Essays on Market Power in the Alberta Wholesale Electricity Market

by

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Abstract

This thesis examines market power in a deregulated electricity market, and comprises two distinct areas of research grouped into three chapters. The thesis begins by overviewing electricity markets, including descriptions of uniform-price and discriminatory-price electricity auctions (and the resulting market power incentives), as well as carbon capture & storage (CCS). The first model is a treatment of the economic withholding potential arising from CCS in a uniform-price electricity auction. A firm that engages in CCS to reduce polluting emissions, thus reducing its carbon tax payment, must devote a fraction of electrical capacity to that effect, removing it from the market. This form of withholding can raise the market price of electricity, providing additional incentive to engage in CCS. With this price effect the carbon tax level at which the firm is indifferent between doing CCS or not is lower compared to without, and the firm may turn on CCS even if the carbon tax does not exceed the cost of doing so. We also analyze CCS in a discriminatory auction, which presents different withholding incentives than the uniform auction, and contributes to the discussion on which format is more desirable. The second area of research investigates allegations of market power abuse in the Alberta electricity market, whereby firms supposedly use public information to raise market prices higher than would otherwise obtain. It studies how this information allows firms to identify themselves through their price offers to their rivals, and asks whether this knowledge affects pricing decisions.

To the memory of Andrew Lin and Eric Lee

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I wish to express my gratitude to my supervisor Andrew Leach and to committee member Andrew Eckert, for their indispensable help and guidance with my thesis. My thanks also to the Economics Department at the University of Alberta, Sustainable Prosperity, and the Canadian Economics Association for financial assistance and opportunities to present my work. I am also indebted to my late uncle Andrew Lin, and to my parents and two sisters for their support.

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Introduction

This thesis examines two areas of research in deregulated electricity markets: the integration of carbon capture & storage (CCS) and associated market power implications, and allegations of market power abuse in the Alberta market.

The first chapter introduces the Alberta electricity market, describing the different agents, their interactions in the electricity auction, the price-setting process, and the difference between uniform and discriminatory auctions. The chapter also discusses the CCS technology, and the state of CCS projects in Canada.

The second chapter analyzes a method through which firms can exercise market power through the integration of CCS into the Alberta electricity market. A firm that engages in CCS sacrifices a fraction of its sellable capacity to that effect, removing it from the market; this reduction in supply can increase the market price depending on demand. Therefore CCS has not only an environmental effect through lower emissions, but a price effect as well. It also allows firms to sell a block of electrical capacity into the market by turning CCS off, or to withdraw it by turning CCS on (with the associated effects on price). This is a more flexible way for firms to manipulate quantity than physically withholding and reintroducing the capacity, which causes physical wear and tear, and is also illegal as firms are required to offer all capacity into the market.

We analyze the integration of CCS through a two-firm model, where one firm has the CCS technology installed and the other does not (the decision to install the technology is not modeled). Two auction formats are analyzed: a uniform one where all dispatched firms (who make offers below that of the price-setter) are paid the same price, and a discriminatory one where each is paid the price it offered. The Alberta auction is uniform, while the discriminatory auction is used in England and Wales. We also consider two timing structures: one where the firm with the CCS technology is required to pre-announce its decision to engage in CCS, and one where it is not. Environmental policy is modeled through an exogenous carbon tax. Firms' offer behaviour is modeled through a computer simulation based on analytical offer functions. In the version where firms are not required to pre-announce a CCS decision, there are shown to be values of the carbon tax for which there is no pure strategy equilibrium CCS decision; namely the firm may mix across CCS and no-CCS.

The profitability of capacity withholding through CCS is shown to depend on the prevailing demand at a given time. CCS is used more often in low demand hours when the firm's quantity sacrifice is palliated by the low price, and less often in high demand hours when the opportunity cost is high. Moreover, a firm's CCS incentive also depends on whether demand is such that the removal of capacity causes the role of price-setter to change from a low-offering firm to a high-offering one. "Shoulder hours" when demand is in between the nighttime low and the early evening peak are shown to present such incentives, hence CCS has the ability to prolong high-price periods.

CCS is also more profitable in the uniform auction where an increased market price is earned by all dispatched firms, than it is in the discriminatory auction where firms continue to receive their own offers if a higher-offering firm becomes dispatched. Discriminatory auctions are subject to other issues such as inefficient dispatch, and price-guessing by profit-maximizing firms. Hence if the Alberta electricity market were to introduce CCS, it must take into account different market power considerations than England and Wales.

The third chapter studies allegations of coordination and collusion through publicly available information among Alberta's large electricity firms, as a means to maintain high market prices. Our data present evidence that a particular firm (Transcanada) employed a complex pricing pattern which may have had communication purposes; this pattern was then abandoned abruptly by the firm. Interestingly, the pattern change coincided with the announcement of a recommendation that market transparency be decreased.

The literature predicts two reasons why firms have incentive to communicate with one another, which lead to different outcomes. The first is to select an equilibrium in a uniform auction duopoly setting, where one firm acts as the price-setter and the other makes a low offer to prevent the first firm from undercutting. Firms are thus expected to set offers far apart from each other. There are different equilibria with different firms in the role of the price-setter:

communication could serve as a role assignment mechanism (a possibility the literature for the most part has not yet considered). The second reason is to sustain over time an outcome that is not a static Nash equilibrium, and has different firms' price offers clustering close together. A firm may allow itself to be undercut by a price-setting rival without responding competitively (and may even raise its offer to give the rival more room to increase its own offer), and can communicate its intentions. Such coordination allows the price-setter to increase price while maintaining its merit order position.

The Alberta Market Surveillance Administrator (MSA) alleges firms are secretly communicating in a manner consistent with the second reason described above, with the aid of a public document called the Historical Trading Report (HTR), which contains detailed, near real-time information about firms' price offers. This information is intended to be anonymous, but firms are shown to engage in "tagging" strategies that can allow them to identify each other through the HTR (an example is the use of a particular decimal price offer ending to signal identity). A change in Transcanada's pricing pattern occurred the day after the MSA formally recommended making the HTR less transparent.

A firm's hourly strategy is approximated through a so-called kink price, which models the point where the merit order undergoes a sharp increase in elasticity. The intuition is that a firm sets capacity at a high price offer (with its remaining capacity at low offers), which it tags in a way that rivals can recognize the firm that offered it. Rivals then undercut the capacity within a certain time delay, confident that the firm will not respond competitively. Econometric analysis of kink prices set by large firms revealed some evidence a firm systematically undercutting particular rivals, though this evidence was not pervasive. The other outcome predicted by the literature, where firms set offers far apart from each other and face a coordination problem to select an equilibrium, therefore remains a possible explanation for future research to explore.

Chapter 1

The Alberta wholesale electricity market

1.1 Introduction

This chapter provides an institutional basis for the thesis, and covers two topics: the Alberta electricity market and its potential for market power, and carbon capture & storage. The electricity section explains the auction and price-setting process, as well as market power through capacity withholding. The carbon capture & storage (henceforth CCS) section gives an overview of the technology and its potential for capacity withholding in the Alberta electricity market.

1.2 Electricity markets

1.2.1 The Alberta electricity market

The current incarnation of the Alberta electricity market was created through the Electric Utilities Act beginning in 1996, in which major utilities separate the operation of their generation, transmission and distribution assets. The

Market Surveillance Administrator (MSA) was then created to monitor and ensure competition among firms. In 2003 the Alberta Electric System Operator (AESO) was created to manage the electricity spot market.[1]

The Alberta system relies on two independent markets, each operated by the AESO: the energy hourly market where buyers and sellers meet and trade, and the ancillary services market, where the AESO is the only buyer (MSA (2010a)). The energy market is where the wholesale price is determined. Sellers of electricity (generators and importers) make price offers into the electricity auction; buyers (domestic load and exporters) make price bids. Details of the energy market are further developed in section 1.2.2. Ancillary services "[...] ensure that electricity can transmitted reliably, efficiently, and securely across Alberta's interconnected transmission system," and include operating reserves and load shed schemes to maintain system balance following an outage (AESO (2013)). And the forward market facilitates electricity trading ahead of real time, allowing buyers and sellers to shield themselves from real time price volatility.

Electricity consumption, known as load, is close to perfectly inelastic in the short term; hour to hour, the quantity demanded changes little in reaction to a change in price, since electricity is not easily storable and has few substitutes. There is a small fraction of electricity demand (about 200 to 300 MW, or 1-3%, see MSA (2012b)) that is responsive to price, and reduces consumption

[1] Source: `http://www.energy.gov.ab.ca/About_Us/1133.asp`.

during times of excess demand; these are mainly industrial loads with flexible production processes. Because of demand inelasticity, most of the competition facing an electricity generator is from other generators.

In 2015 Alberta's electricity load was 51% industrial, 27% commercial, 18% residential, and 3% farm (see AUC (2016a)). On the supply side, Table 1.1 shows the resource mix, with coal and natural gas comprising the majority of generation (AUC (2016b) and (AUC (2016c)).

Table 1.1: Alberta's electricity generation and installed capacity by resource in 2015

Resource	Gen. (GWh)	Gen. (%)	Cap. (MW)	Cap. (%)
Coal	41,378	51	6,267	39
Natural gas	32,215	39	6,953	43
Wind	3,816	5	1,491	9
Hydro	1,745	2	902	6
Biomass	2,149	3	424	3
Other	318	1	97	1
Total	81,621	100	16,133	100

Source: Alberta Utilities Commission

In 2015, the offer control of the five largest firms in Alberta was 1,659 MW for ATCO, 1,722 MW for Capital Power, 2,699 MW for Enmax, 2,221 MW for TransAlta, and 2,609 MW for Transcanada (MSA (2015)). These are MWs that the firm may or may not own, but offer into the market because of Power Purchase Agreements (PPAs), which separate a generating unit's ownership from its offer control for market power mitigation (MSA (2012b)).

The Alberta electricity market is relatively unique because it is a deregulated, uniform-price energy-only market, meaning firms only earn revenue on energy that they produce and sell. For this reason, short run market power is allowed and necessary for firms to recover fixed costs of entry (MSA (2012b)). Firms can engage in cogeneration, where heat from electricity production is reused as an input into (for example) oil sands extraction. This is a form of vertical integration, as a firm that produces its own on-site power reduces its exposure to the real-time price of electricity (MSA (2012b)). As mentioned, PPAs were implemented to reduce market power by selling a generating unit's offer control to a firm other than the owner. Alberta also has interconnections with BC, Saskatchewan and Montana, accounting for 1,468 MW of export capacity and 1,263 MW of import capacity.[2] And transmission rates paid by distribution system owners are independent of distance and location, and are known as "postage stamp rates" (Church et al. (2009)).

Comparable markets to Alberta's include Texas (Hortaçsu and Puller (2008)) and Australia (Weron (2006)), both of which are or were also uniform-price and energy-only, and are also reliant on fossil fuels (Texas has since transitioned to a nodal market with different prices for different areas; see Daneshi and Srivastava (2011)). Another deregulated market is the Nord Pool Spot market in Europe.[3]

[2]See `https://www.aeso.ca/market/current-market-initiatives/intertie-restoration/`.

[3]See `https://www.eia.gov/electricity/state/texas/`, Department of Industry and Science (2015), and `http://www.nordpoolspot.com/How-does-it-work/`.

1.2.2 The Alberta uniform electricity auction

The Power Pool is the physical real time spot market through which sellers and load entities in Alberta trade electricity. The Alberta electricity market determines the spot price and quantity through a uniform price hourly auction. Firms may also sell through long term contracts, which reduce market power incentive through reduced exposure to real time prices, but the power still moves through the market.

Every hour, a generating asset belonging to a firm declares an amount of electrical capacity it will make available to the market, and the minimum price per megawatt-hour it is willing to accept for that block of capacity (50 MW offered at $40/MWh, for example). Individual price offers are compiled into an ascending price merit order.

Large utilities and large individual industrial users submit demand bids. A consumer that bids 100 MW at $150/MWh is stating the price at which it will reduce its demand by the stated quantity. The intersection between the merit order and demand yields the system marginal price (SMP), the price offer of the last dispatched firm, also known as the marginal firm. As the intersection between the merit order and demand shifts, the system operator maintains supply-demand balance by dispatching firms on and off, and the SMP is updated in real time, with a new SMP every minute. Figure 1.1 shows a graphical example of a merit order and system marginal price.

A firm offering at or below the SMP at a given time is dispatched and

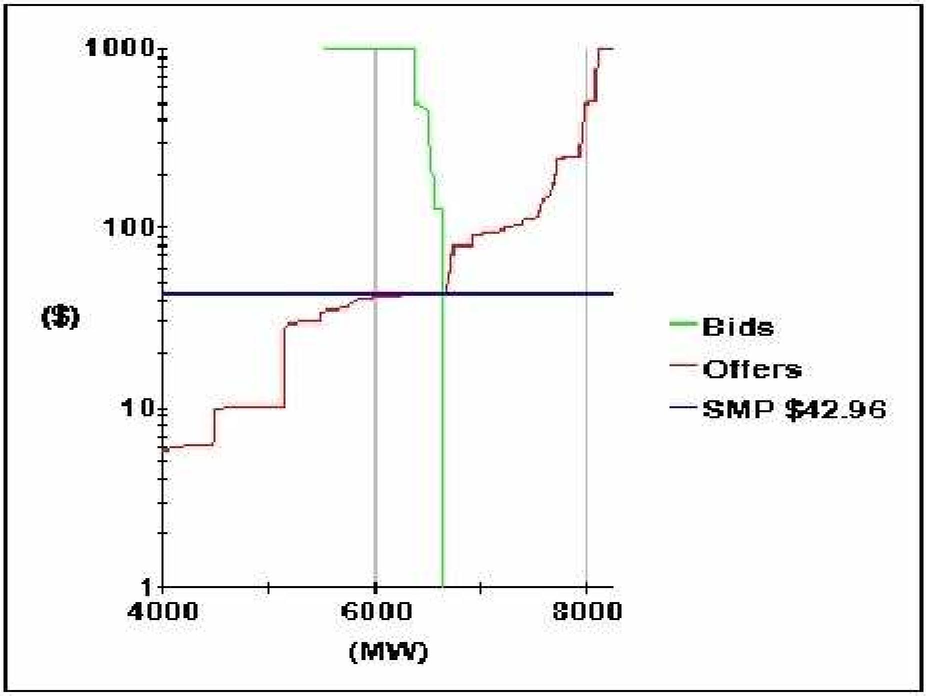

Figure 1.1: Merit order and system marginal price (AESO (2006))

produces electricity; a firm offering above is not dispatched. At the end of the hour, the average of the 60 one-minute SMP's yields the pool price, which is wholesale market price.

Supply offers are in the range \$0/MWh to \$999.99/MWh inclusively, and can be changed up till two hours before the hour in which they come into effect. A firm owning many generating units can submit up to seven price-quantity pairs per unit per hour, and must specify if each offer block is flexible or inflexible. Flexible blocks can be partially dispatched, while inflexible blocks must be dispatched as a whole. If an increase in demand requires an additional block to be dispatched, and the additional block is inflexible with a capacity less than the demand increase, then the block is dispatched on. If its capacity is greater than the demand increase, it is passed over and the AESO goes up the merit order to the next block that can match the increase. If a further demand increase is enough to accommodate the inflexible offer block, it is dispatched on and the previously marginal block higher up in the merit order is dispatched off.

A unit's ability to shut down and to start up again affects its price offer. Given that offers below the SMP are dispatched, a baseload plant with high shutdown cost and low variable cost will make low offers to ensure its minimum stable generation is dispatched, thus avoiding shutting down. A peaking plant with low shutdown cost and high variable cost offers higher to avoid having to produce when the SMP is too low to be profitable.

1.2.3 Market power in a uniform-price electricity market

Electricity markets possess unique features that make them susceptible to market power (see MSA (2012a)). First, electricity is generally non-storable and new plants take time to be built, limiting supply response to rises in demand, leading to potential gains from economic withholding. Second, supply is further constrained by generator outages, which can be anticipated or unanticipated. And third, electricity demand inelasticity due to a lack of substitutes further increases economic withholding's effect on price.

An example of market power estimation in the Alberta electricity market is Brown and Olmstead (2016). Using hourly data on price offers, demand, imports and exports, and asset ownership from 2008 to 2014, they measure firms' marginal costs to create a competitive benchmark, against which they compare observed outcomes. Observed prices are shown to be on average 13% higher than they would be under competition, with inefficiency arising from high-cost firms being dispatched before low-cost ones and from excessive imports from other provinces.

Market power mitigation and forward markets in Alberta

The ability to exercise market power has to do with market structure, while the incentive to exercise it depends on the firm's exposure to the real time price.[4] No firm is allowed to control more than 30% of all electrical capacity in Alberta. Nonetheless the market is still concentrated due to high fixed costs, with the five biggest firms controlling over 70% of capacity.

Forward contracts are traded in a financial forward market, which is not operated by the AESO.[5] A generator can lock down the future price it receives for a block of capacity by selling a contract to a buyer, possibly another generator (MSA (2010b)). The buyer pays the agreed price to the seller, and is paid the prevailing pool price by the seller on the day the contract is honoured. In "Example #2" from MSA (2010b), a generator with a dispatch cost of $30/MWh sells a contract for 25 MW at $60/MW for all hours of the calendar year 2011. Whenever the pool price falls below $30/MW in 2011, rather

[4]This section borrows from MSA (2012b) and MSA (2012a).

[5]The AESO does operate a forward physical market, where physical power is traded in advance.

than shutting down (which it would without the contract) the generator receives \$60/MW for 25 MW from the contract buyer. For forward contracts traded over-the-counter (not through an observable exchange), firms' forward positions are not deducible from publicly available data. Contracts traded though Natural Gas Exchange (or NGX, an electronic trading platform) are anonymous, again hindering the determination of individual forward positions.

In Alberta, 90% of forward contracts are "flat," and cover every hour of every day (MSA (2012b)). Other contracts cover peak hours from HE 8 (hour ending 8, from 7:01 am to 8:00 am) to HE 23, or off-peak hours (HE 24 to HE 7), or weekdays and/or weekends. Forward market liquidity has been decreasing in recent years, due to lower credit availability stemming from the 2008 recession and vertical integration (as some generators have their own load), and because of market power in the Power Pool.

A firm that sells a forward contract and locks down the future price received for its capacity reduces its exposure to the real time pool price of electricity, hence contract cover is a way of reducing a firm's incentive to exercise market power.

