Carbon Capture by Fossil Fuel Power Plants: An Economic Analysis

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Abstract:

For fossil fuel power plants to be built in the future, carbon capture and storage (CCS) technologies offer the potential for significant reductions in CO_2 emissions. We examine the break-even value for CCS adoptions, that is, the critical value in the charge for CO_2 emissions that would justify investment in CCS capabilities. Our analysis takes explicitly into account that the supply of electricity at the wholesale level (generation) is organized competitively in some U.S. jurisdictions, while in others a regulated utility provides integrated generation and distribution services. For either market structure, we find that emissions charges in the range of $25-$30 per tonne of CO_2 would be the break-even value for adopting CCS capabilities at new coal-fired power plants. The corresponding break-even values for natural gas plants are substantially higher, near $60 per tonne. Our break-even estimates serve as a basis for projecting the change in electricity prices once carbon emissions become costly. CCS capabilities effectively put an upper bound on the rise in electricity prices. We estimate this bound to be near 30% at the retail level for both coal and natural gas plants. In contrast to the competitive power supply scenario, however, these price increases materialize only gradually for a regulated utility. The delay in price adjustments reflects that for regulated firms the basis for setting product prices is historical cost, rather than current cost.

1 Introduction

The intense political discussion about a cap-and-trade system for CO_2 emissions has not yielded a consensus regarding the impact of carbon constraints on different sectors of the economy. One crucial question mark for policy makers is the market price per tonne of CO_2 emitted that will result under a cap-and-trade system for particular emission limits (caps). This market price will be the effective carbon tax imposed on the economy and its magnitude will reflect the cost of reducing emissions for different sectors. In this context, fossil fuel power plants are destined to play a central role since they are currently a major source of CO_2 emissions. For the U.S. alone, coal-fired and natural gas power plants contributed more than 40% of the economy's total 6 gigatonnes of CO_2 emissions in 2007. At the same time, fossil fuel power plants offer the potential for significant CO_2 abatement by means of Carbon Capture and Storage (CCS) technologies.

This paper examines the economics of currently known Carbon Capture and Storage (CCS) capabilities. Demonstration projects have shown the technical feasibility of several such technologies which capture CO_2 gas either before or after burning the fossil fuel. Thereafter the CO_2 is transported via pipelines to underground formations, such as depleted oil and gas fields, where it is then stored permanently.[1] Investment in CCS capabilities increases both the upfront construction cost and the variable operating cost of a power plant. These changes in fixed and variable costs are the fundamental input to assessing the economics of carbon capture capabilities.[2]

Our analysis first identifies how far the effective carbon tax would have to rise in order for investments in CCS technology to be financially advantageous. We refer to the critical value of the effective carbon tax as the *break even* value for CCS adoption. One would expect this break-even value to depend on the market structure for electricity services. In the U.S., electricity has traditionally been provided by a vertically integrated utility, with product

[1]The M.I.T. (2007) study provides a detailed description of different CCS technologies. There are still significant open questions regarding the certification of these technologies for plants on a commercial-scale. We discuss some of these issues in more detail below.

[2]Several studies have projected the cost of CO_2 abatement by means of CCS technology; see for instance, McKinsey (2008), MIT (2007), IPCC (2006) and IEA (2004). In terms of methodology, most of these projections simply seek to calculate a measure of the full cost of avoiding one tonne of CO_2. The reported estimates nonetheless span a range between $30-50 per tonne for coal-fired power plants. This relatively wide span of estimates seems partly attributable to different assumptions regarding the type and size of power plants and the particular CCS technology to be implemented.

prices determined according to a Rate of Return (RoR) regulation scheme. Prices are then set in each period so as to reimburse the regulated firm for all applicable costs, including a target return on its invested capital. For this traditional market structure, we presume that a consumer-oriented utility regulator will allow the utility to make investments in CCS technology provided such an investment is justified from the perspective of future discounted consumer surpluses.

Currently, some 15 states in the U.S. have deregulated the supply of power generation, as opposed to transmission and distribution, while in eight other states deregulation has been suspended (EIA, 2009a). We therefore consider an alternative scenario in which utilities procure electric power in a competitive wholesale market and then distribute it to consumers at the retail level. In this competitive scenario, the break-even value for CCS adoption is determined by the need to minimize the long-run marginal cost of electric power generation. Our calculations here rely on a model, first developed by Arrow (1964), in which firms make a sequence of overlapping capacity investments such that older capacity becomes obsolete while new capacity is added in each time period. Such a dynamic makes it possible to identify the cost of one unit of capacity made available for *one period of time*.[3] The long-run marginal cost of generating one kWh of electricity then includes both the unit cost of capacity and variable operating costs. In addition, the long-run marginal cost takes into account the corporate income tax rate and depreciation tax shields .

The break-even point for investment in CCS technology provides a significant data point in forecasting the effective carbon tax, that is, the market price for CO_2 emission permits under a cap-and-trade system.[4] Since CCS capabilities are projected to cut CO_2 emissions by 85-90% (Sekar et al., 2007) and fossil fuel plants contribute more than one third of the overall worldwide emissions, the break-even price for investment in CCS technology provides an upper bound for the marginal cost of reducing CO_2 emissions over a substantial range.[5] At the same time, the break-even point for investment in CCS technology generates a sharp

[3]Investment in a new plant inherently constitutes a joint cost for the entire useful life of the asset. As shown by Arrow (1964) and Rogerson (2008b), it is possible to allocate this joint cost unambiguously to individual time periods provided there is a sequence of overlapping capacity investments.

[4]A study by McKinsey(2007) seeks to rank the cost of different abatement strategies including energy saving measures, CCS, biofuels and afforestation. The overall marginal cost of achieving a particular level of emission reductions is then obtained by rank-ordering the costs of the different abatement strategies.

[5]Out of the approximately 28 Gt of global CO_2 emissions in 2008, coal-fired power plants alone contributed near 8 Gt. China recently became the world's largest emitter of CO_2 gases, with two-thirds of that country's electric power being generated by coal-fired plants (Winning, 2008).

upper bound on the price increase for electricity generated by fossil fuel power plants. Since these plants would have to pay emission charges only on the remaining 10-15% of their previous emission levels, electricity prices would be essentially shielded from any increases in the carbon tax beyond the break-even value.

For a scenario of competing power generators, we find that \$26 per tonne of CO_2 emitted is the break-even price for the adoption of CCS capabilities by coal-fired power plants. Thus power generators would attain a lower long-run marginal cost by investing in CCS capabilities provided CO_2 emissions trade for at least \$26 per tonne. Concurrent with the investment in CCS capabilities, firms will switch from Pulverized Coal (PC) plants to so-called Integrated Gasification Combined Cycle (IGCC) plants.[6] Furthermore, we estimate that the competitive wholesale price of electricity would increase by about 43%. Since electricity generation amounts to roughly 60% of the retail price of electricity (the remainder comprising the cost of transmission and distribution), the projected increase in electricity retail prices would be about 26%(=60% · 43%). We emphasize that these estimates apply to *new* coal-fired power plants to be built in the future rather than to retrofitting existing plants.[7]

We obtain an alternative set of cost-and price estimates for the scenario of a vertically integrated utility whose product prices are determined according to Rate-of-Return regulation. In contrast to the competitive power supply scenario, prices are then no longer driven by the long-run marginal cost of power generation but instead by the utility's historical cost basis, a large component of which are the depreciation charges associated with past capacity investments. For coal-fired power plants we find that a consumer-oriented regulator would instruct the utility to invest in CCS capabilities provided emission permits trade for at least \$24.50 per tonne. While this break-even value is remarkably close to that obtained in the competitive scenario, the resulting adjustment in electricity prices is likely to be much slower. Since regulated prices are set to cover the firm's historical accounting cost, product price increases will be phased in gradually under Rate-of-Return regulation. For instance, if utilities receive emission allowances for CO_2 emitted from older power plants constructed

[6]This finding is consistent with those in earlier studies, for instance, Sekar et al. (2007), Rubin et al. (2007).

[7]It also appears that the engineering cost estimates by Sekar et al. (2007) (and other comparable estimates summarized in Appendix-A1 are based on the notion of a "mature" technology. Al-Juaied and Witmore (2009) argue that there may be significant learning-by-doing effects associated with the adoption of CCS technology.

prior to the regulation of CO_2 emissions (100% "grandfathering"), then electricity prices are projected to rise linearly over a 30 year time window to a new equilibrium level which would be about 25-30% above the status quo level.

For power plants running on natural gas, we find that a substantially higher carbon tax of \$63 in the competitive scenario (\$59 in the regulation scenario) would be required to make CCS investments financially attractive. These higher break-even prices emerge because (i) traditional natural gas plants emit only about half as much CO_2 as traditional coal-fired plants per kWh and (ii) the increase in plant construction costs associated with CCS technology is comparatively high for a natural gas plant. It is generally accepted that, absent any CO_2 emission charges, coal-fired power plants generate electricity more cheaply than natural gas plants. We find that this ranking is preserved in a carbon constrained environment. However, the conclusion depends crucially on the availability of CCS technology on the financial terms assumed in our analysis. In fact, the cost advantage of coal-fired plants is rather small for an effective carbon tax in the range of \$25-40 and this advantage would be reversed quickly if CCS technology were either not available or substantially more expensive than projected in our calculations.

