investment in CCS technology.

We demonstrate the possibility that the introduction of a new inflexible emissions rate standard can delay new investment. Delay has a dual disadvantage. It potentially increases cumulative emissions over the model horizon. Second, although outside of this model, it potentially postpones the dynamic process of cost reductions for new technology.

In an analytical framework we show the introduction of flexibility with an opportunity to pay a surcharge for emissions above the emissions standard can lead to earlier investments than under the inflexible standard, with lower aggregate emissions and greater profits to investors. When funds from the payment of the surcharge held in escrow are made available to pay for part of the capital costs of CCS retrofits, investment would occur most quickly. Under this policy aggregate emissions are the lowest and profits to investors are the highest.

We test these analytical results in a simulation framework that combines national and regional level electricity market equilibrium with the multi-stage stochastic optimization problem facing an individual investor over the period 2009-2052. The alternative technology policies and

[1] For illustration, imagine an emissions rate standard for all new fossil steam electricity generating units equivalent to best practice, defined as a natural gas combined cycle unit. If new plants are assumed to have a 30 year planning lifetime, the gas unit has an emissions rate equal to one-half that of a new uncontrolled coal facility, and CCS captured 90 percent of the CO_2 emissions from coal, then CCS retrofit technology would be required with new coal by year 13. That year the owner would be faced with the option to retrofit the facility or to close a relatively new plant; each option provides substantial motivation to expend resources to try to change the requirement.

investment choices are examined under perfect foresight and in the presence of uncertainty about future natural gas prices and the prices of CO_2 emissions allowances. The model examines the incentives for an individual investor to choose the timing of investment and generation technology from among five technology options, with CCS installed or with subsequent retrofit with CCS. The investor's problem is nestled within the relevant electricity market equilibrium, which depends on the realization of the uncertain variables.

In the absence of a technology policy, we find uncertainty leads to basically the same pattern of investments as under perfect foresight but these investments occur later, especially the initial investment in generation technology.

Against this backdrop the three technology policies are evaluated. With perfect foresight an inflexible technology policy delays investment in every scenario except one, which is consistent with several hypotheses that are developed in the paper. We identify an emissions surcharge under a flexible policy that leads to investment in CCS at the same time or earlier as would occur under a strict standard. The introduction of an escrow fund leads to investment in CCS at the same time or earlier than in the absence of the fund. In one interesting case, however, operation of the CCS is delayed. Total cumulative emissions are lower for the flexible policy, and lower still in several scenarios (and never higher) with the escrow fund. Profits are higher with the flexible policy, and higher still in several scenarios (and never lower) with the escrow fund. With uncertainty, similar results consistent with the hypotheses are obtained.

These findings indicate that compared to an inflexible performance standard, the introduction of flexibility in the implementation of an emissions standard could lead to the earlier adoption of CCS for a given type of generation technology, and/or the earlier adoption of new generation technology. Either of these effects would lead to emissions reductions. However, because such a mechanism affects the capital cost of investment in CCS in different ways for various technologies, it could change the choice of generation technology.

The remainder of this paper is organized as follows. The next two sections describe the policy context and the technological choices for baseload generation in the electricity sector, and especially in the specific context of the Illinois basin that forms the basis for the case study. Section 4 reviews the economics literature on the history and performance of technology standards. Section 5 formalizes the new regulatory mechanism that we propose and develops analytical predictions. Section 6 describes the model and parameters that are used in the simulations and section 7 describes simulation results and describes future work. Section 8 concludes.

2. Context and Policy Background

According to the EIA (2010a), electricity demand is expected to grow by 1.0 percent per year over the next quarter century and large amounts of new base-load generation capacity will be needed to meet that demand. EIA predicts that on net 27 GW of new coal fired capacity will be added by 2035, leading coal's share of total generation to decline slightly from the current 49 to 44 percent in 2030. Given the assumed continuation of current environmental policies, in particular the lack of a restriction on CO_2, the new coal-fired capacity forecasted in the EIA projections would not be equipped with CCS technology. These additions of uncontrolled coal-fired capacity coupled with the continued use of a large fleet of existing coal plants contributes importantly to the predicted nearly 9 percent growth in national CO_2 emissions between now and 2035.

Investment in new coal generation has slowed considerably from what was anticipated at the beginning of the decade. According to the National Energy Technology Laboratory (NETL), announced planned additions to coal-fired capacity total nearly 44 GW compared to 72 GW just a few years ago. Roughly 17 GW (at 30 plants) of that 44 GW total have been identified as "progressing" (i.e., either currently under construction, nearing construction or permitted) (Schuster 2007, 2010). Of the 30 plants that are progressing, 11 are using sub-critical pulverized coal technology and only 6 employ integrated gasification combined cycle technology. In an earlier report released in 2002, NETL reported that nearly 12 GW of new coal was expected to be installed by 2005, but only 329 MW were actually added over that time horizon with many projects facing delays in implementation. All of these activities suggest that the future prospects for coal are uncertain and regulatory uncertainty is an important contributing factor.

Despite years of inaction on the part of the federal government on restricting emission of greenhouse gas (GHG) emissions, several recent developments point to the possibility that the United States will adopt federal restrictions on CO_2 regulations in the next few years. These developments include state and regional initiatives,[2] the U.S. Supreme court decision that EPA has the authority to regulate GHGs under the Clean Air Act[3] and a substantial number of federal legislative proposals to limit GHG emissions. Not only do these actions foreshadow federal action, but in some cases they also suggest that the likely climate regulatory regime with be

[2] These initiatives include the Regional Greenhouse Gas Initiative in the northeast, the legislation imposing emissions targets in California, the Western Climate Initiative involving seven western states and four Canadian Provinces, and a cooperative effort among several midwestern governors to develop a regional policy there as well.
[3] *Massachusetts v. EPA*, 549 U.S. 497, 528–29 (2007).

multi-faceted. In the near term, when regulation under the current Clean Air Act is likely, a federal policy is likely to include some type of technology standard for new sources. Eventually, the US may adopt some type of policy to price carbon emissions and technology standards for new generation capacity would be likely to continue under this policy (as occurred previously with the introduction of an emissions trading systems for SO_2 and NO_x).

Signs of support for a federal policy and some ideas about what such a policy might look like can be seen in the debate surrounding the many legislative proposals currently before the congress.[4] Nine bills proposing some form of cap-and-trade or fee program for GHG emissions have been introduced in the 111th Congress. The Waxman (D-CA) -Markey (D-MA) bill (H.R.2454) combines a downstream cap and trade program for large emitters with an upstream cap and trade program for transportation fuels, and was passed by the House of Representatives on June 26, 2009. The bill includes a special allocation of allowances to electricity generators that install CCS technology and specifies a qualifying emission rate standard that plants built (or retrofitted) to capture CO_2 emissions must meet to receive a portion of those set aside allowances. In the senate, the Kerry (D-MA)–Lieberman (I-CT) draft legislation known as the American Power Act includes a requirement that all coal-fired power plants that are permitted after 2020 reduce CO_2 emissions by a minimum of 65 percent below uncontrolled levels, with a more stringent requirement to take effect once it has been established that best practices can achieve greater reductions. Coal-fired electricity units must be in compliance by 2020.[5] Coal-fired power plants permitted before 2020 are required to reduce emissions by 50 percent. [6]

Federal regulation of CO_2 also is forthcoming as the EPA moves toward regulation of GHGs under the Clean Air Act. The form of future EPA regulation is somewhat uncertain, but

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[4] For a summary of the different bills and their provisions see Morris (2010) http://www.rff.org/wv/Documents/Market_Based_Climate_Bills_RFF_05_12_10.pdf (acccessed June 4, 2010).

[5] Alternatively, coal palnts must be in compliance within 4 years after commercial scale CCS technology demonstrates a 10 gigawatt capacity, which may include capacity from industrial sources but must include at least 3 gigawatts from electricity generators with a capacity of 250 megawatts or more, and captures 12 million tons of CO_2 annually, if this is achieved earlier.

[6] At least two of the climate cap and trade bills introduced in the 110th Congress also included maximum CO_2 emission rate standards for new electricity generation introduced in the next decade. The Sanders-Boxer Bill (S. 309) includes an emission rate standard for all generating facilities that operate at a capacity factor of 60 percent or greater that is equivalent to the emission rate achieved by a new combined cycle gas unit. This standard takes effect beginning in 2015, but it applies to all units that begin operating in 2012. The Clean Air/Climate Change Act of 2007 (S 1168) sponsored by Senators Alexander and Lieberman included a new source performance standard of 1,100 pounds of CO_2 per MWh that takes effect in 2015. A new source performance standard (NSPS) for coal generation was also the center piece of the Clean Coal Act of 2006 (1227) sponsored by Kerry (D-MA).

one area that EPA regulators are grappling with is how they will implement CO_2 emission standards for new sources, and major modifications to existing sources, that fall within existing air pollution stationary source categories.[7] Two pending law suits (*New York v. EPA* and *Coke Oven Environmental Task Force v. EPA*) are challenging EPA's failure to set new source performance standards (NSPS) for CO_2 emissions from power plants and industrial boilers. These law suits were filed prior to the Supreme Court decision, and they have been remanded to the agency. As the agency goes about deciding on new source standards for CO_2 it faces challenges in terms of defining an emission threshold that would trigger regulation and what technologies would qualify.

In this paper we envision the possibility of a flexible standard that would allow for payment of a surcharge on emissions in excess of the standard as an alternative compliance mechanism. The federal Clean Air Act does not currently allow for the imposition of emission fees or noncompliance penalties as an alternative to compliance with emissions standards under either new source performance standards (NSPS) or new source review (NSR).[8] If an emissions surcharge were implemented at the federal level as we envision it would require legislative authorization. It is noteworthy that a noncompliance penalty is currently authorized under the Act for heavy duty diesel engines, with revenues directed specifically to go to the general fund.

Technology standards are also part of the environmental and climate regulatory landscape at the state level, and state level programs to adopt an emissions surcharge would not be subject to constraints of the Clean Air Act. In California, Senate Bill 1368 directs the California Public Utilities Commission and the California Energy Commission to set a GHG performance standard that applies to all new long-term financial commitments in baseload power plants. That standard, which applies to power generated within the state or imported from outside, is based on GHG emission rates that are as low as the emission rate for a combined-cycle natural gas power plant. In implementing the legislation, the California Public Utilities Commission and the California Energy Commission have adopted the standard at 1,100 lbs of carbon dioxide (CO_2) per megawatt-hour (MWh) of electricity generated. The policy is really relevant to power

[7] See EPA. *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, 74 F.R. 55292, 55297 (2009).

[8] Both NSPS and NSR apply to new and modified sources. A relevant distinction is that new source performance standards establish an emissions ceiling. NSR can establish a tighter standard through Best Available Control Technology in areas in attainment with National Ambient Air Quality Standards, or Lowest Achievable Emission Rate in areas that are not in attainment.

imported to the state, since the state has no important coal-fired generation in state and none is likely. Assembly Bill 32, which established the state's emission targets in 2006, also specifically addresses emissions associated with imported electricity.

Two other indicators point to the likelihood that some sort of technology standards will be part of a federal climate policy. First, survey research on attitudes toward environmental and climate policy suggest that the U.S. public is in favor of efforts to reduce emissions of GHGs but they don't want to pay an explicit price, such as a carbon tax, to achieve those reductions. The U.S. public has a clear preference for action in the electricity sector, and a preference for standards over cap and trade or taxes (Bannon et al. 2007). Further, survey research indicates Americans continue to be extremely anxious about the cost of energy and investment in clean technology is the most popular policy option (American Environics and EMC, 2007). Economists may chafe at the public view because most analyses indicate that cap and trade or an emission tax would be the most cost-effective way to achieve climate goals. However, the public appears to like its taxes hidden and imposing a technology standard on CO_2 emitters may be one way to impose reductions without introducing an explicit tax or allowance price to the economy.

Second, if a cap and trade policy is enacted, the stringency of that policy is not likely to be sufficient to drive the development of CCS technology. Sekar et al. (2007) found that a CO_2 price of at least $28 (+/- $5) per tonne is required to justify investment in IGCC generation plants. Bergerson and Lave (2007) find that a price of approximately $30 per tonne is required before the cost of electricity from IGCC with CCS is lower than that of a conventional pulverized coal plant. Reinelt and Keith (2007) find that significant replacements of existing plants with IGCC with CCS do not occur at CO_2 prices of less than about $50 per tonne, which implies an explicit retrofit penalty. Patino-Echeverri et al. (2007) find that a carbon price below $40 per tonne is unlikely to produce investments in carbon capture. Al-Juaied and Whitmore (2009) estimate the cost of abating CO_2 emissions through CCS, both for a first-of-a-kind plant and a mature technology plant in 2030, using a range of cost estimates from several previous studies. They conclude a first-of-a-kind plant is likely to have an abatement cost of $100-150 per metric ton CO_2 avoided, while a mature technology plant is likely to have an abatement cost of $30-50 per metric ton CO_2.

The stringency of policies recently debated in the Congress suggest a much lower price of CO_2 in the near term and potentially for some time to come and thus these policies are unlikely to provide sufficient incentive for development of CCS. Supplemental technology policies, either in the form of performance standards, incentives for research and development or both, will be required to bring these technologies on line. Without these policies and at CO_2 tax levels of less than $30, investment in uncontrolled pulverized coal generation is likely to continue as investors will have insufficient incentive to invest in CO_2 controls or to build a coal plant in a way that would make it easier to retrofit with CCS in the future. For example, utility resource plans for utilities in the non-coastal western states all plan to include some amount of new uncontrolled coal capacity in their preferred future resource plan even when their analyses assume a positive price on CO_2 emissions in the future (Barbose 2008).

3. Technology Background

Preserving a future for coal fired generation in a carbon constrained world will require the successful implementation of technology to capture the CO_2 emitted by coal-fired power plants and then transport and sequester that CO_2 in a secure storage site. The development of CCS technology and facilities and regulations to facilitate long-term geological storage of CO_2 are major areas of research.

The commercialization of carbon capture technology at coal plants and the development of sequestration sites are particularly important in the Illinois Basin, a region that covers most of Illinois and western parts of Indiana and Kentucky and is a major producer of coal and of coal-fired electricity. Nearly 75 percent of electricity in the region is generated by coal and there are over 120,000 million short tons of demonstrated coal resources in the region. (EIA 2010b, 2009a) The region is home to three types of geologic formations potentially suitable for storage: depleted oil and natural gas reservoirs, saline aquifers and deep coal mines that are inaccessible for mining.[9] Some estimates peg the total amount of area in the region covering potential geologic sequestration sites as roughly 60,000 square miles. Currently, a large consortium of university, government, and private sector researchers known as the Midwest Geological Sequestration Consortium is studying the feasibility of geological sequestration at each type of site in the region.[10] There are important technical and regulatory hurdles that must be overcome before geological sequestration becomes a viable and economic option for dealing with CO_2 emission from burning fossil fuels in the region. The Illinois Basin is of special interest for this analysis because transportation of carbon represents an important part of the cost of CCS and this could be minimized at plants in the region.

[9] Rawson (2007) of GE Research suggests that coal beds have a high leakage risk and therefore low storage capacity.
[10] More information about this effort can be found at www.sequestration.org.

In this paper we focus on the decision to invest in carbon capture at coal and gas-fired generation facilities. Arguably, the technologies that would be used for carbon capture at pulverized coal plants are at a later stage of development than the options for long term storage. Nonetheless, implementing carbon capture at pulverized coal facilities that are operating today is likely to be very expensive, with output losses on the order of 40 percent from existing pulverized coal facilities and costs per ton of CO_2 reduction of between $48 and $72 ($2005) per tonne (MIT, 2007, p. 28).[11] In this study we focus on the construction of new coal and gas fired facilities and opportunities for applying CCS either at the time of initial construction or as a post-construction retrofit. We consider five options for new generation investment including sub-critical pulverized coal, supercritical pulverized coal, ultra-supercritical pulverized coal, integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC). The technology used to capture carbon at pulverized coal facilities is chemical separation, absorption into an amine solution (often using monoethanolamine (MEA)) and then recovery from the flue gas through temperature change. This process has a substantial energy cost due to the heat needed to recover and compress the CO_2 and the increased energy use can have implications for emissions of other pollutants (Rubin et al. 2007).[12] At the combined cycle facilities, carbon capture is assumed to take place in a pre-combustion stage. In this setting an air separation unit is used to create pure oxygen for the gasification stage to facilitate removal of CO_2 in high concentrations using a combination of a solvent and a change in pressure.

The performance characteristics and costs for these different technologies come from the 2007 Carnegie Mellon University Integrated Environmental Control Model-Carbon Sequestration Edition, version 5.2.1(c) (referred to hereafter as IECM). [13] These data suggest that the differences in efficiency between a new facility retrofitted with CCS and one without CCS vary across the different coal technologies. For sub-critical pulverized coal, the efficiency

[11] The substantial output losses in this instance suggest that if an existing facility is to be retrofitted, it might be worthwhile actually repowering the facility using supercritical or ultra-supercritical technology to lower the cost per ton of CO_2 emissions reduced.

[12] This is typically not the case for SO_2 as the CCS leads to further reductions in SO_2 beyond the reductions achieved by the FGD scrubber that substantially outweigh any increase in emissions assocated with additional energy consumption.

[13] The IECM model was developed by the Department of Engineering and Public Policy of Carnegie Mellon University with support from the United States Department of Energy's National Energy Technology Laboratory NETL. The database provided by the model is a later vintage of the same database that was used for the MIT coal study (MIT 2007).

penalty of CCS measured by the increase in net heat rate is close to 40 percent.[14] For a supercritical facility the heat rate penalty is about 1/3, and it is close to 30 percent for ultra-supercritical pulverized coal facilities. For IGCC, the heat rate penalty introduced by CCS is closer to 20 percent. The capital costs of retrofit are also typically slightly lower for the more advanced coal technologies. This implies that under specific assumptions about coal type there is a dominance, that is CCS is least expensive on ultra-supercritical, then supercritical, and relatively more expensive for sub-critical. The initial cost of constructing advanced facilities is higher (per MW) than for a sub-critical pulverized coal facility, but this is somewhat offset by lower fuel consumption at the more advanced facilities. We focus on policy tools that can accelerate the deployment of CCS in the face of substantial uncertainty about how large-scale commercialization of CCS will take shape.

For a pulverized coal plant, be it sub-critical, supercritical or ultra-supercritical, the cost of adding CCS later is moderately larger than the cost of adding the CCS at the time of installation of the plant, because the CCS is a post-combustion system. We assume a retrofit penalty of 20 percent for a pulverized coal plant and also for NGCC. For an IGCC, this is not the case. The removal of CO_2 from the flue gas changes its flow rate before entering the gas turbines, which causes the specifications for the combustion system of an IGCC with and without CCS to differ significantly, as discussed by Bohm et al. (2007) and Rutkowski et al. (2003). An investor considering the installation of an IGCC in a world with no carbon constraints has two alternatives: (1) to install an IGCC that operates optimally without a CCS or (2) to install an IGCC that would operate optimally if it had a CCS system in place but is suboptimal when it is operated before the CCS is installed. Alternative (2) can be labeled as "capture ready" or "IGCC with pre-investment" and implies larger capital costs and O&M costs than (1) but lower CCS retrofit costs. In our analysis we consider only the capture ready option, alternative (2), and assume a retrofit penalty of 30 percent.

4. Review of Economics Literature on Technology Standards

The most widely used type of policy for influencing the path of technology for environmental purposes is a technology standard. The literature on the economics of technology

[14] With a sub-critical plant, rebuilding it as a super or ultra-supercritical plant and retrofitting with MEA capture has a higher capital cost but is cheaper per MWh than retrofitting a sub-critical plant with no rebuild, because the rebuilt plant will have higher energy output for lower fuel input than the sub-critical plant (MIT 2007).

standards for achieving environmental goals generally contrasts performance of standards to an incentive-based approach to regulation such as an emissions tax or cap and trade system, as incentive based approaches have been shown to be the most efficient way to achieve a particular emissions reduction target (Baumol and Oates 1988). In the presence of heterogeneous costs of reducing emissions across different sources, homogenous technology standards are not a cost effective approach. Moreover, the informational requirements for the regulator to promulgate heterogeneous technology standards to accommodate the full range of costs are challenging. In contrast, incentive-based approaches place authority in the hands of firm-level decisionmakers who have better information about options. These approaches tend to be more flexible than prescriptive regulation as they allow those who can reduce emissions at lower cost to do more abatement and those who have higher costs to do less. Incentive-based approaches also tend to provide greater incentives for firms to innovate to find less expensive ways to reduce emissions in the future by providing an incentive to exceed emission standards (Downing and White 1986, Magat 1978, Milliman and Prince 1989 and Zerbe 1970).

In practice, technology standards for environmental performance typically are not uniform across all regulated sources of emissions. In particular, air emissions standards for particular pollutants differ across vintages of regulated sources for both fixed sources and mobile sources. New Source Review (NSR) provisions under the Clean Air Act apply limits on emissions rates to new facilities or facilities that have been substantially updated. Economic theory suggests that applying stricter environmental standards to new or modified facilities than apply to existing facilities will raise the cost of investing, limit the rate of capital turnover and extend the lives of existing, often dirty, facilities. (Gruenspecht 1982) The size of this disincentive to invest can be limited by imposing less stringent standards on facilities that are constructed earlier and more stringent standards for later investment (Stavins 2007).

Empirical evidence suggests that the incentive to delay investment can be born out in practice. Gruenspecht (1982) looks at the effects of corporate average fuel efficiency (CAFE) standards for new automobiles on the turnover of the existing automobile fleet and finds that CAFE depressed sales of new automobiles by a few percentage points when they initially came into effect and actually resulted in a small increase in emissions of carbon monoxide in the early years, although this effect was undone over time. Maloney and Brady (1988) find that air quality regulations decreased the rate of new plant investment in the electricity sector and led to an increase in SO_2 emission over the 70s and early 80s. Nelson et al. (1993) study the effect of new source regulations on the age of installed capital of electricity generators and associated effects on emissions. They find that differential regulations retard capital turnover in the electricity sector, but do not result in a significant increase in emissions. More recently, Bushnell and Wolfram (2006) find weak evidence that NSR increases the lifetimes of existing plants in areas with more stringent environmental regulations. Because NSR standards can be triggered by major investments at existing plants, some have suggested that NSR could accelerate the closure of existing plants that fail to make those necessary investments. List et al. (2004) studies the relationship between plant alteration and closure decisions and attainment of air quality standards at the county level as a proxy for stringency of NSR requirements. The authors find that NSR appears to retard the rate of alteration of existing plants, but find little evidence that NSR accelerates the closure of existing plants.

Researchers have also examined how differences in regulatory stringency over space affect the location of new investment with mixed findings. Levinson (1996) studies whether births of new manufacturing plants respond to differences in state environmental regulation and finds that they do not. Becker and Henderson (2000) study the effects of differences in environmental regulation on where new plants choose to locate, plant sizes for new plants and the timing of investments. They find that new plants are more likely to locate in areas that are in attainment of air quality standards, where stricter regulations do not apply.

5. A New Regulatory Mechanism

The mechanism we examine would combine an emissions rate standard for new facilities with an emissions surcharge on every ton of CO_2 emitted by facilities that fail to meet a new source performance standard. The fee assessed on new generation would provide incentives for firms to consider the cost of likely future retrofit options in their initial investment plans.[15] In one version of the policy, revenue from the surcharge could be accumulated in a fund that might eventually be used to offset some or all of the capital costs of retrofitting a facility with CCS technology.[16]

[15] We assume a constant retrofit penalty that varies by technology but is not affected by any design considerations in the construction of the facility except whether to install CCS at time of construction or to add it later as a retrofit.
[16] This fund would be similar to the nuclear waste fund that was established under the Nuclear Waste Policy Act of 1982. The Act established a fee of 0.1 cent per kWh of electricity generated at nuclear plants with the money going toward the Nuclear Waste Fund, intended to fund a civilian waste disposal project in the U.S. The fund is intended to fund the long term waste storage facility at Yucca Mountain, but given the difficulties with licensing that site, most of the fund remains unexpended. Another incentive-based policy has been considered in the Canadian provinces.