Examples of market power exercise by electricity firms

In Alberta Queen's Printer (2003, page 18), firms are required to adhere to a "fair, efficient and openly competitive" market operation. The following examples, in the opinions of the MSA and the Alberta Utilities Commission (AUC), violated this principle by manipulating prices in a non-competitive manner.

In the fall of 2011, TransAlta admitted to having manipulated market prices in November 2010 by allegedly blocking cheaper imports from British Columbia (CBC (2011, November 8)). Consumers paid an additional \$5.5 million as a result, and the AUC imposed a \$370,000 fine on TransAlta.

In May 2014, the MSA claimed that TransAlta took three coal plants offline during peak winter demand hours in 2010 and 2011 (see Cryderman (2014, May 16) and AUC (2015a)). The sudden excess demand for electricity forced other firms to bring higher cost units online, allegedly creating \$16 million in additional profits for TransAlta, who denied the accusation and lodged a complaint against the MSA. In October 2015 TransAlta was fined \$56 million (AUC (2015b)).

A prominent subject in the electricity market power literature is the California withholding crisis of 2000-01, which led to bankruptcies and widespread blackouts.[6] While there were the usual factors such as inelastic demand, high peak demand during a particularly hot summer, and inability to increase supply on short notice, the main causes of the crisis were regulatory rather than economic. The California Power Exchange (PX) is a day-ahead market that provides the electricity auction, while the California Independent System Operator (ISO) operates in real time and oversees the network and transmission grid. The Federal Energy Regulatory Commission (FERC) was responsible for

[6]See Bushnell (2004), Navarro and Shames (2003) and Wolak (2003). Borenstein and Bushnell (1999) study market power in California before the crisis occurred.

mitigating market power, but failed to account for the conditions under which firms had incentive to engage in market power, setting restrictions that were not stringent enough (Wolak (2003)). The PX and ISO meanwhile did not have the authority to monitor firms nor to enforce production levels (Navarro and Shames (2003)), hence firms withheld output during shortages.

These examples show that the incentives for and monetary consequences of economic withholding in electricity markets occur in practice, and that mitigation requires both economic and regulatory policies. While market power is necessary for firms to recover fixed costs in an energy-only market such as Alberta's, excessive use of this power is not tolerated because of the associated high costs and deadweight loss.

1.2.4 Discriminatory auctions: England and Wales

Unlike Alberta's one price auction where the marginal generator sets the price for all dispatched generators, electricity markets such as those in England and Wales or the Mid-C market in the northwestern US have a discriminatory (or pay-as-bid) auction, where dispatched firms are paid their price offers. The England and Wales market underwent a transition from uniform to discriminatory auction in 2001, with the expectation that market power and prices would decrease (Federico and Rahman (2003), Fabra et al. (2006)).

In Kahn et al. (2001), firms in a uniform auction might engage in economic withholding to raise the market price received by units offered at low prices; this incentive is not present in a discriminatory auction, where those units continue to receive their own offer. But firms in a discriminatory auction engage in costly-price-guessing as they attempt to undercut the marginal firm to maximize their price while still being dispatched; this introduces its own inefficiencies, and the authors argue in favour of the uniform auction. Ausubel et al. (2014) list additional reasons to prefer a uniform auction: it encourages marginal cost bidding, and allows market power exercise by small firms (who would be disadvantaged in a price-guessing setting due to their size).

1.3 Carbon capture and storage

This section describes the basic engineering features of CCS, including the CCS energy penalty which allows for economic withholding. It also provides an overview of both existing and upcoming CCS projects in Canada.

1.3.1 How carbon capture works

The most common method is post-combustion capture, where the emissions are captured after the burning of the fossil fuel.[7] The burning process produces a flue gas, into which a solvent such as amine is poured and binds with the CO_2 molecules, which settle at the bottom. The CO_2-rich amine is then separated into pure amine (for reuse in subsequent rounds of carbon capture) and a CO_2 stream. This method captures about 80% to 90% of emissions, with an energy penalty of 20% to 30%; this capacity fraction is devoted to CCS and does

[7]Source for this section: `http://www.old.ico2n.com/what-is-carbon-capture/capture-basics` and IPCC (2005).

not produce sellable output, hence CCS has a capacity withholding aspect.[8] Post-combustion capture can be installed as a retrofit to existing power plants.

In pre-combustion carbon capture, also called gasification, chemical impurities are captured before the burning of the fossil fuel. The fossil fuel is burned in pure oxygen, creating a synthetic gas (syngas). A catalytic converter or shift reactor transforms the syngas into CO_2 streams, which are captured with amine. This method is cheaper on a per-tonne-of-emissions-captured basis than post-combustion, but has higher fixed cost and is not a retrofit for existing plants.

In oxyfuel combustion, the fossil fuel is burned in pure oxygen; the resulting steam turns turbines to produce electricity. The exhaust contains a high concentration of CO_2, which is subsequently captured and compressed.

Current research and development into post-combustion carbon capture aims to (among other things) develop ways of using waste heat as an input to reduce the energy penalty (Global CCS Institute (2012)). This raises the possibility that a firm could sell its waste heat to another firm engaging in carbon capture, creating a market for the operation of the capture process distinct from electricity generation. Market power exercise would depend on the third party provider's ability/willingness to provide CCS during certain hours to affect electricity prices. The generating firm would have incentive to run CCS during low demand hours when the opportunity cost of foregone

[8] Other sources define the energy penalty as the extra capacity required to produce a given amount of sellable electricity.

capacity is low (same as if it provided its own power for CCS).

1.3.2 Canadian CCS projects

Alberta has two CCS projects, while others have been canceled.[9] The Alberta CO_2 Trunk Line from Enhance Energy is a planned project that will start operating in 2017, transporting CO_2 from a fertilizer plant and a bitumen upgrader for enhanced oil recovery (EOR) in Clive, Alberta, receiving \$495 million from the Government of Alberta and \$63.2 million from the federal government.[10] The Quest Project from Shell captures up to 1.08 million tonnes of emissions per year from the Scotford upgrader in Fort Saskatchewan for storage, beginning operation in 2015 and receiving \$745 million from the Government of Alberta and \$120 million from the federal government.[11]

Project Pioneer was a planned CCS facility for the Keephills 3 coal plant near Edmonton and owned by TransAlta and Capital Power. With an initial expected start date of 2015, the involved parties ultimately abandoned it in April 2012 due mainly to an inadequate carbon tax that did not justify the cost of the investment (CBC News (2012, April 26)).

In February 2013 the Swan Hills Synfuels CCS project for a 300 MW coal power plant in White Court was postponed indefinitely (Blackwell (2013, February 25)). Expected to start in 2015, it would have captured 1.3 million tonnes of CO_2 per year through coal gasification (pre-combustion capture)

[9] Source for this section is `http://www.energy.alberta.ca/CCS/3822.asp`, unless otherwise stated.

[10] See `http://www.nrcan.gc.ca/energy/publications/16233`.

[11] See `http://www.nrcan.gc.ca/energy/funding/current-funding-programs/18168`.

for EOR. The Alberta Government withdrew $285 million in funding because the low price of natural gas rendered the project unprofitable and would have pushed completion beyond scheduled deadlines.

Alberta has nine smaller CCS projects funded through the Climate Change and Emissions Management Corporation (CCEMC), an independent organization that supports the development of clean energy and energy efficiency in accordance with the province's priorities.[12] Funding is obtained through the Specified Gas Emitters Regulation, which stipulates that firms emitting more than 100,000 tonnes of CO_2 equivalent per year must reduce emissions intensity by 12% below a baseline (Leach (2012)). Those unable to do so have the option of paying $15 per tonne of CO_2 in excess of their limit into a Climate Change Emissions Management Fund, managed by the CCEMC, or buying carbon offsets or performance credits.

Elsewhere in Canada, Weyburn-Midale is a carbon storage project storing 2.2 million tonnes of CO_2 per year originating from Beulah, North Dakota in Weyburn, Saskatchewan for EOR since 2000. And SaskPower's Boundary Dam project in Estevan, Saskatchewan began operation in October 2014, capturing 1 million tonnes of coal plant emissions per year for EOR and storage.[13]

[12] See `http://ccemc.ca/projects/ccs/` and `http://ccemc.ca/about/`.

[13] SaskPower (2014, October 12) and `http://ccs101.ca/ccs_pro/ccs_projects/canadian_projects`.

1.3.3 CCS in the rest of the world

CCS is used in the rest of the world as well (Global CCS Institute (2012) and Global CCS Institute (2015)). Sleipnir CO_2 Injection in Norway and In Salah CO_2 Injection in Algeria use pre-combustion to capture emissions from natural gas processing. Similar projects in the United States include Val Verde Gas Plants (Texas) and Shute Creek Gas Processing Facility (Wyoming).

Yanchang Integrated Carbon Capture and Storage Demonstration Project is an upcoming project in Shaanxi, China (pre-combustion capture, coal gasification, 2017 expected start date).[14] The Gorgon Carbon Dioxide Injection Project in Australia (pre-combustion capture, natural gas processing) has begun development of the gas fields, with carbon capture and storage expected to begin in 2017.[15]

As noted in Section 1.2.1, Texas and Australia are notable for having similar deregulated market structures to Alberta. Norway operates mainly under the Nord Pool Spot, which is also deregulated. Unlike Alberta, these markets do not have plans for fossil fuel power plants enabled with post-combustion CCS allowing for a new form of capacity withholding, hence the Alberta electricity market is facing a unique situation.

[14]See `https://www.globalccsinstitute.com/projects/yanchang-integrated-carbon-capture-and-storage-demonstration-project`.

[15]See `https://www.globalccsinstitute.com/projects/gorgon-carbon-dioxide-injection-project`.

1.4 Conclusion

We provided a brief description of the Alberta electricity market, including the uniform auction process, and examples of how firms exercise market power in such a setting. We discussed discriminatory auctions as well, which entail a separate set of market power considerations. This chapter also described the basic CCS technology (including post-combustion carbon capture which carries an energy penalty for a firm employing it), and CCS projects in Alberta and in the rest of Canada.

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Chapter 2

Capacity withholding from carbon capture in a deregulated electricity market

2.1 Introduction

Climate change concerns have changed electricity production in recent years and decades, be it through new power sources or through modifications to existing systems. This chapter considers an example of the second approach, namely the introduction of carbon capture & storage (CCS) into fossil fuel-based electricity production. We find dual effects via reduced pollution and increased market power potential, and a method for firms to withhold capacity or to offer it into the market at will without having to turn generating units off or on.

Post-combustion carbon capture is an end-of-the-pipe method that is installed either as a retrofit to existing coal- or gas-fired power plants, or as a new plant. To date, only a few power plants in Canada employ this technology, including the coal-fired plant at Boundary Dam, Saskatchewan. This technology has two attributes of primary interest to our study. First, emissions abatement via CCS significantly reduces the *net to grid* generation from the power plants on which it is deployed. Second, the CCS unit may be activated or deactivated at shorter intervals than can a traditional coal-fired power plant. These two attributes imply that a power plant equipped with CCS can vary both its emissions intensity and effective capacity on an hourly basis.

Electricity generators submit price offers that establish a merit order supply curve that, along with demand, determines the equilibrium price of electricity. In the Alberta market, generators are forbidden from physically withholding capacity - that is all capacity must be made available in each hour, within the minimum and maximum price parameters established in a given market. The addition of a CCS unit to a power plant creates a new player with an effective capacity withholding decision in each hour, which could be manipulated to extract rents through market power.

Recent developments in Alberta have suggested that this endogenous capacity decision could have real impacts for electricity markets. For example, the proposed Project Pioneer in Alberta was to be equipped with post-combustion technology which could, when operational, reduce flue gas emissions by up to 90%, however the aggregate emissions reductions forecast from the Keephills 3 coal plant were expected to be only 31%.[1] The operational strategy would likely have seen TransAlta operate the CCS unit during low-

[1] See `http://www.capitalpower.com/MediaRoom/newsreleases/2009-news-releases/Pages/101409.aspx`.

price times, while the unit would be shut down to allow more energy to be sent to the grid during high-price times. The decision point of when to shut down CCS and operate at full capacity is the focus of this chapter. If firms internalize the impact of this decision on market price, the addition of CCS to the grid is likely to increase market power rents and thus increase deadweight loss. Conversely, increased CCS use also leads to lower levels of polluting emissions.

There will be an important role for environmental policy in this model. A carbon tax (or a similar measure, such as a tradeable quota on emissions) places a marginal cost on emissions, providing an incentive for emissions reductions. A sufficiently high carbon price would lead a firm to always operate the CCS unit. However, as electricity prices tend to vary throughout the day, for a given carbon price, it may be optimal to operate the CCS unit only at low-price times. Regardless, the carbon price and the potential gains from capacity withholding interact in an important way: if the firm can gain from capacity withholding through CCS, it may operate the CCS unit even if its marginal cost of operation is higher than the carbon price.

We examine the impact of CCS disclosure in the market - we ask whether there is a material change if firms are required to declare their CCS decisions in advance, thus allowing competing suppliers to optimize their price offers accordingly. This is accomplished by studying sequential games both with and without a mandatory announcement of a firm's intention to engage in CCS or not, followed by private offer decisions. Without a pre-announced

CCS decision, we were unable to solve for a firm's equilibrium CCS decision. In such cases, a mandated disclosure could remove the uncertainty.

Finally, this chapter considers whether a uniform or discriminatory auction would be more conducive for firms to engage in CCS. The literature draws various conclusions on which auction format yields lower prices or higher efficiency; the option of CCS adds to the discussion on capacity withholding incentives under each format.

Our conclusions present regulators with countervailing incentives. We show that rents from the exercise of market power may accompany CCS expansion in the market. This means that emissions abatement would occur with otherwise less stringent GHG policies. However, this dual incentive to deploy CCS does not imply that emissions abatement becomes cheaper, only that different entities pay the costs. We show that regulators can improve outcomes in terms of the exercise of market power, but argue that this will have negative implications for emissions and positive implications for electricity prices.

In what follows, Section 2.2 reviews the relevant literature, Section 2.3 sets up a theoretical model, with an overview of the merit order structure, demand, bidding, timing, and equilibrium. Section 2.4 derives the firms' bidding functions. Section 2.5 discusses the concept of equilibrium for the different types of games considered, including the role of the carbon tax. Section 2.6 shows results on which equilibria will hold under which conditions, and conducts sensitivity analysis of the model's parameters. Section 2.7 concludes.

2.2 Literature Review

The existing literature on electricity firms' auction behaviour deals with firms making pre-auction decisions that will affect their payoffs in the auction process itself. Crampes and Creti (2003) consider a market where generators choose capacity levels, and then engage in a uniform-price auction. Withholding is likely when demand is low or medium, especially when the uniform auction yields a high markup. There may also be inefficiency if a high-cost generator produces first due to non-competitive pricing. Mougeot and Naegelen (2005) study firms that must compete for the right to serve the market as an oligopolist by bidding for licenses. More competition in the market entails less competition for the market, and there is also a tradeoff between auction revenue and competition in the market.

Other papers look at the likelihood of capacity withholding in a Cournot quantity competition setting. Borenstein and Bushnell (1999) and Brennan (2002) show that market power measures such as the Herfindahl-Hirschman index or the Lerner index are flawed, because they ignore aspects of the market such as elasticities and fixed costs. For example, the ability to raise price by withholding capacity decreases if electricity demand elasticity increases, or if large generators divest their assets. Green (2004) considers generators that may have incentive to withhold capacity, such as a multi-unit owner trying to make an expensive unit marginal, or a peaking plant during off-peak hours. He finds little evidence of withholding for the purposes of raising price.

Wolfram (1997) and von der Fehr and Harbord (1992) qualify the equilibrium in multi-unit auctions where one firm owns more than one unit of capacity. Any firm that has a positive probability of being marginal has incentive to increase its price offer to just undercut the firm with the next highest offer, thus obtaining a higher price on the same amount of capacity. The firm with the next highest offer then wants to undercut the first firm and become marginal. There is a tradeoff from making high offers: the firm receives a higher price if marginal, but risks pricing itself out of the market. The conclusion is that, if the support of demand is sufficiently large, then there is no pure strategy equilibrium. Firms play a mixed strategy in which they randomize via price offer functions that are best responses to other firms' offer functions.

Electricity generators also show evidence of strategic bidding if one firm owns several generators. The aforementioned Wolfram (1997) establishes a bidding function for a multi-unit owner. Results suggest that high cost units have higher markups, large firms offer higher than small firms (in both cases because those units have more inframarginal capacity), and a firm offers higher on a given unit if it also owns the units running before it. Strategic offers can be inefficient if small, high cost generators run because bigger generators offer too high. von der Fehr and Harbord (1993) also predict how firms will bid based on the demand level. Price tends to be lower when there are many generators, since the smaller chance of being marginal causes generators to make lower offers (to ensure they are in the market). Moreover, with multi-unit owners, prices are higher because firms internalize the effects of higher offers (implicit collusion between a given firm's different generators).

The Alberta electricity market has a uniform auction, while England and Wales employ the discriminatory auction. There is debate over which auction format yields lower prices and increased competition/decreased market power. Wolfram (1999), Kahn and al. (2001) and Mukerji et al. (2008) argue in favour of the uniform price auction. The discriminatory auction will not yield lower prices but will have higher transaction costs, as firms try to guess the system marginal price and offer just below to maximize their price (without marginal cost offers, a high-cost firm may be dispatched before a low-cost one). Mukerji et al. (2008) further conclude that discriminatory auctions will at best have no effect on price; at worst they lead to inefficiency.

Fabra (2003) and Fabra et al. (2006) consider both auction formats, and find that the discriminatory auction has weakly lower prices, but effects on efficiency are ambiguous. Ausubel et al. (2014) find the discriminatory auction is more efficient and yields higher revenue with symmetric bidders, and uniform auctions are susceptible to demand reduction as a method to increase the price received by all dispatched units. The simulation of the England and Wales market in Bower and Bunn (2001) shows that the discriminatory prices can be higher in the long run because of higher baseload firm offers, which also ease the competitive pressure on the marginal plant.

Fabra (2003) looks at the sustainability of collusion in a repeated auction.

Since low offers don't affect payoffs in the uniform auction equilibrium, they can be used to prevent undercutting, yielding higher collusive profits than the discriminatory auction, where in equilibrium firms offer symmetrically high. Collusion is easier to detect in the discriminatory auction, since with a low probability of firms making identical offers, observing ties is a sign of cooperative behaviour.