Taken together, our results indicate that CCS technologies for fossil fuel power plants could play a central role in reducing carbon dioxide emissions in the future. The abatement potential of these technologies is considerable. In particular the relatively low break-even value for CCS adoption by coal-fired power plants could have a significant effect on limiting the effective carbon tax under a cap-and-trade system. One recurring suggestion in the current policy debate is the introduction of "safety valves" that would commit the government to issue additional permits once the effective carbon tax exceeds certain threshold levels. Our calculations for coal and gas plants speak to the likelihood that such valves would ever need to be activated if the price threshold were to be set above \$60 per tonne.[8] We also conclude that predictions which foresee a doubling of electricity prices as a consequence of CO_2 regulations appear too dire (Warner, 2009). Because CCS effectively shields electricity prices from further increases in the charge for CO_2 emissions, we find that a 30% increase in the retail price of electricity constitutes an upper bound even for a relatively high carbon tax in the range of \$70 per tonne.

[8]Predictions about the role of safety valves are obviously sensitive to the time table for progressively lower emission caps. In general, CCS will become a more effective abatement strategy as the schedule for emission reductions is "backloaded" over time.

As of now, there are no commercial-scale CCS power plants in operation. However the significant investments in CCS pilot plants and development programs that are currently underway make it plausible that CCS technology will be fully established for commercial power plants (at least 500 Megawatt)within the next few years.[9] In the U.S., the FutureGen project in Illinois is perhaps the most prominent attempt to build an integrated gasification combined cycle (IGCC) plant on a commercial scale with the capability to capture and sequester CO_2. While this project was shelved by the Bush administration in 2008 , it now appears that a consortium of U.S. firms has agreed to proceed with partial funding provided by the Department of Energy (Galbraith, 2009).

Aside from demonstrating CCS for new power plants to be built, five North American utility companies plan to partner with the Electric Power Research Institute (EPRI) to explore carbon capture technology at existing coal-fired plants. The program will focus on post-combustion CO_2 capture, which faces site challenges such as limited space and heat, cooling requirements and possible steam turbine modifications. According to EPRI, fifteen other companies and organizations have joined the program (ClimateBiz, 2009).[10]

The remainder of the paper is organized as follows. Section 2 focuses on the scenario of competitive power suppliers. We present the economic framework and the engineering cost data in Sections 2.1 and 2.2. Our main results on break-even values, projected increases in electricity prices and a cost comparison of coal versus natural gas plants are presented in Section 2.2. Section 3 is organized like Section 2, except that the analysis focuses on the scenario of a price regulated utility. We conclude in Section 5.

[9] Sutter (2009) describes several such initiatives.

[10] American Electric Power Corporation (AEP), one of the biggest utilities in the U.S., plans to install technology at its Mountaineer coal plant in New Haven (West Virginia) that uses chilled ammonia to trap CO_2. The greenhouse gas will then be turned into a liquid and injected into the ground. According to Warner (2009), this will be the first such project that will both capture and store carbon from an existing plant. The Swedish utility company Vattenfall inaugurated a pilot CCS plant in Germany in the summer of 2008 that turns Germany's most important resource, lignite coal, into oxyfuel. Vattenfall plans to build an industrial scale CCS demonstration plant that will begin operation in 2015 (ClimateBiz, 2008). Finally, Japan's Toshiba Corporation announced on December 3, 2008 that it will accelerate the development of its CCS technology by building a retrofit pilot CCS plant at Sigma Power Ariake Co. Ltd.'s Mikawa Power Plant.

2 Competitive Power Generation

2.1 Model Framework

Some 15 states in the U.S. have deregulated the supply of power generation. The distributors of electricity (utilities) then purchase electric power at the wholesale level from competing power suppliers. For modeling purposes, we take this framework to an idealized extreme by supposing that wholesale electricity prices are fully competitive in that they are equal to the long-run marginal cost of electricity generation.

The long-run unit cost of electricity comprises both variable operating costs and capacity costs associated with plant, property and equipment. In order to assign the latter costs to an individual unit of output, we adopt a model of sequential and overlapping capacity investments, first studied by Arrow (1964). Specifically, a single-product firm builds up productive capacity through a sequence of investments. In each period, the firm's output, q_t, is bounded by the total capacity available in that period, K_t. Production capacity is generated by assets, which have a useful life of T periods. Specifically, an investment expenditure of $v \cdot I_t$ at date t will add capacity to produce an additional I_t units of output at date $t+\tau$, where $1 \leq \tau \leq T$. Thus, new investments come "online" with a lag of one period and they retain their productivity over T years.[11] The firm's total productive capacity at date t is then given by: $K_t = I_{t-T} + ... + I_{t-1}$.

Suppose the firm makes strictly positive investments in each period. This dynamic may reflect increasing market demand for the product in question.[12] Given a path of strictly positive investments, the joint cost of acquiring one unit of capacity for T periods becomes inter-temporally separable. In particular, the long-run marginal cost of obtaining one unit of capacity *for one period of time* is given by:

$$c = \frac{v}{A(r,T)}. \tag{1}$$

where $A(r,T)$ is the value of an annuity of \$ 1 paid over T years at an interest rate (cost of capital) of r. Arrow (1964) points out that c can be interpreted as the rental price of capacity since this price would be charged for one unit of capacity made available for one unit of time in a rental market in which suppliers make zero economic profits.

[11] In the regulation literature, this productivity pattern is sometimes referred to as the *one-hoss shay* scenario; see, for example, Rogerson (2008).

[12] In the context of electricity, this assumption is supported by the assessment of the Annual Energy Outlook 2009 which projects the demand for electricity in the U.S. to increase through 2030 (EIA, 2009d).

In addition to capacity related costs, the firm incurs variable production costs for inputs such as fuel, transportation, labor and maintenance. For simplicity, these costs are assumed to vary proportionately with output and the corresponding unit cost is denoted by w. Finally, let $0 \leq \alpha < 1$ denote firms' marginal tax rate and suppose that for tax purposes the depreciation charges per dollar of investment undertaken at date 0 is d_i^o at date i. Our numerical analysis below will reflect current IRS rules allowing for an accelerated depreciation schedule (150% declining balance) with a recovery period of 20 years. The competitive wholesale price of electricity is then given by:

$$p = w + c(\alpha), \tag{2}$$

where

$$c(\alpha) = \frac{1}{1-\alpha} \cdot c \cdot [1 - \alpha \cdot \sum_{i=1}^{T} d_i^o \cdot \gamma^i],$$

and $\gamma \equiv \frac{1}{1+r}$ denotes the discount factor corresponding the interest rate (cost of capital) r. The price identified in (2) reflects a competitive market price in the sense that the present value of all after-tax cash flows associated with a dollar of investment is indeed zero.[13] We note in passing that, as one would expect, the after-tax long-run marginal cost of capacity $c(\alpha)$ exceeds the pre-tax cost c. It can be shown that $c(\alpha)$ is increasing and convex in α and that more accelerated tax depreciation rules tend to lower $c(\alpha)$ closer to c.

2.2 Data Calibration

The key cost parameters in the model described above are v and w. The fixed cost v represents the capacity investment expenditure required per unit of output (one kWh). In the context of power plants, this parameter is calculated as:

$$v = TPC/(365 * 24 * CF),$$

where TPC stands for total plant cost in ¢/kW, CF is a capacity utilization factor (percentage), and $365 * 24$ represents the number of hours per year. Since the capacity cost v

[13] In particular, the present value of after-tax cash flows associated with one unit of investment at date 0 is

$$\sum_{i=1}^{T} \gamma^i \cdot x_i \cdot [p - w] - \alpha \sum_{i=1}^{T} \gamma^i \cdot [x_i \cdot [p - w] - v \cdot d_i^o]. \tag{3}$$

If investments have zero net-present value (NPV), then the present value of these cash flows must be equal to the initial investment expenditure v. Solving for the corresponding product price then yields $p = w + c(\alpha)$.

represents a joint cost for the entire useful life of the asset, this joint cost cost is divided by the annuity factor $A(r, T)$ in equation (1) to obtain the cost of one unit of capacity available for *one year*.[14] Consistent with most other studies, we assume that the coal-fired plants under consideration are base-load plants that are operated 85% of the time. Accordingly, we set $CF = .85$. Fuel costs and other variable operating costs, including maintenance, are aggregated in the parameter w.

The following table provides a summary of the engineering estimates we rely on with regard to v and w for different fossil fuel plants. Specifically, we seek to compare cost estimates for the following types of fossil fuel plants: (i) Pulverized Coal (PC) plants, (ii) Integrated Gasification Combined Cycle (IGCC) coal-fired plants and (iii) Natural Gas Combined Cycle (NGCC) plants. For all three types of plants we quantify the increase in the parameters v and w that results if new plants are equipped with some carbon capture technology. Table 1 reports the corresponding higher cost parameters as $\hat{v}$ and $\hat{w}$, respectively. Finally, Table 1 also shows the amount of CO_2 emitted per kWh of electricity, both with and without carbon capture capabilities.

	No CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
PC plant	19.50	1.93	0.774	33.79	3.39	0.108
IGCC plant	20.39	2.06	0.769	26.27	2.79	0.089
NGCC plant	7.56	4.67	0.361	15.96	5.53	0.042

Table 1: *Construction- and Operating Costs per kWh and CO_2 Emissions per MWh*

For coal-fired power plants, the "point estimates" shown in Table 1 are based on Sekar et al. (2007). Their figures are roughly in the middle of a range of other studies that have provided cost estimates for both the construction and operation of fossil fuel power plants. Appendix A-1 contains a summary of these other studies and the assumptions they employ. For natural gas plants, we rely on a study by the National Energy Technology Laboratory NETL (2007). The increase in variable operating costs, i.e., the increase from w to $\hat{w}$ resulting from the adoption of carbon capture technology, reflects two factors. First, this cost now

[14]The expenditure v includes the annual expense for insurance and property taxes which equals 1.78% of the initial capital investment.

includes the transportation and storage of captured CO_2.[15] Secondly, the capture of CO_2 itself requires electric energy and, as a consequence, the variable fuel and operating cost per kWh delivered as net-output increases. For future reference, we also note that natural gas plants emit only about *one-half* of the CO_2 emissions of coal-fired power plants. Carbon capture capabilities would reduce CO_2 emissions by about 85% for both types of fossil fuel plants.