The idea of taxing CO_2 or electricity sales to create a fund to promote the introduction of CCS is not new. Previous climate policy proposals include a set aside of emission allowances to be allocated to firms that install CCS, with those that are first to install getting a bigger amount of allowances than later installers. Other proposals envision using some portion of the revenue from a CO_2 emission allowance auction to fund research related to CCS. Kuuskra (2007) advocates a fund to promote CCS demonstration activities to be funded in part by a small assessment on electricity generated by existing coal-fired facilities. Pena and Rubin (2007) analyze prior experiences with trust funds in search of lessons on how to promote CCS pilot and commercial scale projects. In those two proposals, the purpose of the fee is to raise revenue to fund technology demonstration and deployment, but not to change behavior as would the performance standard with an emissions surcharge.

We consider three versions of a performance standard for CO_2. A traditional inflexible new source performance standard imposes a maximum emission rate. Second we introduce flexibility that enables a new source to be out of compliance if it pays an emission surcharge on emissions in excess of the standard, possibly in addition to a price on CO_2. Third, we assign the revenue from the emission surcharge to an escrow fund that can be used to offset the capital cost of retrofitting CCS in the future. In the remainder of this section we examine these policies in a simple analytical framework to develop intuition and hypotheses that can be tested with the simulation model.

5.1 New Source Performance Standard

We introduce a fuel-neutral performance standard (*s*) that would limit the emission rate for CO_2 (tons/MWh) at new sources to be less than the emission rate of a sub-critical pulverized coal plant with CCS, which implies that any new coal or natural gas facility would require CCS technology in order to comply. An "uncontrolled facility" refers to the absence of CCS technology, which also affects other pollutants (SO_2, NO_x, mercury and particulates). A given fuel and generation technology (*k*) will achieve uncontrolled emissions $\left(e_{k,j}\right)$ for each pollutant (*j*). CCS would modify the emission rate for each pollutant ($u_{k,j}$) to achieve a controlled rate: $e_{k,j}^{ccs} = \left(1-u_{k,j}\right)e_{k,j}$. Typically CCS is expected to reduce emissions of CO_2 by 70-90 percent and by over 99 percent for SO_2, but this varies according to the generation technology.

In the absence of new investment we assume continued operation of an existing facility (or purchase from the wholesale power market) with cost equal to the prevailing wholesale power price, so profits associated with the operation of the existing facility are zero.

The turn-key capital cost of new baseload generation technology $\left(\tilde{c}_{k,t}\right)$ is indexed by year (t). We assume a decline in capital costs over time, which is the result of a decline in the cost of individual components of generation and CCS technology, but at less than the rate of interest $\left(r < \frac{\partial \tilde{c}_{k,t}}{\partial t}, \frac{\partial \tilde{c}^{ccs}_{k,t}}{\partial t} \leq 0\right)$. For other variables we assume no trend over time. In the simulation model, the capital cost over time may be uncertain because of the effect of climate policies on technological learning rates, but we ignore learning rates in the analytical formulation. The annual variable cost of generation includes the operating and maintenance (O&M) expense $\left(m_k\right)$ and fuel cost, which is the product of the fuel used and its uncertain price $\left(q_k \times \tilde{p}_f\right)$.[17]

The turn-key capital cost of CCS varies with the matching generation technology and year $\left(c^{ccs}_{k,t}\right)$. The annual variable cost of CCS includes the O&M cost ($m^{ccs}_{k,t}$) and the reduction in electricity available for sale, from v to v^{ccs}_k, which results from reduced flow of air through turbines after CO_2 is stripped from the air stream in an IGCC plant, and the parasitic loss of electricity that is used to power the post-combustion controls in an IGCC or pulverized coal plant. The decision-making investor is obligated to deliver power (v) every period to a local distribution company.[18] The revenue from electricity production of an uncontrolled plant is the product $(\tilde{w}_t \times v)$, where $\tilde{w}_t$ is the wholesale power price per MWh of electricity (a random variable). When CCS is installed the revenue from electricity production falls to $\left(\tilde{w}_t \times v^{ccs}_k\right)$.[19] The difference in output between v and v^{ccs}_k must be purchased at the wholesale market price to meet the assumed obligation to serve load.

A performance standard for CO_2 is likely to coexist with an emissions cap and trade program (or emissions tax), as occurred with previous trading programs for SO_2 and NOx. A trading program introduces a price per ton of emissions ($\tilde{o}_{j,t}$) that is uncertain over time. In the absence of a change in policy, the emissions price rises in expected value at the rate of interest. The traditional (inflexible) performance standard requires that the date at which new generation

[17] Natural gas price is stochastic in our model, and this also has an effect on coal prices in the simulation model.
[18] The investor could be the utility, an independent power generator or a power marketer.
[19] In this section we assume the technology options are configured so that they generate the same power output before the addition of CCS. However, given the lumpiness of some technologies (as represented in the available configurations in the IECM model), and our assumption of equal capacity factors across technologies, the electricity output of different plants in practice might differ, which we model in the simulation exercise.

is built (τ) is the same as for CCS (υ). The time it takes to complete construction is λ. Notation is summarized in Table 5.1.

The investor maximizes profit (minimizes costs) by choosing the type of generation technology and timing to minimize the discounted cash flow of cost $\psi\left(C_{k,\tau}, C_{k,\upsilon}^{CCS}\right)$ over the planning horizon to period *T*. The problem is labeled ψ^{std} to denote a traditional emission rate standard $(\tau = \upsilon)$.

$$
\begin{aligned}
\min_{k,\tau=\upsilon} \psi^{std} &= \sum_{t=1}^{\tau+\lambda} (1+r)^{-t} E\left[v\,\tilde{w}_t \right] \\
&+ (1+r)^{-\tau} E\left[\tilde{c}_{k,\tau} \right] + \sum_{t=\tau+\lambda}^{T} (1+r)^{-t} \left(m_{k,t} + E\left[q_k \tilde{p}_{f,t} \right] \right) \\
&+ (1+r)^{-\upsilon} E\left[\tilde{c}_{k,\upsilon}^{ccs} \right] + \sum_{t=\upsilon+\lambda}^{T} (1+r)^{-t} \left(m_{k,t}^{ccs} + E\left[\sum_j e_{k,j}^{ccs} \tilde{o}_{j,t} \right] \right) \\
&+ \sum_{t=\upsilon+\lambda}^{T} (1+r)^{-t} E\left[\left(v - v_k^{ccs} \right) \tilde{w}_t \right]
\end{aligned} \tag{1}
$$

Table 5.1. Summary of parameters and variables

Indices		**Range or Units**
Ψ	Cost in:	
	Baseline (no performance standard)	*bsln*
	Inflexible performance standard	*stnd*
	Flexible standard with emissions surcharge	*flex*
	Flexible standard with escrow fund	*esc*
k	Generation Technology	Subcritical Pulverized Coal Supercritical Pulverized Coal Ultrasupercritical Pulverized Coal Integrated Gasification Combined Cycle (IGCC) Natural Gas Combined Cycle (NGCC)
t	Year	1,2,3...T
j	Air pollutant	SO_2, NO_x, Mercury, CO_2
f	Fossil fuel	Coal, Natural Gas
Deterministic parameters and variables		
τ	Date of investment in new generation	Year
υ	Date of investment in CCS	Year
λ	Time to complete the construction of a project (new plant or CCS retrofit)	Years
r	Discount rate	% per annum (discrete discounting)
$m_{k,t}$	O&M costs of base plant of generating	$/year

	technology k at year t (excluding fuel costs)	
$m_{k,t}^{ccs}$	O&M costs of CCS component of generating technology k at year t (not including fuel use)	\$/year
q_k	Amount of fuel required by technology k	mmBtu/year
$e_{k,j}$	Emissions of pollutant j from uncontrolled technology k (i.e. without CCS)	Short tons/ year for SO_2, NO_x, CO_2 Lbs/year for Mercury
$u_{k,j}$	Emissions modification factor	Percent
$e_{k,j}^{ccs}$	Emissions of pollutant j from technology k after installing CCS	Short tons/ year for SO_2, NO_x, CO_2 Lbs/year for Mercury
v	Electricity output without CCS	kWh/year
v_k^{ccs}	Electricity output with CCS	kWh/year
Uncertain parameters and variables		
$\tilde{c}_{k,t}$	Capital cost of technology k at time t. It is uncertain due to learning.	\$
$\tilde{c}_{k,t}^{ccs}$	Capital cost of technology CCS for technology k at time t. It is uncertain due to learning.	\$
$\tilde{p}_{f,t}$	Price of fuel f at time t	\$/mmBTU
$\tilde{o}_{j,t}$	Emissions fee of pollutant j and time t	\$/short ton for SO_2, NO_x, CO_2 \$/lb for mercury
$\tilde{w}_t$	Wholesale power price	\$/MWh
Additional deterministic parameters for flexible policy		
s	CO_2 emissions standard	Short tons/MWh
β_t	Emission surcharge	\$/short ton
$z_{k,\tau,\upsilon}$	CCS retrofit penalty for technology k	Percent, $z_{k,\tau,\nu} = 0$ for $\tau = \upsilon$

The first line of expression (1) pertains to the cost of providing power in the absence of new investment. The second line pertains to installing and operating a new uncontrolled technology, including capital costs, O&M and fuel costs. The third line pertains to the cost of CCS and emissions. The fourth line pertains to power purchased to make up for the loss in output after the installation of CCS. We designate the solution to this problem: $\left\{k^{std};\ \tau^{std} = \upsilon^{std}\right\}$.[20]

For a given technology k the new investment would be profitable at time τ when the cost of generating power is less than the cost of the existing plant (equivalent to the price of power in the wholesale market):

[20] In this section we do not consider the case in which the installation of more than one technology along the planning horizon might be optimal. Multiple choices are considered in the simulation.

$$E\left[\sum_{t=\tau+\lambda}^{T} v^{ccs}\tilde{w}_{\tau}\right] > E\left[\tilde{c}_{\tau}\right] + \sum_{t=\tau}^{T}(1+r)^{-(t-\tau)}\left(m + E\left[q_t\tilde{p}_{f,t}\right]\right)$$
$$+E\left[\tilde{c}_{\tau}^{ccs}\right] + \sum_{t=\tau}^{T}(1+r)^{-(t-\tau)}\left(E\left[\sum_j e_j^{ccs}\tilde{o}_{j,t}\right] + m^{ccs}\right) \quad (2)$$

In the absence of a standard requiring CCS, investing in an uncontrolled plant at time τ , which we denote τ^{bsln}, will be profitable when:

$$E\left[\sum_{t=\tau+\lambda}^{T} v\,\tilde{w}_{\tau}\right] > E\left[\tilde{c}_{\tau}\right] + \sum_{t=\tau}^{T}(1+r)^{-(t-\tau)}\left(m + E\left[q_t\tilde{p}_{f,t} + \sum_j e_j\tilde{o}_{j,t}\right]\right) \quad (3)$$

In a given year and technology, the left-hand side of expression (2) is less than the left-hand side of (3) because $v^{ccs} < v$. The right-hand side of expression (2) is greater than the right-hand side of (3) unless the prices of pollution justify the installation of CCS independent of the standard. Hence, for a given technology the investment in new generation capacity will happen at the same time or later than in the absence of the standard: $\tau^{bsln} < \tau^{std}$. This implies aggregate emissions will increase, since new uncontrolled generation technology is expected to have lower emissions than current technology.

5.2 Flexible New Source Performance Standard

A flexible performance standard would allow the investor to delay or avoid construction of CCS by incurring an emission surcharge (β_t), in addition to the cost of CO_2 emissions, for every ton of emissions in excess of the standard (*s*). The cost of CO_2 emissions at a facility would be equal to $\tilde{o}_t e_{k,\mathrm{CO2}} + \beta_t\left(e_{k,\mathrm{CO2}} - s\right)$ for $e_{k,\mathrm{CO2}} \geq s$. The first term includes the price of emissions allowances and the second term represents the cost of the emission surcharge. In addition, the capital cost of CCS is higher for a retrofit than for new construction, indicated by the factor $z_{k,\tau,\upsilon}$. The problem with a flexible emissions surcharge is labeled as ψ^{flex}:

$$
\begin{aligned}
\min_{k,\tau,\upsilon} \psi^{flex} = & \sum_{t=1}^{\tau+\lambda} (1+r)^{-t} E\left[v \tilde{w}_t \right] \\
& +(1+r)^{-\tau} E\left[\tilde{c}_{k,\tau} \right] + \sum_{t=\tau+\lambda}^{T} (1+r)^{-t} \left(m_{k,t} + E\left[q_k \tilde{p}_{f,t} \right] \right) \\
& \quad + \sum_{t=\tau+\lambda}^{\upsilon+\lambda-1} (1+r)^{-t} \left(E\left[\sum_j e_{k,j} \tilde{o}_{j,t} \right] + \left(e_{k,CO2} - s \right) \beta \right) \\
& + (1+r)^{-\upsilon} \left(1 + z_{k,\tau,\upsilon} \right) \tilde{c}^{ccs}_{k,\upsilon} + \sum_{t=\upsilon+\lambda}^{T} (1+r)^{-t} \left(m^{ccs}_{k,t} + E\left[\sum_j e^{ccs}_{k,j} \tilde{o}_{j,t} \right] \right) \\
& + \sum_{t=\tau+\lambda}^{\upsilon+\lambda-1} (1+r)^{-t} E\left[\left(v - v^{ccs}_k \right) \tilde{\omega}_t \right]
\end{aligned} \tag{4}
$$

In expression (4) the third line reflects the introduction of the surcharge and the fourth reflects the capital cost penalty on CCS retrofit. The solution is denoted: $\left\{ k^{flex}, \tau^{flex}, \upsilon^{flex} \right\}$.

The time at which a new facility would be built given that the investor could pay the flexible emission surcharge in lieu of achieving the standard would be no later than τ^{std} because the investor could always opt to build a facility with CCS technology at τ^{std} and avoid the emission surcharge, i.e. $\left(\tau^{flex} \le \tau^{std} \right)$. If a new generation facility is built at τ^{flex} without CCS, the investor's decision about whether to retrofit the facility depends on whether it is less expensive to install and operate the CCS than to continue to pay the emission fee and emission surcharge for an uncontrolled level of emissions.

Given construction of technology *k* at τ^{flex}, the addition of CCS would be profitable at time υ^{flex} when:

$$
\begin{aligned}
& \sum_{t=\upsilon}^{T} (1+r)^{-(t-\upsilon)} \left(E\left[\sum_j e_j \tilde{o}_{j,t} \right] + \left(e_{CO2} - s \right) \beta \right) \ge \\
& \qquad E\left[\left(1 + z_v \right) \tilde{c}^{ccs}_{k,t} \right] + \sum_{t=\upsilon+\lambda}^{T} (1+r)^{-(t-\upsilon)} \left(m^{ccs}_t + E\left[\sum_j e^{ccs}_j \tilde{o}_{j,t} \right] + E\left[\left(v - v^{ccs} \right) \tilde{w}_t \right] \right)
\end{aligned} \tag{5}
$$

For a given technology *k*, an increase in the emission surcharge increases the left hand side of expression (5) and thereby moves forward the time at which retrofit will occur $\left(\frac{\partial \upsilon^{flex}}{\partial \beta} < 0 \right)$. We define $\beta*$ as the value that would achieve investment in CCS by the same time as would a traditional emission performance standard, that is $\tau^{std} = \upsilon^{flex}$. The implication is that at $\beta*$ emissions would not rise compared to the traditional performance standard even if $\tau^{flex} < \tau^{std}$

because emissions from the new uncontrolled technology are expected to be less than from existing technology. Furthermore, since construction of a new facility with CCS at τ^{std} remains an option, we expect profits for the investor would not fall with the introduction of a flexible performance standard. However, the investor might choose a different technology, an issue we explore in simulation.

5.3 New Source Performance Standard Escrow Fund

If a new facility were built without CCS under a flexible performance standard, revenue from the surcharge would accumulate over time and earn interest at a rate $\rho < r$ to be to be $\sum_{t=\tau^{flex}+\lambda}^{\upsilon^{flex}+\lambda-1} (1+\rho)^{t-\tau-\lambda} \beta \max\left[\left(e_{k,\mathrm{CO2}} - s\right), 0\right]$. What should become of this revenue? It is plausible that regulators would direct the revenue to achieve goals related to the program; one approach would be to help overcome the initial capital cost and accelerate the introduction of CCS. This might be especially compelling in the early years of deployment of CCS when capital costs are expected to fall as a result of learning by doing, and therefore new investment may reduce the cost for subsequent investors.

In this scenario, we assume the escrow fund is tied to each plant so that the investor's cost minimization problem, indexed as ψ^{esc} to designate the availability of the escrow fund, can be expressed:

$$
\begin{aligned}
\min_{k,\tau,\upsilon} \psi^{esc} = & \sum_{t=1}^{\tau+\lambda} (1+r)^{-t} E\left[v\,\tilde{w}_t \right] \\
& + E\left[(1+r)^{-\tau}\tilde{c}_{k,\tau}\right] + \sum_{t=\tau+\lambda}^{T} (1+r)^{-t}\left(m_{k,t} + E\left[q_k \tilde{p}_{f,t}\right]\right) \\
& + \sum_{t=\tau+\lambda}^{\upsilon+\lambda-1} (1+r)^{-t}\left(E\left[\sum_j e_{k,j}\tilde{o}_{j,t}\right] + \left(e_{k,CO2} - s\right)\beta \right) \\
& + (1+r)^{-\upsilon} E\left[\left(1+z_{k,\tau,\upsilon}\right)\tilde{c}^{ccs}_{k,\upsilon}\right] - (1+r)^{-\upsilon} \sum_{t=\tau+\lambda}^{\upsilon+\lambda-1} \left(1+\rho\right)^{t-\tau-\lambda}\left(e_{k,CO2} - s\right)\beta \\
& + \sum_{t=\upsilon+\lambda}^{T} (1+r)^{-t}\left(m^{ccs}_{k,t} + E\left[\sum_j e^{ccs}_{k,j}\tilde{o}_{j,t}\right]\right) \\
& + \sum_{t=\tau+\lambda}^{\upsilon+\lambda-1} (1+r)^{-t} E\left[\left(v - v^{ccs}_k\right)\tilde{\omega}_t\right]
\end{aligned}
\tag{6}
$$

where ρ represents the rate of return on funds held in escrow and $\rho < r$. Denote the solution: $\left\{k^{esc}, \tau^{esc}, \upsilon^{esc}\right\}$.

If the new plant of type *k* was built without CCS technology at period τ^{esc}, retrofit would occur when the expected discounted value of the capital and O&M costs of operating with CCS and pollution fees minus the funds from escrow is less than the O&M costs, pollution fees and emissions surcharge without CCS:

$$\sum_{t=\upsilon}^{T}(1+r)^{-(t-\upsilon)}\left(E\left[\sum_{j}e_{j}\tilde{o}_{j,t}\right]+\left(e_{\mathrm{CO2}}-s\right)\beta\right)\geq$$

$$E\left[\left(1+z_{\upsilon}\right)\tilde{c}_{\upsilon}^{ccs}\right]+\sum_{t=\upsilon+\lambda}^{T}(1+r)^{-(t-\upsilon)}\left(m_{t}^{ccs}+E\left[\sum_{j}e_{j}^{ccs}\tilde{o}_{j,t}\right]+E\left[\left(v-v^{ccs}\right)\tilde{w}_{t}\right]\right) \quad (7)$$

$$-\sum_{t=\tau+\lambda}^{\upsilon+\lambda-1}\left(1+\rho\right)^{t-\tau-\lambda}\left(e_{\mathrm{CO2}}-s\right)\beta$$

The left-hand side of expression (7) is identical to expression (5) and the right hand-side differs only due to the subtraction of funds from the escrow. Therefore, given plant type *k*, the time at which the CCS is installed with an escrow fund should occur no later than the time with the flexible performance standard $\left(\upsilon^{esc}\leq\upsilon^{flex}\right)$. This would be true because after time υ^{flex} the going-forward cost of installing and operating CCS is always less than the variable costs of not doing so, and the availability of the escrow fund strictly reduces further the cost of retrofit.

Note that the emissions surcharge would not play a role in the timing of investment if the full opportunity cost of the total amount paid in surcharges can be recovered at the time of CCS installation ($\rho=r$). In that case $\upsilon^{esc}=\upsilon^{flex}$. If $\rho>r$, we would expect retrofit with CCS under the escrow policy to occur sooner with the escrow account.

When will investment in generation capacity occur? Consider a given plant type *k* built at period τ^{flex} with the expectation that the plant would be retrofitted with CCS at υ^{flex}. Period τ^{flex} occurs when:

$$\sum_{t=\tau+\lambda}^{\upsilon+\lambda-1}(1+r)^{-t}E\left[v\,\tilde{w}_{t}\right]+\sum_{t=\upsilon+\lambda}^{T}(1+r)^{-t}E\left[v^{ccs}\tilde{w}_{t}\right]>$$

$$(1+r)^{-\tau}E\left[\tilde{c}_{\tau}\right]+\sum_{t=\tau+\lambda}^{T}(1+r)^{-t}\left(m_{t}+E\left[q\,\tilde{p}_{f,t}\right]\right)$$

$$+\sum_{t=\tau+\lambda}^{\upsilon+\lambda-1}(1+r)^{-t}\left(E\left[\sum_{j}e_{j}\tilde{o}_{j,t}\right]+\left(e_{\mathrm{CO2}}-s\right)\beta\right) \quad (8)$$

$$+(1+r)^{-\upsilon-\tau}E\left[\left(1+z_{\upsilon}\right)\tilde{c}_{\upsilon}^{ccs}\right]+\sum_{t=\upsilon+\lambda}^{T}(1+r)^{-t}\left(m_{t}^{ccs}+E\left[\sum_{j}e_{j}^{ccs}\tilde{o}_{j,t}\right]\right)$$

The introduction of the escrow account reduces the right hand side of expression (8) by the amount:

$$-(1+r)^{-\upsilon-\tau}\sum_{t=\tau+\lambda}^{\upsilon+\lambda-1}(1+\rho)^{-t}\left(e_{CO2}-s\right)\beta \tag{9}$$

Consequently, the date of construction of new capacity with the escrow fund is expected to be earlier than under the flexible emission standard, i.e. ($\tau^{esc}<\tau^{flex}$). Given the expectation that new capacity displaces higher emitting existing capacity, either of these changes suggests unambiguous reductions in emissions. Finally, since construction of a new facility with CCS at τ^{flex} remains an option, we expect profits for the investor would not fall with the introduction of the escrow fund.

In summary, this analysis suggests several hypotheses to be tested with the simulation model. These hypotheses, which apply for a given technology, are listed in Table 5.2.

These results provide preliminary intuition that increased flexibility coupled with economic incentives in the performance standard would lead to lower emissions, more timely achievement of investment in CCS, and greater profits. However, the actual outcome is an empirical question that we test with numerical simulations and stochastic optimization.

Table 5.2. Hypotheses Regarding Performance of Technology Policy

Number	
1	A traditional inflexible emission standard is expected to delay construction of new generation facilities: $\tau^{bsln}<\tau^{std}$. With no technological change this should lead to an unambiguous increase in emissions.
2	Under a flexible emissions standard, an increase in the emissions surcharge should move forward the time at which CCS technology is built: $\frac{\partial\upsilon^{flex}}{\partial\beta}<0$.
3	A flexible emission standard with an emission surcharge $\beta>\beta^*$ should lead to investment in CCS by the same point in time as would a traditional emission performance standard: $\upsilon^{flex}\le\upsilon^{std}$.
4	Under the flexible emission performance standard, emissions would not rise compared to the traditional performance standard, and emissions could fall unambiguously: $\sum_t e_t^{flex}\le\sum_t e_t^{stnd}$.