Bushnell and Oren (1994) look at electricity firms' incentive to invest in generation in the presence of an environmental adder (a tax or subsidy that internalizes the environmental costs of generation). The adders are shown to affect not only the investment incentives, but also the operation of the resulting market through firms' strategic behaviour; hence the regulator must be willing to have the adder affect both processes if it is to be used at all. Cason and Gangadharan (2005) compare a uniform and discriminative auction when owners of a nondescript pollution abatement bid to have their goods purchased by a buyer. While the uniform auction encourages marginal cost bidding, the discriminative auction yields higher market performance (when environmental quality and overpayments are accounted for).

The literature examines market power in electricity markets, incentives for economic withholding and efficiency outcomes under different assumptions about the auction format. Our contribution is to consider the potential for firms to withhold capacity through on-site load and CCS, which allow firms a new flexibility to offer or withdraw a block of capacity into/from the market on an hourly basis.

2.3 A model of carbon capture and electricity

Our static model focuses on a single hour; as such, we would view the day as 24 instances of a static game. This assumption is reasonable because the main exogenous hourly variable that affects firm behaviour, demand, will be accounted for with parameters based on data. The market actors are two electricity firms, one with the capability to capture carbon emissions through CCS technology and one without. Demand for electricity is exogenous, and environmental policy exists in the form of a carbon tax.

2.3.1 The firms

There are two risk-neutral fossil fuel firms: firm 1, who can engage in CCS if desired, and firm 2, who cannot. While the decision to install the CCS technology is not considered, the two firms in this model reflect the possibility that some will make the investment and others will not. We incorporate the CCS decision through firm 1's ability to reduce its sellable capacity by some amount by turning on CCS, which reduces carbon emissions. Besides firm 1's ability to engage in CCS, the two firms are otherwise identical (this helps isolate the effect of CCS on firms' behaviour).

Both firms have the same total capacity in the absence of CCS, normalized to 1. The CCS emissions capture ratio is $\delta \in (0, 1)$, such that a percentage $1-\delta$ of total emissions escapes when CCS is on (and the emitting firm must still make a carbon tax payment on that amount). When firm 1 engages in CCS, the energy penalty is $\gamma \in (0, 1)$, such that firm 1's full capacity, normalized to 1 under no-CCS, becomes $(1 - \gamma)$ with CCS, with proportion γ of capacity assumed to be used to power the CCS unit. For simplicity, we assume that the foregone capacity is the only cost incurred to operate the CCS unit in a given hour, with no incremental capital nor operational costs. The unit generating cost is c, and the emissions intensity in units of carbon per unit of electrical output is i, and the carbon tax is t. The parameters γ, δ, c, i and t are exogenous, with the latter three common to both firms.

Firm 1 will have different realized profits depending on whether or not it engages in CCS. The firms' realized profits, conditional on being dispatched, are:

$$\Pi_{1n} = \Pi_2 = p - c - ti \tag{2.1}$$

$$\Pi_{1c} = p(1 - \gamma) - c - ti(1 - \delta). \tag{2.2}$$

In all that follows, the subscript $1n$ on a given function denotes a function for firm 1 when it does not do CCS, and $1c$ denotes the CCS case. Firm 2's realized profit, Π_2, is the same as firm 1's when the latter does not do CCS. In equation (2.2), firm 1 is doing CCS, and earns revenue on the quantity $1 - \gamma$ while paying the carbon tax on emissions $1 - \delta$. The p refers to a price that could equal either firm 1's own offer or firm 2's, depending on the auction format (uniform or discriminatory) and on the merit order.

In a competitive market, taking prices as given, firm 1 will engage in CCS if $\Pi_{1c} > \Pi_{1n}$. Denote the price facing the competitive firm by p^{comp}. The threshold carbon tax above which CCS is profitable is:

$$t > \frac{p^{\text{comp}}\gamma}{i\delta}. \tag{2.3}$$

A price-taking competitive firm would engage in CCS if equation (2.3) holds.

If firm 1 has market power, it will internalize the fact that it can raise price through CCS and capacity withholding. Denote the market price when this market power is present by p^{mp}, where $p^{\text{mp}} \geq p^{\text{comp}}$. Under this scenario, firm 1 engages in CCS if:

$$p^{\text{mp}}(1-\gamma) - ti(1-\delta) \geq p^{\text{comp}} - ti. \tag{2.4}$$

And the threshold carbon tax becomes:

$$t \geq \frac{p^{\text{comp}} - p^{\text{mp}}(1-\gamma)}{i\delta}. \tag{2.5}$$

The threshold in equation (2.5) is positive if $\gamma \geq 1 - \frac{p^{\text{comp}}}{p^{\text{mp}}}$. In other words, if the share of production lost to the deployment of CCS is less than the relative increase in price, it will always be optimal to engage in CCS for price reasons alone. The critical value of the carbon price required to induce a firm to engage in CCS is decreasing in δ, the share of emissions captured, and increasing in γ, the opportunity cost of CCS.

2.3.2 Demand

Demand is stochastic but perfectly inelastic. This is a common assumption in electricity literature (see for example Wolak (2001), which deals with the

Australian National Electricity Market), and is not far removed from reality, as shown in MSA (2010a). For simplicity, assume that demand is discrete, and lies in one of four possible intervals in the merit order, discussed below. The von der Fehr and Harbord (1993) and Wolfram (1997) papers on which this model is based also employ discrete demand distributions.

In the Alberta electricity market, if there is not sufficient demand to dispatch an entire generation unit, then it will be partially dispatched if it is "flexible". We will assume that if a 100 MW unit is offered at a single price but there is only sufficient demand for 25 or 75 of those MWs, then the unit has the flexibility to supply either of those quantities but no others, other than being dispatched in full (the reason for this will be made clear in Section 2.3.3). The assumption that a firm can only offer (and be paid for) discrete quantities will magnify the effect of capacity withholding through CCS, as a given block of capacity will either be completely dispatched or not at all.

Demand is drawn randomly from a known distribution and firms' price offers are sorted from lowest to highest price to form a merit order. Define the probabilities that demand d falls within each region at a given hour as follows:

$$\pi_1 = \Pr(0 \leq d \leq 1 - \gamma)$$

$$\pi_2 = \Pr(1 - \gamma < d \leq 1)$$

$$\pi_3 = \Pr(1 < d \leq 2 - \gamma)$$

$$\pi_4 = \Pr(2 - \gamma < d \leq 2).$$

Impose the condition $\pi_1 + \pi_2 + \pi_3 + \pi_4 = 1$. These four probabilities exogenously determine where demand lies within the [0,2] interval, and constitute the discrete demand distribution and firms' beliefs therein (meaning both firms believe there is a π_1 chance demand will lie in region 1, etc.). Recall that, from a given firm's perspective, realized demand will be one of the quantities $1-\gamma$, 1, $2-\gamma$, or 2 (occurring with respective probabilities π_1, π_2, π_3 and π_4), to ensure that the marginal firm's supply meets residual demand.

The discrete demand assumption will matter if expected profits are non-linear in demand (which they will be in this model). Under linearity, Jensen's inequality holds for two discrete demand points: the expected profits at the average of those two points equals the average of the expected profits at each point. But with non-linearity they are not equal, hence the limitation of our model and others that make this assumption; we make it nonetheless for the reasons outlined above.

2.3.3 The electricity market

The market clearing mechanism is a multi-unit auction in which each firm must offer their entire sellable capacity in a single block at a price of their choosing; the auction formats considered are uniform and discriminatory. Price offers are bounded by a (non-binding) minimum offer price of 0, and an import offering price which provides an effective price ceiling.

The market settles as follows: the lowest-priced block which allows the market to clear sets the price and all blocks offered at higher prices are not sold. All blocks offered below the market price receive the market price in the uniform auction, or their own price offer in the discriminatory auction. Our assumption of a single capacity block per firm further motivates withholding incentives, as the CCS capacity fraction is either entirely in the market or out.

The interaction of CCS, price offers, and stochastic demand is formalized as follows. Consider a merit order with the two aforementioned firms: firm 1 has the option of CCS, firm 2 does not. In the absence of CCS, each firm has one unit of flexible capacity and aggregate supply is 2. If firm 1 does CCS, aggregate supply is $(1-\gamma)+1=2-\gamma$, with any residual demand being supplied by imports in both cases. Firms submit price offers $p \in [0, \bar{p}]$, where $\bar{p}$ is an exogenous maximum import price.

Figures 2.1 and 2.2 show the *ex post* merit order when firm 1 offers respectively higher and lower than firm 2. When firm 1 engages in CCS and reduces output by γ, the merit order to the right of firm 1 shifts leftward by γ, the amount of the withheld capacity. In Figure 2.1, if demand is greater than $2-\gamma$ then CCS on firm 1's part creates excess demand at p_1, which is filled by the import price's supply. In Figure 2.2 there are two such regions of the merit order where CCS can create excess demand, the left one of which would be filled by firm 2.

In the merit order in Figure 2.1, firm 1 is offering higher. If demand lies in the region between the aggregate supply levels $2-\gamma$ and 2, in the uniform auction firm 1 can increase price by doing CCS, as the leftward contraction of

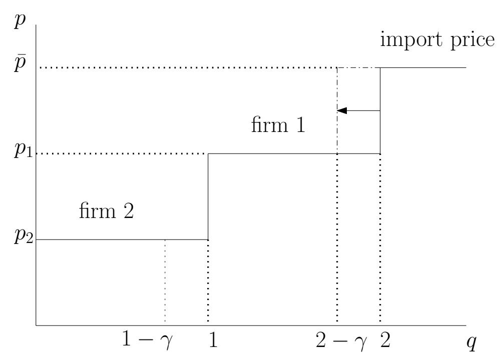

Figure 2.1: Firm 1 offers higher

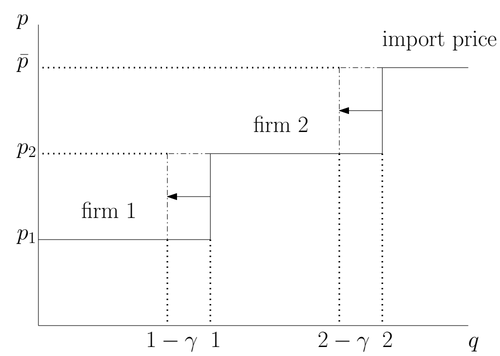

Figure 2.2: Firm 1 offers lower

the merit order to the right of firm 1 shifts the intersection of the merit order with demand from p_1 to $\bar{p}$.

When firm 1 offers lower than firm 2 as in Figure 2.2, there are two regions where, if demand falls within either of them, CCS on firm 1's part will raise price in the uniform auction. In Figure 2.1 CCS will raise price only if firm 1 is marginal (that is if firm 1 is the price-setter); in Figure 2.2 this can happen regardless of which firm is marginal.

Demand d will fall within one of four regions in the merit order depending on which firm makes the higher offer. When firm 1 makes a higher offer as in Figure 2.3, region 4 is the region where CCS can raise price if demand lies there. If firm 2 makes a lower offer as in Figure 2.4 then there are two such regions, 2 and 4.

In the discriminatory auction, when demand is in region 2 in 2.4 and firm 1 engages in CCS, firm 2 is marginal and receives price p_2, while firm 1 continues to receive p_1.

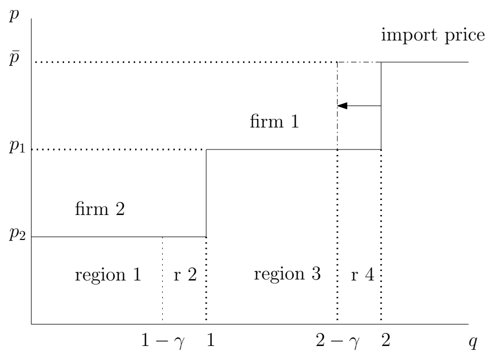

Figure 2.3: Demand regions (1 offers higher)

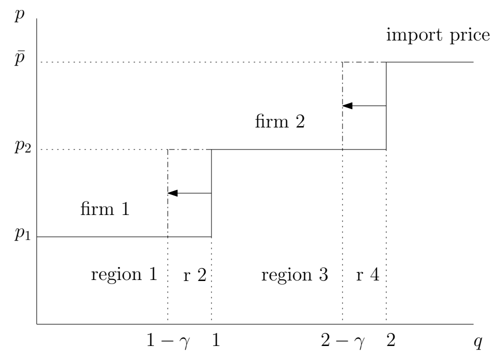

Figure 2.4: Demand regions (1 offers lower)

Market outcomes

Looking at Figures 2.3 and 2.4, the following will happen in the uniform auction if demand falls respectively in each of the four regions:

1. In region 1, the firm with the lower offer is marginal regardless of firm 1's CCS decision and produces $1-\gamma$ units, and the other firm is not dispatched. The only determining factor is who makes the lower offer.

2. In region 2, if CCS is off the lower firm produces at full capacity and the higher one is not dispatched, and likewise if CCS is on and firm 2 offers lower. If CCS is on and firm 1 offers lower, it produces $1-\gamma$ units while firm 2 is marginal and produces γ units.

3. In region 3, both firms are dispatched and the higher one is marginal. Under CCS firm 1 produces $1-\gamma$ and firm 2 produces 1; under no-CCS the higher firm is at partial capacity.

4. In region 4 both firms are in the market. Under CCS both firms receive

the same price $\bar{p}$ and offering higher/lower than the other firm does not affect anything. Under no-CCS both firms receive the higher offer as price, and the only determining factor is who offers higher.

Region 2 presents the widest range of possible outcomes. Namely, firm 1's CCS decision and who offers higher/lower will jointly determine both who is dispatched and who is marginal. Region 3 presents a narrower range, as the CCS decision affects neither who is dispatched nor the fact that the higher offering firm is marginal, though it does affect individual capacities. Regions 1 and 4 are of intermediate variability, though there does not seem to be an objective way to rank them against each other.

The reason for the flexibility assumption in Section 2.3.2 has to do with point 2 above: when demand is in region 2, CCS from a low-offering firm 1 would cause demand to rise from $1-\gamma$ to $2-\gamma$ in order to accommodate firm 2's capacity if the latter is inflexible. The assumption that firm 2 can supply either γ units or 1 unit allows demand to remain independent of firm 1's CCS decision. And for consistency, when demand is in region 1 the marginal firm only produces $1-\gamma$.

In practice, firms can reduce their exposure to the real-time price of electricity through forward contracts, which lock down the future price received for a block of capacity. Hence forward contracts would reduce incentive for market power and capacity withholding. Because this model analyzes strategic behaviour, we assume away contract cover to increase firms' incentive for static market power.

2.3.4 The game: a one-shot electricity market auction

Timing

We consider a static model of CCS, where firm 1 is deciding in a given hour whether or not to engage in CCS, and what price offer to make. We do not consider the initial decision to invest or not in CCS technology, and start from a state where firm 1 has the technology installed and firm 2 does not.

There are two possible timing structures: one where firm 1 makes a publicly-known and binding CCS decision before firms choose price offers, and one where it makes a privately-known CCS decision before firms choose offers. In the first case, firm 2 knows the CCS decision before offering; in the second case it does not.

If firm 1 announces the CCS decision, then firm 2 knows if CCS is on or off by the time they (simultaneously) choose their respective offers. At the top of the game tree in Figure 2.5, firm 1 makes a publicly-known decision: CCS or no-CCS. Firm 1 then chooses a privately-known price offer p_1, while firm 2 chooses its own privately-known offer p_2. Offers p_1 and p_2 are each chosen from a continuum of available bids. If the game were repeated many times, the firms could randomize their offers according to some offer function, or they could play the same offer over and over again.

Figure 2.6 shows the game without announcement. Firm 1 makes a CCS decision and a price offer choice, and firm 2 chooses its own price offer without

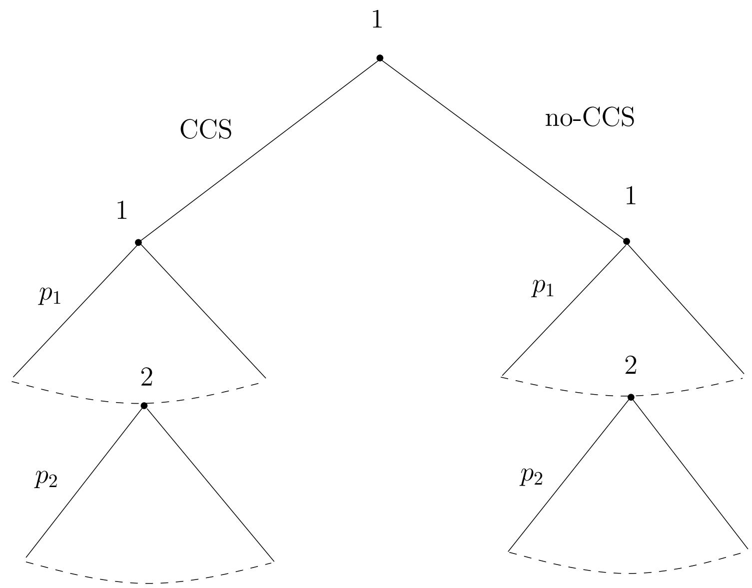

Figure 2.5: Game with announcement

knowing firm 1's actions. Firm 1 is no longer committed to a given CCS decision, and can freely choose whether or not to engage in CCS without firm 2 knowing.

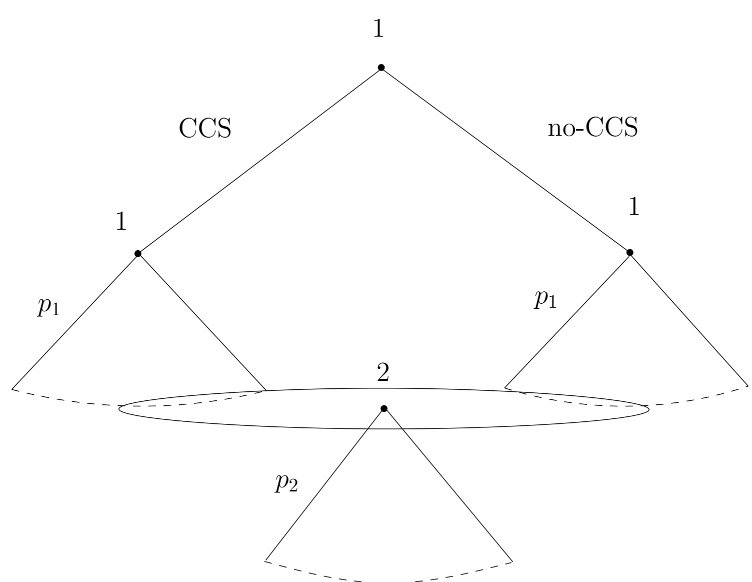

Figure 2.6: Game without announcement

The equilibrium concept will depend on the game. With the announcement in Figure 2.5, there will be a subgame-perfect Nash equilibrium (SPNE), because there are two subgames (in addition to the full game). And without the announcement in Figure 2.6, which has only one subgame, there will be a Nash equilibrium. Equilibrium actions involve a CCS decision from firm 1 (which may be randomized) and offer functions.