In the numerical analysis below, the remaining model parameters are assessed as follows:

- The useful life of new power plants, i.e., the parameter T, is assumed to be 30 years.
- The depreciation rules used for tax purposes, $\{d_i^o\}$, conform to the current IRS rules requiring that steam generating power plants are depreciated according to the 150% declining balance method with a recovery period of 20 years.[16]
- The marginal tax rate α is set equal to 35%.
- Firms impute a common cost of capital (discount rate), r equal to 10%.[17]

As a first validation of the above parameter choices, we note that absent any CO_2 emission charges and without CCS capabilities our parameter choices yield a competitive price of electricity at the wholesale level of 4.6¢/kWh for coal fired Pulverized Coal (PC) plants. Similarly, for a coal-fired IGCC plant, we obtain a long-run unit cost (competitive wholesale price) of 4.9 ¢/kWh, while a natural gas NGCC plant the projected cost is 5.7¢/kWh. These forecast values are reasonably close to observed prices for many jurisdictions in the U.S. (EIA, 2009e). However, since there is considerable variation in the wholesale electricity prices across different regions of the U.S., our price projections will not focus on absolute values but rather on the *percentage increase* in electricity prices due to CO_2 regulations.

[15] Consistent with earlier studies, we assume a charge of $5 per tonne of CO_2 for transportation and storage.

[16] These rules are based on the the Modified Accelerated Cost Recovery System (MACRS). Under straight-line depreciation, the annual depreciation charge would be 5% of the invested amount if the asset recovery period is 20 years. Under the 150% declining balance method, the depreciation charge is 7.5% (or 1.5 times 5%) of the remaining book value of the asset.

[17] The choice of the discount rate has been contentious in the well-publicized Stern Report (Stern, 2007) that seeks to forecast both the increases in the average temperature on earth and the social costs associated with various levels of CO_2 concentrations in the atmosphere; see also Arrow(2007). Our analysis could be refined by using state-of-the-art techniques for estimating the cost of capital (i.e., the weighted average cost of capital) of electricity producers and utilities. We expect such refinements to point to a weighted average cost capital somewhere in the range of 8-10%.

2.3 Results

Suppose first that power generators are confined to coal-fired power plants. One would expect that for low emission charges firms will continue to use PC plants and simply purchase the required number of CO_2 permits. On the other hand, Table 1 suggests that once permits become sufficiently expensive, coal-fired plants will have an incentive to switch to ICC plants and adopt CCS technology. The following baseline result identifies the *break-even price* for CO_2 emission permits, at which it would be cost effective to adopt CCS capabilities. The result also quantifies the increase in wholesale electricity prices that would result for alternative levels of the effective carbon tax that could emerge under a cap-and-trade system.

Result 1: *For coal-fired power plants, an investment in CCS technology becomes advantageous once emission charges for CO_2 exceed the break-even price of $q^* = \$26$ per tonne. For an emission charge of $\$q$ per tonne of CO_2, the competitive wholesale price of electricity is projected to increase by the following percentage changes, Δp:*

$$\Delta p = \begin{cases} 1.68 \cdot q & \text{for } q \leq 26 \\ 43.89 + .19 \cdot (q - 26) & \text{for } q > 26. \end{cases}$$

Our findings in Proposition 1 are predicated on the parameter choices in Table 1. Absent any CCS capabilities and absent any CO_2 emission charges, the long-run unit cost of 4.6¢/kWh for power generation can be achieved by a PC plant, but not an IGCC plant (which would have a marginal cost of 4.9¢/kWh). Beyond the break-even point of \$26 per tonne, firms would find it advantageous to adopt CCS technology and at the same time switch to IGCC plants. The cost parameters $\hat{v} = 26.79$ and $\hat{w} = 2.79$ correspond to an IGCC plant with CCS capabilities. For an effective carbon tax of $q^* = \$26$ per tonne, the long-run unit cost would increase to about 6.6¢/kWh.[18]

[18] For a PC plant, in contrast, the corresponding cost figure would be 8.0¢/kWh. Sekar, Parsons, Herzog and Jacoby (2007) perform a break-even analysis that is related to our finding in Result 1. Their break-even values are 45.29\$/ton for a PC plant and 20.27\$/ton for IGCC plants. These values are obtained in a setting in which for either type of plant the firm initially operates without CCS capabilities and then after four years makes the adoption decision so as to minimize the future discounted cash costs over the remaining useful life of the plant. Clearly the economic premises in the Sekar et al. study are different from ours. The most important difference is that they view the initial construction cost of the plant (without CCS) as a sunk cost. In effect, their analysis speaks to the economics of retrofitting an existing plant with CCS capabilities.

The wholesale price for electricity is a piecewise linear function of the effective carbon tax, with a sharp kink at the break-even point of $26 per tonne. Because traditional coal-fired plants emit large amounts of CO_2, wholesale electricity prices increase at a rate of 16.8 % for every additional $10 in the effective carbon tax up to the break-even point of $26. With CCS capabilities, in contrast, further price increases are limited to a rate of 1.9% for every additional $10 in the carbon tax. Thus, an investment in CCS capabilities effectively insulates electricity prices from further increases in the carbon tax, because power generators have to buy permits only for the remaining 15% percent of their previous emissions (Table 1). The sharp kink in the projected price of wholesale electricity can be interpreted as an "option" (a put option) associated with CCS capabilities: operators of coal-fired plants and electricity consumers are protected from potential further increases in the market price of emission permits.

The public discussion about the economic consequences of a cap-and-trade system has seen a number of dire predictions for the economy's most energy intensive sectors. In particular, some commentators have suggested that electricity prices may *double* (Warner, 2009). Our numbers in Result 1 suggest a far more modest impact. The 43.6% increase in the price of electricity generation corresponding to an emission permit price of $ 26 per tonne would roughly translate into a 26% (= 43% · 60%) increase in the retail price of electricity. This calculation assumes that power generation constitutes about 60% of the overall retail price of electricity, while transmission and distribution services account for the remainder. Furthermore, because of the option embedded in CCS capabilities, retail electricity prices would increase by no more than 30%, even if the effective carbon tax were to reach $70 per tonne of CO_2.

The break-even value of $26 per tonne for coal-fired plants also provides a significant data point in forecasting the effective carbon tax under a cap-and-trade system. Reliable predictions regarding the emerging market price for emission permits are notoriously difficult because they ultimately depend on the incentives for different industries to embrace measures and technologies that reduce CO_2 emissions. The study by McKinsey (2007) seeks to combine a range of alternative CO2 abatement strategies, including energy saving measures, biofuels and reforestation. The effective carbon tax under a cap-and-trade-system is principally the overall marginal cost that is obtained by rank-ordering alternative abatement strategies in terms of their incremental costs. Coal-fired power plants have the potential to contribute a major segment to this aggregate cost curve. On a worldwide scale, they currently account for roughly 8 Gt out of the approximately 28 Gt of CO_2 that were emitted globally in 2008. Our analysis indicates that over the course of the next 30 years CCS technology offers the potential for an 85-90% abatement of these emissions at a marginal cost of $26 per tonne.

If the supply of electric power is indeed competitive, equilibrium prices should not be affected by any "grandfathering" rules that the government may adopt with regard to emission permits. While the exact policy of issuing emission allowances for incumbent power plants has significant effects on the profitability of firms' existing assets, it should be of no consequence to the long-run marginal cost of production and therefore the competitive equilibrium price. As a caveat, however, we note that our cost-and price projections do not address the dynamics of the price adjustment that results once firms have to buy emission permits. The precise dynamics here will depend on the expectations that firms have regarding the price of CO_2 emission permits. In the short-run, capacity related costs are obviously sunk and electricity prices are determined by both variable operating costs and consumers' willingness to pay for the quantity corresponding to the aggregate industry capacity.

To conclude our analysis of CCS for coal-fired power plants in the competitive scenario, we conduct several robustness checks on our finding in Result 1. Since CCS technology is still to to be "certified" for power plants on a commercial scale, it is essential to examine how sensitive the projected break-even value is to variations in the underlying cost parameters. Figure 1 considers alternative parameter values for $\hat{v}$, the construction cost of a new plant with CCS capabilities per kW, and for $\hat{w}$, the unit variable cost. The lines in Figure 1 depict isoquants that correspond to the same break-even price for alternative combinations of $\hat{v}$ and $\hat{w}$. Consistent with our base line calculations, the parameter values $\hat{v} = 26.79$ and $\hat{w} = 2.79$ will lead to a break-even value of $26 per tonne.[19]

[19] Appendix-A1 summarizes the results of other studies that have issued a range of other forecasts regarding the parameters $\hat{v}$ and $\hat{w}$. If one were to take the highest $\hat{v}$ and the highest $\hat{w}$, reported in any of these studies, the break-even value would still be near $30 per tonne.