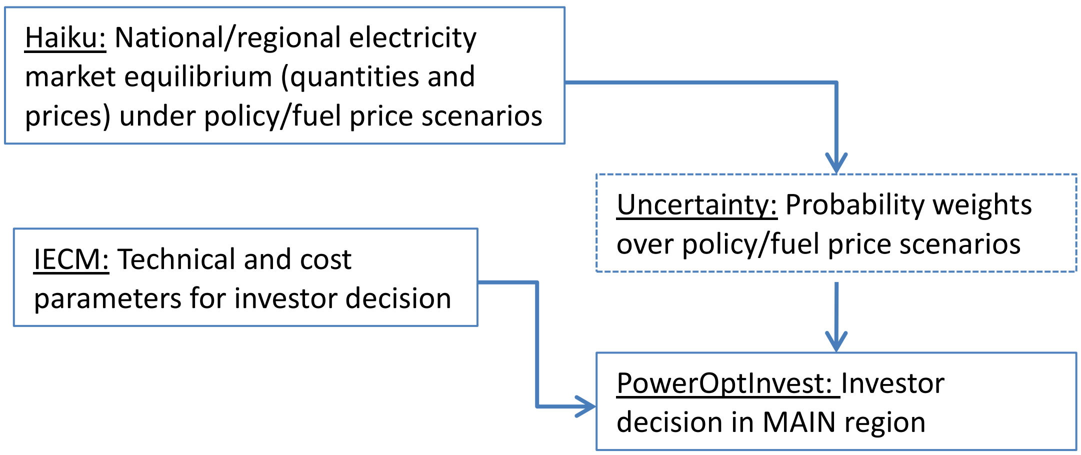
5	Profits for an investor would not fall with the introduction of a flexible standard: $\psi^{flex} \leq \psi^{std}$.
6	The escrow fund will cause the construction of new generation capacity to be earlier than in the absence of the fund: $\tau^{esc} < \tau^{flex}$.
7	The time at which the CCS is installed with an escrow fund should occur no later than with the flexible performance standard: $\upsilon^{esc} \leq \upsilon^{flex}$.
8	Emissions should not rise and could fall unambiguously with the escrow fund: $\sum_t e_t^{esc} \leq \sum_t e_t^{flex}$.
9	Profits for an investor would not fall with the introduction of an escrow fund: $\psi^{esc} \leq \psi^{flex}$.

The simulation model adds realism in several ways. One is a comparison across technology choices. For instance, the possibility exists that the introduction of a performance standard, a flexible standard or an escrow fund would cause a different technology to be chosen. If the choice of technology varies, the timing of construction of the generation facility or the CCS technology could also vary. Another is a fuller representation of the structure of information indicating how new information becomes available. In the simulation model, decisions can be revised and the investor can switch technologies, subject to appropriate opportunity costs. Also, there is endogenous learning associated with the rate of improvement in capital cost, which is affected by the climate policy and national electricity market equilibrium.

6. Model and Parameters

We use three models to explore the incentives created under an emission rate standard (Figure 6.1). The Haiku model is a simulation model of regional electricity markets and inter-regional electricity trade in the continental United States. The model provides equilibrium forecasts of relative prices of fuel, wholesale and retail electricity and allowance prices, which are treated as parametric in the decision of the individual investor. We solve the model over twelve scenarios regarding natural gas price levels and federal climate policy, and apply probability weights over the scenarios to characterize uncertainty about the future. The decision for an investor is to choose the timing and choice of technology, based on technical information about the performance and cost of configurations of a plant from IECM (described above). These characteristics include heat rates, capital and O&M costs and emission rates. With input from the Haiku and IECM models, we use PowerOptInvest, a multi-period investment decision model with embedded multi-stage stochastic optimization to determine the actions of an individual investor in the MAIN power region (Illinois). Each model is described below.

Figure 6.1. Model Relationships



6.1 The Market Equilibrium Context

The Haiku model (Paul et al. 2008) solves for electricity market equlibria in 20 regions of the US linked by transmission capability. The model solves for capacity investment and retirement and system operation over twenty years, accounting for three seasons and four time blocks. The model uses an iterative algorithm to solve for equilibria in spatially and temporally linked markets by obtaining simultaneous compliance with a large set of constraints including regulations to control emissions of NO_x, SO_2, CO_2 and mercury from the electricity sector. The model uses separate electricity demand curves for each region and time block and for each class of customers. The supply curves are composed of model plants that are each constructed by aggregating the generating unit inventory according to salient technology characteristics. The solution identifies the minimum cost strategy for investment and operation of the electricity system for meeting demand given a wide set of regulatory institutions.

The model includes secular reductions in capital cost over time for various technologies. In all scenarios the Clean Air Interstate Rule including both an annual and summer seasonal constraints for NO_X and an annual SO_2 constraint, and the proposed Clean Air Mercury Rule are included.[21] SO_2, NO_X and mercury emissions allowances are initially distributed for free ("grandfathered") on the basis of historic generation. All scenarios include the northeast Regional Greenhouse Gas Initiative (with allowance distribution through an auction), along with initiatives to promote renewable energy at the state level. The federal renewable production tax credit appears with a discount factor to account for the historic intermittency of the policy. The regions are classified by the method for determining electricity price. Nine of the 20 regions have competitive pricing in place, according to the model, including the MAIN power region that covers Illinois, the location under study. The other 11 regions are modeled to have traditional cost of service regulation.

The model is solved for five simulation years spanning 2012 through 2030. Investment decisions look forward over a time period that serves as a threshold for anticipated cost recovery that depends on the technology, typically 20 years. We maintain market variables and equilibria obtained in 2030 for investment decisions and policy scenarios that unfold through 2050.

The market equilibrium identified in Haiku is dynamically consistent but does not account for uncertainty. Each scenario is solved assuming foresight with certain expectations of future market equilibria. Haiku results provide estimates of equilibrium allowance prices for CO_2, SO_2, NO_x and mercury and several parameters specific to the MAIN power region including the cost of generation to wholesale customers, which represents the opportunity cost of generation that is lost due to reduction in output from adding CCS onto a facility.

Table 6.1. Twelve scenarios developed in Haiku

	Climate Policy Scenario			
Natural Gas Price Scenario	BAU	50% L-M	100% L-M	150%L-M
Low NG Price	Low0	Low50	Low100	Low150
Mid NG Price	Mid0	Mid50	Mid100	Mid150
High NG Price	High0	High50	High100	High150

[21] CAIR was promulgated in 2005, and then vacated and subsequently remanded to the EPA for revision by the DC Circuit Court in 2008 (*North Carolina v. EPA, 531 F.3d 896,908 (D.C. Cir. 2008) (per curiam)*). The rule remains in effect until a substitute is finalized. CAMR was also promulgated in 2005 and overturned in 2008 (*New Jersey v.* EPA, 517 F.3d 574 (D.C. Cir. 2008)). Many states have regulated mercury from the power sector, and it is expected to come under prescriptive federal regulation in 2011.

To represent uncertainty, twelve climate policy/natural gas price scenarios are assigned probability weights that evolve toward resolution in 2020. The four federal climate policy scenarios include a business-as-usual (BAU) scenario with no federal climate policy. The other three scenarios assume an emissions cap with allowance banking assumed to take effect in 2010. One climate policy scenario solves for an aggregate quantity of CO_2 emissions from the electricity sector that matches the quantity anticipated by the EIA (2007b) in its core analysis of S.280 (Lieberman-McCain) by 2030. With allowance banking, the allowance price rises at the opportunity cost of capital (the real interest rate) of 8 percent over time. The two other climate policy scenarios aim for emissions levels with price trajectories that are 50 percent or 150 percent of the core analysis. This is achieved approximately, subject to small variations stemming from model convergence. In every case CO_2 allowances are distributed through auction. Each of the climate policy scenarios is combined with three levels of natural gas prices, low, medium or high, which completes the twelve scenarios as summarized in Table 6.1.[22] The twelve climate policy/natural gas price scenarios imply uncertainty around market parameters that affect the investment decision including electricity price, national and regional investment and retirement, allowance and fuel prices.

Under the climate policy scenarios the opportunity cost of emissions of the other pollutants change, with the exception of particulate emissions, which are not regulated by an emission cap. For example, in 2025 for the mid level natural gas price scenarios, the value of SO_2 allowances falls from $1,270/ton in the Mid0 to $160/ton under the most stringent case (Mid150) (All prices are in 2004 dollars.). NOx allowance value within the annual trading program falls from $1,538/ton to $199/ton, and mercury allowance value falls from $51,279/pound to $44,951/pound.

[22] Haiku uses EIA (2007a) data on the supply and prices of natural gas to construct a supply curve for natural gas that is used in the mid natural gas price case. In the low natural gas price case, the supply curve prices are reduced by 33%; in the high natural gas price case, they are increased by 33%. The price of natural gas is then solved endogenously, determined by the quantity demanded by gas-fueled electricity generators. See Table A6.

Table 6.2. Equilibrium prices for 2025 in MAIN

Scenario	**CO_2** ($/ton)	**SO_2** ($/ton)	**NOx** ($/ton)	**Mercury** ($/lb)	**Coal** Illinois #6 ($/mmBtu)	**Gas** ($/mmBtu)	**Wholesale Electricity** ($/MWh)
Low0	0	940	1,029	43,081	1.59	3.59	47
Low50	9	580	495	43,719	1.49	3.59	53
Low100	18	286	268	38,159	1.39	3.63	56
Low150	29	149	49	2,642	1.31	3.72	61
Mid0	0	1,235	1,447	48,998	1.65	4.87	52
Mid50	12	1,040	723	51,260	1.56	4.83	57
Mid100	24	480	300	48,147	1.50	4.92	64
Mid150	36	200	210	42,552	1.45	5.14	72
High0	0	1,246	822	50,529	1.65	6.35	52
High50	11	1,117	406	52,611	1.60	6.13	58
High100	28	518	323	50,857	1.54	6.15	69
High150	45	237	244	46,824	1.49	6.45	84

The type of coal used at a newly constructed facility in the MAIN power region is assumed to be Illinois # 6, a high sulfur bituminous coal from the eastern interior coal supply region. This coal has an advantage compared to other coals available in the region because of its proximity and because new facilities must be controlled for SO_2 under new source performance standards so the sulfur content is not a significant cost disadvantage.[23] Table 6.2 reports the range of equilibrium allowance, fuel and electricity prices under the twelve scenarios is illustrated for the year 2025. The values for all years appear in the appendix.

The impacts on prices and the fuel mix at the national level and in the MAIN region under each scenario for the mid natural gas price case in 2025 are reported in Table 6.3. The CO_2 allowance price ranges from $0/ton with no climate policy (Mid0) to $36ton in the strictest climate policy (Mid150). This corresponds to a reduction in national electricity sector emissions in 2025 from 3,166 million tons with no climate policy to 1,491 million tons under the strictest

[23] CCS requires very high level of sulfur removal beyond that typically achieved by flue gas desulfurization today, but this does not change the choice of coal that is likely to occur.

climate policy.[24] The reduction within the MAIN region is proportionately greater, with emissions falling from 234 million tons with no climate policy to 78 million tons.

At the national level, new gas-fired generation capacity increases by 31 GW and pulverized coal falls by 45 GW under the strictest policy. The largest change in capacity is the addition of 167 GW of new renewables capacity. The largest change in generation at the national level is the 65 percent reduction in coal-fired generation, which is made up most significantly by expanded renewable and gas-fired generation.[25] Annual average retail electricity price in MAIN ranges from $99/MWh in the baseline to $120/MWh. Wholesale prices range from $53/MWh to $75/MWh. While the more stringent climate policies place a greater opportunity cost on CO_2 emissions providing an incentive for CCS, other changes such as a decline in the price of allowances for other pollutants and the increase in the cost of electricity erode the profitability of CCS technology in an equilibrium context, which we discuss next.

[24] Haiku finds allowance prices that are somewhat less than EIA modeling. In the mid100 case, Haiku finds a CO_2 emissions price of $26/ton in 2025would produce electricity sector emissions of 2,055 million (short) tons. EIA (2007b) estimates that S.280 would produce a CO_2 emissions price of $29, and electricity sector emissions of 2,012 million tons. This target is similar but slightly less stringent than H.R. 2454 (Waxman-Markey), which passed the House of Representatives in 2009. EIA (2009) estimates H.R. 2454 would produce a price of $38 and electricity sector emissions of 1,936 million tons in 2025.

[25] The capacity factors for technologies are determined within the model and vary considerably. In the mid0 baseline, new coal has a capacity factor of 84 percent and new NGCC of 43 percent, while new wind has a capacity factor of 34 percent. The model has price-responsive supply curves for natural gas and coal. The shift to gas-fired generation leads to an increase in the delivered cost of gas, as indicated for the MAIN region in Table 6.3. However, the policy modeled here affects only the electricity sector. If an economy-wide policy led to futher substitution toward natural gas use outside the electricity sector then the electricity price impact would be greater than we indicate. Conversely, if the policy led to a substitution away from natural gas outside the electricity sector then the estimate from Haiku would overstate the electricity price impact.

Table 6.3. Overview for mid-natural gas price case for 2025

	Mid0	Mid50	Mid100	Mid150
Nation				
CO_2 Emissions (million tons)	3,166	2,625	2,068	1,491
Generation (billion kWh)				
Coal	2,704	2,187	1,599	940
Gas	641	630	818	1,159
Nuclear	925	1,009	1,009	1,009
Hydro	312	312	312	312
Other Renewable	430	791	1,097	1,347
TOTAL	5,012	4,929	4,835	4,768
New Capacity (GW)				
Gas	116	106	121	147
Nuclear	17	25	25	25
Pulverized Coal	60	26	14	15
IGCC w/CCS	0	0	4	12
Renewables	88	152	205	255
TOTAL	282	309	365	443
MAIN Region				
CO_2 Emissions (million tons)	234	174	134	78
Wholesale Electricity Price (2004$/MWh)	53	58	65	75
Delivered Fuel Price($/mmBTU)				
Coal (Illinois #6)	1.66	1.56	1.50	1.45
Gas	4.97	4.92	5.03	5.27

6.2 Technology Cost and Performance

Technology and cost parameters that describe the specific investment options come from IECM. These parameters are modified by information from Haiku about the evolution of capital cost, allowance prices, electricity and fuel prices over time and vary under the policy scenarios. Investment in CCS is assumed to be first of a kind and not to affect equilibrium prices. Haiku accounts for component-specific learning across technologies. Because different types of generation capacity have similar components, the construction of any type of capacity will contribute to the improvement of other types of capacity via those similar components. For example, both IGCC plants and combined cycle plants incorporate a heat recovery steam generator. When either type of plant is constructed, the learning achieved about the heat recovery steam generator technology will lower the capital cost of future construction of either type of plant. The rates at which capital costs fall depend on the maturity of the technology; as the technology matures, the rate of improvement declines. We also inflate capital costs of CCS by a risk-premium factor as discussed later.

The technical data governing the investment decision is taken from IECM and represents the expected mature cost given vintage 2007 technical understanding. Three options for new investment use solid coal: sub-critical (sub), supercritical (super) and ultra-supercritical (ultra). In addition we investigate integrated gasification combined cycle coal-fired (IGCC) and natural gas combined cycle (NGCC). Each of these would satisfy standards for new sources for emissions of SO_2, NO_x, mercury and particulates. Each could come with or without CCS, or with retrofit CCS sometime after initial construction. In this exercise we assume that CCS is always operated once it is added to a plant. However, there are economic reasons why that may not be true, which we discuss as potential future work. Finally, we assume that in the absence of new investment, power is taken from the wholesale power market. The change in emissions is calculated from the emissions rate of the coal plant in the region that is likely to be replaced by new capacity as identified by Haiku.

Several parameters are held constant across these technologies. The capacity factor (percent of time the facility is in operation) is 75 percent. The capacities of the coal plants before the addition of CCS are similar. Supercritical, ultra-supercritical and IGCC plants have 1,359 MW of capacity and the subcritical plant has 1,358 MW. This scale represents the largest IGCC plant included in the IECM database, which also has the lowest average cost for IGCC plants.[26] The NGCC plant is 7 percent smaller, with a capacity of 1,266MW before the addition of CCS.

A number of other factors including heat rates and emission rates vary. The operating characteristics of each configuration are summarized in Table 6.4. The addition of CCS, as a component of new construction or as a retrofit, affects the performance of these technologies to different degrees, raising O&M costs and reducing the power output of the plant. The emission characteristics of the technologies vary both for CO_2 and for other pollutants; however, the addition of CCS always achieves a CO_2 emissions rate reduction (tons/MWh) of at least 86 percent (accounting for lost energy production) in CO_2 emissions compared to the emissions from an uncontrolled sub-critical coal-fired plant.[27] In the absence of a national climate policy (no emission fee) and in the absence of a new source performance standard for CO_2, the least cost technology according to IECM database would be ultra-supercritical coal without CCS, and it would be built within the next decade.

Tables 6.5 and 6.6 illustrate the levelized and variable cost of each technology under Haiku projections for each climate policy and natural gas price scenario, but in the absence of a new source performance standard.

The process of CCS includes the capture and compression of CO_2 to high pressures, transportation to a storage site, injection into a suitable geologic reservoir, and long term site-monitoring. While the IECM capital cost estimates of CCS represent current knowledge on post-combustion and IGCC technologies, there are still tremendous uncertainties about the timing, mitigation potential, safety, regulatory framework, and overall costs of a national system to capture, transport and store large quantities of CO_2. To reflect these uncertainties we have adjusted the IECM estimates of CCS capital costs by a premium. We multiply by 2 current estimates of CCS capital costs for year 2009, and linearly decrease this factor until it becomes 1 in year 2020. The premium as a multiplier of CCS capital costs for year t < 2020 is given by:

$$\text{Premium}\, CCS_t = 2 - \left(\frac{t - 2009}{2020 - 2009} \right)$$

[26] The IGCC plant has 5 GE7FA turbines with GE oxygen-blown gasifiers, four operating trains and one spare train which provides a measure of reliability.

[27] This does not include the emissions associated with power that must make up for the lost production from the plant, but his is included in the analytical and simulation modeling.

As mentioned before, IECM capital costs of all technologies are modified to reflect technological learning rates forecast by Haiku. Capital costs are multiplied by a factor lower than one to reflect the reduction expected every year. Learning factors vary by scenario for all coal-fired plants (including IGCC), and stay approximately the same across scenarios for the NGCC plants because it is a relatively mature technology. The appendix reports the exogenous learning factors as multipliers of capital costs, for each scenario and each year of the planning horizon.

Table 6.4. Cost and performance of technologies

(2004 dollars)	Sub	Sub +CCS	Super	Super +CCS	Ultra	Ultra +CCS	IGCC	IGCC +CCS	NGCC	NGCC +CCS
Capacity (MW)	1,358	1,358	1,359	1,359	1,359	1,359	1,359	1,359	1,266	1,266
Capital Cost (million$)	1,480	2,049	1,541	2,048	1,529	2,003	2,239	3,003	795	1,119
CCS Retrofit Penalty (%)[1]	20		20		20		30		20	
Generation (GWh/yr)[2]	8,929	6,403	8,935	6,667	8,935	6,877	8,935	7,903	8,324	7,108
O&M ($/MWh)	7.98	32.25	7.76	28.66	7.45	25.91	7.28	12.69	1.66	3.95
Net Plant Heat Rate, HHV (Btu/kWh)	9,786	9,786	8,791	8,791	7,981	7,981	9,856	9,856	6,803	6,803
Emissions[3]										
CO_2	9,144	916	8,220	823	7,463	747	8,789	742	3,369	337
SO_2	27,030	30	24,300	27	22,061	24	5,539	603	-	-
NO_x	6,553	6,470	5,891	5,817	5,349	535	857	846	849	838
Particulate	1,311	655	1,178	589	1,070	535	44	44	-	-
Mercury	55	55	49	49	45	45	-	-	-	-

[1] The retrofit penalty for CCS is applied only to the CCS capital cost.

[2] The power loss involves reduced flow through turbines and power for CCS technology and other emission control devices.

[3] Emissions are tons/year except CO_2 (thousand tons/yr) and Mercury (pounds/year).

Table 6.5. Levelized total cost of energy under deterministic climate policy projections for 2009-2038 ($/MWh)

Scenario\Plant	SUB	SUB + CCS	SUPER	SUPER + CCS	ULTRA	ULTRA + CCS	IGCC	IGCC + CCS	NGCC	NGCC + CCS
Low0	41.52	84.00	39.98	76.08	38.00	68.73	45.91	64.52	34.83	46.85
Low50	46.64	83.94	44.58	76.04	42.17	68.74	51.41	64.38	37.64	47.41
Low100	52.20	83.72	49.57	75.84	46.70	68.73	57.17	64.24	40.79	48.28
Low150	58.88	83.73	55.58	75.85	52.16	68.94	64.11	64.41	44.31	49.15
Mid0	42.52	84.71	40.88	76.69	38.81	69.24	46.48	65.07	41.30	54.43
Mid50	50.02	85.17	47.62	77.10	44.93	69.59	54.12	65.25	44.68	54.78
Mid100	57.75	85.49	54.56	77.37	51.23	69.98	62.11	65.46	48.80	55.86
Mid150	64.85	85.78	60.94	77.62	57.03	70.37	69.50	65.71	53.05	57.40
High0	42.79	84.86	41.13	76.83	39.04	69.33	46.59	65.16	48.15	62.45
High50	50.42	85.50	47.98	77.38	45.26	69.83	54.32	65.51	50.98	62.20
High100	60.88	86.38	57.38	78.14	53.79	70.61	65.00	66.08	55.58	62.71
High150	68.44	86.78	64.16	78.49	59.95	71.07	72.73	66.39	59.93	64.23

[1]Total levelized cost of energy includes all capital, O&M, fuel and allowance cost over a 30 year horizon. Capital costs are paid in year 2008 and do not include the risk-premium for CCS discussed below, or technological learning forecasted by Haiku. Discount rate is 8%. No depreciation/ taxes are included.

[2]Shaded cells show technologies with lowest LCOE for each scenario.

Table 6.6. Variable cost of energy under deterministic climate policy projections for 2009-2038 ($/MWh)

Scenario\Plant	SUB	SUB + CCS	SUPER	SUPER + CCS	ULTRA	ULTRA + CCS	IGCC	IGCC + CCS	NGCC	NGCC + CCS
Low0	26.80	55.57	24.67	48.80	22.80	42.86	23.65	30.77	26.36	32.87
Low50	31.92	55.52	29.26	48.75	26.97	42.86	29.15	30.63	29.16	33.42
Low100	37.47	55.30	34.25	48.56	31.50	42.86	34.91	30.48	32.31	34.29
Low150	44.16	55.31	40.26	48.57	36.96	43.07	41.86	30.66	35.83	35.16
Mid0	27.79	56.28	25.56	49.41	23.61	43.37	24.22	31.32	32.82	40.44
Mid50	35.30	56.75	32.30	49.81	29.73	43.72	31.86	31.50	36.20	40.80
Mid100	43.02	57.07	39.24	50.09	36.03	44.11	39.85	31.71	40.32	41.88
Mid150	50.13	57.36	45.62	50.34	41.83	44.50	47.24	31.96	44.57	43.42
High0	28.07	56.44	25.81	49.54	23.84	43.46	24.33	31.40	39.68	48.47
High50	35.70	57.07	32.66	50.09	30.06	43.96	32.06	31.76	42.50	48.21
High100	46.16	57.96	42.06	50.86	38.59	44.74	42.74	32.33	47.10	48.72
High150	53.71	58.36	48.84	51.20	44.75	45.20	50.47	32.64	51.45	50.24

[1] Variable cost of energy includes O&M, fuel and allowance cost over a 30 year horizon. Discount rate is 8%. No depreciation/ taxes are included.

[2] Shaded cells show technologies with lowest Variable Cost of Energy for each scenario. The Ultra-supercritical coal plant has the lowest Variable Cost of Energy for scenarios with low CO_2 prices, while the IGCC+CCS has the lowest Variable Cost of Energy for scenarios with high CO_2 prices.

6.3 The Investor's Problem

Each of the policy scenarios is an example of possible outcomes and each has some probability of occurring. The investor faces the problem of managing investment in the face of uncertainty. We proceed as if the level of stringency spans the possible course of climate policy, and associate a probability distribution over the set of possible policy scenarios. We identify the investor's best strategy by running PowerOptInvest a multi-period investment decision model that uses optimization to maximize the investor's profits in light of uncertainty about future regulatory and other parameters. At each point in time the investor has the option to invest in any of the identified generation technologies, with CCS or without. If the investment does not include CCS the investor retains the option of retrofitting with CCS at a later date. Alternatively, in a given period the investor can delay the investment altogether thereby retaining the option to choose a different generation technology in the future. No matter what investments have been made in previous years, the investor can always choose to change technologies and build any new plant with or without CCS, but sunk capital investment costs are not recoverable.