The nature of market power

Market power is exercised through firm 1's ability to affect the market price of electricity through its actions. Namely, by restricting its output, firm 1 can raise the price if conditions are right. Firm 1 also has an asymmetric information advantage in the game without announcement in Figure 2.6. Firm 1 has both knowledge of and control over its CCS decision, and may deviate from a given decision without firm 2 knowing. The information advantage is a strategic variable in firm 1's decision-making process rather than an instance of market power, since it does not directly involve price, and can be neutralized with a mandatory announcement of the CCS decision (Figure 2.5).

2.4 The firms' problems

Section 2.4.1 motivates the decision to model firms' offers as mixed strategies. Sections 2.4.2 and 2.4.3 cover the respective cases where firm 1 announces its intention to engage in no-CCS or in CCS, for both the uniform and discriminatory auctions. In Section 2.4.4 firm 1 makes no announcement.

2.4.1 Mixed strategy motivation

Firms are assumed to draw randomized price offers. Figure 2.7 shows an example of firm offer behaviour, with average hourly price offers for Sundance generators over a one-week period in October 2011 (data are from the AESO website). The Sundance power station is a coal plant owned by TransAlta located near Edmonton. Each curve represents average hourly offers for a given day. While some generators tend to make consistent offers, Sundance's offer behaviour in Figure 2.7 also exhibits variation throughout the day. The apparent randomness in price offers motivates our use of price offer distributions.

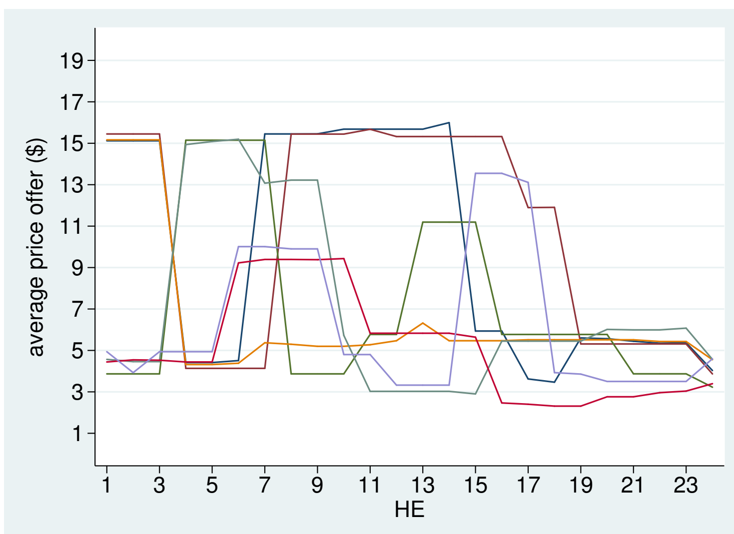

Figure 2.7: Sundance average daily price offers, October 9-15, 2011

In von der Fehr and Harbord (1993), if the support of demand exceeds the greater of the two firms' capacities, then there is shown to be no pure strategy equilibrium because of the tradeoff from offering high or low: the market price conditional on dispatch is weighed against the probability of dispatch. Indeed, for firms i and j, common marginal cost c and price cap $\bar{p}$, the following pure strategy scenarios cannot be equilibria:[2]

1. $p_i = p_j > c$: Firm i should slightly undercut j to gain the whole market with a negligible change in price; j should then undercut i for the same reason, etc.

2. $p_i = p_j = c$: Firm i should increase its offer to $\bar{p}$ to earn a high price on residual demand in the event it is marginal (which can happen since demand is variable).

3. $c \leq p_i < p_j \leq \bar{p}$: Firm i should unilaterally undercut j by a small amount to increase the expected price without affecting dispatch; for sufficiently close p_i and p_j, j could undercut i to increase its dispatch probability with a negligible change in price.

Our model is therefore in mixed strategies; however we do not show whether the mixed equilibrium is unique.

2.4.2 Firm 1 announces it will not engage in CCS

Uniform auction

Following von der Fehr and Harbord (1992) and Wolfram (1997), we start with the expected profit function as a function of p for firm 2 when firm 1 does not do CCS, denoted by $\Phi_{2n}(p)$. Expectation is over demand and firm

[2]Since this proof has been addressed in the literature, we simply provide a brief outline. Adding a carbon tax to this example would yield a similar result.

1's price offer. Firm 2 cannot control whether firm 1 engages in CCS, however that decision will affect 2's expected profit function. If firm 1 does not do CCS, then taking into account the demand distribution, firm 1's price offer distribution $F_1(p)$ and equation (2.1) on page 38, firm 2's expected profit in the uniform auction is

$$\begin{aligned}\Phi_{2n}^{UA}(p) =& (\pi_1(1-\gamma)+\pi_2)(1-F_1(p))(p-c-ti) \\ &+ \pi_3\left[F_1(p)(1-\gamma)(p-c-ti) + \int_p^{\bar{p}} (x-c-ti) f_1(x)\,dx\right] \\ &+ \pi_4\left[F_1(p)(p-c-ti) + \int_p^{\bar{p}} (x-c-ti) f_1(x)\,dx\right]. \end{aligned} \tag{2.6}$$

Equation (2.6) shows the realized profits from (2.1) weighted by the probabilities of those realizations. Looking at the first line in (2.6), the realized profit $(1-\gamma)(p-c-ti)$ is weighted by π_1, the probability that demand lies in region 1, times $1-F_1(p)$, the probability that firm 2 offers lower than firm 1.[3] The expression $\pi_1(1-F_1(p))$ is thus the probability that firm 2 is marginal in region 1, hence in the market and earning the associated realized profit.

Firm 1's profit without CCS is symmetrical to (2.6):

$$\begin{aligned}\Phi_{1n}^{UA}(p) =& (\pi_1(1-\gamma)+\pi_2)(1-F_2(p))(p-c-ti) \\ &+ \pi_3\left[F_2(p)(1-\gamma)(p-c-ti) + \int_p^{\bar{p}} (x-c-ti) f_2(x)\,dx\right] \\ &+ \pi_4\left[F_2(p)(p-c-ti) + \int_p^{\bar{p}} (x-c-ti) f_2(x)\,dx\right]. \end{aligned} \tag{2.7}$$

When firm 1 does not engage in CCS, the derivative of equation (2.7) with

[3]Recall that $F_1(p)$ is firm 1's offer function, and gives the probability that firm 1 offers lower than some p chosen by firm 2.

respect to p set equal to 0 yields:

$$\begin{aligned} f_2(p)+&\frac{(\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4}{(\pi_1(1-\gamma)+\pi_2+\pi_3\gamma)(p-c-ti)}F_2(p) \\ &= \frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1(1-\gamma)+\pi_2+\pi_3\gamma)(p-c-ti)}. \end{aligned} \tag{2.8}$$

Solving the linear differential equation in (2.8) yields the following when $(\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4 \neq 0$:

$$F_2(p) = \frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4} + (p-c-ti)^{\frac{(\pi_3-\pi_1)(1-\gamma)+\pi_4-\pi_2}{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma}} \cdot \kappa, \tag{2.9}$$

where κ is the constant of integration. And when $(\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4 = 0$, the integral of (2.8) yields:

$$F_2(p) = \frac{\pi_1(1-\gamma)+\pi_2}{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma} \cdot (\ln(p-c-ti)+\kappa). \tag{2.10}$$

Imposing $F_2(\bar{p}) = 1$ to solve for the constant κ in equations (2.9) and (2.10) yields the following price offer distribution:

$$F_{2n}^{UA}(p) = \begin{cases} \frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4} - \frac{\pi_3(1-\gamma)+\pi_4}{(\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4}\left(\frac{p-c-ti}{\bar{p}-c-ti}\right)^{\frac{(\pi_3-\pi_1)(1-\gamma)+\pi_4-\pi_2}{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma}} \\ \quad \text{if } (\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4 \neq 0 \\ \frac{\pi_1(1-\gamma)+\pi_2}{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma} \cdot \ln\left(\frac{p-c-ti}{\bar{p}-c-ti}\right) + 1 \\ \quad \text{if } (\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4 = 0. \end{cases} \tag{2.11}$$

Under no-CCS, there will be some price offer $p_{m,n} \geq 0$ below which firm 2 will not offer, and thus $p \in [p_{m,n}, \bar{p}]$ (see von der Fehr and Harbord (1992)). Since $F_{2n}^{UA}(p_{m,n}) = 0$ by definition, from (2.11) it is seen that:

$$p_{m,n}^{UA} = \begin{cases} \left(\frac{\pi_1(1-\gamma)+\pi_2}{\pi_3(1-\gamma)+\pi_4}\right)^{\frac{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma}{(\pi_3-\pi_1)(1-\gamma)+\pi_4-\pi_2}} (\bar{p}-c-ti)+c+ti \\ \quad \text{if } (\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4 \neq 0 \\ \frac{\bar{p}-c-ti}{\exp\left(\frac{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma}{\pi_1(1-\gamma)+\pi_2}\right)} + c + ti \\ \quad \text{if } (\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4 = 0. \end{cases} \tag{2.12}$$

Since firm 2 has a symmetrical expected profit function to 1's when CCS is off (see equations (2.6) and (2.7)), the equilibrium solution for $F_{1n}^{UA}(p)$ is the same as (2.11). Thus $F_{2n}^{UA}(p) = F_{1n}^{UA}(p)$, and both firms draw from the same price offer distribution when CCS is off.

Discriminatory auction

In the discriminatory auction with CCS off, firm 1's expected profit is:

$$\Phi_{1n}^{DA}(p) = [\pi_1(1-\gamma)+\pi_2+\pi_3)(1-F_2(p))+\pi_3(1-\gamma)F_2(p)+\pi_4](p-c-ti). \quad (2.13)$$

Firm 1 earns its own offer whenever dispatched, regardless of who is marginal. When firm 1 offers lower, it is dispatched at partial capacity when demand is in region 1, and at full capacity when it is in 2 or 3. With the higher offer, firm 1 is dispatched at partial capacity when demand is in region 3. When demand is in region 4 firm 1 is dispatched at full capacity in all offer scenarios. Firm 2's expected profit is symmetrical to (2.13). The resulting offer function is:

$$F_{2n}^{DA}(p) = \frac{1-\pi_1\gamma}{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma} - \frac{\pi_3(1-\gamma)+\pi_4}{\pi_1(1-\gamma)+\pi_2+\pi_3\gamma} \cdot \frac{\bar{p}-c-ti}{p-c-ti}. \quad (2.14)$$

Firm 1's function $F_{1n}^{DA}(p)$ is symmetrical to (2.14).

Imposing $F_{2n}^{DA}(p_{m,n}) = 0$ on (2.14) yields the lower bound price offer for both firms:

$$p_{m,n}^{DA} = \frac{\pi_3(1-\gamma)+\pi_4}{1-\pi_1\gamma}(\bar{p}-c-ti)+c+ti. \quad (2.15)$$

In equilibrium, the discriminatory auction's lower bound offer is higher than the uniform one.

2.4.3 Firm 1 announces it will engage in CCS

Uniform auction

When firm 1 engages in CCS, its profit in the uniform auction is:

$$\begin{aligned}\Phi_{1c}^{UA}(p) =& \pi_1(1 - F_2(p))[p(1-\gamma) - c - ti(1-\delta)] \\ &+ (\pi_2 + \pi_3)\int_p^{\bar{p}} [x(1-\gamma) - c - ti(1-\delta)] f_2(x) dx \\ &+ \pi_3 F_2(p)(p(1-\gamma) - c - ti(1-\delta)) \\ &+ \pi_4[\bar{p}(1-\gamma) - c - ti(1-\delta)]. \end{aligned} \tag{2.16}$$

Firm 1 pays the generation cost on the full capacity when doing CCS, and pays the carbon tax on residual emissions as a fraction of total generating capacity (not as a fraction of the reduced CCS capacity).

When firm 1 does CCS, 2's expected profit becomes:

$$\begin{aligned}\Phi_{2c}^{UA}(p) =& [(\pi_1(1-\gamma) + \pi_2)(1 - F_1(p)) + (\pi_2\gamma + \pi_3)F_1(p)](p - c - ti) \\ &+ \pi_3 \int_p^{\bar{p}} (x - c - ti) f_1(x)\, dx + \pi_4(\bar{p} - c - ti). \end{aligned} \tag{2.17}$$

Firm 2 cannot choose between the expected profit functions (2.6) and (2.17), since it cannot directly control 1's CCS decision.[4]

The derivative of equation (2.17) set equal to 0 is:

$$f_1(p) + \frac{(\pi_1 + \pi_2)(1-\gamma) - \pi_3}{(\pi_1 + \pi_2)(1-\gamma)(p - c - ti)} F_1(p) = \frac{\pi_1(1-\gamma) + \pi_2}{(\pi_1 + \pi_2)(1-\gamma)(p - c - ti)}. \tag{2.18}$$

[4] If firm 1 must publicly declare the CCS decision beforehand, 2 knows which of the two expected profit functions it faces before choosing a price offer.

Solving the linear differential equation yields the following respectively when $(\pi_1+\pi_2)(1-\gamma)-\pi_3 \neq 0$ and $(\pi_1+\pi_2)(1-\gamma)-\pi_3 = 0$:

$$F_1(p) = \frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1+\pi_2)(1-\gamma)-\pi_3} + (p-c-ti)^{\frac{(\pi_1+\pi_2)(1-\gamma)-\pi_3}{(\pi_1+\pi_2)(1-\gamma)}} \cdot \kappa, \tag{2.19}$$

$$F_1(p) = \frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1+\pi_2)(1-\gamma)}(\ln(p-c-ti)+\kappa). \tag{2.20}$$

Imposing $F_1(\bar{p}) = 1$ to solve for κ yields the following offer function for firm 1:

$$F_{1c}^{UA}(p) = \begin{cases} \frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1+\pi_2)(1-\gamma)-\pi_3} - \frac{\pi_2\gamma+\pi_3}{(\pi_1+\pi_2)(1-\gamma)-\pi_3}\left(\frac{p-c-ti}{\bar{p}-c-ti}\right)^{\frac{\pi_3-(\pi_1+\pi_2)(1-\gamma)}{(\pi_1+\pi_2)(1-\gamma)}} \\ \quad \text{if } (\pi_1+\pi_2)(1-\gamma)-\pi_3 \neq 0 \text{ and } p \geq \frac{c+(1-\delta)ti}{1-\gamma} \\ \frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1+\pi_2)(1-\gamma)} \cdot \ln\left(\frac{p-c-ti}{\bar{p}-c-ti}\right) + 1 \\ \quad \text{if } (\pi_1+\pi_2)(1-\gamma)-\pi_3 = 0 \text{ and } p \geq \frac{c+(1-\delta)ti}{1-\gamma}. \end{cases} \tag{2.21}$$

In equilibrium firm 2, the bigger firm, will have a mass point at $\bar{p}$, hence the lower bound on price offers will be such that $p_m > c+ti$, where $c+ti$ is firm 2's cost. Because firm 1 cannot offer below its own unit cost $\frac{c+(1-\delta)ti}{1-\gamma}$ in equilibrium in the event that $\frac{c+(1-\delta)ti}{1-\gamma} > c+ti$ (firm 1 has higher cost than firm 2), firm 1 will have a mass point at $\frac{c+(1-\delta)ti}{1-\gamma}$ whenever the lower bound based on firm 2's cost would make it offer lower than its own cost. Imposing $F_1(p_{m,c}) = 0$ to equation (2.21) yields the lower bound of the offer function:

$$p_{m,c}^{UA} = \begin{cases} \max\left[\left(\frac{\pi_1(1-\gamma)+\pi_2}{\pi_2\gamma+\pi_3}\right)^{\frac{(\pi_1+\pi_2)(1-\gamma)}{(\pi_1+\pi_2)(1-\gamma)-\pi_3}}(\bar{p}-c-ti)+c+ti, \frac{c+(1-\delta)ti}{1-\gamma}\right] \\ \quad \text{if } (\pi_1+\pi_2)(1-\gamma)-\pi_3 \neq 0 \\ \max\left[\frac{\bar{p}-c-ti}{\exp\left(\frac{(\pi_1+\pi_2)(1-\gamma)}{\pi_1(1-\gamma)+\pi_2}\right)}+c+ti, \frac{c+(1-\delta)ti}{1-\gamma}\right] \\ \quad \text{if } (\pi_1+\pi_2)(1-\gamma)-\pi_3 = 0. \end{cases} \tag{2.22}$$

For firm 2's offer function, set the derivative of (2.16) equal to 0:

$$\begin{aligned} f_2(p) + &\frac{(1-\gamma)(\pi_1-\pi_3)}{[p(1-\gamma)-c-(1-\delta)ti](\pi_1+\pi_2)}F_2(p) \\ &= \frac{(1-\gamma)\pi_1}{[p(1-\gamma)-c-(1-\delta)ti](\pi_1+\pi_2)}. \end{aligned} \tag{2.23}$$

Solving the linear differential equation yields the following respectively when $\pi_1 \neq \pi_3$ and $\pi_1 = \pi_3$:

$$F_2(p) = \frac{\pi_1}{\pi_1-\pi_3} + [p(1-\gamma)-c-(1-\delta)ti]^{\frac{\pi_3-\pi_1}{\pi_1+\pi_2}} \cdot \kappa, \tag{2.24}$$

$$F_2(p) = \frac{\pi_1}{\pi_1+\pi_2}(\ln(p(1-\gamma)-c-(1-\delta)ti)+\kappa). \tag{2.25}$$

Impose $F_2(p_{m,c}) = 0$, where $p_{m,c}$ is given in (2.22), and recall that firm 2 has a mass point at $\bar{p}$ (hence $F_2(\bar{p}) = 1$) to obtain firm 2's offer function:

$$F_{2c}^{UA}(p) = \begin{cases} \frac{\pi_1}{\pi_3-\pi_1}\left(\frac{p(1-\gamma)-c-(1-\delta)ti}{p_{m,c}(1-\gamma)-c-(1-\delta)ti}\right)^{\frac{\pi_3-\pi_1}{\pi_1+\pi_2}} - \frac{\pi_1}{\pi_3-\pi_1} & \text{if } \pi_1 \neq \pi_3 \text{ and } p < \bar{p} \\ \ln\left[\left(\frac{p(1-\gamma)-c-(1-\delta)ti}{p_{m,c}(1-\gamma)-c-(1-\delta)ti}\right)^{\frac{\pi_1}{\pi_1+\pi_2}}\right] & \text{if } \pi_1 = \pi_3 \text{ and } p < \bar{p}. \end{cases} \tag{2.26}$$

Thus in equilibrium with CCS on firm 1's part, firm 1 will draw from the offer function (2.21) and firm 2 will draw from (2.26). Both firms have $p_{m,c}$ given in (2.22) as a lower bound on their respective price offer supports, because they cannot have different lower bounds; the firm with the lower one would increase it to that of the other to earn higher expected profits without decreasing its chance of being in the market. The upper bound on both firms' supports is the exogenous $\bar{p}$.