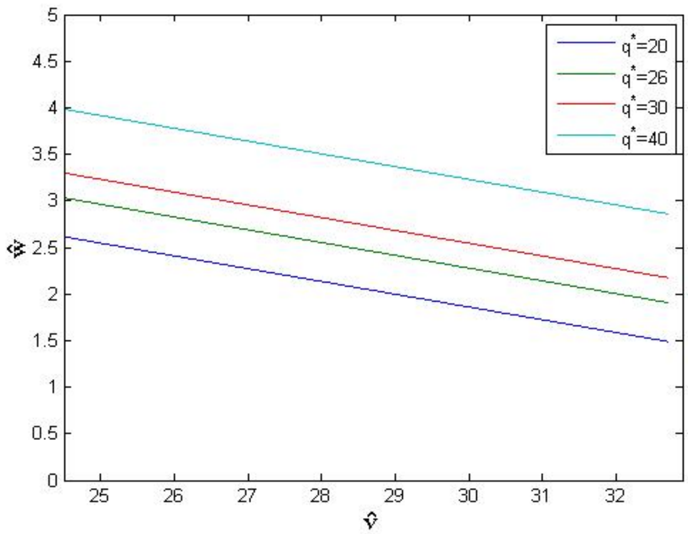

Figure 1: *Cost parameters resulting in the same break-even permit price q^**

As further robustness checks on the finding in Result 1, we also consider variations in the discount rate, r, and the useful life of the plant, T. Figures 2 and 3 show that for "reasonable" parameter values the price curve identified in Result 1 is relatively insensitive to changes in these two parameters.

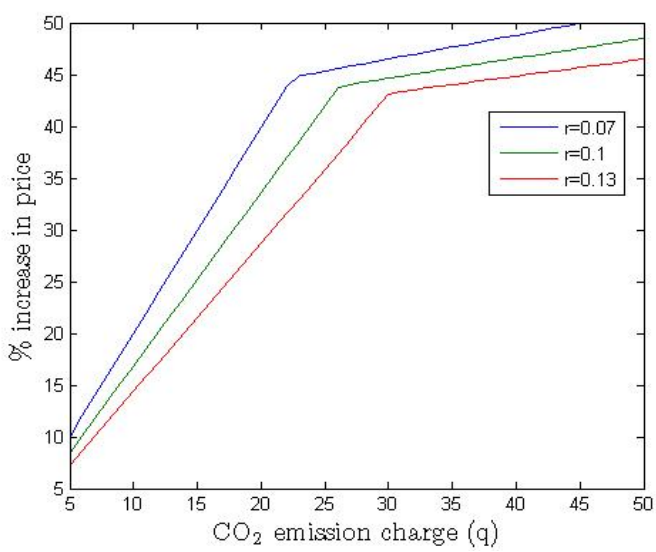

Figure 2: *% Increase in the competitive wholesale price of electricity as a function of the price for CO_2 emission permits for alternative discount rates r*

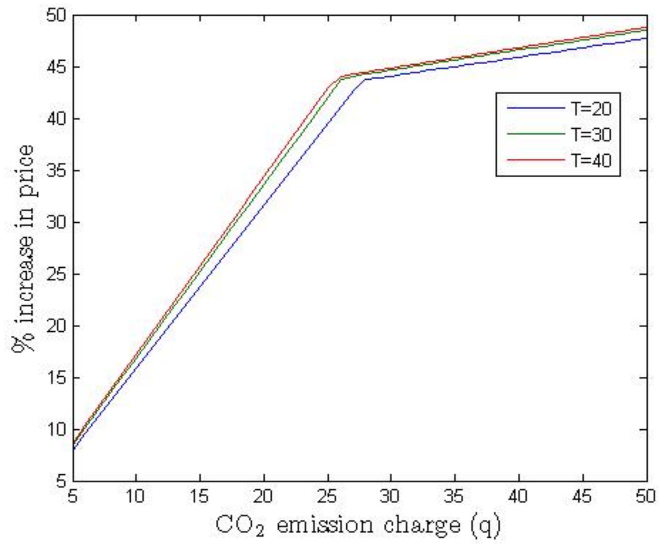

Figure 3: *% Increase in the competitive wholesale price as a function of the price for CO_2 emission permits for alternative levels of the useful life T*

We now turn to an analysis of natural gas plants. Consistent with the preceding calculations for coal-fired plants, we seek to project both the break-even price in terms of CO_2 emission permits and the change in electricity prices if operators of natural gas plants face a choice between purchasing emission permits and adopting costly CCS technology. As before, the relevant cost inputs draw on Table 1 and the determination of the competitive wholesale price of electricity is based on equation (2).

Result 2: *For natural gas power plants (NGCC), an investment in CCS technology becomes advantageous once the charge for CO_2 emissions exceeds the break-even price of $q^* = \$63$ per metric ton. For an emission charge of \$q per metric ton of CO_2, the competitive wholesale price of electricity is projected to rise by the following percentage increases, Δp:*

$$\Delta p = \begin{cases} .63 \cdot q & \text{for } q \leq 63 \\ 39.89 + .07 \cdot (q - 63) & \text{for } q > 63 \end{cases}$$

At \$63 per tonne of CO_2, the break-even charge for investing in CCS technology is almost 2.5 times higher for natural gas plants than for coal-fired plants. This stark discrepancy reflects that (i) natural gas plants emit only about half of the CO_2 of their coal-fired counterparts and (ii) the percentage increase in plant construction costs (the difference between

v and $\hat{v}$) required for CCS capabilities is substantially higher for NGCC plants. Both of these factors make it more attractive for operators of natural gas plants to pay the carbon tax up to much higher values of q rather than incur the upfront investment cost associated with CCS technology. While natural gas plants will seek to invest in CCS capabilities only for a much higher carbon tax, the wholesale electricity price increases are nonetheless no more than those predicted for coal, even for a high tax in the range of $q >$\$70.[20].

One recurring suggestion in connection with a cap-and-trade system is to introduce so-called safety valves which would commit the government to issuing additional emission allowances once the market price for permits reaches a certain threshold. Since in the U.S. fossil fuel power plants account for slightly more than 40% of the overall CO_2 emissions (at a total of roughly 6 Gigatonnes), the availability of CCS speaks directly to the likelihood that safety valves would in fact have to be activated, if the price threshold were to be set above \$60 per tonne. Of course, the chances of the effective carbon tax reaching this level ultimately depend on the timetable for ratcheting down the emission caps. The legislative proposals currently in front of Congress envision a sharp acceleration in CO_2 reductions for the period post 2020. Such "backloading" of the overall reduction levels significantly enhances the prospects for CCS to become a significant abatement strategy. At the same time, backloading of the emissions reduction schedule makes it more likely that safety valves in the range of \$60 per tonne will not be activated.

Our analysis thus far has compared the impact of emissions charges for each type of power plant separately. We conclude this section by comparing the production costs of coal and gas-fired power plants if both fossil fuel sources are available in a particular location and therefore power suppliers could freely choose between them. The following figure plots the two piecewise linear functions derived in Results 1 and 2 in absolute price terms: the wholesale price of electricity (long-run marginal cost) measured in ¢/kWh as a function of the effective carbon tax. We conclude that, *regardless* of the effective carbon tax, coal-fired plants dominate natural gas plants in terms of lower long-run unit costs per kWh. Even though electricity generation at coal-fired plants is far more sensitive to CO_2 emission charges, the sharp kink in the cost curve at \$26 per tonne ensures that coal-based plants retain their cost advantage. However, Figure 3 also indicates that this conclusion relies

[20]Even though NGCC plants emit about half the CO_2 of coal-fired power plants, the slope parameter of .63 in Result 2 is only about one third of the slope parameter 1.63 found in Result 1. These values reflect that natural gas starts out with a higher absolute price: 5.7¢/kWh rather than 4.9 ¢/kWh for coal.

crucially on the availability of CCS technology on the cost terms presented above for IGCC plants.

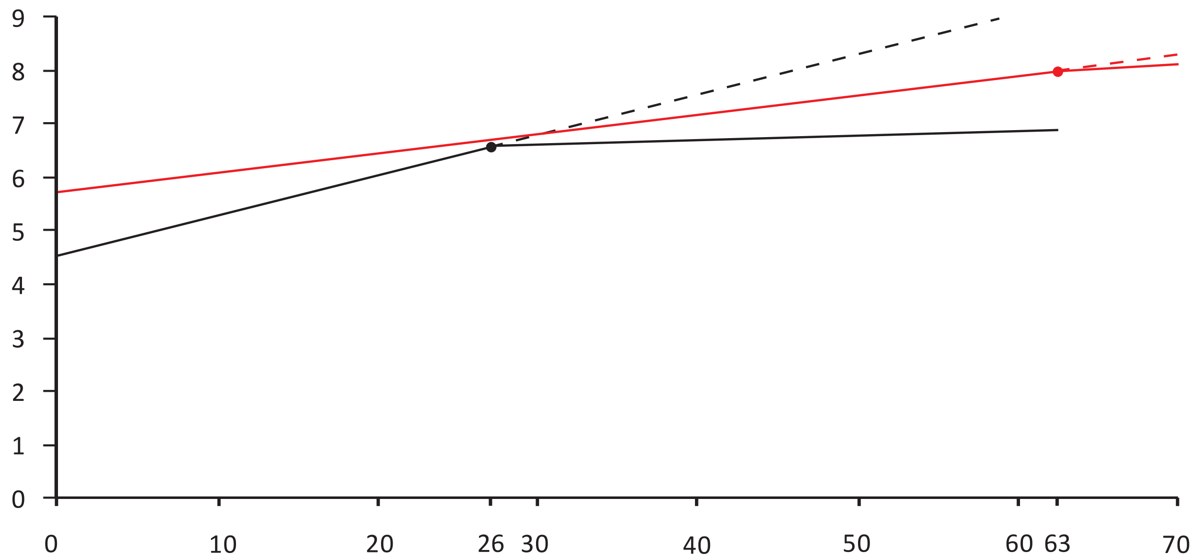

Figure 4: *Cost Comparison of Coal-fired and Natural Gas Power Plants*

The dashed lines in Figure 3 represent the long-run unit costs that would emerge if CCS technology were not to prove far more expensive than was assumed in the preceding calculations. In that scenario, the cost advantage would shift to natural gas, even for relatively low prices for CO_2 emissions charges exceeding \$27 per metric ton. Overall, we conclude that the cost advantage of coal-fired power plants is quite slim for intermediate emission charges in the range of \$20-40. These conclusions are consistent with the reservations that have been expressed recently by investors in connection with new coal-fired power plants (Ball, 2008, and Warner, 2009).[21]