In the optimization problem the investor gains new information about the future natural gas price and the future course of climate policy that determines the emission fee. The first year for planning (year 0) is 2009. Initially in 2009 the investor holds priors of equal probability over each of the twelve policy scenarios, and by 2021 the outcome that governs natural gas price and climate policy over the remainder of the investment horizon through 2052 is known for sure. Each year between 2009 and 2021 the investor updates her priors based on current policy, placing relatively greater probability on the likelihood that the current policy will govern in 2021. At year *t* the probability assigned to any of the twelve scenarios other than the current scenario (*j*) is $p_t^{\bar{j}} = \frac{1}{12} \times \left(\frac{2021 - t}{2021 - 2009} \right)$ and the probability assigned to scenario *j* is $p_t^j = 1 - \frac{11}{12} \times \left(\frac{2021 - t}{2021 - 2009} \right)$.

A description of the formal algorithm of PowerOptInvest appears in an appendix.

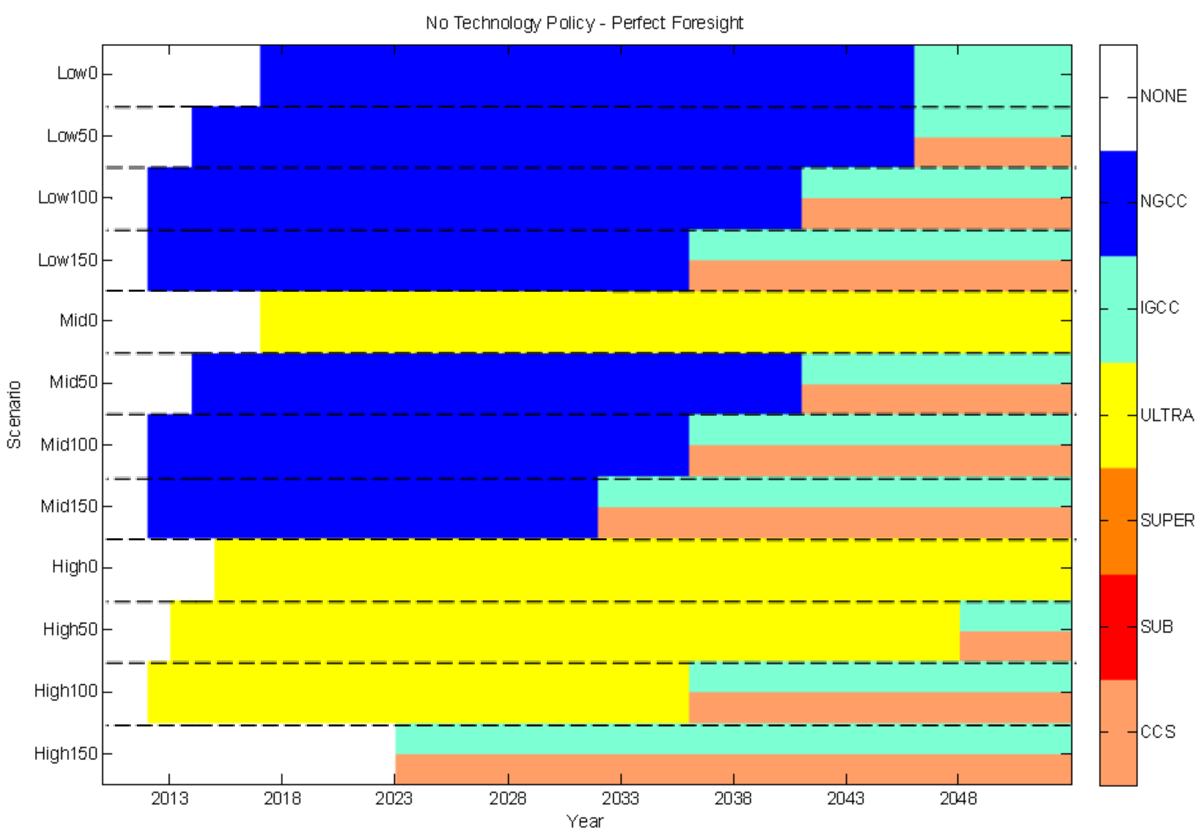
7. Results

The modeling analysis of the effects of different policies on investment decisions of plant owners compares choices under the three different versions of the technology standard identified above to a scenario with no technology policy. We make these comparisons within the context of twelve potential natural gas and federal climate policy scenarios. We look at these investment decisions in an environment of uncertainty, but for comparison, also present results assuming perfect foresight.

7.1 No Technology Policy

The baseline scenarios show what investment decisions are made in the absence of a technology policy under different federal climate policy scenarios. In our modeling the investor is looking forward to installing a new plant and is trying to decide what technology to pick given future natural gas prices and climate policy. For the twelve natural gas price–climate policy scenarios with perfect foresight, Figure 7.1 shows which technology is chosen by the investor to produce electricity and also the pattern of retrofits with CCS over the 43 year horizon in the absence of technology policy, beginning in 2010. The potential technology choices are revealed in the key to the right. The year displayed in the horizontal axis corresponds to the time the installed technology comes on line. We assume construction starts 2 years prior.

Figure 7.1 Technology choices with no technology policy under perfect foresight about gas prices and climate policy



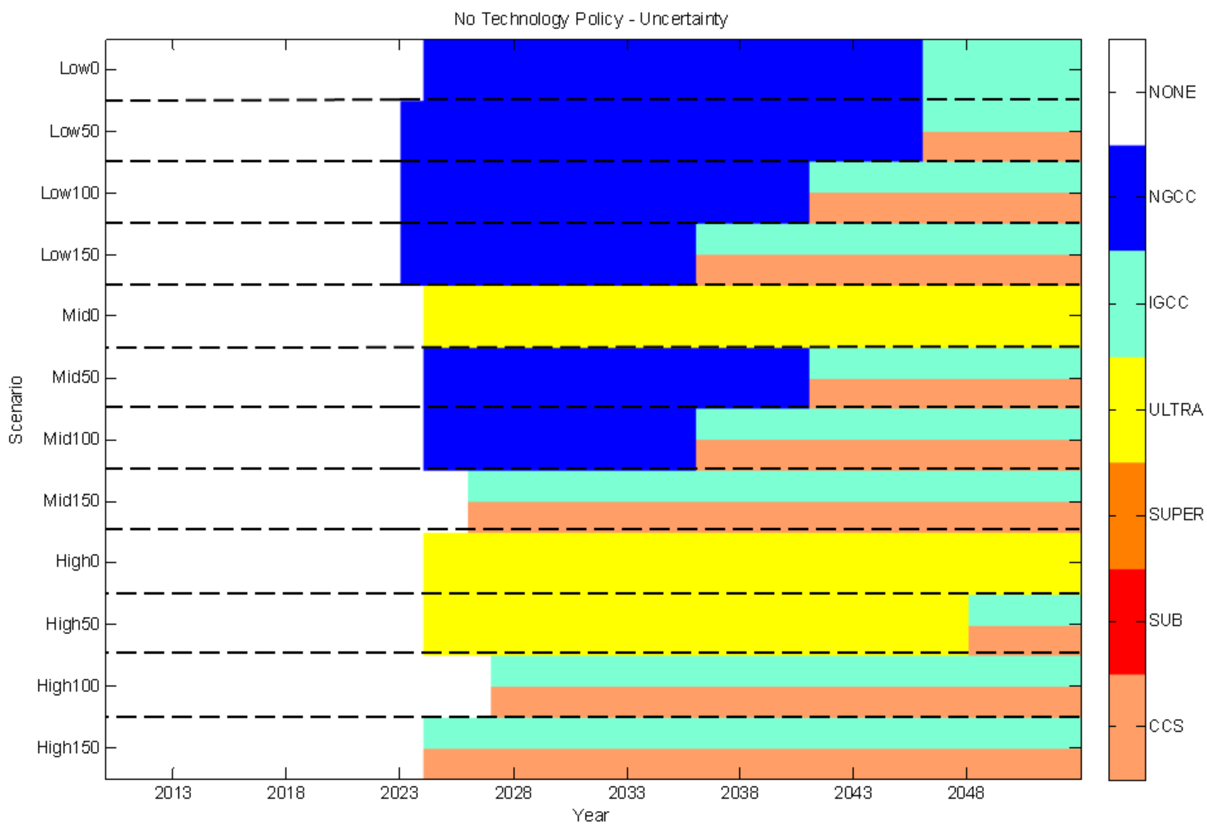
When natural gas prices are low, initially an NGCC plant is always the technology of choice. When there is no federal climate policy in place (low0), NGCC is never retrofit with CCS, but it is finally replaced by IGCC without CCS. Under the weak climate policy (low50), the IGCC plant is built with CCS in 2046. Under the mid climate policy (low100) the IGCC with CCS comes online in 2041, and under strict climate policy (low150) in 2036.

With natural gas prices at their mid level and there is no federal climate policy (mid0), an ultra-supercritical coal plant is the technology of choice. With mid level gas prices, under any type of federal climate policy NGCC is chosen. It is replaced by IGCC with CCS in years 2041 under weak climate policy (mid50), 2036 in the mid case (mid100), and 2032 under strict climate policy (mid150).

For the scenarios with high natural gas prices, ultra-supercritical is chosen for all versions of federal climate policy except for the most stringent one. Under the weak climate policy (high50), it is replaced by IGCC with CCS in 2048, and under the mid climate policy (high100) this occurs in 2036. For the most stringent climate policy (mid150), an IGCC plant comes online with CCS installed in 2023, so in this case technology policy is expected to have no effect.

Figure 7.2 shows the results when natural gas prices and climate policy are uncertain. For the scenarios with low natural gas prices (low*), again generators choose to build an NGCC plant and subsequently replace it with IGCC. With no climate policy, the IGCC does not include CCS. As in the perfect foresight case, with increasing stringency of climate policy the IGCC facility with CCS comes online in years 2046, 2041 and 2036, respectively.

Figure 7.2 Technology choices with no technology policy under uncertainty about gas prices and climate policy



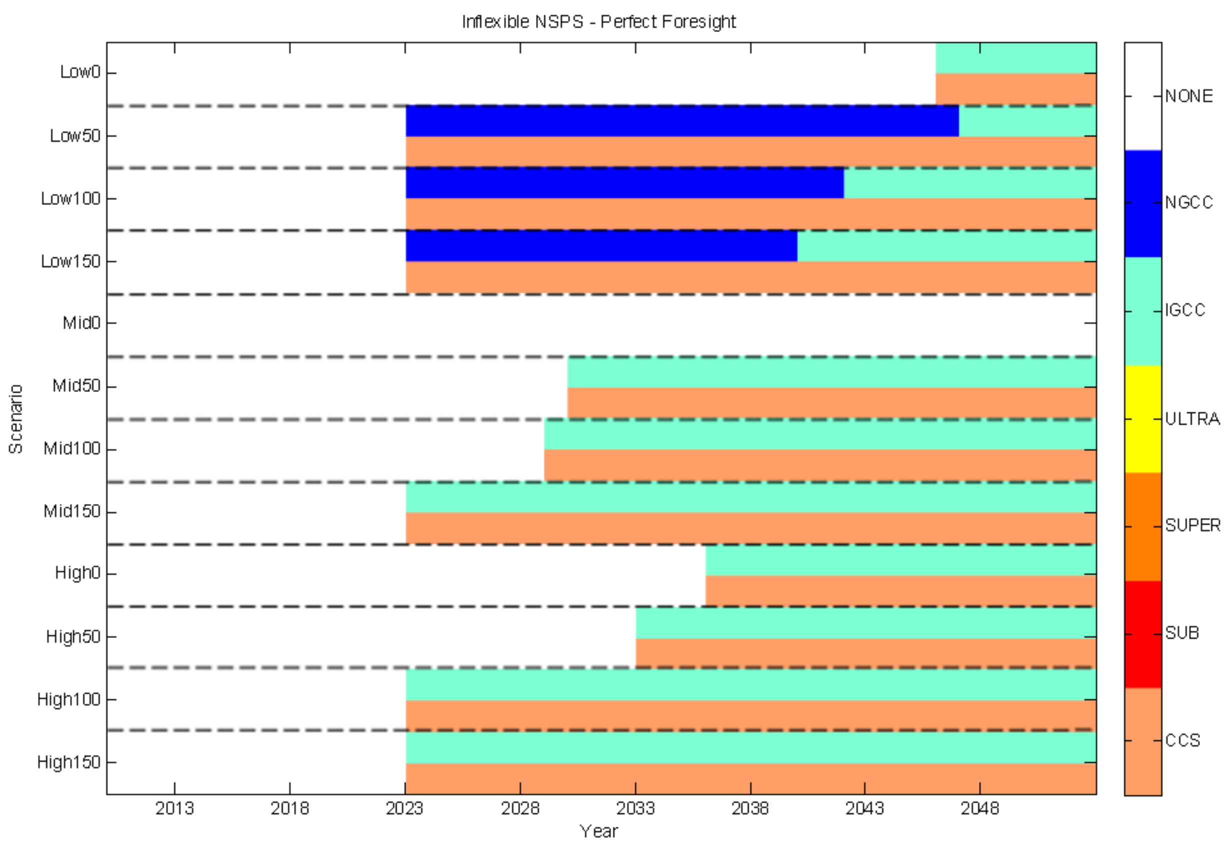
When natural gas prices are at the mid level and there is no federal climate policy (mid0), an ultra-supercritical coal plant is chosen. With weak (mid50) or mid case (mid100) climate policy, an NGCC is initially installed but later replaced by IGCC with CCS in 2041 or 2036. Under strong climate policy (mid150), an IGCC with CCS comes online in 2026.

When natural gas prices are high, an ultra-supercritical plant without CCS is the investment of choice under no (high0) or weak (high50) climate policy. Under the weak climate policy, the plant is replaced with an IGCC with CCS plant in 2048. For the mid (high100) and stringent (high150) climate policies, an IGCC with CCS plant starts operating in 2027 and 2024, respectively. In these two scenarios technology policy is expected to have no effect because the CCS is a component of the initial investment.

7.2 New Source Performance Standard

When there is perfect foresight about the future natural gas price and climate policy, the introduction of an inflexible performance standard on new investments leads to delays in investment for all scenarios except where natural gas prices are high and climate policy is stringent (high150). In this case, technology policy is not expected to have an effect because the initial investment includes CCS in the absence of the standard. This finding is consistent with hypothesis 1 in Section 5, which suggests that technology policy can lead to a delay in the timing of investment. Figure 7.3 illustrates the results.

Figure 7.3 Technology choices under a New Source Performance Standard and perfect foresight about gas prices and climate policy



When natural gas prices are low, and there is no federal climate policy (low0), a new IGCC plant with CCS comes on line in 2046. For the low gas scenarios with federal climate policy, an NGCC plant with CCS is installed in 2023, several years later than the year when new plants first come on line in the absence of a technology policy. In each case it is replaced with IGCC with CCS in 2047, 2042 and 2040, respectively.

When natural gas prices are at mid level, and there is no federal climate policy (mid0), new investment never occurs. Under any climate policy scenarios, an IGCC coal plant with CCS is chosen in 2030, 2029 and 2023. In these cases the new plants come online several years later than when there is no technology policy, but CCS comes online sooner, so the difference in emissions is ambiguous.

With high natural gas prices, an IGCC plant with CCS is always the technology of choice in 2036, 2033, 2023 and 2023. Again, investment happens years later than with no technology policy except under the strict climate policy, with the same technology installed at the same time as with no technology policy.

Figure 7.4 Technology choice under a New Source Performance Standard and uncertainty about gas prices and climate policy

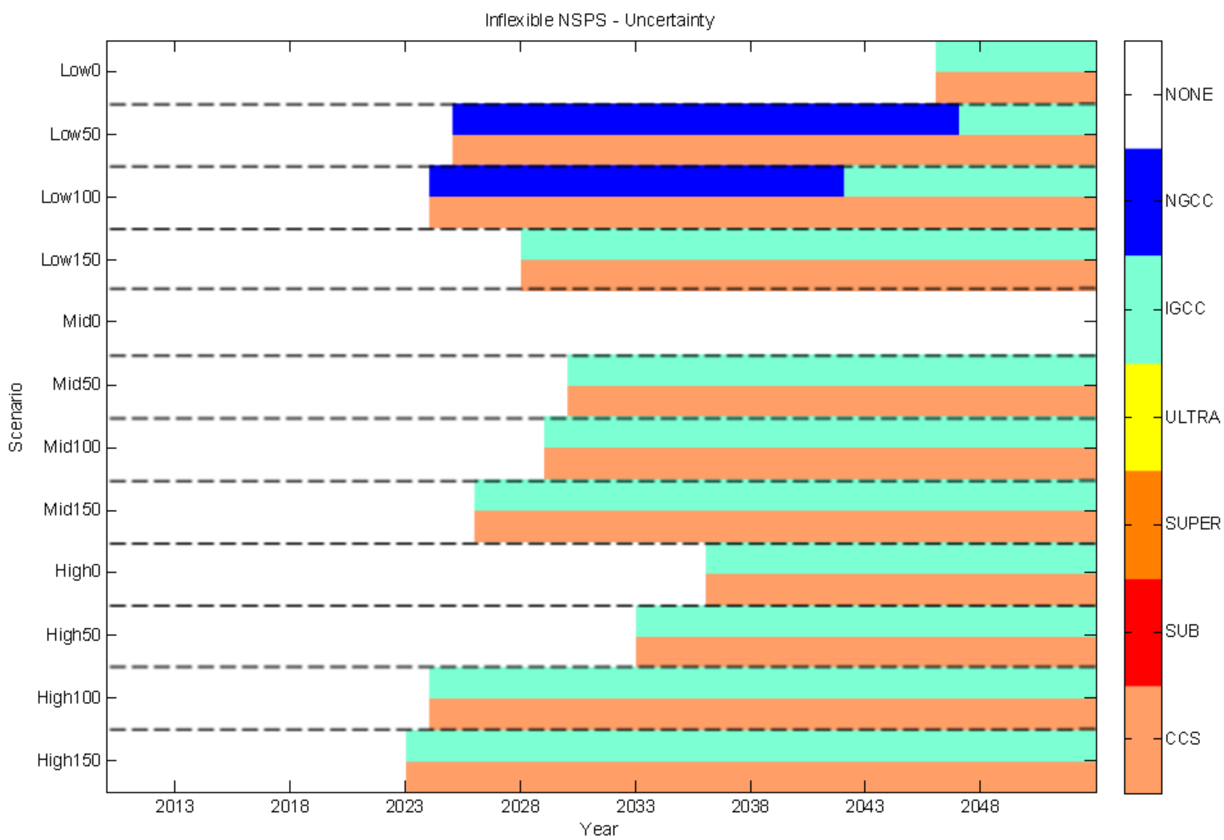


Figure 7.4 illustrates the timing of investments when there is uncertainty about natural gas price and climate policy. The technology policy forces all investment to have CCS, but comparison to Figure 7.2 with no technology policy shows several different technology choices are made. The investment in CCS happens earlier in 11 scenarios and stays the same in one.

Table 7.1 Date when first investments in generation and CCS come into service

Gas price	CO2 tax	Baseline: No Technology Policy		Inflexible NSPS		Flexible NSPS		Flexible NSPS with Escrow	
		Certain	Uncertain	Certain	Uncertain	Certain	Uncertain	Certain	Uncertain
Date that Initial Investment in Generation Begins Operation									
Low	BL	2017	2024	2046	2046	2018	2024	2018	2024
Low	50%	2014	2023	2023	2025	2019	2025	2016	2025
Low	100%	2012	2023	2023	2024	2013	NA	2013	NA
Low	150%	2012	2023	2023	2028	2012	2028	2012	2028
Med	BL	2017	2024	none	none	2017	2024	2017	2024
Med	50%	2014	2024	2030	2030	2030	2030	2015	2030
Med	100%	2012	2024	2029	2029	2013	2029	2013	2029
Med	150%	2012	2026	2023	2026	2013	2026	2012	2026
High	BL	2015	2024	2036	2036	2036	2036	2036	2036
High	50%	2013	2024	2033	2033	2033	2033	2033	2033
High	100%	2012	2027	2023	2024	2023	NA	2023	NA
High	150%	2023	2024	2023	2023	2023	NA	2023	NA
Date that CCS Begins Operation									
Low	BL	none	none	2046	2046	2046	2046	2046	2046
Low	50%	2046	2046	2023	2025	2023	2025	2025	2025
Low	100%	2041	2041	2023	2024	2023	NA	2023	NA
Low	150%	2036	2036	2023	2028	2023	2028	2023	2028
Med	BL	none	none	none	none	NA	NA	NA	NA
Med	50%	2041	2041	2030	2030	2030	2030	2025	2030
Med	100%	2036	2036	2029	2029	2027	2029	2024	2029
Med	150%	2032	2026	2023	2026	2023	2026	2023	2026
High	BL	none	none	2036	2036	2036	2036	2036	2036
High	50%	2048	2048	2033	2033	2033	2033	2033	2033
High	100%	2036	2027	2023	2024	2023	NA	2023	NA
High	150%	2023	2024	2023	2023	2023	NA	2023	NA

However, a technology standard causes initial investments to be delayed in 9 scenarios (highlighted in yellow in Table 7.1.), unaffected in one scenario, and sped up in two scenarios (highlighted in blue in Table 7.1.), and ultra-supercritical is never chosen. Comparison of no technology policy with an inflexible policy illustrates a contradiction of the first hypothesis of section 5. That hypothesis, developed in the context of perfect foresight, suggests that NSPS policy would never speed up investment but with uncertainty the result does not hold in two scenarios.

The reason is that for the case with high natural gas prices, the only two power generation technologies that an investor would consider for an initial investment are an ultra-supercritical plant for the cases with no or weak climate policy (high0 or high50), or an IGCC plant for the mid or strong climate policy (high100 or high150). An NGCC plant is not competitive due to the high prices of the fuel, and the alternative of not installing any plant is not competitive because for these scenarios the expected electricity prices after 2020 are sufficiently high to motivate investment. Assuming a scenario with high natural gas prices and a strong climate policy (High150), at year 2018, the investor sees a high probability of being in one of the stronger climate policies. For example, if scenario is High150, then at year 18 the probability of High150=0.7708, probability of High100=0.0208, probability of Mid100=0.0208 and probability of Mid150=0.0208 for a total 0.83 probability of being in a mid or strong climate policy scenario Under no technology policy, it is optimal to wait one more year to get an updated probability for the climate policy scenarios and decide whether an ultra-supercritical (without CCS) or an IGCC with CCS should be installed. Under a strict technology standard, there is no value of waiting one more year because the choice of an ultra-supercritical without CCS is not available. These results are summarized in Table 7.1. The top half of the table indicates the date an initial investment in generation comes on line, and the bottom half indicates the date when the initial investment in CCS comes on line.