Discriminatory auction

In the discriminatory auction, firm 2's profit is

$$\Phi_{2c}^{DA}(p) = [(\pi_1(1-\gamma)+\pi_2)(1-F_1(p))+\pi_2\gamma F_1(p)+\pi_3+\pi_4](p-c-ti). \quad (2.27)$$

Firm 2's probability of being in the market is the same as in the uniform auction, but in all such cases it earns its own offer regardless of which firm is marginal. Imposing $F_{1c}^{DA}(\bar{p}) = 1$, firm 1's offer function is

$$F_{1c}^{DA}(p) = \frac{1-\pi_1\gamma}{(\pi_1+\pi_2)(1-\gamma)} - \frac{1-\pi_1-\pi_2(1-\gamma)}{(\pi_1+\pi_2)(1-\gamma)} \cdot \frac{\bar{p}-c-ti}{p-c-ti}. \quad (2.28)$$

And imposing $F_{1c}^{DA}(p_{m,c}) = 0$ on (2.28) yields the lower bound offer:

$$p_{m,c}^{DA} = \frac{1-\pi_1-\pi_2(1-\gamma)}{1-\pi_1\gamma}(\bar{p}-c-ti)+c+ti. \quad (2.29)$$

Firm 1's profit is

$$\Phi_{1c}(p) = [(\pi_1+\pi_2)(1-F_2(p))+\pi_3+\pi_4][p(1-\gamma)-c-ti(1-\delta)]. \quad (2.30)$$

Firm 2's offer function is as follows, where $p_{m,c}$ is from (2.29):

$$F_{2c}^{DA}(p) = \frac{1}{\pi_1+\pi_2} - \frac{1}{\pi_1+\pi_2} \cdot \frac{p_{m,c}(1-\gamma)-c-ti(1-\delta)}{p(1-\gamma)-c-ti(1-\delta)} \quad \text{if } p < \bar{p}. \quad (2.31)$$

In the two auctions, firm 2 randomizes according to (2.26) or (2.31) with probability $\Pr(p < \bar{p})$, and has a mass point (played with strictly positive probability) at $\bar{p}$.

2.4.4 Firm 1 makes no announcement

In the game without announcement in Figure 2.6, let firm 1 engage in CCS with probability $\alpha \in (0,1)$ and in no-CCS with probability $1-\alpha$. Since firm

2 does not know which branch of the game tree it is on, it must draw from a single offer function $F_2(p)$, which is a mutual best response to firm 1's $F_{1c}(p)$ and $F_{1n}(p)$, as well as to α.

The four conditions for an equilibrium are as follow for the uniform auction.

1. Firm 1 is indifferent between CCS and no-CCS (derivative of $E(\Phi_1(p))$ with respect to α):

$$E(\Phi_1(p)) = \alpha \cdot \Phi_{1c}(p) + (1-\alpha) \cdot \Phi_{1n}(p)$$
$$\frac{\partial}{\partial \alpha} E(\Phi_1(p)) = \Phi_{1c}(p) - \Phi_{1n}(p), \text{ set equal to } 0$$
$$\Phi_{1c}(p) = \Phi_{1n}(p) \, \forall \, p \text{ in } F_{1c}(p) \text{ and } F_{1n}(p)\text{'s joint support.} \tag{2.32a}$$

2. $F_2(p)$ leaves firm 1 indifferent across its support under CCS (derivative of (2.16) set equal to 0), where $\Phi_{1c}(p)$ contains $F_2(p)$:

$$\Phi'_{1c}(p) = 0 \, \forall \, p \text{ in } F_{1c}(p)\text{'s support, or}$$
$$f_2(p) + \frac{(1-\gamma)(\pi_1 - \pi_3)}{(\pi_1+\pi_2)((1-\gamma)p - c - (1-\delta)ti)} \cdot F_2(p) = \frac{(1-\gamma)\pi_1}{(\pi_1+\pi_2)((1-\gamma)p - c - (1-\delta)ti)}. \tag{2.32b}$$

3. $F_2(p)$ leaves firm 1 indifferent across its support under no-CCS (derivative of (2.7) set equal to 0), where $\Phi_{1n}(p)$ contains $F_2(p)$:

$$\Phi'_{1n}(p) = 0 \, \forall \, p \text{ in } F_{1n}(p)\text{'s support, or}$$
$$f_2(p) + \frac{(\pi_1 - \pi_3)(1-\gamma) + \pi_2 - \pi_4}{(\pi_1(1-\gamma) + \pi_2 + \pi_3\gamma)(p - c - ti)} \cdot F_2(p) = \frac{\pi_1(1-\gamma) + \pi_2}{(\pi_1(1-\gamma) + \pi_2 + \pi_3\gamma)(p - c - ti)}. \tag{2.32c}$$

4. $F_{1c}(p)$ in $\Phi_{2c}(p)$, $F_{1n}(p)$ in $\Phi_{2n}(p)$, and α leave firm 2 indifferent across its support:

$$\frac{\partial}{\partial p}[\alpha \cdot \Phi_{2c}(p) + (1-\alpha) \cdot \Phi_{2n}(p)], \text{ set equal to } 0$$

$$\alpha \Phi'_{2c}(p) + (1-\alpha)\Phi'_{2n}(p) = 0 \,\forall\, p \text{ in } F_2(p)\text{'s support, or}$$

$$\begin{aligned}
&\alpha\left(f_{1c}(p) + \frac{(\pi_1+\pi_2)(1-\gamma)-\pi_3}{(\pi_1+\pi_2)(1-\gamma)(p-c-ti)} \cdot F_{1c}(p)\right. \\
&\quad\left. -\frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1+\pi_2)(1-\gamma)(p-c-ti)}\right) \\
&+(1-\alpha)\left(f_{1n}(p) + \frac{(\pi_1-\pi_3)(1-\gamma)+\pi_2-\pi_4}{(\pi_1(1-\gamma)+\pi_2+\pi_3\gamma)(p-c-ti)} \cdot F_{1n}(p)\right. \\
&\quad\left. -\frac{\pi_1(1-\gamma)+\pi_2}{(\pi_1(1-\gamma)+\pi_2+\pi_3\gamma)(p-c-ti)}\right) = 0. \qquad (2.32\text{d})
\end{aligned}$$

The solutions to equations (2.32a) through (2.32d) completely characterize firms' behaviour when there is no CCS announcement.

2.5 Equilibrium

The offer functions derived in 2.4 follow certain properties. Under no-CCS, $F_{1n}(p)$ and $F_{2n}(p)$ are symmetrical, by definition have an upper bound at $\bar{p}$, and share a common lower bound $p_{m,n}$; moreover, $\Pr(p < \bar{p}) = 1$ for both functions. Under CCS, $F_{1c}(p)$ is bounded above by $\bar{p}$, and below by $p_{m,c}$. Firm 1's $p_{m,c}$ will be a binding lower bound for $F_{2c}(p)$, because if firms have different lower bounds, then the firm with the lower one can profitable raise it to that of its rival without being undercut. Firm 2's function $F_{2c}(p)$ has a mass point at $\bar{p}$, hence $\Pr(p < \bar{p}) < 1$.

2.5.1 Solving the game with announcement

In Figure 2.5, firm 1 makes a pure CCS decision at the top node, then draws a price offer from an offer distribution. Firm 2, knowing the CCS decision but not firm 1's offer, draws its own offer from a distribution. The first SPNE candidate is $[(\text{CCS},\ F_{1c}(p),\ F_{1n}(p)),\ (F_{2c}(p),\ F_{2n}(p))]$, where the first set of brackets has firm 1 engaging in CCS, drawing from $F_{1c}(p)$ on the left branch of the game tree under CCS, and from $F_{1n}(p)$ on the right branch under no-CCS. The second set of brackets has firm 2 drawing from $F_{2c}(p)$ and $F_{2n}(p)$ when CCS is respectively on and off. The second SPNE candidate is $[(\text{no-CCS},\ F_{1c}(p),\ F_{1n}(p)),\ (F_{2c}(p),\ F_{2n}(p))]$, where firm 1 chooses no-CCS at the top node.

2.5.2 Solving the game without announcement

In the game without announcement in Figure 2.6, firm 1 makes a CCS decision at the top node, which may be randomized ($0 < \alpha < 1$) or not ($\alpha = 0$ or $\alpha = 1$). A pure strategy Nash equilibrium would involve: $[(\text{CCS}, F_{1c}(p), F_{1n}(p)), F_2(p)]$ or $[(\text{noCCS}, F_{1c}(p), F_{1n}(p)), F_2(p)]$. In the first one, firm 1 chooses CCS, and in the left branch of Figure 2.6 it draws from $F_{1c}(p)$, and in the right branch it plays $F_{1n}(p)$, while firm 2 plays a single function $F_2(p)$. The second candidate Nash equilibrium is analogous, with firm 1 playing no-CCS.

If the candidate Nash equilibrium with CCS on is in fact not an equilibrium, the firm 1 could make a profitable unilateral deviation to no-CCS (firm 1 could also deviate in the price offer). In the absence of a binding CCS announcement, the equilibrium still involves a CCS decision from firm 1.

Table 2.1 summarizes the candidate equilibria of the two games.

Table 2.1: Candidate equilibria of each game

Firm 1	Announcement (cand. SPNE)	No announcement (cand. NE)
CCS on	[(CCS, F_{1c}, F_{1n}), (F_{2c}, F_{2n})]	[(CCS, F_{1c}, F_{1n}), F_2]
CCS off	[(noCCS, F_{1c}, F_{1n}), (F_{2c}, F_{2n})]	[(noCCS, F_{1c}, F_{1n}), F_2]

We have not been able to solve for an analytical solution satisfying equations (2.32a) through (2.32d). Inferences can be drawn on the offer functions' functional forms. Firm 1's is expected to make higher offers under CCS than under no-CCS, as the smaller total capacity under CCS makes it likelier that either or both firms will be dispatched. Since firm 2 is reacting to both $F_{1n}(p)$ and $F_{1c}(p)$ from (2.32d), a draw from its function $F_2(p)$ is expected to fall between draws from $F_{2n}(p)$ and $F_{2c}(p)$ from the games with announcement. Meanwhile the CCS probability α is expected to be low during high demand hours when there is less CCS incentive, and high during low demand hours.

We are interested in two related questions. First, are there circumstances where both a CCS and a no-CCS equilibrium can be sustained? And second, in the latter case would it be optimal to force disclosure?

Firm 1 will make a CCS decision based on which outcome (CCS or no-CCS) yields it a higher expected profit. There will be some carbon tax value t^* below which firm 1 will not do CCS (and firms will draw from the offer functions $F_{1n}(p)$ and $F_{2n}(p)$), and above which firm 1 will do CCS (and firms draw from $F_{1c}(p)$ and $F_{2c}(p)$). Because there is a maximum price $\bar{p} < \infty$, an equilibrium will only exist if costs are low enough for a firm that is dispatched to earn positive expected profits. In a two-firm market, if there is enough demand for both firms then they will both be dispatched, and the import price will come into effect if demand exceeds both firms' combined capacities. It is conceptually possible for t to rise high enough so that a firm which is constrained on earns negative expected profits, since price (and price offers) cannot rise above $\bar{p}$ to compensate. Therefore t will be restricted to values that allow firms to earn positive expected profits when offering at (and earning) $\bar{p}$.

2.5.3 Capacity withholding

The incentive to undercut in both auctions when demand is low is shown in Figure 2.8. Firm 2 is marginal and earning p_2, while firm 1 is out of the market. But if firm 1 slightly undercuts firm 2, it captures the entire market and earns $p_1' > 0$; meanwhile for a given offer $p_1 > p_2$ from firm 1, firm 2 also wants to raise its offer to just undercut p_1. And when demand is high as in Figure 2.9, firm 1 is marginal and should raise its offer to $p_1' > p_1$ (as should firm 2 for a given p_1).

The capacity withholding aspect of CCS in the uniform auction when demand is in region 4 is illustrated in Figures 2.10 and 2.11. In Figure 2.10 firm 1 makes the higher offer. A sufficient (but not necessary) condition for firm 1 to engage in CCS is for the extra profit from the higher price to exceed

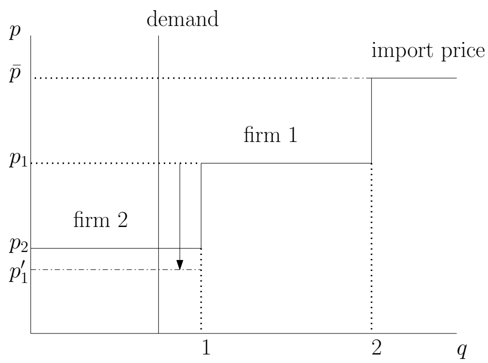

Figure 2.8: Low demand: undercut

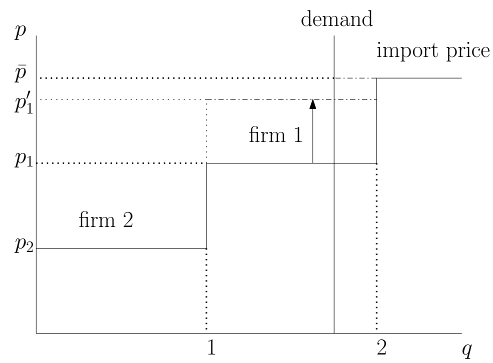

Figure 2.9: High demand: offer higher

the lost profit from foregone capacity.[5] So from a capacity withholding viewpoint, CCS is profitable if earning the higher price $\bar{p}$ on the reduced quantity $2-\gamma-1 = 1-\gamma$ is greater than earning the lower price p_1 on the full quantity of 1. Or put differently, area a is greater than area b. Likewise when firm 1 makes the lower offer as in Figure 2.11, the sufficient condition for CCS is for area a to exceed area $b+c$. A similar reasoning applies to the case where demand is in region 2.

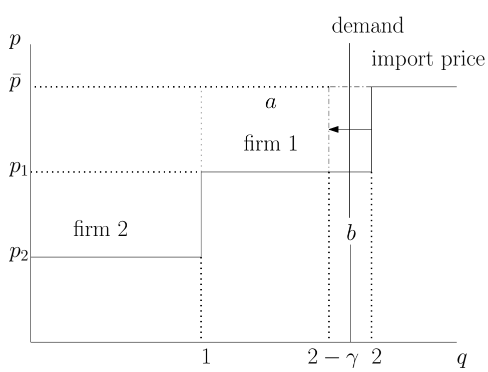

Figure 2.10: Capacity withholding when firm 1 offers higher

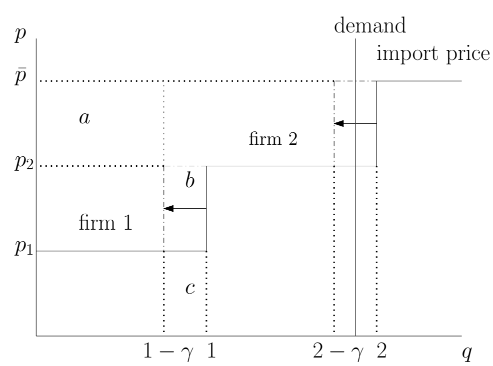

Figure 2.11: Capacity withholding when firm 1 offers lower

[5] This is not a necessary condition because CCS also yields a benefit through lower emissions and a lower carbon tax payment, which are not captured in the graph.

2.6 Results

2.6.1 Making a CCS decision

In the equilibrium of the game with announcement (Section 2.3.4), firms are drawing from their respective price offer functions for a given CCS decision on firm 1's part. To characterize equilibrium outcomes, we invoke a computer simulation to determine the value of the carbon tax t above which firm 1 does CCS, and below which it does not. We simulate 5,000 draws from $F_{1n}(p)$ and $F_{2n}(p)$ for the no-CCS case, and from $F_{1c}(p)$ and $F_{2c}(p)$ for the CCS case, calculate firm 1's realized profits at each of those draws (for a given set of parameters), then take an average over all draws to obtain firm 1's expected profit in each case. This simulation of expected profits characterizes firm 1's CCS decision.