[21]In the context of this cost comparison, it should be kept in mind that historically the price of natural gas has been far more volatile than that of coal. Our cost figures in Table 1 are based on a price for natural gas of approximately \$6.50 per thousand cubic feet for electric power producers (IEA, 2009). This figure is roughly consistent with the overall mean value over the past seven years. However, market prices for natural gas have fluctuated widely over that time period oscillating between \$4 and \$12 per thousand cubic feet. In the fall of 2009 natural gas prices have reached the relatively low level of \$5 per thousand cubic feet.

3 Regulated Power Supply

3.1 Model Framework

The most common industrial structure for electric power services in the U.S. remains a vertically-integrated monopoly that is subject to price regulation. Product prices are then based on the firm's historical cost. Specifically, the regulated firm must meet consumer demand at a price that satisfies the constraint that the firm's accounting rate of return does not exceed an allowable rate of return set by the regulator. This Rate-of-Return (RoR) regulation constraint is usually represented by the requirement that in each period t the firm's Return on Assets does not exceed some allowable rate:

$$\frac{NInc_t}{AV_{t-1}} \leq r. \tag{4}$$

Here, $NInc_t$ is the firm's accounting net-income (income after taxes), AV_{t-1} is the beginning-of-the-period book value of operating assets and r denotes the allowable rate of return set by regulators.[22] It is well known from the regulation literature that a firm, whose cost of capital is also equal to r, will achieve zero-economic profits if and only if output prices are set so that in each period the RoR constraint in (6) is met as an equality.[23]

We assume that the Rate-of-Return (RoR) rules have been in effect for a "long time" and therefore the process has reached its long-run equilibrium. For a baseline reading, we identify the long-run equilibrium price under RoR regulation that emerges absent any CCS technology and absent any CO_2 emission charges. Nezlobin, Rajan and Reichelstein (2009) show that when consumer demand grows at a constant rate over time, there is a generally a unique price which can emerge as an equilibrium under the RoR regulation process.[24] This price depends on the parameters identified in Section 3.1, as well as the depreciation rules used in the computation of income and asset values. In contrast to the accelerated depreciation rules used for tax purposes, regulatory agencies usually rely on straight-line depreciation to determine the regulated firm's income and assets. Specifically, the long-run

[22]Assets are valued at the historical acquisition costs less the cumulative amount of depreciation charged in previous periods.

[23]See, for instance, Schmalensee (1989) and Rogerson (2008b). The meaning of "zero-economic profits" here is that the present value of all investment and operating cash flows paid out and received over time is equal to zero.

[24]Nezlobin et al. provide conditions for the prices under RoR regulation to be converging to this equilibrium price.

equilibrium price under RoR regulation can be expressed as :

$$p^* = w + c(\alpha) \cdot \Gamma. \tag{5}$$

The equilibrium price p^* coincides with the long-run marginal cost derived in Section 2.1, except for the factor Γ. Therefore Γ will be referred to as the *accounting bias* factor. It would be equal to 1 if for regulatory purposes assets are depreciated in a manner that reflects the productivity of the asset over time. In particular, for the "one-hoss shay" scenario of an asset that has identical productivity over its entire useful life, unbiased depreciation would amount to the so-called annuity depreciation method (Rogerson, 2008a, Rajan and Reichelstein, 2009).[25] Since regulators typically use straight-line depreciation for the firm's plant property and equipment, Γ will be different from 1. The magnitude of the bias Γ depends jointly on the growth rate in the size of the product market, the tax rate and the depreciation rules that are used for both regulation and taxation purposes; see Appendix A-2 for details. Our numerical analysis adopts the following parameter assessments:

- For regulatory purposes, the useful life of new power plants, i.e., the parameter T, is assumed to be 30 years. All assets are depreciated according to the straight-line method and therefore $d_i = 0.033$.

- For tax purposes, current IRS rules require that steam generating power plants are depreciated according to the 150% declining balance method with a recovery period of 20 years.

- The marginal tax rate α is set equal to 35%.

- The allowable rate of return, r, for RoR regulation purposes is equal to the firm's cost of capital which we set equal to 10%.

[25]This result stands in contrast to the economic logic articulated in many microeconomics textbooks regarding the systemic inefficiency of rate of return regulation, e.g., Baumol (1971), Nicholson (2005) and Schotter (2008). In order for the firm to break even, prices must therefore cover average cost which include the (historical) fixed cost associated with investments in plant, property and equipment. Yet as argued in Rogerson (2008b), for suitably chosen depreciation rules the historical cost of sunk asset expenditures will align precisely with the long-run marginal cost of capacity, i.e., with $c(\alpha)$; see also Biglaiser and Riordan (2000). Of course, these arguments ignore the concerns that are central to large parts of the literature on incentives and regulation which has argued that a regulated monopolist will be inclined to admit slack in its operations whenever operating expenses are fully reimbursed (Laffont and Tirole, 1993).

- For any given price of electricity, consumer demand exhibits a constant price elasticity, which we set equal to .32.[26]

- Finally, for any given price, the constant elasticity demand is assumed to grow annually at a rate of 3%.[27]

For these choice of parameters, the accounting bias turns out to be near $\Gamma = .88$. At first glance, it may seem implausible that the long-run equilibrium price emerging under RoR regulation can be below the long-run marginal cost $w + c(\alpha)$. After all, the regulated firm achieves zero economic profits over its entire infinite lifetime, i.e., the present value of all cash flows, discounted at the cost of capital r, is zero. The explanation for this seeming "subsidy" is that prices will exceed the long-run marginal cost in early time periods before approaching their equilibrium values below $w + c(\alpha)$.[28]

3.2 Results

We take as our starting point the long-run equilibrium price, p^*, as identified in equation (5). The adoption of CCS technologies and/or the imposition of CO_2 emission charges will cause prices to rise to a new long-run equilibrium. However, as will become clear, it will take a long time to reach the new equilibrium. For that reason, it is essential to map out the resulting trajectory of electricity prices in real time.

Once CO_2 emissions are costly, regulatory commissions will confront the following intertemporal tradeoff. If the utility buys emission permits on the open market, operating costs and prices will increase in the short-run. An investment in CCS technology, on the other hand, will increase depreciation charges now and in future periods. In balancing this tradeoff, the regulatory commission is assumed to take a consumer-oriented approach with an instruction to the firm to respond to the environmental regulation in a way that minimizes the loss to future discounted consumer surpluses.[29] In this context, consumer surplus is

[26] The .32 estimate estimate is based on Bernstein and Griffin (2005).

[27] The assumption of constant growth in consumer demand is reasonable in the case of electricity demand. The projections in the Annual Energy Outlook 2009 suggest that the growth rate for electricity demand will be almost flat through 2030 (EIA, 2009d).

[28] Nezlobin et al.(2009) illustrate the dynamics and global stability of the price process that emerges under RoR regulation for the case where the firm starts out initially with no assets and capacity decays geometrically over time. Prices then converge monotonically to the equilibrium price p^* in (5).

[29] For simplicity, we employ the same discount rate of r =10% in these calculations.

measured only with regard to the consumption of electric power. The benefits for consumers from reduced CO_2 emissions are considered negligible.

Initially, we suppose again that power generators are confined to coal-fired power plants. Our first result is also based on the assumption that the utility has to purchase emission permits only for the emissions associated with new capacity investments. In effect, this amounts to a policy of "100% grandfathering" for incumbent plants that were built prior to the legislation requiring CO_2 emission permits. The following result identifies the *break-even price* for CO_2 emission permits at which a consumer-oriented regulator would instruct the utility to adopt CCS capabilities. Result 3 also identifies the percentage price increases, Δp, that will emerge over time for alternative levels of the effective carbon tax. The percentage increases are calculated with reference to the baseline level of $p^* = 4.3$ ¢/kWh, which is the RoR equilibrium price (equation (5)) for a PC plant in the absence of any CO_2 emission charges.