7.3 Flexible New Source Performance Standard

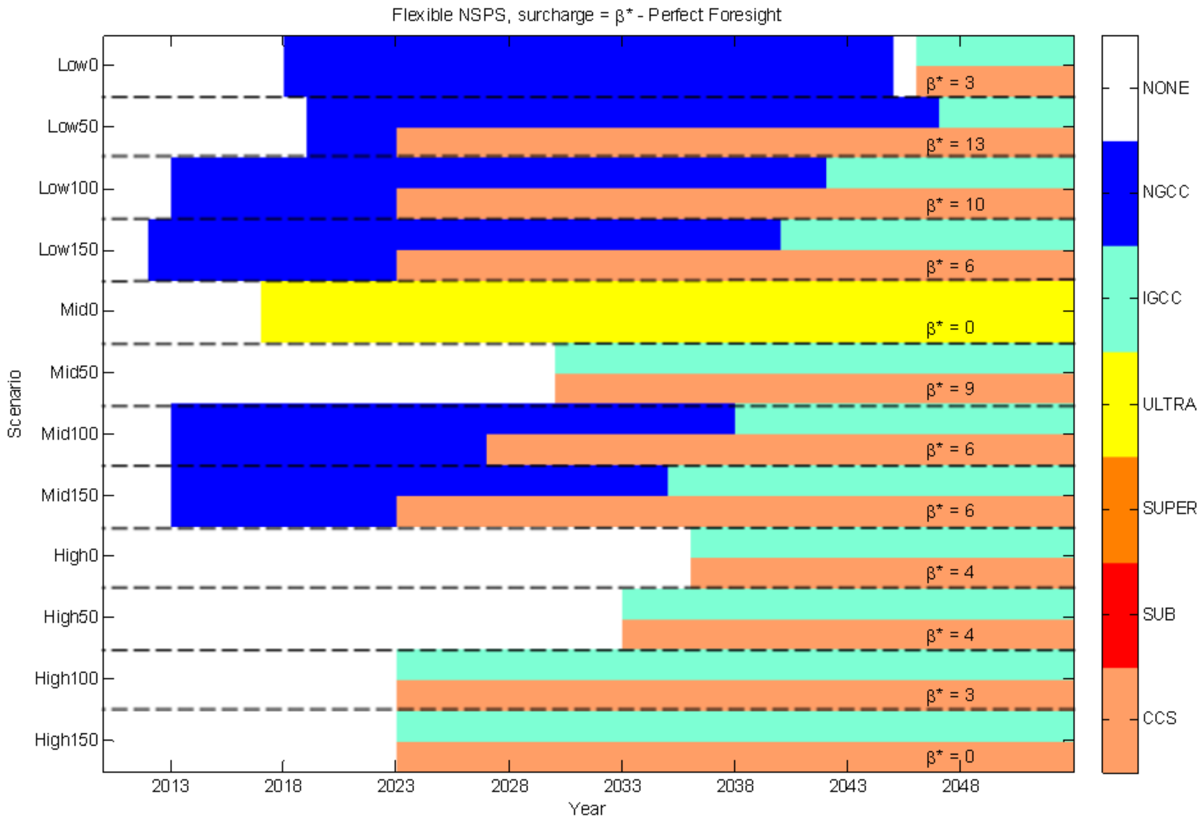
With a flexible NSPS an investor can build a new facility that does not strictly meet the technology standard, but must pay a surcharge on its emissions that are in excess of the standard. Introducing this type of policy raises the question of how to set the emissions surcharge. The approach that we take to this question is to identify the level of the surcharge that leads to the same investment pattern, both in terms of timing and technology choice, as we saw under the strict standard.

We compare the flexible NSPS policy to the inflexible NSPS policy. The value of β^* refers to the year 2009 surcharge in $ per ton that must be paid for each ton in excess of the emissions standard (and potentially in addition to the price on CO_2 emissions under the federal climate policy) that achieves investment in CCS at the same time under both policies. We assume β^* increases every year at rate r which is the same rate of discount used by the investor in the expected NPV calculation. The resulting surcharge is the β^* reported in Figures 7.5-7.8. Sometimes the choice of generation technology is different than installed initially under inflexible NSPS, and for these cases we seek to identify a higher surcharge level $\beta^{**} > \beta^*$, such that the corresponding technology choice and investment time are both the same as under the inflexible NSPS.

With perfect foresight, we always find a value of β^* that leads to investment in CCS at least as soon as under the inflexible technology standard (Figure 7.5). Consistent with hypothesis 2, we find an increase in the value of the surcharge moves forward the time at which CCS technology is built, and consistent with hypothesis 3, we find investment in CCS at or before when it would occur in the absence of technology policy. The values of β^* are between \$0 and \$13 per ton of CO_2 for the perfect foresight situation. When natural gas price is at its mid level and there is no federal climate policy (mid0) the inflexible NSPS policy causes investment to be indefinitely postponed (beyond 2052), so in this case the surcharge value needed to replicate this result under a flexible NSPS policy is \$0. Under perfect foresight and under the most strict federal climate policy, when natural gas prices are high (high150), no technology policy is necessary to get the IGCC with CCS to come on line, so again the surcharge value is \$0. For any other case under perfect foresight there is always a surcharge level β^* for which investment in CCS will happen at the same time or before as under the inflexible NSPS policy.

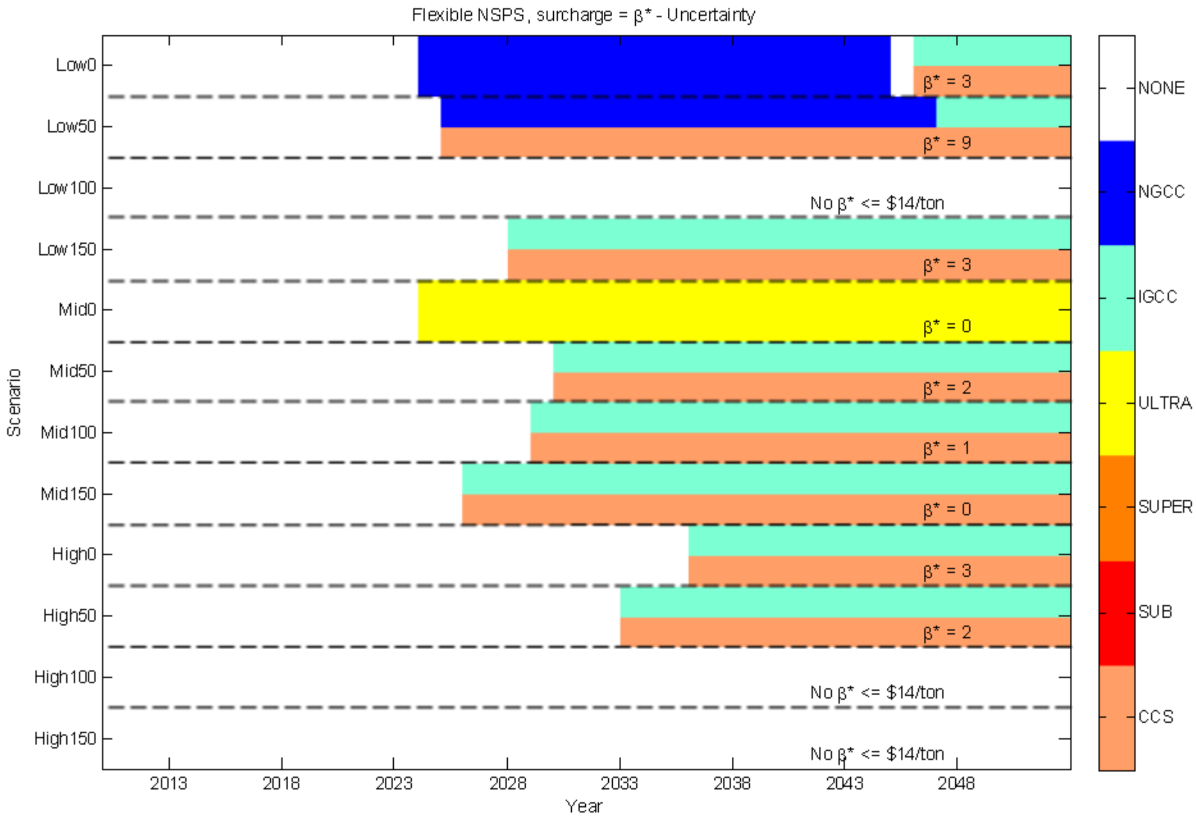
The change in the timing and choice of generation technology can have an important effect on cumulative emissions. In many cases investment in newer technology, albeit absent CCS, comes years earlier than under the inflexible policy. The technology choice is the same for all scenarios except for three. For the scenario with low natural gas prices and no federal climate policy (low0), a surcharge of \$3 per ton of CO_2 produces investment in IGCC with CCS investment in the same year that it occurs under the inflexible NSPS policy. However, in the flexible case NGCC without CCS appears several years earlier and is subsequently replaced. For the scenarios with mid natural gas prices and mid and stringent federal climate policy (mid100, mid150) a surcharge of \$6 per ton yields investment in NGCC with CCS, subsequently replaced by IGCC with CCS, instead of the IGCC with CCS initially chosen under the inflexible NSPS. For these scenarios there is no β^{**} value that would cause identical investment as the inflexible NSPS.

Figure 7.5 Technology choices for β^* under a flexible New Source Performance Standard and perfect foresight



When there is uncertainty about the future federal climate policy (Figure 7.6), there are three scenarios for which there is no surcharge value in the range of $\beta^* \leq 20$ that yields installation of CCS at the same time or before than the inflexible NSPS. In these cases installation happens one or more years later than under the inflexible NSPS. Hence, although increasing β does move forward the time of investment (hypothesis 2), in the range we studied we do not find results that are consistent with hypothesis 3 with respect the timing of investments. For the scenario with mid natural gas prices with no climate policy (mid0), and the scenario with mid natural gas prices and stringent climate policy (mid150), no surcharge is needed to yield identical investment (e.g. β^* =0). For the remaining scenarios there is a surcharge level that yields an identical investment to the one produced by the NSPS policy.

Figure 7.6 Technology choices for β^* under a flexible New Source Performance Standard and uncertainty

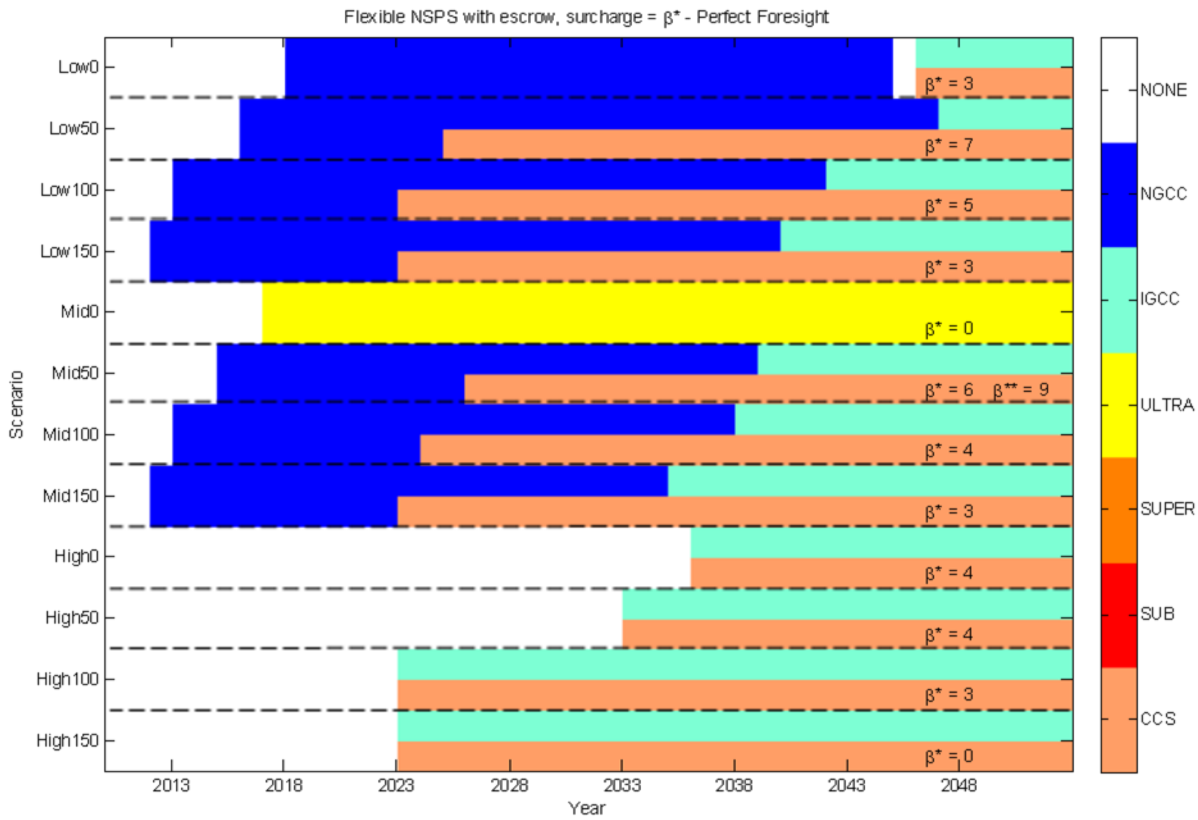


7.4 Flexible New Source Performance Standard Escrow Fund

The escrow fund, comprised of accumulated emission surcharge payments, provides a source of funds that can be used to subsidize the cost of retrofitting a facility with CCS in the future. Thus the policy is most effective when the flexible policy by itself does not lead to CCS being installed with the initial investment. The escrow fund operates with 3 rules that help destroy incentives for delaying CCS investment in the hopes for lower capital costs. The first rule specifies that the funds accumulated in the escrow account do not gain any interest. This makes delaying CCS costly since the surcharge payment accumulates in an escrow fund that loses value with time. The second rule specifies that the maximum amount of funds withdrawn from the escrow cannot exceed the capital costs of the CCS investment (be it a CCS retrofit or a new plant with CCS included). This discourages accumulating funds in the escrow that exceed the capital costs of the needed CCS investment. The third rule specifies that funds from the escrow account can be withdrawn only once. This means that any funds not used for the first

CCS investment (a retrofit or a new plant) are lost.

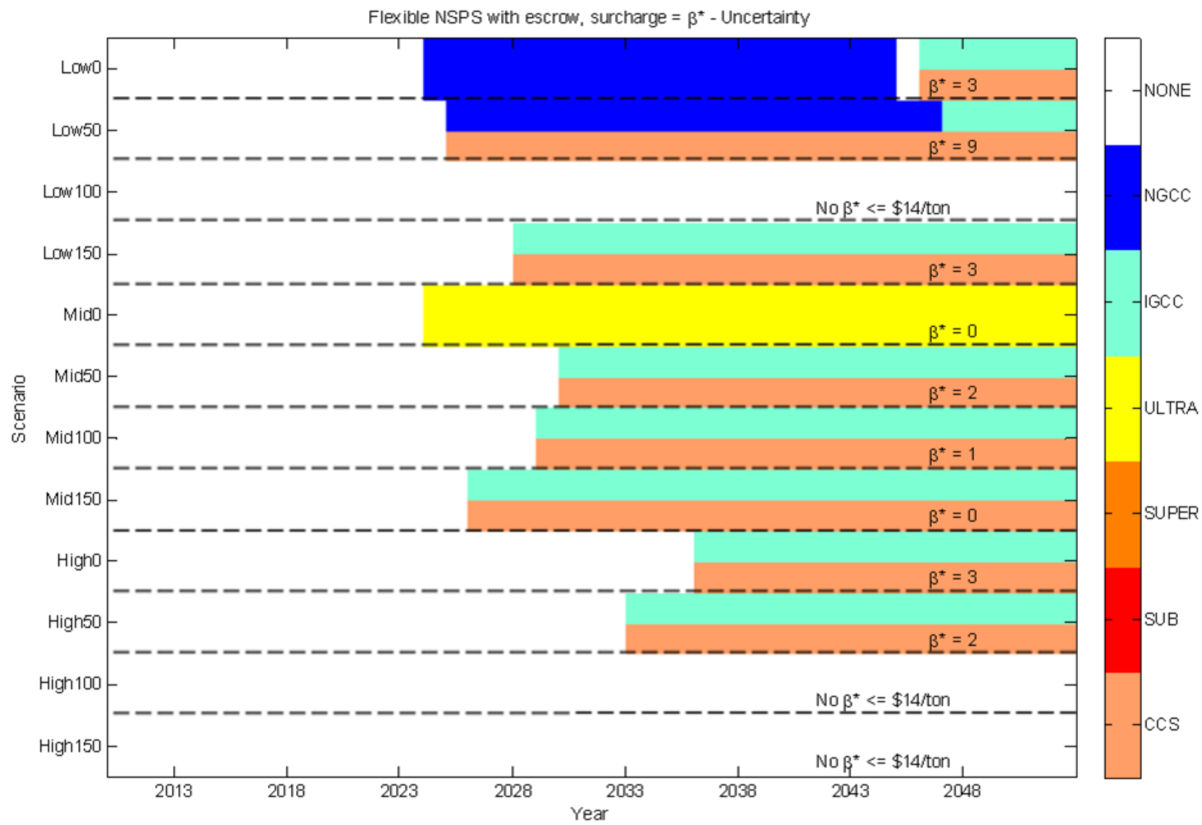
Figure 7.7 Technology choices for β^* under a flexible New Source Performance Standard with escrow and perfect foresight



The effect of introducing the escrow fund option can be seen by contrasting the β^* values. Under perfect foresight the β^* values of NSPS with escrow (Figure 7.7) are lower than the β^* values for flexible NSPS (Figure 7.5) for the 6 scenarios with climate policy and low or mid natural gas prices, and the same for the scenarios with no climate policy or high natural gas prices. Note that with low natural gas prices and no climate policy (Low0) there is a brief period after an initial investment in NGCC in which no plant is used and the investor buys electricity from the market. This results because natural gas prices continue to rise, even in this case. Note also that with modest climate policy (Low50), the operation of the CCS retrofit begins in 2025, two years later than occurs under the flexible standard, but this is not a contradiction of hypothesis 6 because that formulation did not consider a possible distinction between investment and operation of CCS. The actual investment decision is made in 2023 in both cases, but operation is delayed under the escrow fund. For two of the scenarios, the lower β^* required to obtain CCS with the NSPS with escrow also causes earlier investment than occurred with just the flexible NSPS. With low gas prices and a modest climate policy (Low50), the flexible NSPS requires a β^* of $13 to produce the retrofit of an NGCC plant with CCS ready to be used in year 2023, while the NSPS with escrow requires a β^* of only $7 to cause an identical investment. With mid-level gas prices and modest climate policy (Mid50) the flexible NSPS requires a β^* of $9 to produce the installation of an IGCC with CCS in year 2030, while the NSPS with escrow requires a β^* of $6 to cause an investment in NGCC subsequently retrofit in year 2025, and then replaced by IGCC with CCS. These results are consistent with hypothesis 6, suggesting that the introduction of an escrow account should not delay the timing of investment in CCS.

With uncertainty, Figures 7.6 and 7.8 indicate the timing and choice of investments with NSPS and an escrow fund is identical to the flexible NSPS policy and there is no change in the β^* values. This result is consistent with hypothesis 6, which suggests the fund should not delay investment in new generation. It is also consistent with hypothesis 7, which suggests the escrow fund should not delay investment in CCS.

Figure 7.8 Technology choices for β^* under a flexible New Source Performance Standard with escrow and uncertainty



7.5 Emissions Levels under Different Policies

Figures 7.9 and 7.10 show total CO_2 emissions from year 2010 to 2052 under the baseline situation and under the three different policies analyzed. For the flexible NSPS policy without and with the escrow we assume the surcharge is equal to β^* (e.g. the surcharge value that produces a CCS installation the same year or before the inflexible NSPS policy would).

Figure 7.9 shows that under perfect foresight about future natural gas prices and climate policy, the inflexible NSPS policy produces CO_2 emissions higher than those of the baseline for 8 out of 12 scenarios, and equivalent in one scenario. The exceptions are three of the scenarios with high natural gas prices, where inflexible performance standards lead to lower emissions. The majority of these findings are consistent with hypothesis 1.

The flexible NSPS policy with a surcharge value equal to β^* produces cumulative CO_2 emissions that are lower or equal to the inflexible NSPS policy for every scenario (in five cases they are equal). This is consistent with hypothesis 4. Moreover, CO_2 emissions of the flexible NSPS policy with escrow fund are the lowest or equal to lowest in every scenario. They are less than emissions under the flexible NSPS without escrow in four scenarios. This is consistent with hypothesis 8.

In summary, these results demonstrate that for the perfect foresight situation, an inflexible NSPS policy may delay investment and produce CO_2 emissions that are higher than under the baseline. Further, the introduction of flexibility can lead to lower CO_2 emissions than under the inflexible policy or the baseline. In nine scenarios the flexible NSPS leads to lower or equal emissions than in the no technology policy case. In only one case (Mid50) is there an important reversal. In every scenario the flexible policy with an escrow account leads to equal or lower emissions than with no technology policy.

Figure 7.9 CO_2 emissions when surcharge for polices 2 and 3 equals B* and there is perfect foresight about federal climate policy

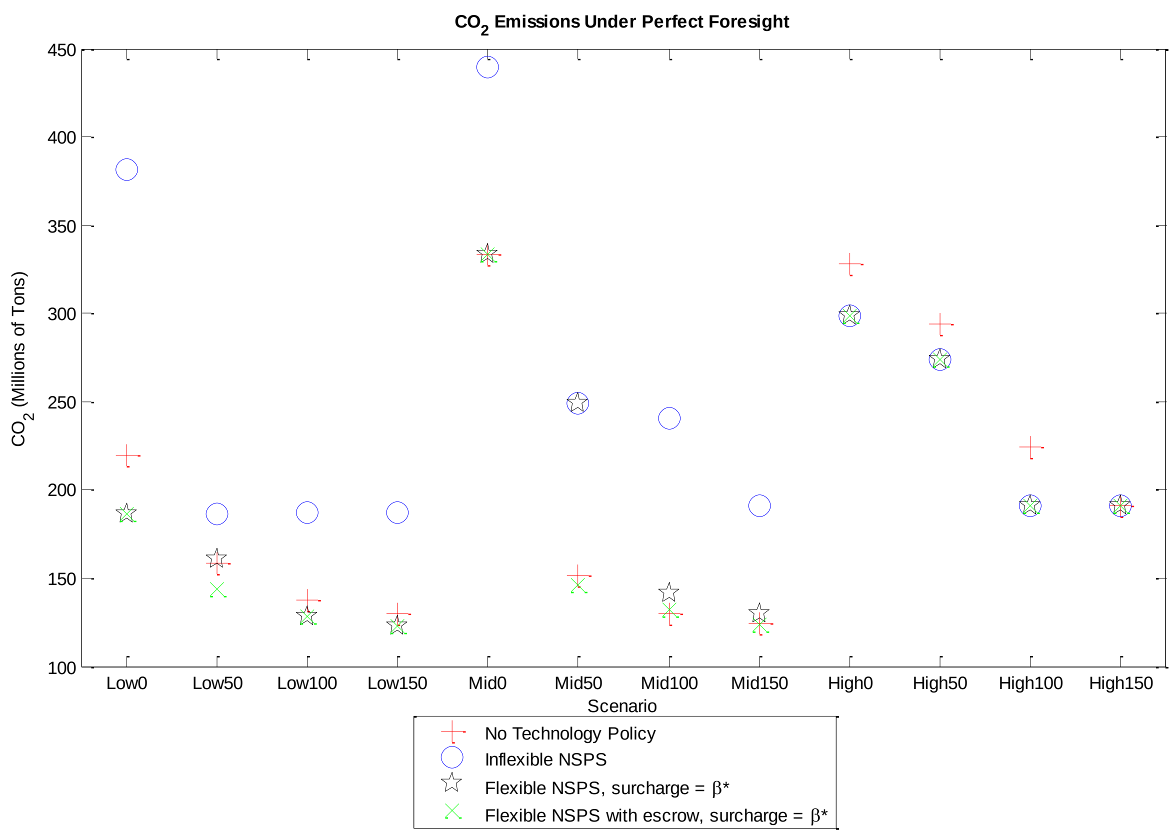
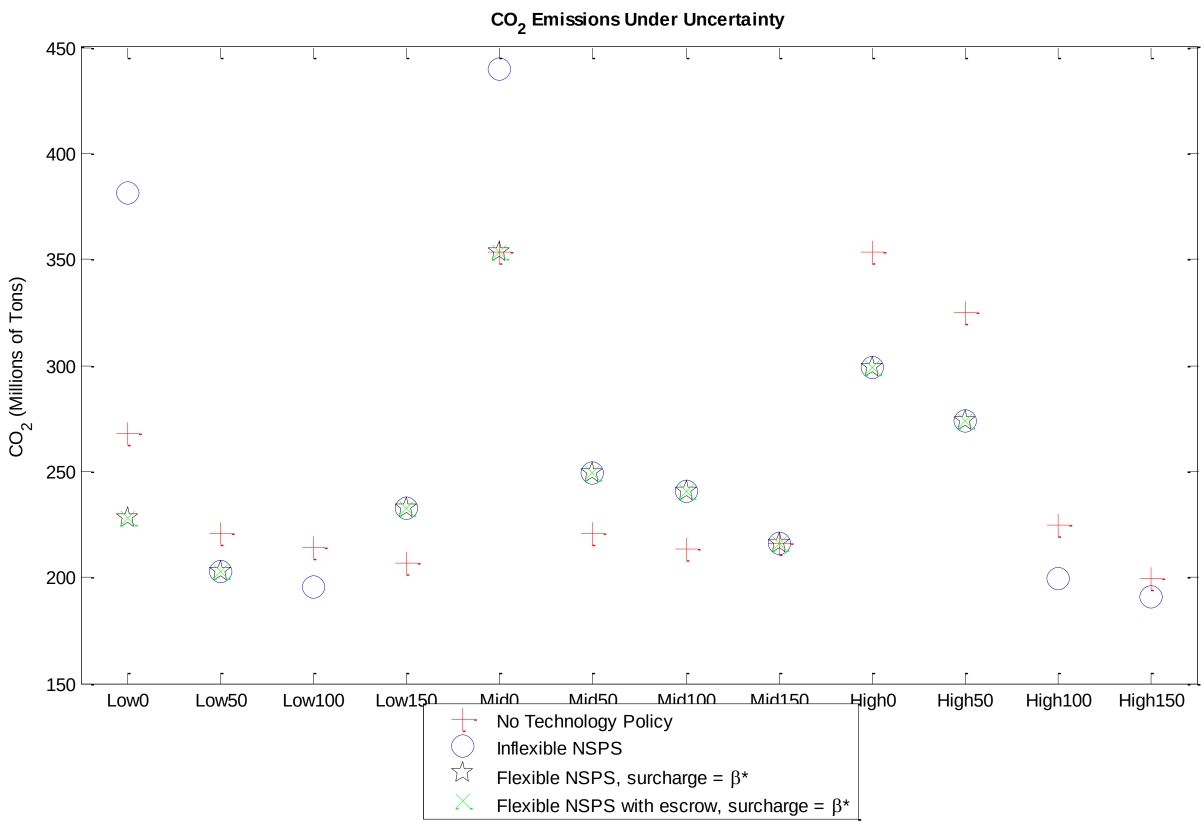


Figure 7.10 shows results with uncertainty, where emissions produced by the inflexible NSPS policy are strictly higher than those of the no technology policy baseline for five of the scenarios (hypothesis 1). The CO_2 emissions produced by the flexible NSPS policy are lower than or equal to emissions in the inflexible policy in all nine of the scenarios where β^* is identified (hypothesis 4). With the escrow fund, the cumulative emissions are the same as for the flexible NSPS policy where β^* is identified (hypothesis 8).