2.6.2 Numerical example with demand data

This section shows a numerical example of the model where two single-unit firms serve the market, with numbers assigned to the following parameters. The price cap $\bar{p}$ of \$999.99 is rounded up to \$1,000. Production cost c is \$130/MWh (EIA (2013)), and includes levelized capital costs, fixed and variable operation & maintenance costs. While each firm's decision to invest in the CCS technology and/or generation capacity is taken as given, its fixed cost recovery is accounted for.[6] Emissions intensity i is 1 tCO_2/MWh (Moomaw

[6] This cost is imposed on both firms for symmetry. In EIA (2013), the value of \$130/MWh is within the cost range for both "advanced coal" and "advanced coal with CCS".

et al. (2011)). Lastly, the CCS energy penalty γ is 0.25 and the CCS capture ratio δ is 0.9 (IPCC (2005)).[7]

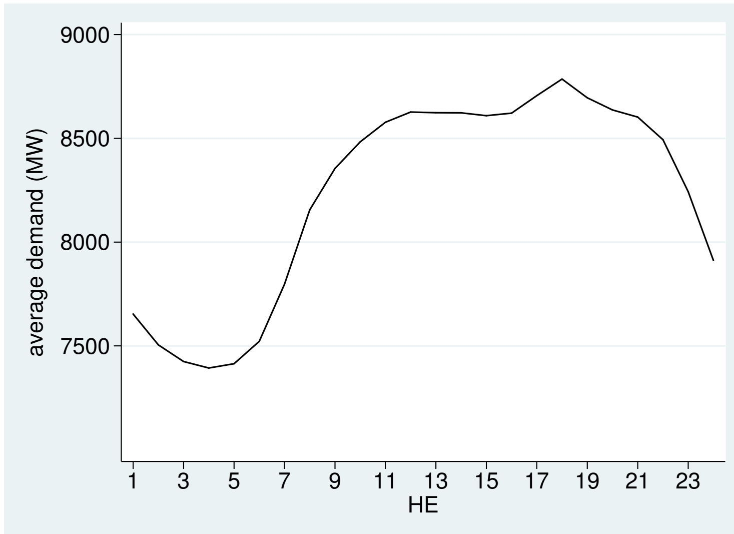

Figure 2.12: Alberta's average hourly load, January 1, 2008 to December 31, 2012

Figure 2.12 shows Alberta's average hourly load over a five-year period.[8] Demand peaks during the late morning, stabilizes throughout the day, then peaks again in the evening before dropping during the night. To approximate the demand parameters, we consider demand at three times of day: the hour from 3:01 am to 4:00 am, known as HE 4 (hour ending 4), when demand is lowest, HE 9 (8:01 am to 9:00 am) during the morning peak, and HE 18 (5:01 pm to 6:00 pm) during the evening peak when demand is highest.

Table 2.2 shows the four demand parameters π_1 through π_4 derived from the data for $\gamma = 0.25$. HE 4 is the low demand period, with close to 90% of

[7] IPCC (2005) defines the energy penalty as the extra capacity required to produce a given amount of electricity under CCS, ranging from 24-40%. Our model defines it as the foregone fraction of total capacity under CCS (derating); under this interpretation, the IPCC numbers yield a penalty of 19.35-28.57%, which we are setting to 25%.

[8] Data are from `ets.aeso.ca`.

the probability in region 1. In HE 9, the probability is almost evenly spread across regions 1, 2 and 3 (about one third each), with a small proportion in region 4. And in HE 18, the high demand period, over half the probability is in region 3, with close to 30% in region 2.

Table 2.2: Alberta's demand parameters based on five-year load data ($\gamma = 0.25$)

Hour Ending	π_1	π_2	π_3	π_4
HE 4	0.8938	0.0952	0.0110	0
HE 9	0.3465	0.3131	0.3399	0.0005
HE 18	0.1374	0.2911	0.5463	0.0252

Applying the model's four region boundaries to Figure 2.12 yields Figure 2.13.[9] Since the curve shows average demand for the hour over a five year period, demand for that hour on a given day can be above or below the curve. Demand tends to be in region 1 in the early hours until the morning peak around HE 8, after which it is in region 2. Then from HE 11 until HE 21 it is in region 3, before returning into 2. Although average demand in any given hour does not enter region 4, π_4 is positive for some hours because of occasional demand points that fall in region 4 on certain days within the sample period. These instances are nonetheless rare; the probability of demand lying in region 4 never exceeds HE 18's value of 2.52% from Table 2.2.

Assuming a carbon tax of $t = \$15$ per tonne of emissions (in line with Alberta's Specified Gas Emitters Regulation) and with the aforementioned parameters, the firms' offer functions will have the features outlined in Table

[9]The minimum and maximum bounds are 6,500 and 10,700 MW respectively, with region one ending at 8,337.5 MW, region two at 8,600 MW, and region three at 10,437.5 MW.

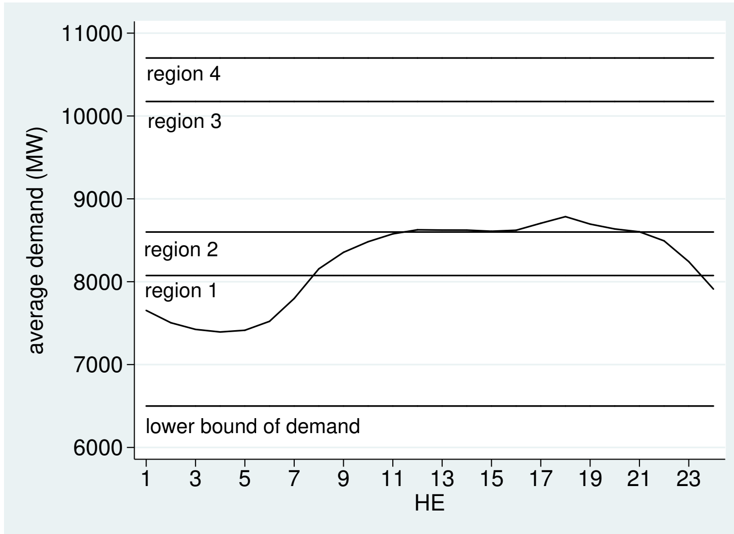

Figure 2.13: Average hourly load with boundaries for regions 1 through 4

2.3 in the uniform auction for the three hours.[10] Recall that both firms have the same lower bound p_m on their support. Firm 2's offer function has a mass point at $\bar{p}$ when firm 1 engages in CCS; so firm 2 will randomize between p_m and $\bar{p}$ with probability $\Pr(p_{2c} < \bar{p})$, and it offers exactly $\bar{p}$ with probability $1 - \Pr(p_{2c} < \bar{p})$. The table shows p_m, as well as the probability that the firm in question randomizes.

Table 2.3: Firms' offer functions from the data

		HE 4	HE 9	HE 18
$F_{1n}(p)$	p_m (\$)	154	305	382
	$\Pr(p_{1n} < \bar{p})$	1	1	1
$F_{2n}(p)$	p_m (\$)	154	305	382
	$\Pr(p_{2n} < \bar{p})$	1	1	1
$F_{1c}(p)$	p_m (\$)	182	458	594
	$\Pr(p_{1c} < \bar{p})$	1	1	1
$F_{2c}(p)$	p_m (\$)	182	458	594
	$\Pr(p_{2c} < \bar{p})$	0.999	0.560	0.306

[10] Alberta's SGER is not a strict carbon tax, as it is an intensity-based requirement imposed on firms emitting more than 100,000 tonnes of emissions per year. See Leach (2012).

Using the demand parameters from Table 2.2, we search for the conditions under which firm 1 engages in CCS or not in the game with announcement, where price offers are chosen while taking firm 1's CCS decision as given. The two advantages of CCS are the reduced carbon tax payment, and the potentially higher market price from the withheld capacity. Given that CCS is almost always on when $t = 0$ (when there are no carbon tax savings to be had) in the following graphs, this shows that the price effect of CCS alone is strong enough to motivate its use even in the absence of a carbon tax.

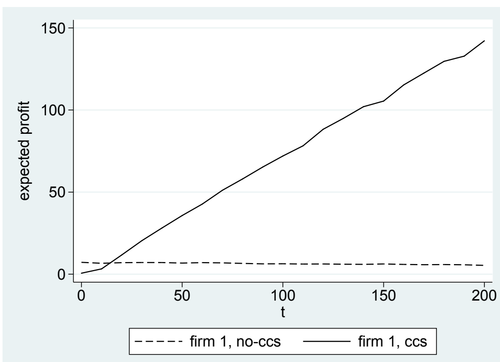

Figure 2.14: HE 4, expected profits under $F_{1n}(p)$ and $F_{1c}(p)$

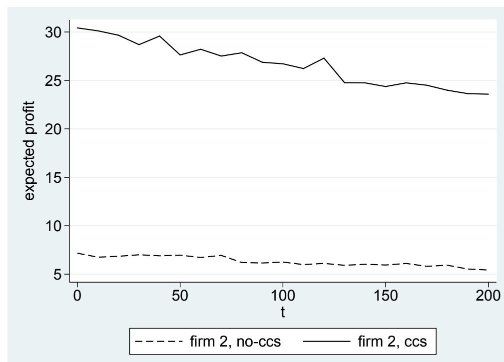

Figure 2.15: HE 4, expected profits under $F_{2n}(p)$ and $F_{2c}(p)$

Figures 2.14 and 2.15 show equilibrium expected profits as functions of the carbon tax t for the two firms when they draw from the respective offer functions $F_{j,n}(p)$ and $F_{j,c}(p)$, $j = 1, 2$. Firm $k \neq j$ is assumed to draw from the corresponding offer functions, and firm 1 engages in the corresponding CCS decision. When CCS is on, firm 2 offers higher than 1, since it has more capacity on which to earn a higher price; both firms' offers are rising in t. Since firm 1 is marginal with its lower offers, it earns a higher price as t rises, hence the rising solid line in Figure 2.14 (as the higher price more than compensates for the higher t). Firm 2 is in the market less often because its average offer rises faster than firm 1's as t rises, hence the falling solid line in Figure 2.15. When CCS is off, both firms' offers rise with t and the two effects almost cancel out, yielding the slightly downward-sloping dotted lines.

In Figure 2.14 CCS profits (the solid line) exceed no-CCS profits (the dashed line) for $t \geq 20$, hence firm 1 engages in CCS for those t's. Both firms have the same no-CCS profits, since $F_{1n}(p) = F_{2n}(p)$.

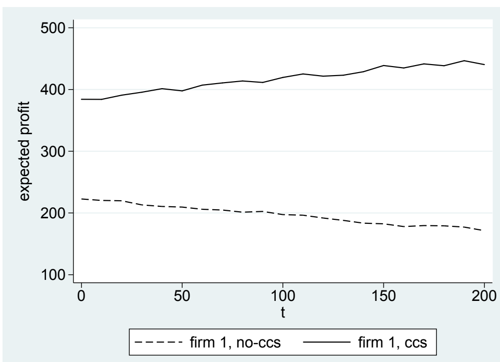

Figure 2.16: HE 9, expected profits under $F_{1n}(p)$ and $F_{1c}(p)$

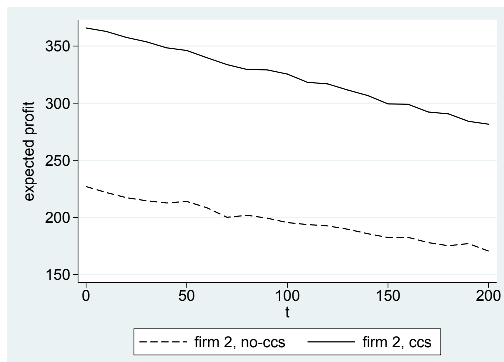

Figure 2.17: HE 9, expected profits under $F_{2n}(p)$ and $F_{2c}(p)$

Figures 2.16 and 2.17 show the equilibrium expected profits for HE 9. Firm 1 is doing CCS for all positive t's, although its CCS profits are rising more slowly than in HE 4, as the rise in t has a larger effect relative to the rise in the average offer. Firm 2's profits in the CCS case are falling in t.

Finally, figures 2.18 and 2.19 show equilibrium expected profits for HE 18. This time the CCS profits for both firms 1 and 2 are falling in t. Firm 1 continues to do CCS for all positive t's.

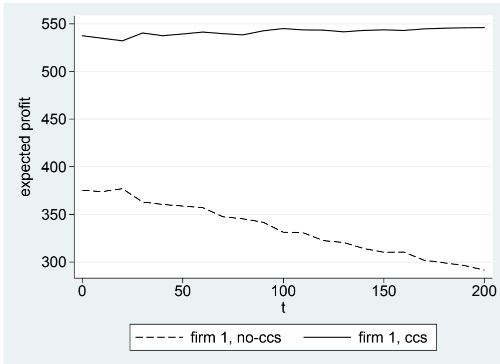

Figure 2.18: HE 18, expected profits under $F_{1n}(p)$ and $F_{1c}(p)$

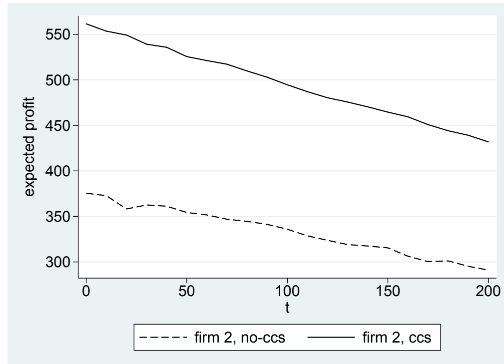

Figure 2.19: HE 18, expected profits under $F_{2n}(p)$ and $F_{2c}(p)$

Both firms' equilibrium expected profits are higher under CCS than under no-CCS for all demand scenarios and for all positive t's. This is because when CCS is on, firms are in the market more often (since there is less total sellable capacity for a given demand), and because the import price $\bar{p}$ become the market price whenever demand is in region 4. This shows that the price effect of CCS through capacity withholding is sufficient for firm 1 to make the quantity sacrifice, *even in the absence of a carbon tax on polluting emissions.*

In Figures 2.16 and 2.18 firm 1's expected profits are higher under CCS than under no-CCS for all $t \geq 0$. However it can be shown that there is some value $t' < 0$ that would induce no-CCS, as in Figure 2.20. In this scenario, the economic withholding effect of CCS is strong enough that firm 1 needs to be paid for emitting pollution in order to turn off CCS. Hence the cutoff t's that determine firm 1's decision to do CCS or no-CCS can be negative.

Firm 1's profit under CCS is rising in t when demand is low (Figures 2.14 and 2.16), and falling in t when demand is high (Figure 2.18). The difference

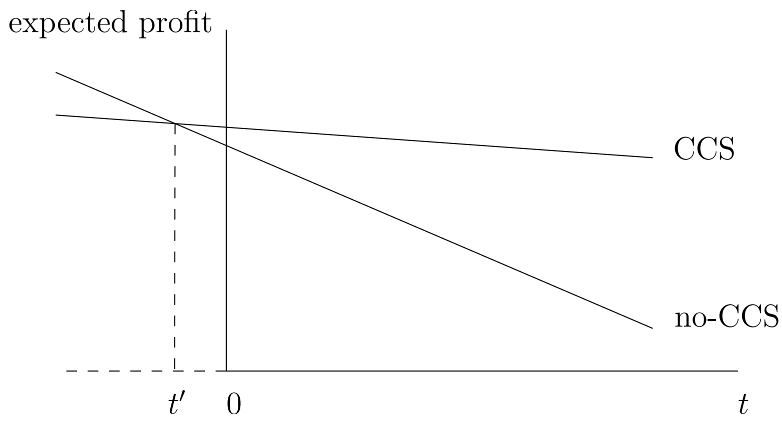

Figure 2.20: Negative cutoff t

between firm 1's CCS and no-CCS profits is increasing in t, in the case of HE 18 because the no-CCS profits fall faster than the CCS profits.

2.6.3 Sensitivity to the firms' parameters

We conduct a numerical sensitivity analysis on the model's parameters to determine the effect that they have on firm 1's willingness to engage in CCS or not. Subsequent changes to a parameter's initial value can cause firms to shift from one equilibrium to another (a firm that does CCS under a certain set of parameters may not under a different set of parameters).

Results are in Table 2.4. The + and − signs refer to a respective increase or decrease in the number of t values for which CCS is an equilibrium when the parameter in question rises. For instance, when the production cost c rises, there are fewer t's for which CCS is an equilibrium. A parameter change that encourages the CCS outcome also discourages the no-CCS outcome.

An increase in the production cost c decreases the number of CCS equilibria. Since firm 1 bears the cost c on the capacity used to run CCS, an increase

Table 2.4: Sensitivity analysis on the model's variables

	CCS outcome
c	$-$
t	$+$
i	$+$
γ	$+$
δ	$+$
$\bar{p}$	$+$

in this cost decreases incentive to do so. An increase in the carbon tax t, on the other hand, makes CCS more attractive (and no-CCS less attractive) because of its ability to decrease polluting emissions. An increase in pollution intensity i also encourages CCS, as the amount of pollution emitted for a given amount of capacity would increase. The energy penalty γ and capture ratio δ are the CCS technology variables; a higher γ encourages CCS because the increased capacity withholding ability overcomes the higher foregone sellable output, while a higher δ also encourages it due to increased CCS abatement efficiency. Lastly, an increase in $\bar{p}$ encourages CCS because of the higher market prices that can be attained through withholding.

Firm 1's decision to do CCS reduces its sellable capacity, and can raise the price of electricity if demand is in region 2 or 4. Setting the CCS capture ratio δ to 0 removes the emissions abatement effect of CCS, and isolates the price effect. As shown in Figure 2.21, firm 1's expected profits fall faster as a function of t under CCS than under no-CCS, creating a strictly positive cutoff carbon tax value at t'. With only the price effect firm 1 does CCS for t below t' and no-CCS otherwise. This means that for $t \leq t'$ the benefit of a higher price of electricity outweighs the opportunity cost of being a smaller firm.

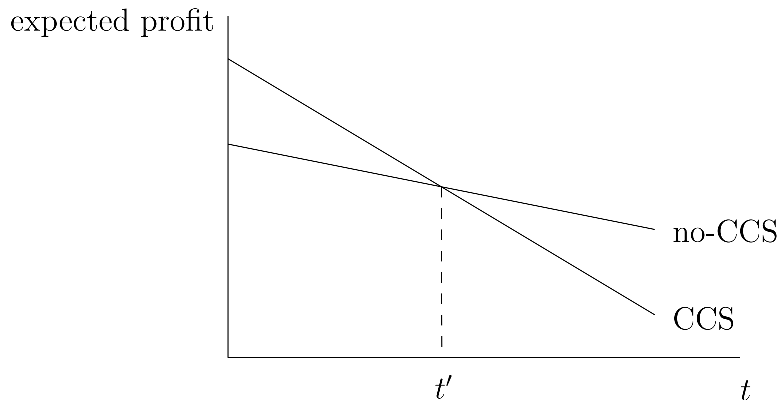

Figure 2.21: Isolating the price effect of CCS ($\delta = 0$)

When δ is 0, the cutoff carbon tax values of t' from Figure 2.21 for hours HE 4, HE 9 and HE 18 are respectively 90, 365 and 250. Economic withholding is only profitable if demand is in region 2 or 4; HE 9 and HE 18 have more weight in those two regions than HE 4 (recall Table 2.2), hence they also have higher values of t' (more values of t for which CCS is an equilibrium).