Result 3: *For coal-fired power plants, a consumer-oriented regulator will instruct the regulated firm to adopt CCS capabilities, provided CO_2 emission permits trade at a price of at least \$24.50. Given a policy of "100% grandfathering," the regulated wholesale price of electricity is projected to increase by the following percentages as a function of time and the CO_2 emission charge q:*

	Emission Charges: \$q									
Years	**5**	**10**	**15**	**20**	**24.5**	**30**	**35**	**40**	**45**	**50**
1	0.4	0.8	1.2	1.5	1.8	2.1	2.2	2.2	2.2	2.3
5	2.0	3.8	5.6	7.4	8.9	10.2	10.4	10.6	10.8	11.0
10	3.7	7.3	10.8	14.2	17.2	19.4	19.8	20.2	20.6	20.9
15	5.3	10.4	15.5	20.5	24.9	27.5	28.1	28.6	29.2	29.7
20	6.7	13.3	19.8	26.3	32.0	34.4	35.1	35.8	36.6	37.3
25	7.9	15.8	23.6	31.4	38.4	40.4	41.3	42.2	43.1	44.0
30	9.0	18.0	27.1	36.1	44.2	45.6	46.6	47.6	48.7	49.7
35	9.0	18.0	27.1	36.1	44.2	45.4	46.4	47.5	48.5	49.5
40	9.0	18.0	27.1	36.1	44.2	45.3	46.3	47.4	48.4	49.5

Table 2: *Coal-fired power plants: % Increase in the regulated wholesale price of electricity as a function of time and the CO_2 emission charge, assuming 100% grandfathering*

Direct comparison of Results 1 and 3 shows certain parallels but also some striking differences between the competitive and the regulation scenario. First, the break-even point of \$24.50 per tonne in the RoR regulation scenario is surprisingly close to that identified in Proposition 1.[30] Second, the ultimate percentage price increases for electricity at the wholesale level are again in the range of 44% for an effective carbon tax of \$ 24.50 and near 49% for an effective carbon tax of \$50 per ton. Third, in sharp contrast to the competitive power supply scenario, the price increases for electricity are phased in gradually for a regulated firm. For any emissions charge q (i.e., for any column in Table 2), it takes about 30 years to reach the new equilibrium price levels. This gradual phase-in reflects that the capital costs (depreciation and interest charges) of old plants without CCS capabilities dominate the historical costs in early years and product prices are calculated to reimburse the firm for its historical cost. After 30 years (the assumed useful life of a power plant) prices settle down to their new equilibrium levels.

In the political discussion over a cap-and-trade system one major point of contention will be the rules for issuing emission allowances to parties that have had high CO_2 emissions in the past. Wholesale electricity prices should not be affected by the specific grandfathering rules if power generation is organized competitively. In contrast, product prices will be sensitive to the number of emission permits given to a regulated firm. Permits issued by the government now effectively become a source of revenue for the firm. Since prices are calculated to meet the RoR regulation constraint, a more generous grandfathering policy will have the effect of slowing down the increases in electricity prices. The following result presents a variant of Result 3 by considering the other extreme grandfathering policy in which the regulated firm receives no emission permits for free.

[30]Once CO_2 emission charges exceed the break-even value of \$24.50 per tonne, the regulated firm stops investing in Pulverized Coal plants and instead switches to IGCC plants with CCS capabilities. The values in Table 2 were obtained in Matlab by a numerical search process which seeks in each period a product price that meets the two conditions: (i) there exists a non-negative level of investment for the current period such that consumer demand at the candidate price is compatible with the currently available capacity and (ii) at this price and quantity the RoR constraint is satisfied with equality (in case there are several such candidate prices, the lowest one is implemented). The iterative search process starts from a steady state solution in which the firm charges the equilibrium price level $p^* = 4.3$ ¢/kWh and investments have been growing at the constant rate $\mu = .03$ over the past T =30 years.

Result 3': *For coal-fired power plants, a consumer-oriented regulator will instruct the regulated firm to adopt CCS capabilities, provided CO_2 emission permits trade at a price of at least \$24.50. Given a policy of "0% grandfathering," the regulated wholesale price of electricity is projected to increase by the following percentages as a function of time and the CO_2 emission charge q:*

	Emission Charges: \$q									
Years	**5**	**10**	**15**	**20**	**24.5**	**30**	**35**	**40**	**45**	**50**
1	8.5	17.0	25.6	34.1	41.8	51.4	60.9	70.7	80.8	91.3
5	8.6	17.2	25.8	34.5	42.2	51.5	59.3	67.4	75.6	84.1
10	8.7	17.5	26.3	35.0	42.9	51.5	57.6	63.9	70.3	76.8
15	9.0	18.0	27.0	36.0	44.0	51.6	56.4	61.1	65.9	70.8
20	9.2	18.4	27.5	36.7	44.9	50.8	54.3	57.8	61.4	64.9
25	9.2	18.4	27.5	36.7	44.9	48.8	51.1	53.3	55.6	57.8
30	9.3	18.7	27.9	37.2	45.5	47.6	49.0	50.3	51.6	52.8
35	8.9	17.7	26.6	35.5	43.5	44.3	45.2	46.0	46.9	47.8
40	8.9	17.8	26.8	35.7	43.7	44.6	45.5	46.4	47.3	48.3

Table 3: *Coal-fired power plants: % Increase in the regulated wholesale price of electricity as a function of time and the CO_2 emission charge, assuming no grandfathering*

The price increases shown in Table 3 reflect that without any emission allowances the regulated firm has essentially no short-run choices for mitigating the effects of a high carbon tax. The percentage increases for the column corresponding to $q = 50$ are quite dramatic (at least at the wholesale level). To cover the cost of high CO_2 emission charges, the firm must raise prices which in turn will drive down demand and slow new capacity investments. In fact, the firm may have to increase the price up to a point where its available capacity is no longer fully utilized.[31] After a few years, however, the retirement of old plants and growth in the demand for electricity will ensure that capacity will again be fully utilized and new investments with CCS capabilities are undertaken. As a consequence, wholesale electricity prices start to decline until they converge to the new steady state level which is again about

[31] Our numerical search allowed for the possibility that the firm could leave old plants with high CO_2 emissions idle and accelerate the investment in new plants with CCs capabilities. However, that alternative did not emerge as a viable option for carbon taxes in the range $q \leq 50$.

48% higher than the status quo.[32]

For low emission charges, say $q \leq 10$, product prices rise monotonically over the first 30 years. The dominant effect here is essentially the one described in connection with Result 3. In the initial years, a large part of the historical cost is contributed by the relatively low depreciation charges of incumbent plants without CCS capabilities. These lower depreciation charges are gradually replaced by the higher depreciation charges of new plants with CCS capabilities. For a carbon tax in the mid-level range of $\$15 \leq q \leq \$30$, this effect is essentially offset by a countervailing effect: higher emission charges are gradually eliminated as the firm adds new capacity with CCS capabilities. The net result of these two countervailing effects is that the price increase is relatively stable for $\$20 \leq q \leq \$30$.

Alternative grandfathering policies do not seem to affect the break-even value of $24.50 for the adoption of CCS at coal-fired plants. Since this finding is consistent with that obtained in Result 1, we obtain yet another confirmation for the value $25 as the (long-run) marginal cost of CO_2 abatement via CCS technology. Given the sheer magnitude of emissions from coal-fired power plants, this estimate should be a major data point in predicting the range of the effective carbon tax that is likely to emerge for particular emission caps.

We finally turn to the scenario of a regulated utility that generates power by burning natural gas. We recall from Section 2 that in order to minimize the long run marginal cost of power generation, new natural gas plant would be outfitted with CCS capabilities once the effective carbon tax passes the break-even value of $63 per tonne. As explained above, this relatively high value results from the fact that natural gas plants emit only one half of the carbon dioxide that coal-fired plants emit per kWh. In addition, the increase in construction costs associated with CCS capabilities is much higher in relative terms for an NGCC plant. The following calculations are based on an initial RoR equilibrium price of $p^* = 4.3$ ¢/kWh for NGCC plants.

[32]In contrast to the values obtained for 100% grandfathering, Table 3 shows that prices increases keep changing even past the first 30 years if the firm receives no emission permits for free. However, beyond the 40 year mark, prices are essentially stable with any further increases limited to less than two tenth of one percent.

Result 4: *For NGCC plants, a consumer-oriented regulator will instruct the regulated firm to adopt CCS capabilities, provided CO_2 emission permits trade at a price of at least \$59.00. Given a policy of "100% grandfathering," the regulated wholesale price of electricity is projected to increase by the following percentages as a function of time and the CO_2 emission charge q:*

		Emission Charges: \$q							
		10	**20**	**30**	**40**	**50**	**59**	**70**	**80**
Years	**1**	0.3	0.6	0.9	1.2	1.4	1.9	1.95	2.0
	5	1.5	2.9	4.3	5.6	6.9	9.2	9.3	9.5
	10	2.7	5.4	8.1	10.6	13.2	17.2	17.5	17.8
	15	3.9	7.7	11.4	15.1	18.8	24.0	24.4	24.8
	20	4.9	9.7	14.5	19.2	23.9	29.4	30.0	30.6
	25	5.7	11.4	17.1	22.7	28.3	34.3	35.0	35.6
	30	6.5	12.9	19.4	25.9	32.3	38.2	39.0	39.7
	35	6.5	12.9	19.4	25.9	32.3	38.1	38.9	39.7
	40	6.5	12.9	19.4	25.9	32.3	38.0	38.9	39.7

Table 4: *Natural gas power plants: % Increase in the regulated wholesale price of electricity as a function of time and alternative CO_2 emission charges, assuming 100% grandfathering*

The values in Table 4 are consistent with the general pattern established in Results 1-3. In terms of the break-even price, the competitive and regulated scenario lead to approximately the same critical value for emission charges, i.e., \$60 per tonne, that would make it advantageous to endow new NGCC plants with carbon capture capabilities. The ultimate percentage price increases are also comparable across the two market structure scenarios. In particular, we find an effective upper bound of about 40% at the wholesale level (25% at the retail level) even if the effective carbon tax were to reach a level of \$70 per tonne of CO_2. These price increases are again phased in almost linearly over 30 years provided older installations are fully grandfathered. Our findings in Result 3' suggests that such a gradual monotonic increase would probably not be obtained for partial grandfathering policies.