Figure 7.10 CO_2 emissions when surcharge for polices 2 and 3 equals B* and there is uncertainty about federal climate policy



7.6 Comparing Profits for Investors under Different Policies

Figure 7.11 reports the net present value of investor profits across the four policies under perfect foresight. In the no technology policy case, profits are always at least weakly highest and usually strictly highest. Profits are always strictly lower under the inflexible policy than under no technology policy, with the exception of the scenario with high natural gas prices and stringent climate policy (High150). Further, the flexible policy always leads to profits that are at least as great as under the inflexible policy, which is consistent with hypothesis 5. In turn, the introduction of an escrow fund leads to profits that are always as at least as great as under the flexible policy without an escrow fund, and strictly greater in five scenarios, consistent with hypothesis 9.

Figure 7.11 Investor's profits when surcharge for polices 2 and 3 equals B* and there is perfect foresight about federal climate policy

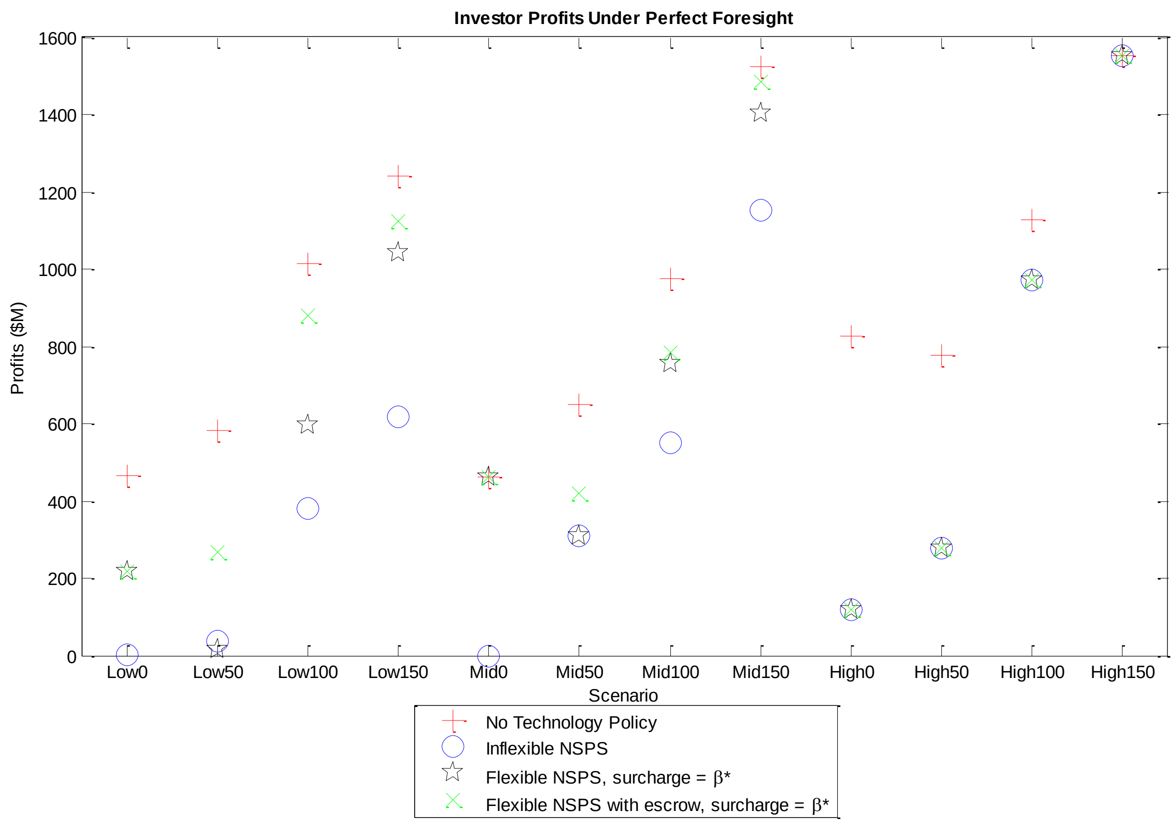
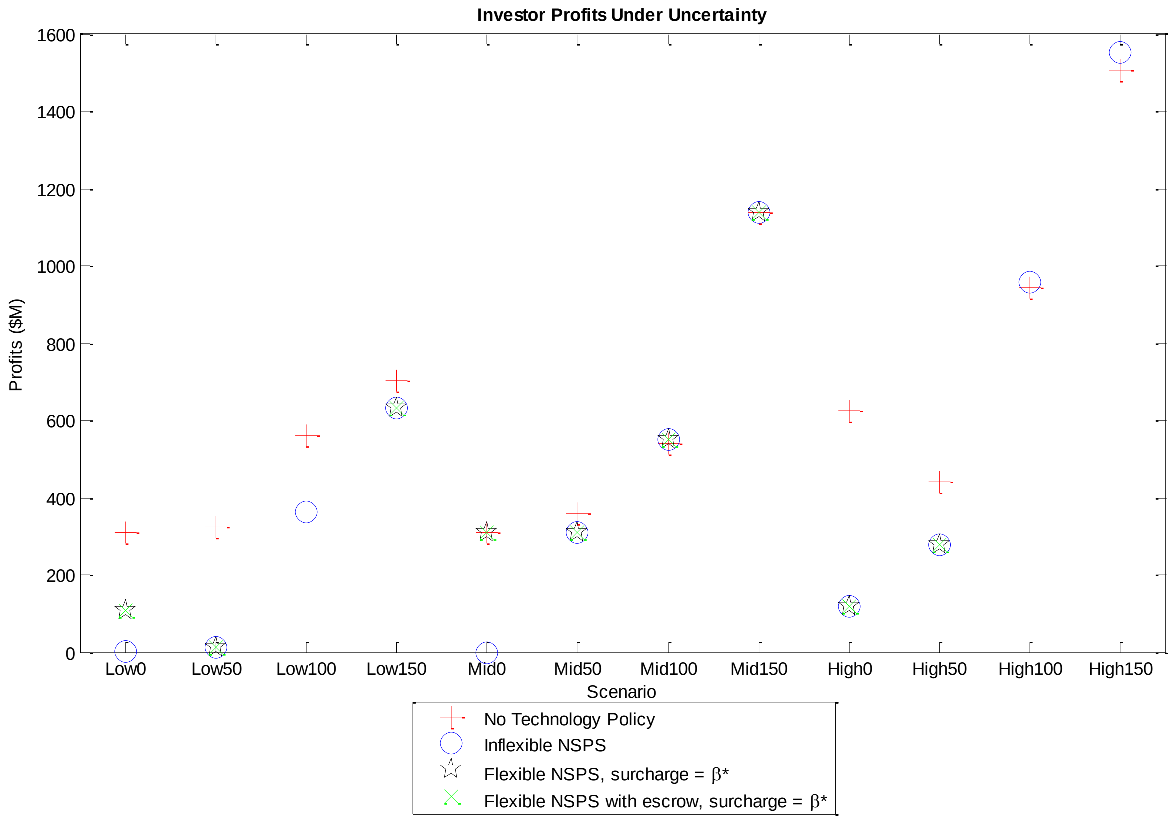


Figure 7.12 reports investor profits under uncertainty. Compared to perfect foresight, profits are never higher with uncertainty under any scenario or policy (with one exception in the High 150 case). The inflexible policy leads to lower or equal profits than under the no technology policy baseline in every case except with high natural gas prices and stringent climate policy (High150). The introduction of flexibility leads profits to be no lower than in the absence of flexibility where β^* is identified (hypotheses 5 and 9). Profits are the same with and without the escrow account because the investment choices are the same under these policies and the

majority of those investments include CCS from the beginning so no money is accumulated in the escrow fund.

Figure 7.12 Investor's profits when surcharge for polices 2 and 3 equals B* and there is uncertainty about federal climate policy



8. Conclusion

This study examines policies to promote the state-of-the art technologies in the electricity sector in the United States. Using the challenge of reducing CO_2 emissions from the electricity sector as a case study, we examine a new source performance standard, and two variations that introduce flexibility to the standard. One policy would allow for payment of a surcharge on emissions (in addition to payments for CO_2 emissions under federal climate policy) if CCS were not installed at time of new investment. The second would allow the surcharge to accumulate in an escrow fund, and the fund would be available to offset capital costs for subsequent retrofit if it occurs within ten years. These policies are examined under twelve scenarios that vary the level of natural gas prices and the stringency of federal climate policy (cap and trade) in the U.S. The analysis compares perfect foresight over the twelve scenarios with uncertainty.

The study uses a suite of models including an electricity market model that provides background equilibrium conditions with respect to delivered prices of fuel, allowance prices, electricity prices, etc. Another technology model provides detailed information about the capital and operating costs of coal generation technology and CCS. A third model provides stochastic optimization of the uncertain fuel price/climate policy scenarios. The model is solved over an investment horizon through 2021, taking into account a planning horizon through 2052.

We model the choice of an individual investor whom we consider to be the first mover with respect to new investment within this policy setting and market equilibrium. Analytical characterization of the investor's problem provides a list of hypotheses that we examine using numerical simulation. With perfect foresight, we find results that are consistent with the hypotheses, but with uncertainty results are not always consistent with the hypotheses.

In the absence of any technology policy and under perfect foresight, when natural gas prices are low, an NGCC plant is always the technology of choice. When there is no federal climate policy in place, NGCC is never retrofit with CCS, but it is finally replaced by IGCC in 2043. Under the weak climate policy, NGCC is retrofit with CCS in 2037. Under the mid climate policy, the CCS retrofit comes online in 2036, and under strict climate policy the retrofit comes into service in 2034. For natural gas prices at their mid level, an ultra-supercritical technology is chosen when there is no federal policy. NGCC is chosen under any federal climate policy, and subsequently retrofit depending on the stringency of the policy. For high natural gas prices, ultra-supercritical technology is chosen for all versions of federal climate policy, and subsequently retrofitted with CCS, except for the most stringent climate policy where an IGCC plant with CCS is installed.

In the absence of a technology policy, uncertainty leads to a delay in investment in in new generation. Investment in CCS is also always later. In a few cases, a subsequent investment in a different generation technology occurs at a later time.

With perfect foresight, the introduction of an inflexible technology policy delays investment almost across the board, consistent with the hypotheses developed in the paper. The introduction of a flexible policy leads to investment at the same time or earlier under an appropriately chosen emissions surcharge. We also find that the introduction of an escrow fund leads to investment in CCS that is at the same time or earlier than in the absence of the fund, although in one case operation of the CCS is delayed. Similarly, total cumulative emissions are lower for the flexible policy, and lower still with the escrow fund, under most scenarios. Profits are no lower and sometimes higher with the flexible policy, and equal or higher still with the escrow fund. With uncertainty, similar results consistent with the hypotheses are obtained.

A standard criticism from the economics literature and from industry is that inflexible mandates requiring a specific technology for new investments tend to delay the time of investment. This not only lowers profits, but arguably can lead to an overall increase in emissions if the new investment absent a technology mandate would have led to lower emissions than the existing facility it might replace.

We construct a modeling platform in which these concerns are validated in most cases. However, we find that the introduction of two types of flexibility can overcome these concerns and lead to a comparable or earlier timing of investment as would occur under an inflexible standard. Moreover, this is accompanied over time by lower cumulative emissions and greater profits.

A key limitation of this result is the lack of a decision algorithm for the regulator over the design of the flexibility mechanism, including the choice of a level of a surcharge. This question will be addressed in a subsequent paper.

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Appendix

This appendix has two parts. The first part is a set of tables include results drawn from the Haiku electricity market model that are used as parameters in the multi-stage stochastic optimization model. The second part of the appendix is a description of the algorithm used in the multi-stage stochastic optimization.

Data Tables

These tables include allowance prices, fuel prices, electricity prices and learning rates for various technologies.

Table A.1. SO2 allowance prices ($/ton)

Year	*Low0*	*Low50*	*Low100*	*Low150*	*Mid0*	*Mid50*	*Mid100*	*Mid150*	*High0*	*High50*	*High100*	*High150*
2010	438	438	438	438	438	438	438	438	438	438	438	438
2011	429	398	380	350	490	453	427	375	514	476	439	408
2012	420	358	322	262	543	468	417	313	590	514	441	378
2013	411	318	264	174	595	483	406	251	667	552	443	348
2014	447	346	287	190	647	525	441	272	724	600	481	378
2015	482	373	310	205	698	567	477	294	782	648	519	409
2016	518	401	332	220	750	608	512	316	840	696	558	439
2017	568	434	356	227	819	667	547	324	907	763	590	450
2018	618	467	380	235	889	726	582	333	973	831	622	462
2019	669	500	404	242	958	785	617	341	1040	898	655	474
2020	719	534	429	249	1027	844	652	349	1107	966	687	486
2021	770	567	453	257	1097	903	688	358	1174	1033	720	498
2022	812	570	411	230	1131	937	636	318	1192	1054	669	432
2023	855	573	369	203	1166	971	584	279	1210	1075	619	367
2024	897	576	327	176	1201	1006	532	239	1228	1096	568	302
2025	940	580	286	149	1235	1040	480	200	1246	1117	518	237
2026	982	583	244	122	1270	1075	428	160	1264	1139	467	171
2027	1012	554	229	100	1248	975	387	147	1251	1052	435	158
2028	1041	524	215	79	1227	875	347	134	1238	966	404	145
2029	1070	495	201	58	1205	775	306	120	1225	879	372	132
2030	1099	466	186	37	1184	676	265	107	1212	793	340	119
2031	1128	437	172	16	1162	576	224	94	1199	706	308	106
2032	1157	417	164	15	1141	550	214	89	1186	674	294	101
2033	1186	397	156	15	1119	523	204	85	1173	642	280	96
2034	1216	377	148	14	1098	497	194	81	1160	610	266	91
2035	1245	358	140	13	1076	471	183	77	1147	578	252	87
2036	1274	338	133	12	1055	445	173	72	1134	546	238	82
2037	1303	318	125	12	1033	419	163	68	1121	514	224	77
2038	1332	298	117	11	1011	393	153	64	1108	482	210	72
2039	1361	278	109	10	990	366	143	60	1095	449	196	67
2040	1391	258	101	10	968	340	132	55	1082	417	182	63
2041	1420	238	94	9	947	314	122	51	1069	385	168	58
2042	1449	218	86	8	925	288	112	47	1056	353	154	53
2043	1478	199	78	7	904	262	102	43	1043	321	140	48
2044	1507	179	70	7	882	236	92	38	1030	289	126	43
2045	1536	159	62	6	861	209	82	34	1017	257	112	39
2046	1565	139	55	5	839	183	71	30	1004	225	98	34
2047	1595	119	47	4	818	157	61	26	991	193	84	29
2048	1624	99	39	4	796	131	51	21	978	161	70	24
2049	1653	79	31	3	775	105	41	17	965	128	56	19
2050	1682	60	23	2	753	79	31	13	952	96	42	14
2051	1711	40	16	1	732	52	20	9	939	64	28	10
2052	1740	20	8	1	710	26	10	4	926	32	14	5

Table A.2. NO_x allowance prices ($/ton)

Year	Low0	Low50	Low100	Low150	Mid0	Mid50	Mid100	Mid150	High0	High50	High100	High150
2010	879	879	879	879	879	879	879	879	879	879	879	879
2011	974	1062	1028	985	968	964	1122	1091	974	968	1243	1075
2012	1070	1245	1177	1091	1058	1050	1366	1304	1070	1058	1607	1272
2013	1166	1429	1327	1197	1147	1135	1609	1516	1166	1147	1971	1469
2014	1255	1549	1439	989	1232	1498	1701	1366	1500	1821	1932	1453
2015	1344	1669	1552	782	1317	1861	1794	1217	1834	2495	1893	1438
2016	1433	1789	1665	575	1402	2224	1886	1067	2169	3169	1854	1422
2017	1372	1652	1398	508	1338	2061	1575	904	1897	2623	1551	1192
2018	1310	1516	1131	442	1274	1899	1265	741	1626	2078	1248	962
2019	1249	1379	864	375	1211	1736	955	579	1354	1533	945	732
2020	1188	1242	597	309	1147	1573	645	416	1083	988	642	502
2021	1127	1106	330	242	1083	1411	334	253	811	442	339	272
2022	1102	953	314	194	1174	1239	326	242	814	433	335	265
2023	1078	801	299	145	1265	1067	317	231	817	424	331	258
2024	1054	648	284	97	1356	895	308	220	819	415	327	251
2025	1029	495	268	49	1447	723	300	210	822	406	323	244
2026	1005	343	253	0	1538	552	291	199	825	397	319	237
2027	1014	342	207	0	1449	523	286	160	871	403	314	209
2028	1023	341	161	0	1359	494	280	122	917	408	309	181
2029	1033	340	115	0	1270	466	274	84	963	414	305	153
2030	1042	339	69	0	1180	437	269	45	1008	419	300	126
2031	1051	339	23	0	1090	408	263	7	1054	424	296	98
2032	1060	338	21	0	1041	390	258	7	1100	430	291	93
2033	1070	337	20	0	991	371	252	6	1146	435	286	89
2035	1088	335	18	0	892	334	241	6	1238	446	277	80
2036	1098	334	17	0	843	315	235	5	1284	451	273	76
2037	1107	334	16	0	793	297	230	5	1330	457	268	71
2038	1116	333	15	0	743	278	224	5	1376	462	263	67
2039	1125	332	14	0	694	260	219	5	1422	467	259	62
2040	1135	331	13	0	644	241	213	4	1468	473	254	58
2041	1144	330	12	0	595	223	208	4	1514	478	249	53
2042	1153	329	11	0	545	204	202	4	1560	483	245	49
2043	1162	329	10	0	496	186	196	3	1605	489	240	44
2044	1172	328	9	0	446	167	191	3	1651	494	236	40
2045	1181	327	8	0	396	148	185	3	1697	500	231	36
2046	1190	326	7	0	347	130	180	2	1743	505	226	31
2047	1199	325	6	0	297	111	174	2	1789	510	222	27
2048	1209	324	5	0	248	93	169	2	1835	516	217	22
2049	1218	324	4	0	198	74	163	1	1881	521	213	18
2050	1227	323	3	0	149	56	157	1	1927	526	208	13
2051	1237	322	2	0	99	37	152	1	1973	532	203	9
2052	1246	321	1	0	50	19	146	0	2019	537	199	4

Table A.3. Mercury allowance prices ($/lb)

Year	Low0	Low50	Low100	Low150	Mid0	Mid50	Mid100	Mid150	High0	High50	High100	High150
2010	18478	18478	18478	18478	18478	18478	18478	18478	18478	18478	18478	18478
2011	19050	18528	17566	12661	19956	19121	19001	18111	19560	19763	19202	18696
2012	19623	18578	16654	6844	21434	19764	19525	17744	20643	21048	19926	18915
2013	20195	18629	15743	1027	22911	20407	20048	17377	21725	22333	20650	19133
2014	21788	20245	17105	1116	24248	22274	21834	19062	23691	24102	22438	20983
2015	23380	21862	18468	1205	25585	24142	23620	20746	25657	25871	24226	22833
2016	24973	23479	19831	1294	26922	26009	25405	22431	27623	27640	26014	24683
2017	27358	25682	21692	1415	29513	28450	27790	24536	30220	30235	28455	26999
2018	29744	27886	23554	1537	32104	30892	30175	26641	32817	32829	30897	29316
2019	32129	30090	25415	1658	34695	33333	32559	28747	35415	35424	33339	31633
2020	34514	32294	27277	1780	37286	35774	34944	30852	38012	38018	35781	33950
2021	36900	34498	29138	1901	39876	38216	37329	32958	40609	40613	38222	36267
2022	38445	36803	31394	2086	42157	41477	40033	35356	43089	43612	41381	38906
2023	39991	39108	33649	2272	44437	44738	42738	37755	45569	46612	44540	41545
2024	41536	41414	35904	2457	46718	47999	45442	40154	48049	49611	47698	44184
2025	43081	43719	38159	2642	48998	51260	48147	42552	50529	52611	50857	46824
2026	44627	46025	40415	2828	51279	54522	50851	44951	53009	55610	54016	49463
2027	43615	44078	37731	2263	49859	50667	46271	37256	52449	51755	48700	42477
2028	42603	42131	35047	1699	48440	46812	41690	29562	51888	47899	43385	35491
2029	41590	40184	32363	1135	47020	42958	37110	21868	51328	44043	38070	28505
2030	40578	38236	29679	571	45601	39103	32530	14173	50768	40187	32754	21519
2031	39566	36289	26995	7	44181	35249	27950	6479	50207	36332	27439	14532
2032	38554	34640	25768	6	42762	33646	26679	6184	49647	34680	26192	13872
2033	37542	32990	24541	6	41342	32044	25409	5890	49086	33029	24944	13211
2034	36529	31341	23314	6	39922	30442	24138	5595	48526	31377	23697	12551
2035	35517	29691	22087	6	38503	28840	22868	5301	47966	29726	22450	11890
2036	34505	28042	20860	5	37083	27238	21597	5006	47405	28074	21203	11230
2037	33493	26392	19633	5	35664	25635	20327	4712	46845	26423	19955	10569
2038	32481	24743	18406	5	34244	24033	19057	4417	46285	24772	18708	9909
2039	31468	23093	17179	4	32825	22431	17786	4123	45724	23120	17461	9248
2040	30456	21444	15952	4	31405	20829	16516	3828	45164	21469	16214	8587
2041	29444	19794	14725	4	29985	19226	15245	3534	44604	19817	14967	7927
2042	28432	18145	13498	3	28566	17624	13975	3239	44043	18166	13719	7266
2043	27420	16495	12270	3	27146	16022	12704	2945	43483	16514	12472	6606
2044	26407	14846	11043	3	25727	14420	11434	2650	42922	14863	11225	5945
2045	25395	13196	9816	2	24307	12818	10164	2356	42362	13212	9978	5285
2046	24383	11547	8589	2	22888	11215	8893	2061	41802	11560	8731	4624
2047	23371	9897.1	7362	2	21468	9613.2	7623	1767	41241	9908.6	7483	3963
2048	22359	8247.6	6135	2	20048	8011	6352	1472	40681	8257.2	6236	3303
2049	21347	6598.1	4908	1	18629	6408.8	5082	1178	40121	6605.8	4989	2642
2050	20334	4948.6	3681	1	17209	4806.6	3811	883	39560	4954.3	3742	1982
2051	19322	3299	2454	1	15790	3204.4	2541	589	39000	3302.9	2494	1321
2052	18310	1650	1227	0	14370	1602	1270	294	38440	1651	1247	661