Consider firm 1's profit under CCS when the capture ratio δ is 0, meaning CCS has only an economic withholding benefit. The difference between this value and expected profit under no-CCS gives a measure of firm 1's incentive to do CCS for economic withholding only, shown in Figure 2.22 for both auctions. Because of the uniform auction provides more incentive for CCS through higher prices, the solid line lies above the dotted one (the jaggedness of the lines has to do with the number of simulated draws; a higher number of draws would yield a smoother curve).

The CCS incentive in both auctions is strongest around HE 10 and HE

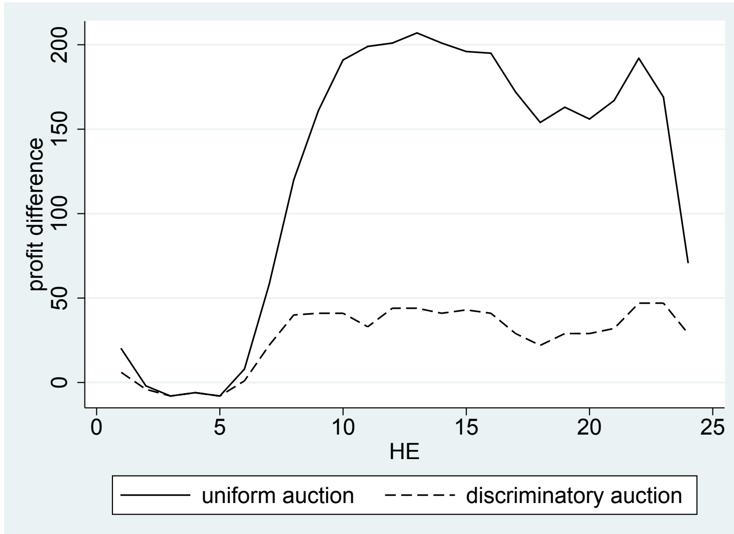

Figure 2.22: Firm 1's CCS incentive for economic withholding purposes only

23 (these hours also exhibit the largest difference between the two curves). Economic withholding is profitable if demand is in region 2 but less so in 4. This is because in high demand scenarios, such as HE 18, one of the firms (firm 2) is offering at the maximum $\bar{p}$; hence when demand is in region 4, firm 1's decision to do CCS causes the marginal firm to switch from firm 2 to the import price, without a change in price. When demand is in region 2 and firm 1 offers lower and is marginal, then CCS causes firm 2 to become marginal at a higher offer. Therefore hours with the most weight in region 2 have high incentive for economic withholding. The CCS withholding incentive for firm 1 in a discriminatory auction derives from increases in the market price and in producer surplus, though this does not affect the price it receives.

HE 18 has highest overall demand, but most of the weight is in regions 3 and 4, so the incentive to withhold capacity drops during that hour, suggesting that shoulder hours with intermediate demand are most susceptible to market power. It is high in HE 10 and HE 23 because those hours have significant demand in region 2. For both auction formats there is the least incentive to withhold in the early morning hours, when demand is mostly in region 1 and CCS is unlikely to affect price.

This result implies for policy that a system operator looking to minimize economic withholding should focus on firm behaviour in hours with intermediate levels of demand, as during peak hours the volume of offers at $\bar{p}$ mitigates price increases from withholding. The wider variation of price offers among marginal firms in hours with intermediate demand creates potential for higher prices through economic withholding. This result also assumes that peak demand is high enough so that firms offering $\bar{p}$ become marginal.

Figure 2.23 shows the cutoff t' for two different values of γ in the uniform auction. The curve for $\gamma = 0.125$ lies above the one for $\gamma = 0.25$. Since the $\gamma = 0.125$ scenario has a lower cost of CCS, there is more incentive for CCS but less incentive for capacity withholding, and the latter effect dominates.

In the early morning hours and at the evening peak, when demand probability is mainly in either region 1 or 3, the magnitude of the CCS energy penalty γ has little effect on the incentive for CCS, and the cutoff t's are close together. As demand probability moves into region 2 during the morning peak and in the late evening and nighttime, incentive for CCS increases (since it can raise price).

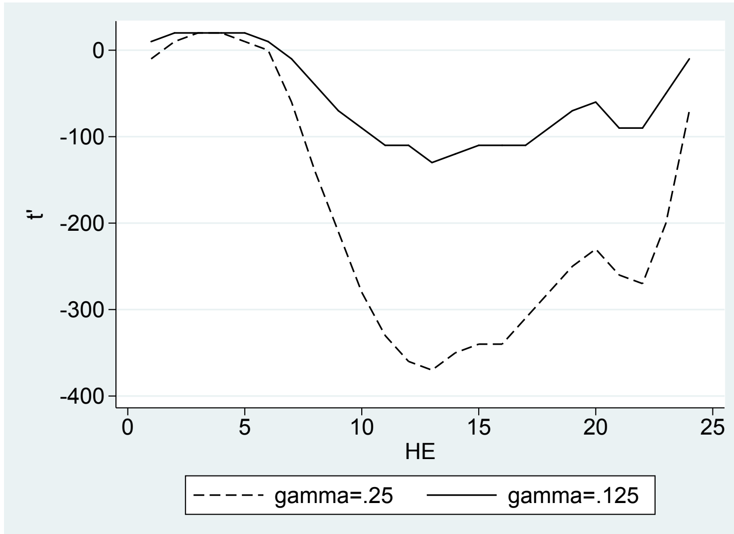

Figure 2.23: Cutoff t' with different CCS energy penalties (uniform auction)

2.6.4 Sensitivity to the demand parameters

Consider next the π variables, the demand probabilities. We conduct a sensitivity analysis by successively placing greater probability weight in each of the four regions, and look at outcomes when demand has a higher chance of landing in a particular region than in the others. There are opposing forces that make it difficult *ex ante* to predict what will happen. For instance, engaging in CCS will decrease polluting emissions (thus decreasing the carbon tax payment), and under the right conditions can also raise market price in the uniform auction, but will also decrease the amount of sellable output, which becomes more significant at higher prices. Sensitivity analysis on the demand probabilities helps determine which effects dominate in a given situation. Table 2.5 shows the results for the uniform and discriminatory auctions. The $+$ and $-$ signs show a respective increase and decrease in the number of t values for which CCS is an equilibrium when demand is in a particular region.

Table 2.5: Sensitivity analysis on the demand probabilities

Demand region	CCS outcome	
	UA	DA
1	+	+
2	+	+
3	−	−
4	−	−

In both auctions, firm 1 has incentive to do CCS when demand is in regions 1 or 2, and less incentive to do so when demand is in regions 3 and 4. At low levels of demand, the market price of electricity is low and hence there is a lower opportunity cost of foregone capacity through CCS as expected, encouraging its use. And at high levels of demand, the high opportunity cost of CCS overrides the price benefit, and firm 1 does not engage in CCS. When demand is in region 2 or 4, firm 1 can raise price by engaging in CCS. According to Table 2.5 firm 1 has incentive to do so when demand is in 2 but not when it is in 4.

Table 2.6 shows the cutoff carbon tax values: below said value, firm 1 does not engage in CCS, and above it firm 1 engages in CCS. The column "Demand π's" shows the respective values for π_1, π_2, π_3 and π_4. When demand is in region 1 with probability .7 and in the other three regions with equal probability, the cutoff t is \$20. In contrast when demand is in region 3 with probability .7, firm 1 does CCS if t is greater than \$30, hence there is a narrower range of t's for which CCS is an equilibrium.

Table 2.6: Cutoff carbon tax levels, $\gamma = 0.25$

Demand π's	t_{UA}	t_{DA}
.7,.1,.1,.1	20	20
.1,.7,.1,.1	-350	-110
.1,.1,.7,.1	30	40
.1,.1,.1,.7	150	200
.4,.2,.2,.2	90	100
.2,.4,.2,.2	-200	70
.2,.2,.4,.2	100	120
.2,.2,.2,.4	160	200

Demand must be sufficiently concentrated in the high regions in order for no-CCS to be a profitable outcome, since the high price of electricity presents a high opportunity cost of withheld capacity from doing CCS. In the top panel of Table 2.6, firm 1 is doing CCS for a wider range of t's when demand is concentrated in regions 1 or 2, since there is a low opportunity cost of foregone capacity. When demand is concentrated in 3 or 4, CCS is profitable for firm 1 only at higher levels of t. The bottom panel shows a similar pattern, with demand more evenly spread out among the four regions.

The fact that CCS tends to be used in low demand periods rather than in high demand periods because of its opportunity cost has interesting implications. First, the economic withholding associated with CCS will occur at nighttime when demand is low. During this time the low market price stemming from low demand is counteracted by economic withholding. Second, if CCS is off when demand is high, peak prices are consequently unaffected by economic withholding. This also confirms our interest in daily decisions in shoulder hours.

Table 2.7 shows a base case in its first line, with demand probability spread evenly throughout (recall that the CCS regions 2 and 4 occupy one eighth each of the total capacity of 2 when $\gamma = 0.25$). In this base case, firm 1 engages in CCS if $t > -40$. If probability shifts away from 2 to any of the other three regions, the cutoff t rises (hence there are fewer t's for which CCS is an equilibrium), and vice versa when probability shifts towards 2 from other regions. Shifting probability from 1 to 3 raises the cutoff t, since the associated higher market price reduces incentive to engage in CCS.

Table 2.7: Cutoff t when $\gamma = 0.25$ relative to a base case

Demand π's		t_{UA}	t_{DA}
.375, .125, .375, .125	Base case	-40	10
.375, .025, .375, .225	From region 2 to 4	50	60
.375, .225, .375, .025	4 to 2	-140	-40
.425, .025, .425, .125	2 to 1, 3	20	30
.275, .125, .475, .125	1 to 3	-30	20
.475, .125, .275, .125	3 to 1	-50	0

Table 2.7 shows that firm 1 has more CCS incentive when demand is in region 2, and less when demand is in the other regions. It also gives insight into CCS incentives during "shoulder" periods when demand is split between regions that encourage CCS and regions that discourage it. Namely if CCS tends to be off during peak demand hours when prices are high, then running CCS during shoulder hours will prolong high-price periods.

Note that the results in Sections 2.6.3 and 2.6.4 regarding firm 1's market power incentive through CCS can be mitigated through forward contract cover, which reduces the firm's exposure to the real-time electricity price.

Section 2.5.2 also mentioned the values of t for which firms earn positive expected profits and hence an equilibrium exists. For the aforementioned parameters there is an equilibrium if $t \leq 870$, since $\bar{p}(1-\gamma) - c - ti(1-\delta)$ is weakly positive for such t's. For $t > 870$, costs are too high firms to earn positive profits since price cannot rise beyond $\bar{p} = 1000$ to compensate.

2.6.5 Uniform vs. discriminatory auction comparison

Table 2.8 summarizes the differences between the discriminatory and uniform auctions. For "price offers," the first row shows that firms make the same offers (in expectation) under no-CCS, since they are symmetric. Firms make higher offers under CCS; total capacity is smaller and for a given demand there is higher chance of being in the market (this is true in both auction formats). Under CCS firm 2 offers higher than 1 to earn a higher market price while maintaining 1's indifference across its own pure offers.

Table 2.8: Comparison of the two auction formats

	Uniform	Discriminatory
Price offers	$1n = 2n < 1c < 2c$	$1n = 2n < 1c < 2c$
	$DA_{1n} > UA_{1n}$, $DA_{1c} > UA_{1c}$, $DA_{2c} < UA_{2c}$	
Expected profits	$1n = 2n \lesseqgtr 1c$ $1n = 2n < 2c$ $1c \lesseqgtr 2c$	$1n = 2n \lesseqgtr 1c$ $1n = 2n < 2c$ $1c \lesseqgtr 2c$
	$DA_{1n} = UA_{1n}$, $DA_{1c} < UA_{1c}$, $DA_{2c} = UA_{2c}$	

Note: The $1n$ and $2n$ subscripts denote offers/profits for firms 1 and 2 under no-CCS, and likewise for $1c$ and $2c$ under CCS; UA and DA denote offers/profits for the uniform and discriminatory auctions.

For both auctions, firm 1 under CCS may earn higher or lower profits than under no-CCS, since the higher market price is balanced by 1's smaller capacity, while firm 2 earns a higher profit since its capacity remains the same. Under CCS, firm 1 may earn a higher or lower profit than 2, since 1 is smaller but is dispatched more often (since if offers lower). Each firm earns the same profits in both auction formats under no-CCS. When CCS is on, firm 1 earns more in the uniform auction (because of higher prices from capacity withholding), while firm 2 earns the same in both. In the uniform auction, aggregate profits are higher under CCS than under no-CCS; this is especially true in hours where demand is such that CCS can increase price. The difference in aggregate profits under CCS between the uniform and discriminatory auctions is also greater in such hours.

To summarize, in a simple two-firm market there is more incentive for CCS in the uniform auction than in the discriminatory one, as CCS can raise the market price for all dispatched firms, and not just for the marginal one. The uniform auction is also expected to yield higher profits to the firm who engages in CCS, hence the discriminatory auction is better at preventing capacity withholding. The decision to implement CCS for electricity therefore depends crucially on the auction design, as certain markets lend themselves to capacity withholding. A caveat is that in practice, with many firms in the market, the uniform auction encourages marginal cost offers (an efficient outcome), since one does not need to offer high to receive a high price. Meanwhile the discriminatory auction encourages higher-than-marginal cost offers as firms attempt to predict the marginal price and undercut it (Wolfram (1999)). The role of

CCS is also magnified in a two-firm market; with many firms, an individual CCS decision will have less effect on market outcomes.

In Fabra et al. (2006), under long-lived bids and the resulting uncertain demand, with symmetric firms it is shown that the uniform and discriminatory auctions yield the same revenue. This matches our result under no-CCS. But under CCS, revenue is higher under the uniform auction, because of the price effect through capacity withholding.

2.6.6 The CCS announcement

While we were unable to solve for an equilibrium in the game without announcement, we can use the simulation model to shed light on the conditions under which firm 1 plays a pure or mixed CCS strategy at the top node of Figure 2.6. In the second and third columns of Table 2.9, the uniform auction's HE 4 has firm 1 playing CCS as a pure strategy when $t > 85$, and no-CCS as a pure strategy when $t < -20$; for $t \in (-20, 85)$, firm 1 plays CCS with probability $\alpha \in (0, 1)$. A similar reasoning extends to HE 9 and HE 18, and to the discriminatory auction.

Table 2.9: Carbon tax values below (CCS candidate equilibrium) or above (no-CCS candidate equilibrium) which the CCS announcement prevents firm 1 from deviating

hour ending	t^{CCS} (UA)	t^{noCCS} (UA)	t^{CCS} (DA)	t^{noCCS} (DA)
HE 4	85	-20	100	-20
HE 9	185	40	150	55
HE 18	240	55	200	60

As demand increases, the CCS outcome is an equilibrium for fewer t's, while the no-CCS outcome is an equilibrium for more t's. There is less incentive to engage in CCS during high demand periods, since the foregone capacity prevents firm 1 from fully benefiting from the associated higher price. From a policy perspective, a rise in the demand can cause a firm to unilaterally deviate from CCS to no-CCS in the absence of a commitment device (such as a mandatory announcement).

A change in the CCS energy penalty γ will have a corresponding effect on the values in Table 2.9. If γ falls, then the CCS outcome will be an equilibrium for lower values of t, because CCS becomes cheaper for firm 1.

In Table 2.2, demand in HE 4 is concentrated in a single region (region 1, where CCS cannot affect price); in the uniform auction, firm 1 has less incentive to randomize across no-CCS and CCS, since demand is comparatively predictable. In HE 9, where demand is more spread across different regions (hence increased uncertainty over the price benefit of CCS), firm 1 has more incentive to randomize. And in HE 18, demand is further spread between regions 2 and 4 (both of which encourage CCS) and concentrated in region 3.

In the absence of a pure strategy equilibrium, a CCS announcement imposes a non-random outcome, with firm 1 acting deterministically. The CCS announcement can allow firm 1 to announce the equilibrium it intends to play. It can also serve as an implicit announcement of firm 1's costs, which are based on private information. This raises a discussion of the appropriate amount of market transparency in a deregulated electricity market.

The literature is unclear on whether a mixed strategy equilibrium in capacity choices/CCS decisions would be worth pursuing. For example, the two-stage model in De Frutos and Fabra (2011) has two firms first choosing capacities, and then (with known demand and known capacities) prices. The authors analyze mixed strategies in the second stage, but the first focuses on pure strategies because mixed strategies in capacity choices are hard to justify (a firm randomly making an irreversible decision simply to maintain an opponent's indifference makes little practical sense). An hourly CCS decision offers more flexibility than a one-time capacity choice, but unlike price offers, in practice there is little evidence that a firm would randomize.

2.6.7 Decomposing the effect of CCS

Firm 1's decision to engage in CCS has two effects: raising the market price under certain conditions, and reducing the carbon tax payment. The two effects can be separated and compared, along with production costs. Equations (2.1) and (2.2) on page 38 showed firms' realized profits, and are reproduced below on a per unit of sellable capacity basis:

$$p_{\text{not}} - c - ti \quad \text{no CCS, firms 1 and 2} \tag{2.33}$$

$$p_{\text{CCS}} - \frac{c}{1-\gamma} - \frac{ti(1-\delta)}{1-\gamma} \quad \text{CCS, firm 1.} \tag{2.34}$$

The different components of (2.33) and (2.34) (price, cost and carbon tax payment per unit of sellable capacity) can thus be compared. (Firm 2 earns $p_{\text{CCS}} - c - ti$ if dispatched when firm 1 does CCS.)

Consider the following three dollar values:

$$p_{\text{ccs}} - p_{\text{not}} \quad \text{price effect} \tag{2.35a}$$

$$c - \frac{c}{1-\gamma} \quad \text{cost effect} \tag{2.35b}$$

$$ti - ti \cdot \frac{1-\delta}{1-\gamma} \quad \text{carbon tax payment effect.} \tag{2.35c}$$

In each equation a positive value encourages CCS, as it implies a higher price under CCS in (2.35a), a lower cost in (2.35b), and a lower carbon tax payment in (2.35c). The carbon tax payment effect is linear in t for firm 1, while the cost effect is not affected by changes in t; both are 0 for firm 2.