4 Concluding Remarks

Coal and natural gas are the dominant energy sources for electricity generation in many parts of the world. For countries like the U.S. and China, CO_2 emissions from fossil fuel power plants constitute more than 40% of the overall "emissions pie". Carbon Capture and Storage (CCS) technologies offer considerable potential as a CO_2 abatement strategy because CCS capabilities are projected to reduce emissions from fossil fuel power plants by 85-90%. Our analysis indicates that investors and regulators would prefer to include CCS capabilities in new coal-fired power plants once the market price for CO_2 emission permits moves beyond the range of $25-30 per tonne. This estimate is obtained consistently for the two scenarios of competitive and regulated power generation. Given the sheer magnitude of emissions form coal, the break-even value for CCS adoption should prove a significant factor in limiting the effective carbon tax that will emerge under a cap-and-trade system.

An important option value associated with CCS capabilities is that electricity prices are essentially shielded from increases in the carbon tax beyond the break-even value. In contrast to some of the dire predictions reported in the popular press, we find that a 30% increase in the retail price of electricity constitutes an upper bound, even if the carbon tax were to reach $70 per tonne. This upper bound applies to both coal-fired and natural gas power plants. Furthermore, if electricity is provided by a price regulated utility, the resulting price increases will be phased in gradually over a 30 year time span. The specific price path will depend on the government's policy of issuing free emission allowances. If firms receive emission allowances for their existing plants (100% grandfathering), we find that electricity prices would rise in an almost linear fashion to their new equilibrium levels.

The analysis in this paper can be extended in a number of promising directions. First, our analysis has focused on CCS technologies for *new* power plants. As indicated in the Introduction, a number of energy companies are currently seeking to demonstrate techniques for retrofitting existing power plants with carbon capture capabilities. The possibility of retrofitting would add significant CO_2 abatement potential even within the next decade. Cost estimates emerging from the development programs currently underway will enable an economic analysis that parallels the one in this paper. In addition, decision makers will confront a richer set of choices between operating traditional power plants and paying for emission permits, as compared to retrofitting incumbent plants, or investing in new capacity with CCS capabilities.

Our observations regarding the effects of alternative grandfathering policies need to be explored in more detail. In particular, it would be useful to understand how fast electricity prices will rise in the short-run if a regulated firm is given emission allowances for existing plants, yet these allowances are either time limited or they diminish over time. Such policies would fall in between the two extreme scenarios of 0% and 100% grandfathering considered in this paper. Alternative policies for providing emission allowances are also likely to affect firms' decisions to retrofit existing plants.

Future research could also examine potential spillover effects associated with the availability of CCS technologies at fossil fuel power plants. The remaining 60% of the CO_2 "emissions pie" currently rely on oil, gas and coal as direct power sources for transportation, industrial production processes and residential energy use.[33] In case the effective carbon tax moves beyond the break-even values calculated in this paper, other sectors of the economy will have incentives to switch to electric power rather than burn fossil fuels directly. This effect could, for instance, accelerate the transition to electric vehicles or induce investment in industrial furnaces that are powered by electricity.

The results of this paper reinforce the urgency of demonstrating the feasibility of currently known CCS technologies at power plants on a commercial scale. Initiatives like the FutureGen project in Illinois are crucial in this regard. Further confidence about the availability of CCS for fossil fuel power plants, on the financial terms currently projected, will result in more reliable projections of the economic costs associated with CO_2 emission reductions.

[33]In some parts of the world coal is still used widely in industrial processes to power machinery and equipment.

Appendix-A1

The fundamental cost parameters for our study are the capacity acquisition cost v and the unit variable cost w, both with and without CCS capabilities. This Appendix documents that the estimates we rely on are roughly comparable to those obtained in other studies. We also provide more details regarding the varying technology assumptions that have been used in those different studies. Tables 5 and 6 summarize the parameters estimated in several major studies for Integrated Gasification Combined Cycle (IGCC) and pulverized coal (PC) power plants.

	PC power plants					
	no CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
Sekar et al. (2007)	19.5	1.93	0.774	33.79	3.39	0.108
EPRI (2002)	17.04	2.37		29.5	3.67	
Simbeck (2002)	19.2	2.01		33.5	2.93	
NETL (2008)	18.9	2.45	0.800	31.1	3.65	0.095
NRRI (2007)	18.1		0.800	30.4		0.052

Table 5: *Parameter estimates for PC power plants with and without CCS*

	IGCC power plants					
	no CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
Sekar et al. (2007)	20.39	2.06	0.769	26.27	2.79	0.089
EPRI (2002)	16.6	2.03		24.5	2.45	
Simbeck (2002)	19.3	2.01		26.8	2.5	
NETL (2007)	24.82	2.26	0.796	32.69	2.71	0.093
NRRI (2007)	20.0		0.86	25.8		0.156

Table 6: *Parameter estimates for IGCC power plants with and without CCS*

For both types of plants, the above tables show the parameter estimates with and without CCS technologies. In particular, v and w for the initial cost parameters of the power plants without CCS technology, and $\hat{v}$ and $\hat{w}$ for the cost parameters of the power plants with CCS technology. The variation in estimates obtained from the earlier studies is primarily attributable to the following assumptions:

- Sekar et al. (2007) compare a subcritical air-fired PC plant to an IGCC plant. Carbon in the PC plant is captured by flue gas scrubbing using the monoethanolamine (MEA) process, while carbon in the IGCC plant is captured by scrubbing the shifted syngas using the Selexol process. The costs are in 2004 US$.

- The parameters in EPRI (2002) and Simbeck (2002) are consistent with those provided in the MIT Coal Study (2007). The EPRI (2002) data are taken from PITG (2002). EPRI (2002) compares a supercritical PC plant to an e-gas IGCC plant. The PC plant uses the MEA process to capture carbon. Simbeck (2002) compares an ultra super critical PC plant to a Texaco IGCC plant. The PC plant captures carbon by the MEA process. The costs are in 2005 US$.

- The National Energy Technology Laboratory NETL (2008) reports parameters for air-fired supercritical PC plant with and without Econamine carbon capture technology. All costs are in January 2007 US$. NETL (2007) reports parameters for a General Electric Energy (GEE) IGCC plant which can capture CO_2 with Selexol process. All costs are in 2006 US$.

- The National Regulatory Research Institute NRRI (2007) data is consistent with EPRI's 2006 presentation, and the costs are in 2006 US$. The CO_2 emission parameters of the PC plant are specific to supercritical PC plants.

For natural power plants, Table 7 summarizes some parameters estimated in Rubin et al. (2007) and NETL (2007).

	NG power plants					
	no CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
Rubin et al. (2007)	9.01		0.367	14.65		0.043
NETL (2007)	7.56	4.67	0.361	15.96	5.53	0.042

Table 7: *Parameter estimates for natural gas power plants with and without CCS*

The specific technological assumptions employed in these studies are:

- Rubin et al. (2007) provide parameters of a natural gas combined-cycle (NGCC) plant which includes two GE (General Electric) 7FA gas turbines and 3-pressure reheat recovery steam generators (HRSG). Carbon capture is based on amine absorber technology. All costs are in 2005US$.

- The National Energy Technology Laboratory NETL (2007) reports parameters for a General Electric Energy (GEE) IGCC plant which can capture CO_2 via the Selexol process and for an NGCC plant which includes two advanced F class combustion turbines and HRSG. Again, CO_2 is captured by an amine absorber. All costs are in 2006 US$.

Appendix-A2

This Appendix provides further details for the equilibrium price p^* identified in equation (5). The following derivations extend the analysis in Nezlobin et al. (2009) by considering income taxes and the possibility that tax depreciation rules will generally differ from the depreciation rules used for regulatory purposes.

To formalize the conditions for a price equilibrium rules under the RoR regulation regime, we denote the relevant history of past investment decisions as the current *state* at date t :

$$\boldsymbol{\theta}_t = (I_{t-T}, ..., I_{t-1}).$$

By definition, the production capacity available at date t is $K_t(\boldsymbol{\theta}_t) = I_{t-T} + ... + I_{t-1}$. New assets are capitalized in their acquisition period and then fully depreciated according to the schedule $\mathbf{d} = (d_1, \ldots, d_T)$, that is used for regulatory purposes. Given the current state $\boldsymbol{\theta}_t$, the total depreciation charge in period t is then given by:

$$D_t(\boldsymbol{\theta}_t) = v \cdot (d_T \cdot I_{t-T} + \ldots + d_1 \cdot I_{t-1}).$$

Pre-tax income is given by revenues less variable operating costs and depreciation:

$$Inc_t(\boldsymbol{\theta}_t) = P_t(K(\boldsymbol{\theta}_t)) \cdot K_t(\boldsymbol{\theta}_t) - w \cdot K_t(\boldsymbol{\theta}_t) - D_t(\boldsymbol{\theta}_t).$$