Table A.4. CO_2 allowance prices ($/ton)

Year	Low0	Low50	Low100	Low150	Mid0	Mid50	Mid100	Mid150	High0	High50	High100	High150
2010	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	1	2	4	0	2	3	5	0	2	4	4
2012	0	2	5	7	0	3	6	9	0	4	7	9
2013	0	3	7	11	0	5	10	14	0	6	11	13
2014	0	3	8	13	0	5	10	15	0	6	12	14
2015	0	4	9	15	0	5	11	16	0	6	13	16
2016	0	5	9	17	0	6	12	18	0	6	14	17
2017	0	5	10	18	0	6	13	19	0	7	15	19
2018	0	6	11	19	0	7	14	21	0	7	16	22
2019	0	6	12	21	0	8	15	23	0	7	18	25
2020	0	6	13	22	0	8	17	24	0	7	19	27
2021	0	6	13	24	0	9	18	26	0	7	20	30
2022	0	7	15	25	0	9	19	28	0	8	22	34
2023	0	8	16	26	0	10	21	31	0	9	24	37
2024	0	8	17	28	0	11	23	33	0	10	26	41
2025	0	9	18	29	0	12	24	36	0	11	28	45
2026	0	10	20	30	0	13	26	38	0	12	30	48
2027	0	11	22	33	0	14	29	42	0	14	33	52
2028	0	12	23	35	0	15	31	45	0	15	36	55
2029	0	13	25	38	0	16	33	49	0	16	38	58
2030	0	14	27	40	0	18	36	53	0	17	41	62
2031	0	15	29	43	0	19	38	56	0	18	44	65
2032	0	16	31	45	0	20	41	60	0	20	47	69
2033	0	17	33	48	0	21	43	63	0	21	50	72
2034	0	18	34	50	0	22	45	67	0	22	53	75
2035	0	19	36	53	0	24	48	71	0	23	56	79
2036	0	20	38	56	0	25	50	74	0	25	58	82
2037	0	20	40	58	0	26	53	78	0	26	61	85
2038	0	21	42	61	0	27	55	81	0	27	64	89
2039	0	22	43	63	0	28	57	85	0	28	67	92
2040	0	23	45	66	0	29	60	88	0	30	70	96
2041	0	24	47	68	0	31	62	92	0	31	73	99
2042	0	25	49	71	0	32	65	96	0	32	75	102
2043	0	26	51	73	0	33	67	99	0	33	78	106
2044	0	27	53	76	0	34	69	103	0	35	81	109
2045	0	28	54	78	0	35	72	106	0	36	84	113
2046	0	29	56	81	0	37	74	110	0	37	87	116
2047	0	30	58	83	0	38	77	114	0	38	90	119
2048	0	31	60	86	0	39	79	117	0	40	93	123
2049	0	32	62	88	0	40	81	121	0	41	95	126
2050	0	33	64	91	0	41	84	124	0	42	98	130
2051	0	34	65	93	0	43	86	128	0	43	101	133
2052	0	35	67	96	0	44	89	132	0	45	104	136

Table A.5. Coal prices in MAIN region (Illinois # 6, $ / million Btu)

Year	Low0	Low50	Low100	Low150	Mid0	Mid50	Mid100	Mid150	High0	High50	High100	High150
2010	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
2011	1.67	1.65	1.64	1.63	1.68	1.67	1.66	1.65	1.69	1.68	1.67	1.66
2012	1.64	1.61	1.58	1.57	1.67	1.65	1.62	1.61	1.68	1.66	1.64	1.63
2013	1.61	1.56	1.52	1.5	1.66	1.62	1.58	1.57	1.67	1.64	1.61	1.59
2014	1.59	1.54	1.5	1.47	1.65	1.61	1.56	1.54	1.66	1.63	1.59	1.57
2015	1.58	1.52	1.47	1.44	1.64	1.59	1.54	1.51	1.65	1.61	1.56	1.55
2016	1.56	1.5	1.45	1.4	1.63	1.58	1.52	1.47	1.63	1.59	1.54	1.52
2017	1.57	1.5	1.44	1.39	1.63	1.57	1.52	1.47	1.64	1.59	1.54	1.52
2018	1.57	1.5	1.43	1.37	1.63	1.57	1.51	1.46	1.64	1.59	1.54	1.51
2019	1.57	1.5	1.43	1.36	1.63	1.57	1.51	1.45	1.64	1.59	1.53	1.5
2020	1.57	1.5	1.42	1.34	1.63	1.57	1.5	1.44	1.64	1.58	1.53	1.49
2021	1.58	1.5	1.41	1.32	1.64	1.57	1.5	1.43	1.64	1.58	1.53	1.49
2022	1.58	1.5	1.41	1.32	1.64	1.56	1.5	1.43	1.65	1.59	1.53	1.49
2023	1.58	1.5	1.4	1.32	1.64	1.56	1.5	1.44	1.65	1.59	1.53	1.49
2024	1.59	1.49	1.4	1.32	1.65	1.56	1.5	1.44	1.65	1.59	1.54	1.49
2025	1.59	1.49	1.39	1.31	1.65	1.56	1.5	1.45	1.65	1.6	1.54	1.49
2026	1.59	1.49	1.38	1.31	1.66	1.56	1.5	1.45	1.66	1.6	1.54	1.49
2027	1.59	1.5	1.38	1.31	1.66	1.56	1.5	1.44	1.66	1.61	1.55	1.48
2028	1.6	1.5	1.38	1.31	1.66	1.56	1.5	1.44	1.66	1.61	1.55	1.48
2029	1.6	1.5	1.38	1.32	1.66	1.57	1.49	1.43	1.66	1.61	1.55	1.47
2030	1.6	1.5	1.38	1.32	1.66	1.57	1.49	1.43	1.67	1.62	1.56	1.47
2031	1.61	1.5	1.38	1.32	1.66	1.57	1.49	1.42	1.67	1.62	1.56	1.47
2032	1.61	1.5	1.38	1.32	1.66	1.58	1.49	1.42	1.67	1.62	1.57	1.46
2033	1.61	1.5	1.38	1.32	1.66	1.58	1.49	1.41	1.67	1.63	1.57	1.46
2034	1.62	1.5	1.38	1.32	1.67	1.58	1.49	1.41	1.68	1.63	1.57	1.45
2035	1.62	1.51	1.38	1.33	1.67	1.59	1.48	1.41	1.68	1.64	1.58	1.45
2036	1.62	1.51	1.38	1.33	1.67	1.59	1.48	1.4	1.68	1.64	1.58	1.44
2037	1.62	1.51	1.38	1.33	1.67	1.59	1.48	1.4	1.69	1.64	1.58	1.44
2038	1.63	1.51	1.38	1.33	1.67	1.6	1.48	1.39	1.69	1.65	1.59	1.43
2039	1.63	1.51	1.37	1.33	1.67	1.6	1.48	1.39	1.69	1.65	1.59	1.43
2040	1.63	1.51	1.37	1.33	1.67	1.6	1.48	1.38	1.69	1.65	1.6	1.42
2041	1.64	1.51	1.37	1.33	1.67	1.61	1.47	1.38	1.7	1.66	1.6	1.42
2042	1.64	1.52	1.37	1.34	1.67	1.61	1.47	1.37	1.7	1.66	1.6	1.41
2043	1.64	1.52	1.37	1.34	1.67	1.61	1.47	1.37	1.7	1.66	1.61	1.41
2044	1.64	1.52	1.37	1.34	1.67	1.62	1.47	1.36	1.7	1.67	1.61	1.41
2045	1.65	1.52	1.37	1.34	1.67	1.62	1.47	1.36	1.71	1.67	1.61	1.4
2046	1.65	1.52	1.37	1.34	1.67	1.63	1.47	1.35	1.71	1.68	1.62	1.4
2047	1.65	1.52	1.37	1.34	1.68	1.63	1.46	1.35	1.71	1.68	1.62	1.39
2048	1.66	1.52	1.37	1.34	1.68	1.63	1.46	1.34	1.71	1.68	1.63	1.39
2049	1.66	1.52	1.37	1.35	1.68	1.64	1.46	1.34	1.72	1.69	1.63	1.38
2050	1.66	1.53	1.37	1.35	1.68	1.64	1.46	1.33	1.72	1.69	1.63	1.38
2051	1.67	1.53	1.36	1.35	1.68	1.64	1.46	1.33	1.72	1.69	1.64	1.37
2052	1.67	1.53	1.36	1.35	1.68	1.65	1.46	1.32	1.72	1.7	1.64	1.37

Table A.6. Natural gas prices in MAIN region ($ / million Btu)

Year	*Low0*	*Low50*	*Low100*	*Low150*	*Mid0*	*Mid50*	*Mid100*	*Mid150*	*High0*	*High50*	*High100*	*High150*
2010	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18	4.18
2011	3.9	3.92	3.94	3.94	4.19	4.21	4.21	4.21	4.44	4.44	4.47	4.44
2012	3.62	3.67	3.7	3.71	4.2	4.23	4.24	4.25	4.71	4.7	4.76	4.7
2013	3.35	3.41	3.46	3.47	4.21	4.26	4.28	4.29	4.98	4.96	5.05	4.96
2014	3.3	3.35	3.4	3.42	4.22	4.26	4.25	4.27	5.07	5.04	5.08	5.03
2015	3.25	3.29	3.34	3.36	4.23	4.25	4.23	4.25	5.16	5.11	5.11	5.1
2016	3.2	3.22	3.27	3.31	4.24	4.25	4.21	4.23	5.25	5.19	5.14	5.16
2017	3.24	3.27	3.3	3.35	4.29	4.29	4.26	4.31	5.34	5.28	5.22	5.25
2018	3.28	3.31	3.34	3.39	4.34	4.33	4.32	4.39	5.44	5.37	5.31	5.34
2019	3.33	3.35	3.37	3.43	4.39	4.38	4.38	4.47	5.53	5.46	5.39	5.43
2020	3.37	3.39	3.4	3.47	4.44	4.42	4.44	4.55	5.63	5.55	5.47	5.52
2021	3.41	3.43	3.43	3.51	4.49	4.46	4.5	4.63	5.72	5.64	5.56	5.61
2022	3.45	3.47	3.48	3.56	4.59	4.56	4.61	4.76	5.88	5.76	5.71	5.82
2023	3.5	3.51	3.53	3.61	4.68	4.65	4.71	4.88	6.04	5.88	5.85	6.03
2024	3.55	3.55	3.58	3.67	4.78	4.74	4.82	5.01	6.2	6.01	6	6.24
2025	3.59	3.59	3.63	3.72	4.87	4.83	4.92	5.14	6.35	6.13	6.15	6.45
2026	3.64	3.62	3.68	3.77	4.97	4.92	5.03	5.27	6.51	6.25	6.3	6.66
2027	3.71	3.7	3.79	3.91	5.06	5.01	5.16	5.46	6.61	6.37	6.41	6.82
2028	3.77	3.78	3.91	4.04	5.14	5.09	5.3	5.64	6.72	6.49	6.53	6.98
2029	3.84	3.86	4.02	4.17	5.23	5.18	5.44	5.83	6.82	6.62	6.64	7.14
2030	3.91	3.94	4.14	4.31	5.31	5.27	5.57	6.01	6.92	6.74	6.75	7.29
2031	3.97	4.02	4.26	4.44	5.4	5.36	5.71	6.19	7.03	6.86	6.87	7.45
2032	4.04	4.1	4.37	4.57	5.49	5.45	5.85	6.38	7.13	6.98	6.98	7.61
2033	4.11	4.18	4.49	4.71	5.57	5.53	5.98	6.56	7.23	7.1	7.1	7.77
2034	4.17	4.26	4.61	4.84	5.66	5.62	6.12	6.75	7.33	7.22	7.21	7.93
2035	4.24	4.34	4.72	4.97	5.74	5.71	6.26	6.93	7.44	7.34	7.33	8.09
2036	4.31	4.42	4.84	5.11	5.83	5.8	6.39	7.12	7.54	7.46	7.44	8.25
2037	4.37	4.5	4.96	5.24	5.92	5.88	6.53	7.3	7.64	7.59	7.55	8.4
2038	4.44	4.58	5.07	5.37	6	5.97	6.67	7.49	7.75	7.71	7.67	8.56
2039	4.51	4.66	5.19	5.51	6.09	6.06	6.81	7.67	7.85	7.83	7.78	8.72
2040	4.58	4.74	5.3	5.64	6.17	6.15	6.94	7.86	7.95	7.95	7.9	8.88
2041	4.64	4.82	5.42	5.77	6.26	6.23	7.08	8.04	8.06	8.07	8.01	9.04
2042	4.71	4.9	5.54	5.91	6.35	6.32	7.22	8.22	8.16	8.19	8.13	9.2
2043	4.78	4.98	5.65	6.04	6.43	6.41	7.35	8.41	8.26	8.31	8.24	9.35
2044	4.84	5.06	5.77	6.17	6.52	6.5	7.49	8.59	8.36	8.43	8.35	9.51
2045	4.91	5.14	5.89	6.31	6.6	6.58	7.63	8.78	8.47	8.56	8.47	9.67
2046	4.98	5.22	6	6.44	6.69	6.67	7.76	8.96	8.57	8.68	8.58	9.83
2047	5.04	5.3	6.12	6.57	6.77	6.76	7.9	9.15	8.67	8.8	8.7	9.99
2048	5.11	5.38	6.23	6.71	6.86	6.85	8.04	9.33	8.78	8.92	8.81	10.15
2049	5.18	5.46	6.35	6.84	6.95	6.94	8.17	9.52	8.88	9.04	8.93	10.31
2050	5.25	5.54	6.47	6.97	7.03	7.02	8.31	9.7	8.98	9.16	9.04	10.46
2051	5.31	5.62	6.58	7.11	7.12	7.11	8.45	9.88	9.09	9.28	9.15	10.62
2052	5.38	5.7	6.7	7.24	7.2	7.2	8.58	10.07	9.19	9.41	9.27	10.78

Table A.7. Electricity prices to generators in MAIN region ($/MWh)

Year	Low0	Low50	Low100	Low150	Mid0	Mid50	Mid100	Mid150	High0	High50	High100	High150
2010	32	32	32	32	32	32	32	32	32	32	32	32
2011	31	33	35	36	33	35	37	38	33	36	39	39
2012	31	33	38	41	34	38	42	45	35	40	46	46
2013	30	34	42	45	35	41	48	52	37	44	53	53
2014	30	36	43	47	36	43	50	53	38	46	54	54
2015	31	37	44	49	37	45	51	54	40	48	54	55
2016	31	39	46	51	37	47	53	55	41	50	55	56
2017	33	40	47	52	39	48	54	57	42	51	56	58
2018	35	42	48	53	41	50	55	58	43	52	58	61
2019	37	44	49	54	43	51	56	60	45	53	59	64
2020	40	46	50	55	45	53	57	61	46	53	61	66
2021	42	47	51	56	46	54	58	62	47	54	62	69
2022	43	49	52	58	48	55	60	65	48	55	64	73
2023	45	50	53	59	49	56	61	67	49	56	66	76
2024	46	52	55	60	51	56	63	70	50	57	68	80
2025	47	53	56	61	52	57	64	72	52	58	69	84
2026	49	55	57	62	53	58	65	75	53	59	71	87
2027	49	55	58	64	53	59	67	79	53	60	74	91
2028	48	55	60	67	52	61	70	82	54	62	78	94
2029	48	55	62	69	52	62	72	86	55	63	81	98
2030	48	55	63	71	51	63	74	90	56	64	84	102
2031	48	55	65	73	50	64	76	94	56	66	88	105
2032	48	55	67	76	50	66	78	98	57	67	91	109
2033	48	55	68	78	49	67	80	102	58	68	94	112
2034	48	55	70	80	49	68	82	105	59	70	98	116
2035	48	55	72	82	48	69	84	109	59	71	101	119
2036	48	55	73	85	47	71	87	113	60	72	104	123
2037	48	55	75	87	47	72	89	117	61	74	107	127
2038	48	55	77	89	46	73	91	121	61	75	111	130
2039	48	55	78	91	46	74	93	125	62	76	114	134
2040	48	55	80	94	45	75	95	129	63	78	117	137
2041	48	55	82	96	44	77	97	132	64	79	121	141
2042	48	55	83	98	44	78	99	136	64	80	124	145
2043	48	55	85	100	43	79	101	140	65	82	127	148
2044	48	55	87	103	43	80	104	144	66	83	130	152
2045	48	55	88	105	42	82	106	148	67	84	134	155
2046	48	55	90	107	41	83	108	152	67	86	137	159
2047	48	55	92	109	41	84	110	155	68	87	140	162
2048	48	55	93	112	40	85	112	159	69	88	144	166
2049	48	55	95	114	40	87	114	163	69	90	147	170
2050	48	55	97	116	39	88	116	167	70	91	150	173
2051	48	55	98	118	38	89	119	171	71	92	154	177
2052	48	55	100	121	38	90	121	175	72	93	157	180

Table A.8 Technological learning factors for pulverized coal plants (sub-critical, super-critical and ultra-supercritical) with and without CCS

Year	*Low0*	*Low50*	*Low100*	*Low150*	*Mid0*	*Mid50*	*Mid100*	*Mid150*	*High0*	*High50*	*High100*	*High150*
2010	1	1	1	1	1	1	1	1	1	1	1	1
2011	0.997	0.997	0.997	1.001	0.997	1.001	0.997	0.997	0.997	0.997	0.997	0.997
2012	0.995	0.995	0.995	1.001	0.995	1.001	0.995	0.995	0.995	0.995	0.995	0.995
2013	0.989	0.989	0.989	1.003	0.989	1.003	0.989	0.989	0.989	0.989	0.989	0.989
2014	0.987	0.987	0.987	1.004	0.987	1.004	0.987	0.987	0.987	0.987	0.987	0.987
2015	0.984	0.984	0.984	1.004	0.984	1.004	0.984	0.984	0.984	0.984	0.984	0.984
2016	0.981	0.981	0.981	1.005	0.981	1.005	0.981	0.981	0.981	0.981	0.981	0.981
2017	0.979	0.979	0.979	1.002	0.979	1.002	0.979	0.979	0.979	0.979	0.98	0.98
2018	0.976	0.976	0.976	1	0.976	1	0.976	0.976	0.976	0.976	0.978	0.978
2019	0.973	0.974	0.973	0.997	0.974	0.997	0.973	0.973	0.973	0.973	0.976	0.976
2020	0.971	0.971	0.971	0.994	0.971	0.994	0.971	0.971	0.971	0.971	0.974	0.974
2021	0.968	0.968	0.968	0.992	0.968	0.992	0.968	0.968	0.968	0.968	0.972	0.972
2022	0.965	0.966	0.965	0.989	0.966	0.989	0.965	0.965	0.965	0.965	0.969	0.969
2023	0.963	0.963	0.963	0.986	0.963	0.986	0.963	0.963	0.963	0.963	0.967	0.967
2024	0.96	0.961	0.96	0.983	0.96	0.983	0.96	0.96	0.96	0.96	0.964	0.964
2025	0.957	0.958	0.957	0.981	0.958	0.981	0.957	0.957	0.957	0.957	0.961	0.961
2026	0.955	0.956	0.955	0.978	0.955	0.978	0.955	0.955	0.955	0.955	0.959	0.959
2027	0.952	0.953	0.952	0.975	0.952	0.975	0.952	0.952	0.952	0.952	0.956	0.956
2028	0.949	0.951	0.949	0.972	0.95	0.972	0.949	0.949	0.949	0.949	0.953	0.953
2029	0.947	0.948	0.947	0.97	0.947	0.97	0.947	0.947	0.947	0.947	0.95	0.95
2030	0.944	0.945	0.944	0.967	0.944	0.967	0.944	0.944	0.944	0.944	0.948	0.948
2031	0.941	0.943	0.941	0.964	0.942	0.964	0.941	0.941	0.941	0.941	0.945	0.945
2032	0.938	0.94	0.938	0.961	0.939	0.961	0.938	0.938	0.938	0.938	0.942	0.942
2033	0.936	0.938	0.936	0.959	0.936	0.959	0.936	0.936	0.936	0.936	0.939	0.939
2034	0.933	0.936	0.933	0.956	0.934	0.956	0.933	0.933	0.933	0.933	0.937	0.937
2035	0.93	0.933	0.93	0.953	0.931	0.953	0.93	0.93	0.93	0.93	0.934	0.934
2036	0.928	0.931	0.928	0.951	0.928	0.951	0.928	0.928	0.928	0.928	0.931	0.931
2037	0.925	0.928	0.925	0.948	0.926	0.948	0.925	0.925	0.925	0.925	0.929	0.929
2038	0.922	0.926	0.922	0.945	0.923	0.945	0.922	0.922	0.923	0.922	0.926	0.926
2039	0.92	0.923	0.92	0.942	0.92	0.942	0.92	0.92	0.92	0.92	0.923	0.923
2040	0.917	0.921	0.917	0.94	0.918	0.94	0.917	0.917	0.917	0.917	0.921	0.921
2041	0.914	0.918	0.915	0.937	0.915	0.937	0.914	0.914	0.915	0.915	0.918	0.918
2042	0.912	0.916	0.912	0.934	0.912	0.934	0.912	0.912	0.912	0.912	0.916	0.916
2043	0.909	0.913	0.909	0.932	0.91	0.932	0.909	0.909	0.909	0.909	0.913	0.913
2044	0.907	0.911	0.907	0.929	0.907	0.929	0.907	0.907	0.907	0.907	0.91	0.91
2045	0.904	0.909	0.904	0.926	0.905	0.926	0.904	0.904	0.904	0.904	0.908	0.908
2046	0.901	0.906	0.902	0.924	0.902	0.924	0.901	0.901	0.902	0.902	0.905	0.905
2047	0.899	0.904	0.899	0.921	0.899	0.921	0.899	0.899	0.899	0.899	0.902	0.902
2048	0.896	0.901	0.896	0.919	0.897	0.919	0.896	0.896	0.897	0.896	0.9	0.9
2049	0.894	0.899	0.894	0.916	0.894	0.916	0.894	0.894	0.894	0.894	0.897	0.897
2050	0.891	0.897	0.891	0.913	0.892	0.913	0.891	0.891	0.891	0.891	0.895	0.895
2051	0.888	0.894	0.889	0.911	0.889	0.911	0.888	0.888	0.889	0.889	0.892	0.892
2052	0.886	0.892	0.886	0.908	0.887	0.908	0.886	0.886	0.886	0.886	0.89	0.89

Table A.9. Technological learning factors for IGCC with and without CCS

Year	Low0	Low50	Low100	Low150	Mid0	Mid50	Mid100	Mid150	High0	High50	High100	High150
2010	1	1	1	1	1	1	1	1	1	1	1	1
2011	0.993	0.993	0.993	0.977	0.973	0.977	0.994	0.994	0.99	0.992	0.989	0.989
2012	0.986	0.986	0.987	0.954	0.946	0.954	0.987	0.987	0.98	0.984	0.978	0.978
2013	0.972	0.973	0.974	0.911	0.895	0.911	0.975	0.975	0.961	0.968	0.957	0.957
2014	0.965	0.966	0.967	0.889	0.871	0.889	0.968	0.968	0.951	0.96	0.947	0.947
2015	0.958	0.96	0.961	0.869	0.847	0.869	0.962	0.962	0.942	0.952	0.936	0.936
2016	0.951	0.953	0.954	0.849	0.824	0.849	0.956	0.956	0.932	0.944	0.926	0.926
2017	0.944	0.929	0.943	0.834	0.814	0.834	0.942	0.942	0.914	0.936	0.905	0.905
2018	0.937	0.906	0.932	0.82	0.804	0.82	0.928	0.928	0.895	0.927	0.884	0.884
2019	0.93	0.883	0.922	0.806	0.795	0.806	0.914	0.914	0.877	0.919	0.863	0.863
2020	0.923	0.861	0.911	0.793	0.785	0.793	0.901	0.901	0.86	0.911	0.843	0.843
2021	0.916	0.839	0.901	0.779	0.776	0.779	0.887	0.887	0.843	0.903	0.823	0.823
2022	0.907	0.831	0.884	0.765	0.762	0.765	0.878	0.878	0.834	0.896	0.82	0.82
2023	0.898	0.822	0.867	0.751	0.748	0.751	0.869	0.869	0.825	0.89	0.817	0.817
2024	0.889	0.814	0.85	0.738	0.735	0.738	0.861	0.861	0.816	0.884	0.814	0.814
2025	0.881	0.806	0.834	0.724	0.722	0.724	0.852	0.852	0.807	0.877	0.81	0.81
2026	0.872	0.798	0.818	0.711	0.709	0.711	0.843	0.843	0.798	0.871	0.807	0.807
2027	0.858	0.787	0.809	0.709	0.707	0.709	0.835	0.835	0.792	0.855	0.805	0.805
2028	0.844	0.777	0.801	0.707	0.706	0.707	0.828	0.828	0.786	0.839	0.804	0.804
2029	0.83	0.767	0.793	0.706	0.704	0.706	0.82	0.82	0.78	0.823	0.802	0.802
2030	0.816	0.757	0.785	0.704	0.702	0.704	0.812	0.812	0.774	0.808	0.8	0.8
2031	0.803	0.748	0.777	0.702	0.701	0.702	0.805	0.805	0.768	0.793	0.799	0.799
2032	0.79	0.738	0.77	0.7	0.699	0.7	0.798	0.798	0.762	0.778	0.797	0.797
2033	0.777	0.729	0.762	0.699	0.698	0.699	0.79	0.79	0.757	0.764	0.795	0.795
2034	0.764	0.719	0.754	0.697	0.696	0.697	0.783	0.783	0.751	0.75	0.794	0.794
2035	0.752	0.71	0.747	0.695	0.694	0.695	0.776	0.776	0.745	0.736	0.792	0.792
2036	0.74	0.701	0.739	0.693	0.693	0.693	0.768	0.768	0.739	0.722	0.79	0.79
2037	0.728	0.692	0.732	0.691	0.691	0.691	0.761	0.761	0.734	0.709	0.789	0.789
2038	0.716	0.683	0.724	0.69	0.69	0.69	0.754	0.754	0.728	0.695	0.787	0.787
2039	0.704	0.674	0.717	0.688	0.688	0.688	0.747	0.747	0.722	0.682	0.786	0.786
2040	0.693	0.665	0.71	0.686	0.686	0.686	0.741	0.741	0.717	0.67	0.784	0.784
2041	0.681	0.657	0.703	0.684	0.685	0.684	0.734	0.734	0.711	0.657	0.782	0.782
2042	0.67	0.648	0.696	0.683	0.683	0.683	0.727	0.727	0.706	0.645	0.781	0.781
2043	0.659	0.64	0.689	0.681	0.682	0.681	0.72	0.72	0.701	0.633	0.779	0.779
2044	0.649	0.632	0.682	0.679	0.68	0.679	0.714	0.714	0.695	0.621	0.777	0.777
2045	0.638	0.624	0.675	0.678	0.679	0.678	0.707	0.707	0.69	0.61	0.776	0.776
2046	0.628	0.616	0.668	0.676	0.677	0.676	0.7	0.7	0.685	0.599	0.774	0.774
2047	0.617	0.608	0.662	0.674	0.676	0.674	0.694	0.694	0.679	0.587	0.773	0.773
2048	0.607	0.6	0.655	0.672	0.674	0.672	0.688	0.688	0.674	0.576	0.771	0.771
2049	0.597	0.592	0.648	0.671	0.672	0.671	0.681	0.681	0.669	0.566	0.769	0.769
2050	0.588	0.584	0.642	0.669	0.671	0.669	0.675	0.675	0.664	0.555	0.768	0.768
2051	0.578	0.577	0.635	0.667	0.669	0.667	0.669	0.669	0.659	0.545	0.766	0.766
2052	0.569	0.569	0.629	0.666	0.668	0.666	0.663	0.663	0.654	0.535	0.765	0.765

Table A.10. Technological learning factors for NGCC (approximately equal across scenarios)

Year	*Learning Rates*
2010	1.000
2011	0.997
2012	0.995
2013	0.989
2014	0.987
2015	0.984
2016	0.981
2017	0.979
2018	0.976
2019	0.973
2020	0.971
2021	0.968
2022	0.965
2023	0.963
2024	0.96
2025	0.957
2026	0.955
2027	0.952
2028	0.949
2029	0.947
2030	0.944
2031	0.941
2032	0.938
2033	0.936
2034	0.933
2035	0.93
2036	0.928
2037	0.925
2038	0.922
2039	0.92
2040	0.917
2041	0.914
2042	0.912
2043	0.909
2044	0.907
2045	0.904
2046	0.901
2047	0.899
2048	0.896
2049	0.894
2050	0.891
2051	0.888
2052	0.886

Algorithm for the Multi-Period Stochastic Optimization Model PowerOptInvest

	Performance			Emissions					OM	
Plant Type	Energy Input (MBTU/yr)	Gross Electricity Output (1) (MWh/yr)	CCS Energy Use (in MWh)	CO2 (Tons)	SO2 (Tons)	NO2 (Tons)	Particulate (Tons)	Hg (Lbs)	O&M CCS (2)	O&M Base Plant + Default Controls (No fuel)(3)
1. Subcritical	87,377,726	8,928,850	0	9,144,079	27,030	6,553	1,311	55	0	71.26
2. Subcritical + CCS(*)	87,377,726	8,928,850	2,525,458	915,719	30	6,470	655	55	135.23	71.26
3. Supercritical	78,551,321	8,935,425	0	8,220,396	24,300	5,891	1,178	49	0	69.35
4. Supercritical + CCS(*)	78,551,321	8,935,425	2,268,375	823,218	27	5,817	589	49	121.7	69.35
5. Ultrasupercritical	71,313,627	8,935,425	0	7,462,971	22,061	5,349	1,070	45	0	66.59
6. Ultrasupercritical + CCS(*)	71,313,627	8,935,425	2,057,975	747,367	24	535	535	45	111.62	66.59
7. IGCC (**)	88,067,549	8,935,425	0	8,789,141	5,539	857	44	0	0	65.02
8. IGCC + CCS (**)	88,067,549	8,935,425	1,032,275	741,969	603	846	44	0	35.28	65.02
9. NGCC	56,627,832	8,323,950	0	3,369,356	0	849	0	0	0	13.83
10.NGCC+CCS(*)	56,627,832	8,323,950	1,216,375	336,936	0	838	0	0	14.23	13.83

Table 1. Performance, Emissions and O&M costs of configurations considered. (All costs are given in 2004 million U.S. dollars.)

(1) Total electricity output (without subtracting CCS energy usage).
(2) Does not include costs of energy used. It includes the extra-costs of additional sulfur removal. CO_2 costs of sequestration based on pipeline transport distance of 161 km (100 miles); CO_2 stream compressed to 13.7 MPa (2,000 psig) with no booster compressors.
(3) Includes fixed costs such as operating labor, maintenance labor, maintenance material, administrative & support labor, and variable costs such as water and waste disposal. For the PC plants it includes the fixed and variable costs of the NOx and SO_2 emissions controls (catalyst, ammonia, water, waste disposal, and reagent). For the IGCC it includes fixed and variable costs of the air separation unit and gasifier (oil, water, slag disposal) and the costs of sulfur removal (makeup Selexol solvent, makeup Claus catalyst, makeup Beavon-Streetford Catalyst). (*) CCS includes a MEA system for CO_2 capture. (**) Based on Texaco quench gasifier (2 + 1 spare), 2 GE 7FA gas turbine, 3-pressure reheat HRSG with steam parameters 1400 psig/1000 F/1000 F. Sulfur removal efficiency is 98% via hydrolyser + Selexol system; Sulfur recovery via Claus plant and Beavon-Stretford tailgas unit.

Configuration Installation	Resulting Plant Type (As in Table 1)	PreRequisite Configuration	IECM Adjustment and Retrofit Penalty Factor(1)	Capital Cost (2)	Configuration that also becomes available with this installation
1. Subcritical	1		1	1,480.00	
2. Subcritical+CCS	2		1	2,049.00	1
3. CCS on Subcritical	2	1	1.2	682.80	
4. Supercritical	3		1	1,541.00	
5. Supercritical+CCS	4		1	2,048.00	4
6. CCS on Supercritical	4	4	1.2	608.40	
7. Ultrasupercritical	5		1	1,529.00	
8. Ultrasupercritical+CCS	6		1	2,003.00	7
9. CCS on Ultrasupercritical	6	7	1.2	568.80	
10. IGCC	7		1	2,239.00	
11. IGCC + CCS	8		1	3,003.00	
12. CCS on IGCC	8	10	1.3	993.20	
13. NGCC	9		1	794.50	
14. NGCC+CCS	10		1	1,119.00	13
15. CCS on NGCC	10	13	1.2	389.40	

Table 2. Alternative investments considered by decisionmaker and resulting configuration (Capital costs given in 2004 million U.S. dollars.)

(1)Multiplying factor to convert the Capital Costs for a new facility given by IECM into the Retrofitting factors.
(2) Capital costs as given by IECM, multiplied by the retrofit factor.

Scenario #	CO2 prices	NG Price
1	No federal climate policy. CO2 price = $0	Low
2	CO2 prices of S.280 (Lieberman-McCain)	Low
3	CO2 Prices are 50% of S.280	Low
4	CO2 Prices are 150% of S.280	Low
5	No federal climate policy	Medium
6	CO2 prices of S.280 (Lieberman-McCain)	Medium
7	CO2 Prices are 50% of S.280	Medium
8	CO2 Prices are 150% of S.280	Medium
9	No federal climate policy	High
10	CO2 prices of S.280 (Lieberman-McCain)	High
11	CO2 Prices are 50% of S.280	High
12	CO2 Prices are 150% of S.280	High

Table 3. Scenarios considered

In the business-as-usual baseline scenario there is no federal climate policy. In the other three policy scenarios a federal climate policy is assumed to be in effect beginning in 2012 that specifies an emission cap with banking. One climate policy scenario solves for an aggregate quantity of CO_2 emissions from the electricity sector that matches the quantity anticipated by the EIA in its analysis of S.280 (Lieberman-McCain) by 2030. With banking, the allowance price rises at the opportunity cost of capital (the real interest rate) of 8% over time. The two other climate policy scenarios simply take the price trajectory for CO_2 from this run and diminish it by roughly 50% (labeled "50%_L-M")or increase it by 50% (labeled "150%_L-M") to achieve a different aggregate level of emissions between 2012 and 2030. In every case CO_2 allowances are distributed through auction.

Constants to distinguish between different models. Need to be specified for each run	Description	Range
Policy	Integer variable specifying which of the three types of policies is being analyzed	0. No technology policy. 1. NSPS (Only plants that meet the CO2 emissions standard b can be installed 2. NSPS flexible (Plants that do not meet the CO2 emissions standard b must make a payment of $/ton for each ton in excess of the standard) 3. NSPS Flexible with escrow account (Payment is deposited in an escrow fund and can be withdrawn for CCS retrofit)
AllowNGCC	Binary variable specifying whether installing an NGCC plant is an option or not. (To represent those utilities that only want to use coal)	=1 if NGCC can be installed = 0 otherwise
UseAPlant	Vector in R^{30} that specifies for each period whether the utility needs to use the plant or not. (To represent those utilities that need to install new capacity and use it every year in the future)	Each component of the vector is a binary variable: =1 if there is a need to use a plant in that period =0 otherwise

Index	Description	Range
c	Investment or configuration. It specifies the type of plant and/or controls being installed and/or used	$0 \le c \le 15$ as described in Table 2.
t	Current time period	$1 \le t \le 12$
τ	Time period in the future	$t < \tau \le t+30$
f	Fuel	Coal, natural gas
p	Pollutants	SO_2, NO_x, Hg, CO_2
s	Regulatory scenarios	12 as described in Table 3.

Parameters (in order of appearance in objective function)	Description	Units
$k_{c,t}$	Capital costs of installing configuration c at time t	$
$m_{c,t}$	Operating and maintenance costs of running configuration c at time t (not including fuel or electricity)	$
v_c	Quantity of electricity produced by configuration c	MWh/year
w_t	Price of electricity at time t	$/MWh
$q_{c,f}$	Quantity of fuel f used by configuration c	MBTU/year
$n_{f,t}$	Price of fuel f at time t	$/MBTU
$e_{p,c}$	Emissions of pollutant p by configuration c	Tons/year for SO_2, NOx, CO_2 Lbs/year for mercury
$a_{p,t}$	Price of emissions allowances for pollutant p at time t	$/ton for SO_2, NOx, CO_2 $/lb for mercury
b	CO_2 emissions standard	tons
β_t	CO_2 emissions surcharge at time t, under flexible NSPS	$/ton CO_2
π_s	Probability of scenario s	
r	Discount rate	%/annum

Parameters for second and other future stage decisions	Description	Units
$\tilde{n}_{f,\tau,s}$	Price of fuel f at time t under scenario s	$/MBTU
$\tilde{a}_{p,\tau,s}$	Price of emissions allowances for pollutant p at time t, under scenario s	$/ton for SO2, NOx, XO2 $/lb for mercury
$\tilde{w}_{\tau,s}$	Price of electricity at time t, under scenario s	$/MWh

Sets to handle the prerequisites for installation and plant availability	Description	Sets:
Y_c	Set of configurations that serve as pre-requisite for installation of configuration *c*	$Y_3 = \{1\}, Y_6 = \{4\}, Y_9 = \{7\},$ $Y_{12} = \{10\}, Y_{15} = \{13\},$ $Y_1 = Y_2 = Y_4 = Y_5 = Y_7 =$ $Y_8 = Y_{10} = Y_{11} = Y_{13} = Y_{14} = \{ \}$

Decision Variables (First Stage)	Description	Variable type and range
$i_{c,t}$	Investment indicator. $i_{c,t}$ = 1 if there is an investment to install configuration *c* at time *t*	Binary
$u_{c,t}$	Utilization indicator. $u_{c,t}$ =1 if configuration *c* is used at time *t*	Binary

Decision Variables (Posterior Stage)	Description	Variable type and range
$i_{c,\tau,s}$	Investment indicator. $i_{c,\tau,s}$ = 1 if there is an investment to install configuration c at time τ under scenario *s*	Binary
$u_{c,\tau,s}$	Utilization indicator. $u_{c,\tau,s}$ =1 if configuration c is used at time τ under scenario *s*	Binary

Other decision variables	Description	Variable type and range
$R_{c,t}$	Availability indicator $R_{c,t}$ = 1 if configuration c is ready to be used at time *t*	Binary
$R1_{c,t}$	Next year availability indicator $R1_{c,t}$ =1 if configuration c will be available at time *t+1*	Binary
$NSPSPayment_t$	Payment due to CO_2 emissions that exceed NSPS rule at time t	Real. $NSPSPayment_t = \sum_c Max\left[e_{c,CO2} - b, 0\right] \beta u_{c,t}$ Since under policy 1, CO_2 emissions are lower than b, NSPSPayment is 0.
$NSPSPayment_{s,\tau}$	Payment due to CO_2 emissions that exceed NSPS rule, under scenario s during period τ	Real. $NSPSPayment_{s,\tau} = \sum_c Max\left[e_{c,CO2} - b, 0\right] \beta u_{c,\tau,s}$ Since under policy 1, CO_2 emissions are lower than b, NSPSPayment is 0.

Intermediate decision variables (necessary to represent policy 3)	Description	Variable type and range
$TotalFunds_{s,t}$	Total amount of money deposited in the escrow fund under scenario *s* at the beginning of time period *t*	

$UsedFunds_{s,t}$	Funds withdrawn from the escrow account and used to offset capital costs of CCS, under scenario *s* at future time period *t*	
$TotalFunds_{s,t}$	Total amount of money deposited in the escrow fund under scenario s at the beginning of period τ	Real. $0 \le TotalFunds_{s,t} \le \sum_t \beta_t \left(CO2Emissions_t - b\right)$
$UsedFunds_{s,\tau}$	Funds withdrawn from the escrow account and used to offset capital costs of CCS, under scenario s at future time period τ	$0 \le UsedFunds_{s,t} \le TotalFunds_{s,t}$

Minimize the expected capital and O&M cost (minus revenue from electricity sales) at time t.

$$\text{Minimize } f(i_{c,t},, u_{c,t}, i_{c,\tau,s}, u_{c,\tau,s}) =$$

$$\sum_c \left[k_{c,t} i_{c,t} + \left(m_{c,t} - v_c w_t + \sum_f q_{c,f} n_{f,t} + \sum_p e_{c,p} a_{p,t} + Max\left[e_{c,CO2} - b, 0\right]\beta \right) u_{c,t} \right] - UsedFunds_t$$

$$+ \sum_s \pi_s \left[\sum_{\tau=t+1}^{t+T} (1+r)^{-\tau} \left[\sum_c k_{c,\tau,s} i_{c,\tau,s} + \left(m_{c,\tau} - v_c \tilde{w}_{\tau,s} + \sum_f q_{c,f} \tilde{n}_{f,\tau,s} + \sum_p e_{c,p} \tilde{a}_{p,\tau,s} + Max\left[e_{c,CO2} - b, 0\right]\beta \right) u_{c,\tau,s} \right] - UsedFunds_{s,\tau} \right]$$

Subject to:

1. Used configuration must be available (assume construction time is 2 periods):

$$u_{c,t} \le R_{c,t} \qquad \forall c$$

$$u_{c,t+1,s} \le R_{c,t} + R1_{c,t} \qquad \forall c$$

$$u_{c,t+2,s} \le R_{c,t} + R1_{c,t} + i_{c,t} \qquad \forall c$$

$$u_{c,t+l,s} \le R_{c,t} + R1_{c,t} + i_{c,t} + \sum_{v=3}^{l} \left(i_{c,t+v-2,s} \right) \forall 3 \le l \le T \qquad \forall c$$

2. Configuration prerequisites must be met:

$$i_{c,t} \le \sum_{y \in Y_c} \left(R_{y,t} + R1_{y,t} \right) \quad \forall c$$
$$i_{c,t+1,s} \le \sum_{y \in Y_c} \left(R_{y,t} + R1_{y,t} + i_{y,t} \right) \quad \forall c, s$$
$$i_{c,t+2,s} \le \sum_{y \in Y_c} \left(R_{y,t} + R1_{y,t} + i_{y,t} + i_{y,t+1,s} + \right) \quad \forall c, s$$
$$i_{c,t+l,s} \le \sum_{y \in Y_c} \left(R_{y,t} + R1_{y,t} + i_{y,t} + \sum_{v=3}^{l} i_{y,t+v-1,s} \right) \quad \forall c, s; \qquad 3 \le l \le T$$

3. Different policies imply different values of recoverable or "usable" funds:

If Policy $\ne 3 \rightarrow$
$UsedFunds_t = 0$
$UsedFunds_{s,\tau} = 0 \quad \forall s, \tau$

If Policy $= 1 \rightarrow$
$i_{1,t} = i_{3,t} = i_{4,t} = i_{6,t} = i_{7,t} = i_{9,t} = i_{10,t} = i_{12,t} = i_{13,t} = i_{15,t} = 0 \quad \forall t$
$i_{1,t,s} = i_{3,t,s} = i_{4,t,s} = i_{6,t,s} = i_{7,t,s} = i_{9,t,s} = i_{10,t,s} = i_{12,t,s} = i_{13,t,s} = i_{15,t,s} = 0 \quad \forall t$
$UsedFunds_{s,\tau} = 0 \quad \forall s, \tau$

If Policy $= 3 \rightarrow$
if $\left(i_{2,t} + i_{3,t} + i_{5,t} + i_{6,t} + i_{8,t} + i_{9,t} + i_{11,t} + i_{12,t} + i_{14,t} + i_{15,t} = 0 \right) \rightarrow UsedFunds_t = 0$
otherwise $\rightarrow UsedFunds_t \le TotalFunds_t \forall t$
if $\left(i_{2,\tau,s} + i_{3,\tau,s} + i_{5,\tau,s} + i_{6,\tau,s} + i_{8,\tau,s} + i_{9,\tau,s} + i_{11,\tau,s} + i_{12,\tau,s} + i_{14,\tau,s} + i_{15,\tau,s} = 0 \right) \rightarrow UsedFunds_{\tau,s} = 0$
otherwise $\rightarrow UsedFunds_{\tau,s} \le TotalFunds_{s,\tau} \forall s, \tau$

4.Every period update the balance in the escrow fund

$$TotalFunds_{s,1} \le InitialFunds$$
$$TotalFunds_{s,2} \le TotalFunds_{s,1} - UsedFunds_{s,1} + NSPSPayment_{s,1}$$
$$TotalFunds_{s,\tau} \le TotalFunds_{s,\tau-1} - UsedFunds_{s,\tau-1} + NSPSPayment_{s,\tau-1} \forall \tau = 3, 4..30$$

An alternative way of formulate this problem could specify that a fixed amount of power must be supplied, either by generating it or by acquiring it in the market. To formulate this problem we define one more parameter and two more sets of decision variables:

Parameter	Description	Units
ϕ	Power required to meet demand	MWh/year

Decision Variables (First Stage)	Description	Variable type and range
o_t	Power purchased in electricity market to meet demand of year t	MWh/year
$o_{\tau,s}$	Power purchased in electricity market to meet demand of year τ under scenario s	MWh/year

Assuming the price of the power purchased in the electricity market is the same as the price of the power sold by the utility, the objective function can be expressed as:

$$f' = \sum_c \left[k_{c,t} i_{c,t} + \left(m_{c,t} \cancel{- v_c w_t} + \sum_f q_{c,f} n_{f,t} + \sum_p e_{c,p} a_{p,t} + Max\left[e_{c,CO2} - b, 0 \right] \beta \right) u_{c,t} \right] + o_t w_t - \phi w_t$$

$$+ \sum_s \pi_s \left[\sum_{\tau=t+1}^{t+T} (1+r)^{-\tau} \left[\sum_c k_{c,\tau,s} i_{c,\tau,s} + \left(m_{c,\tau} \cancel{- v_c \tilde{w}_{\tau,s}} + \sum_f q_{c,f} \tilde{n}_{f,\tau,s} + \sum_p e_{c,p} \tilde{a}_{p,\tau,s} + Max\left[e_{c,CO2} - b, 0 \right] \beta \right) u_{c,\tau,s} + o_{\tau,s} \tilde{w}_{\tau,s} - \phi \tilde{w}_{\tau,s} \right] \right]$$

Where we have added the cost of purchasing o units of power and the revenue of selling the total quantity of power ϕ.

And the additional set of constraints specifies that power generated plus power purchased in the market must meet the target quantity of power ϕ

$$\sum_c v_c u_{c,t} + o_t = \phi \quad \forall t$$

$$\sum_c v_c u_{c,\tau,s} + o_{\tau,s} = \phi \quad \forall \tau, s$$

Note that once ϕ is replaced by $\sum_c v_c u_{c,t} + o_t$ or $\sum_c v_c u_{c,\tau,s} + o_{\tau,s}$ in equation *f'*, we obtain equation f. This proves that the problem of minimizing operating and maintenance costs minus revenue form electricity sales, is equivalent to the same problem but adding the constraint that a target amount of power must be supplied by either producing or buying in the wholesale electricity market