Here, $P_t(K_t)$ denotes the price that consumers are willing to pay in period t if K_t units of output are supplied. The regulated firm's taxable income is then given by:

$$Inc_t^o(\boldsymbol{\theta}_t) = P_t(K(\boldsymbol{\theta}_t)) \cdot K_t(\boldsymbol{\theta}_t) - w \cdot K_t(\boldsymbol{\theta}_t) - D_t^o(\boldsymbol{\theta}_t),$$

where, by definition, the total depreciation for tax purposes is given by $D_t^o(\boldsymbol{\theta}_t) = v \cdot (d_T^o \cdot I_{t-T} + \ldots + d_1^o \cdot I_{t-1})$. After-tax (or net-income) is therefore given by:

$$NInc_t(\boldsymbol{\theta}_t) \equiv Inc_t(\boldsymbol{\theta}_t) - \alpha \cdot Inc_t^o(\boldsymbol{\theta}_t).$$

The regulated firm is allowed to set product prices so as to recover both variable operating costs and capital costs, that is depreciation charges plus an imputed capital charge on the book value of the firm's capacity assets. To complete the description of the RoR regulation scheme, we note that the remaining book value of a new asset acquired at date t, is originally recorded at its cost v and then amortized over the depreciation schedule, $\mathbf{d}$, is:

$$bv_\tau = (1 - \sum_{i=1}^{\tau} d_i) \cdot v$$

at date $t+\tau$, where $0 \leq \tau \leq T$. Given the current state, $\boldsymbol{\theta}_t$, the firm's aggregate value of capacity assets at date $t-1$ is given by:

$$BV_{t-1}(\boldsymbol{\theta}_t) = bv_{T-1} \cdot I_{t-T} + \ldots + bv_0 \cdot I_{t-1}.$$

Thus, the constraint imposed by Rate of Return (RoR) regulation is usually represented in terms of the firm's accounting rate of return on assets as follows:

$$\frac{NInc_t}{BV_{t-1}} \leq r. \tag{6}$$

Alternatively, the RoR constraint can be represented in terms of the residual income:

$$RI_t \leq 0, \tag{7}$$

where the residual income at time t is given by $RI_t \equiv NInc_t - r \cdot BV_{t-1}$.[34]

The prices and quantities that emerge from the RoR regulation process obviously depend on the choice of depreciation schedule $\mathbf{d} = (d_1, ..., d_T)$. An *unbiased* depreciation schedule would have the property that the regulation process results in the competitive price $p = w + c(\alpha)$. Such a depreciation schedule indeed exists. To see this, define the date t *capital cost* per unit of investment undertaken at date $t-i$ as the sum of depreciation and imputed interest charges:

$$z_i \equiv v \cdot d_i + r \cdot bv_{i-1}. \tag{8}$$

Thus, $z_i \cdot I_{t-i}$ is the capital cost charged in period t for investment I_{t-i} undertaken at date $t-i$. Suppose now the regulator were to choose a depreciation schedule $\mathbf{d}^*$ such that the corresponding capital costs satisfy:[35]

$$z_i^* = x_i \cdot (1-\alpha) \cdot c(\alpha) + \alpha \cdot v \cdot \ d_i^o. \tag{9}$$

[34] It has long been recognized in both the regulation and the accounting literature that a firm operating consistently under the constraint imposed by (6) will not make any positive economic profits in the sense that the present value of all cash flows is non-positive. This follows from the *conservation property of residual income* which states that, for a firm with no assets at its inception, the present value of cash flows is equal to the present value of all residual incomes, regardless of the applicable depreciation rules (Hotelling, 1925, Preinreich, 1938 and Schmalensee, 1989). Conversely, the firm will break even over its entire life time in terms of discounted cash flows if the inequality constraint in (6) is met as an equality in *every* period.

[35] It is well known from earlier studies of the residual income metric that there is a one-to-one relation between depreciation schedules $\mathbf{d} = (d_1, ..., d_T)$ and the historical cost charges $(z_1, ..., z_T)$; see, for example, Rogerson (1997). Formally, the linear mapping defined by (8) is one-to-one: for any intertemporal cost charges $(z_1, ..., z_T)$, with the property that $\sum_{\tau=1}^{T} z_\tau \cdot \gamma^\tau = v$, there exists a unique depreciation schedule $\mathbf{d}$ such that (8) is satisfied.

It is a matter of straightforward algebra to check that if the depreciation schedule used for regulatory purposes and the corresponding capital costs satisfy (9), then for any sequence of investment levels $\boldsymbol{\theta}_t = (I_{t-T}, ..., I_{t-1})$, the RoR constraint in (7) will be met if the product price is set equal to $w + c(\alpha)$. This follows from the observation that for each generation of investments $I_{t-\tau}$ the corresponding contribution to residual income is exactly zero at date t.[36]

An equilibrium price of the RoR regulation process, say p^*, must be supported by a sequence of past investments such that (i) the resulting capacity levels satisfy demand at the price p^* and (ii) the RoR constraint is satisfied in each period.

Claim: *Suppose that for any given price p, market demand grows at the constant rate μ. Then*

$$p^* = w + c(\alpha) \cdot \frac{\sum_{i=1}^{T} (1+\mu)^{T-i} \cdot [z_i(\mathbf{d}) - \alpha \cdot v \cdot d_i^o]}{\sum_{i=1}^{T} (1+\mu)^{T-i} \cdot [z_i^* - \alpha \cdot v \cdot d_i^o]} \tag{10}$$

is an equilibrium price of the rate of return regulation process. This price is supported by a sequence of constant growth investments of the form $I_{t+1} = I_t \cdot (1+\mu)$.

Proof of Claim:

It suffices to show that for a constant growth trajectory of the form $I_{t-T} = I$ and $I_{t-\tau} = (1+\mu)^{T-\tau} \cdot I$, the RoR regulation constraint:

$$RI_t(\boldsymbol{\theta}_t) = NInc_t(\boldsymbol{\theta}_t) - r \cdot BV_{t-1}(\boldsymbol{\theta}_t) = 0, \tag{11}$$

will be met provided the product price is set equal to p^*, as given in the statement of the Claim. The expression for residual income in (11) can be rewritten as:

$$(p^* - w) \cdot K_t(\boldsymbol{\theta}_t) - C_t(\boldsymbol{\theta}_t) - \alpha \cdot [(p^* - w) \cdot K_t(\boldsymbol{\theta}_t) - \sum_{i=1}^{T} (1+\mu)^{T-i} \cdot d_i^o \cdot v \cdot I], \tag{12}$$

where, by definition,

$$C_t(\boldsymbol{\theta}_t) \equiv D_t(\boldsymbol{\theta}_t) + r \cdot BV_{t-1}(\boldsymbol{\theta}_t).$$

The expression for capital costs is also equal to:

$$C_t(\boldsymbol{\theta}_t) = \sum_{i=1}^{T} (1+\mu)^{T-i} \cdot z_i(d) \cdot I.$$

[36] In the absence of income taxes, Rogerson (2008b) refers to such unbiased capital costs as the Relative Replacement Cost rule. The concept of replacement cost is more complex in Rogerson (2008b) since his model allows for the acquisition cost of new assets to decline geometrically over time.

Equation (12) is therefore equivalent to:

$$(1-\alpha)\cdot c(\alpha)\cdot \Gamma \cdot K_t(\boldsymbol{\theta}_t) = C_t(\boldsymbol{\theta}_t) - \alpha \cdot \sum_{i=1}^{T}(1+\mu)^{T-i}\cdot d_i^o \cdot v \cdot I,$$

where:

$$\Gamma \equiv \frac{\sum_{i=1}^{T}(1+\mu)^{T-i}[z_i(d) - \alpha \cdot v \cdot d_i^o]}{\sum_{i=1}^{T}(1+\mu)^{T-i}[z_i^* - \alpha \cdot v \cdot d_i^o]}.$$

To complete the proof, it therefore suffices to show that:

$$(1-\alpha)\cdot c(\alpha)\cdot K_t(\boldsymbol{\theta}_t) = \alpha \sum_{i=1}^{T}(1+\mu)^{T-i}[z_i^* - \alpha \cdot v \cdot d_i^o].$$

This step follows from the following two observations. First,

$$K_t(\boldsymbol{\theta}_t) = \sum_{i=1}^{T}(1+\mu)^{T-i}\cdot x_i \cdot I,$$

and, secondly:

$$z_i^* = (1-\alpha)\cdot x_i \cdot c(\alpha) + \alpha \cdot v \cdot d_i^o,$$

as shown in equation (9). ■

Nezlobin et al.(2008) show that the price in (10) is in fact the only candidate for an asymptotic outcome of the RoR regulation process. More specifically, if the product prices that emerge from the regulation process converge at all, they must converge to (5). While Nezlobin et al.(2009) prove this result only in a model without income taxes ($\alpha = 0$), we conjecture this uniqueness result to carry over to the present setting. We refer to the fraction:

$$\Gamma \equiv \frac{\sum_{i=1}^{T}(1+\mu)^{T-i}\cdot[z_i(\mathbf{d}) - \alpha \cdot v \cdot d_i^o]}{\sum_{i=1}^{T}(1+\mu)^{T-i}\cdot[z_i^* - \alpha \cdot v \cdot d_i^o]} \tag{13}$$

as the *accounting bias*. This factor will differ from 1 only to the extent that the depreciation rules for regulatory purposes differ from the unbiased rule identified in (9). Clearly, the bias factor is a joint function of the regulatory depreciation schedule, the depreciation schedule used for tax purposes and the growth rate in the product market, μ. The most common depreciation policy used for regulatory purposes is straight-line depreciation. For the choice of parameters identified in Section 3.2 above, the accounting bias is close to $\Gamma = .88$, provided the growth parameter μ is equal to 3%.

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