Figure 2.24 shows the three values for firm 1 in HE 4. The price effect is small because demand is mainly in region 1; however as t rises, the price effect increases and exceeds the other two, becoming the primary incentive for firm 1's CCS. Firm 2 also benefits from a CCS price effect in Figure 2.25 (the cost and carbon tax payment effects are not depicted, as they are simply horizontal lines at 0).

Figures 2.26 and 2.28 for firm 1 in HE 9 and HE 18 are similar to each other: the price effect dominates the other two, as there is substantial demand probability in region 2. The price effects for firm 2 in Figures 2.27 and 2.29 are also higher than in HE 4, though not as high as for firm 1.

These hours are relevant because HE 4 and HE 18 are when demand reaches its early morning low and evening peak respectively, and HE 9 is a "shoulder" hour in between. Shoulder hours were shown to present firm 1 with the most

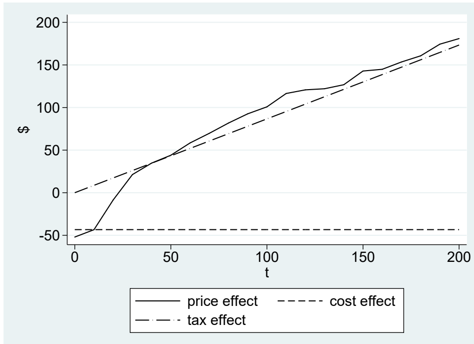

Figure 2.24: CCS effect decomposition for firm 1, HE 4

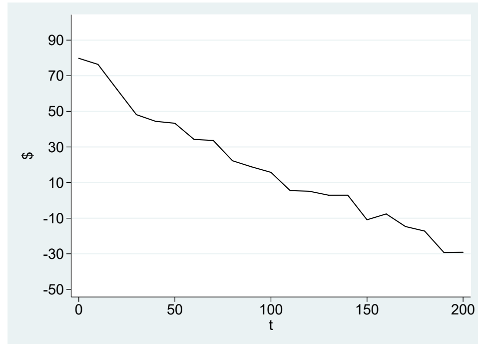

Figure 2.25: CCS effect for firm 2, HE 4

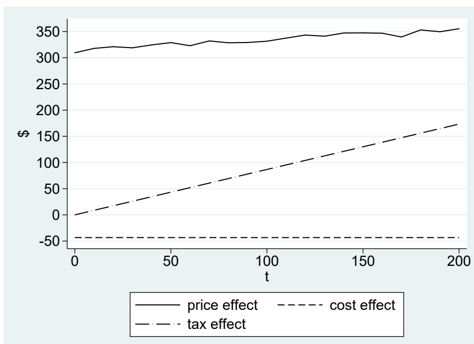

Figure 2.26: CCS effect decomposition for firm 1, HE 9

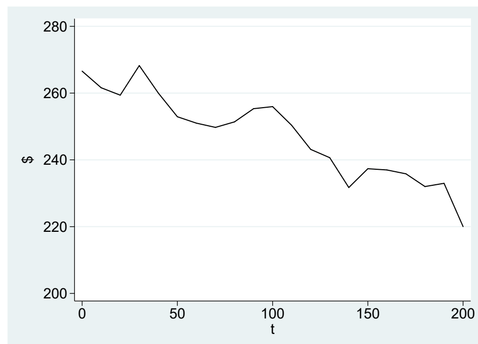

Figure 2.27: CCS effect for firm 2, HE 9

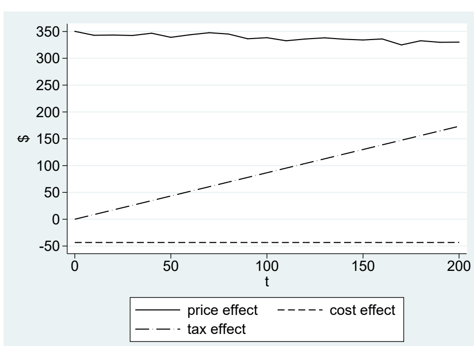

Figure 2.28: CCS effect decomposition for firm 1, HE 18

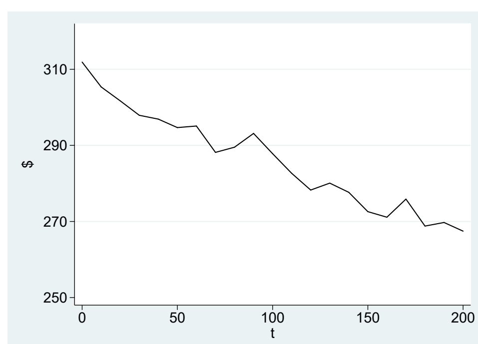

Figure 2.29: CCS effect for firm 2, HE 18

market power incentive, because of their demand probability in regions 1 and 2 (low opportunity cost of foregone capacity, and ability to raise price through capacity withholding).

2.7 Conclusion

This chapter analyzed the market power effects of introducing CCS into electricity markets, namely through the feature of CCS that requires the firm to remove sellable output from the market (capacity withholding). Our model had two firms, one of which, firm 1, had the option of engaging in CCS. We examine their market behaviour through best response offer functions, which in turn show whether firm 1 would do CCS in either a uniform or discriminatory auction. An assumption of discrete demand allowed us to separate the support of demand into four discrete sections into which the vertical demand curve could lie, two of which presented the opportunity for a higher price through CCS. We considered two forms of the game: one with a CCS announcement where firm 1 publicly announced (and committed to) its CCS decision before both firms simultaneously chose price offers, and one where firm 1 did not make an announcement. The game without announcement allowed firm 1 to deviate from its CCS decision because there was no commitment device.

Results suggest that firm 1 engages in CCS more often in low demand hours and less often in high demand hours, because of the high opportunity cost of CCS when demand is high. CCS is also more profitable in the uniform auction than in the discriminatory one, because the increased prices from economic withholding benefit all dispatched firms, and not only the price-setter. These situations will have higher deadweight loss from market power, and lower emissions levels due to pollution abatement, with an ambiguous effect on total surplus. Total surplus is expected to be higher during early morning hours when demand is low and CCS is used for emissions abatement; it may be lower during the shoulder hours when CCS is used for market power, depending on the level of emissions that are allowed to escape.

The implementation of a binding CCS announcement can steer firms towards a particular equilibrium if there are more than one, or if there is no pure strategy equilibrium in the CCS announcement. Appropriate policies are required to ensure that the proper timing structure and carbon tax (which also exists for other purposes than to encourage CCS) are in place to achieve a desired outcome. It is also important to determine whether firms are engaging in excessive market power, because in practice moderate levels are necessary in the short run for firms to recover fixed costs and to encourage investment.

If market power through CCS is deemed excessive by the system operator, the CCS decision and price offer decision could be separated, similar to how the Power Purchase Agreements divested a generating unit's offer control from its ownership. A PPA buyer earns revenue from offering a unit into the market, and compensates the unit owner for the cost of its operation (MSA (2012)). Analogously, the hypothetical buyer of the rights to the CCS control (separate from the buyer of the offer control) would compensate the owner, while earning revenue directly related to turning CCS on or off. (Modeling a firm whose CCS control is managed by another firm was outside the scope of this chapter.) Another method of market power mitigation could be to allow CCS only in hours with low market power potential, such as early morning or nighttime hours. Lastly, incentive for market power through CCS can be mitigated through forward contract cover.

A further extension would be to introduce dynamics, and to allow interdependence between variables. The CCS technology could change over time, with efficiency improvements in the capture ratio and the energy penalty, with changes in one affecting the other. Dynamics can also include entry of new firms and fixed cost recovery, and an examination of the level of short run market power that ensures long run efficiency. Fixed cost consideration also implies the endogeneity of a firm's decision to invest or not in the CCS technology, a decision that this chapter took as given. A firm would invest in the CCS technology if the long term gains from doing so are high enough; this would also depend on the requirement (or lack thereof) to announce the CCS decision, and expectations about the carbon tax.

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Chapter 3

Market transparency and alleged coordination in the Alberta electricity market

3.1 Introduction

This chapter examines coordination practices among firms as a means to raise market prices, and is motivated by recent allegations in Alberta that electricity firms are engaging in anti-competitive behaviour, and secretly communicating with each other. The electricity literature predicts two outcomes resulting from such practices:

1. Both non-cooperative and collusive models can exhibit asymmetric equilibria, with one firm acting as price-setter, and the existence of multiple equilibria corresponding to different firms acting as price-setter, suggesting a coordination problem for firms with regards to role assignment. The literature has paid little attention to how this problem is solved.[1]

[1] An exception is Crawford et al. (2007), who estimate how a firm's probability of being the price-setter depends on its capacity and marginal cost relative to rivals.

2. Collusive models also predict coordination around a collusive price level after firms' roles have been assigned. The price-setter may choose to offer just below the next highest rival to maximize market price; this incentive is especially strong if the rival can signal its intention to remain high without reacting competitively to being undercut.

Electricity firms in Alberta, in contrast to other jurisdictions, have access to near-real-time information on price offers of other firms. The document containing information on individual price offers and the associated capacity sizes is called the Historical Trading Report (HTR). It is updated hourly about 10 minutes after real time, and the information contained within is intended to be anonymous. In August 2013 the Market Surveillance Administrator (MSA) issued a report alleging that firms were setting offers in a way that revealed their identities through the HTR using so-called "tagging" strategies, potentially facilitating coordination between certain firms. Our investigation into tagging reveals a particular firm (Transcanada) that employed a detailed and predictable pricing pattern, only to abruptly switch to seemingly random pricing within our sample period; this switch coincided with the MSA's announcement of proposed modifications to the HTR. A possible explanation for the pattern change is that the firm may have changed the signal of its future intentions in anticipation of a less transparent HTR.

MSA (2013a) describes instances where firms allegedly used information in the HTR to maintain prices higher than they would otherwise be. In these examples, a firm sets a large amount of capacity at a high price offer, and rivals are assumed to know the identity of that firm through its tagged offers, and that it will maintain that pricing throughout the day. This creates a supply function merit order that experiences a rapid change in elasticity at a certain point. At a later hour, a rival undercuts the firm by a small amount, leading to a series of similarly-priced capacity blocks (similar to outcome 2 above). The MSA alleges that the undercutting rival knows the exact price to undercut thanks to the HTR, potentially holding the market price higher than it would otherwise be, while maintaining its merit order position. These allegations raise a discussion of optimal transparency and market power levels in a deregulated, energy-only electricity market.

Our contribution is a treatment of how (if at all) transparency affects the exercise of market power in Alberta's deregulated electricity market, in light of evidence that firms (such as Transcanada) might be surreptitiously communicating. We identify two scenarios from the literature under which firms could have incentive to communicate, and which are expected to yield different outcomes: equilibrium selection (outcome 1) and undercutting of willing rivals by small amounts (outcome 2). Conditional on firms self-identifying themselves through so-called tagging strategies, our empirical analysis shows some evidence of firms setting offers consistent with undercutting of rivals. While this gives credence to the second hypothesis, it is not sufficient to rule out equilibrium selection, which remains a possibility.

Section 3.2 describes the HTR's role in the Alberta electricity market. Section 3.3 reviews the relevant literature on collusion and price leadership, and outlines the predicted firm behaviour. Section 3.4 states the MSA allegations. A selection of firms' tagging strategies are described in Section 3.5; 3.6 models firms' price offer strategies and provides summary statistics on pricing behaviour, and 3.7 carries out empirical tests of how (if at all) firms' revealed identities affect offer decisions. Section 3.8 concludes. Appendices A and B contain additional figures and technical details.

3.2 The Alberta wholesale electricity market

Alberta has an energy-only electricity market, and firms are only paid for the output they produce.[2] Hence, the MSA concludes that market power is both allowed and necessary in the short run to allow firms to recover the high fixed cost of entry.

An electricity-generating asset belonging to a given firm offers up to seven price-quantity pairs into an auction in each hour of the day (a certain number of MWs of capacity offered at a certain number of dollars per MW).[3] The auction is run by the Alberta Electric System Operator (AESO). Price offers range from \$0/MW to \$999.99/MW inclusively, and are ranked from lowest to highest to form an hourly merit order, a step function supply curve. At a given time, the firm whose offer sets the market price by intersecting with the

[2] In contrast, a capacity market pays a firm for having capacity ready to produce, regardless of whether or not it does.

[3] This section is based on MSA (2010), unless otherwise noted.

demand curve is known as the marginal firm. The marginal firm's price offer is the system marginal price (SMP), and is updated every minute; at the end of the hour the average of 60 SMPs yields the pool price paid to firms offering at or below it in that hour.[4] Figure 3.1 shows a simple example with three firms, each offering one capacity block. Firm 2 is marginal, and its capacity is dispatched along with firm 1's (firm 3's is not). The SMP is $100. Demand in this example is perfectly inelastic.

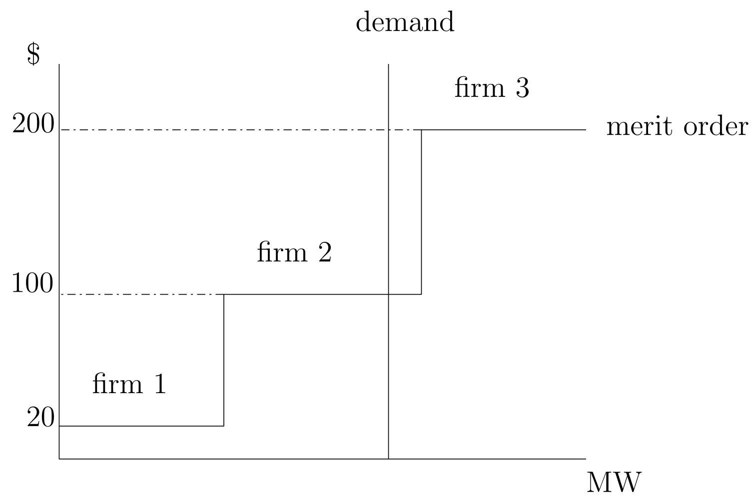

Figure 3.1: Merit order example

Firms set price offers and quantities one day ahead of the hour when the offers come into effect, known as "real time". Firms have until two hours before real time to adjust their offers (but not quantities) in reaction to changing market conditions. So price offers that come into effect at HE 10 (hour ending 10, from 9:01 am to 10:00 am) can be modified up to and including HE 7.

The AESO provides firms with publicly available information to help man-

[4]If there is a tie among candidate marginal firms, partial volumes from so-called flexible blocks are dispatched first on a *pro rata* basis. See AESO (2006).

age the risks (of, among other things, pricing oneself out of the market) associated with the setting of price offers. This includes near-real-time information on supply and demand, the SMP, and generator outages. The document of interest to this chapter is the Historical Trading Report, with an example shown in Table 3.1. The HTR is published about 10 minutes after real time, so information up to and including HE 8 on a given day is available at 8:10 am. The first two columns show respectively the individual price offers from lowest to highest, and the associated capacities. The third and fourth columns are the original prices and quantities for that hour that were set one day prior. The identity of the firm that submitted each offer is not revealed.

Table 3.1: HTR example for HE 8 on May 13, 2014

Price a.l.r.	MW a.l.r.	Price p.d.o.	MW p.d.o.
0	10	0	10
0	154	0	154
0	26	0	26
⋮	⋮	⋮	⋮
13.13	12	13.13	12
13.32	30	13.32	30
15.38	50	20.38	50
15.56	46	15.56	46
⋮	⋮	⋮	⋮
999.99	181	999.99	181
999.99	29	999.99	0
999.99	3	999.99	3

Firms set their price offers and quantities the day before real time, and can restate them up until two hours before real time.
a.l.r.="after last restatement"
p.d.o.="previous day's offer"

MSA (2012a) classifies the Alberta electricity market as a "tight oligopoly," where the four largest firms have 60-100% of the market (see also Chessler

(1996)). The five largest firms in Alberta (ATCO, Capital Power, Enmax, TransAlta and Transcanada) are shown to own 76% of total capacity. The Alberta electricity market exhibits high concentration due to high fixed costs, lack of storage capability, and inelastic demand. Other examples of tight oligopolies are aluminum and cement.

Several factors constrain market power, either by design or by nature. First, Power Purchase Agreements (PPAs) transferred offer control of coal and natural gas units from the unit owner to the PPA buyer (MSA (2012b)). The buyer sells the electricity into the market and pays the owner the fixed and variables costs of operation, separating ownership from offer decisions. Second, cogeneration units (which reuse heat from electricity production as inputs for eg. oil sands extraction) reduce market power incentive, by creating non-dispatchable must-run power and reducing the firm's exposure to the market price. And third, long term contracts that remove price uncertainty also reduce a firm's exposure.

Barriers to entry such as high fixed costs enhance the ability to exercise market power, by limiting entry and maintaining high market concentration. Incumbent actions including physical withholding also serve as strategic barriers; the MSA monitors the market for such activity and its findings can lead to monetary penalties for contravening firms (economic withholding is not prohibited). Lastly, inelastic demand allows firms to raise the market price without a large fall in demand in any given hour or short time period.

3.3 Relevant literature

3.3.1 Non-cooperative and collusive models of electricity markets

We survey models in which firms submit bids for a finite number of discrete blocks, because of our focus on the bids/offers made on specific blocks (see Fabra et al. (2002) for modeling alternatives). A key result of this literature is that for deterministic levels of demand, multiple non-cooperative Nash equilibria can exist, with one firm setting the price and the remaining firms that are dispatched offering lower prices. Since in equilibrium, for a given set of parameters, either firm could be the price-setter, there is a coordination problem that could be resolved (for example) by communication between firms.

In Fabra et al. (2006), duopoly firms differing in capacity and marginal cost offer their entire capacity at a single price. With uniform pricing and low demand, the equilibrium price equals the marginal cost of the least efficient firm. For demand greater than one firm's capacity but smaller than combined capacities, one firm sets the price equal to the price cap (equal to the monopoly price under inelastic demand), while the other sets a low price to prevent the price-setter from undercutting. Crucially, either firm could be the price-setter, and for certain parameter values there are multiple equilibria. While each firm would unilaterally prefer an equilibrium in which it is *not* the price-setter (since it would sell to capacity at the monopoly price), the equilibrium that maximizes combined profits has the lowest cost firm selling to capacity, and the higher cost firm setting the market price and selling partial capacity. Basiliauskas et al. (2011, footnote 15) refer to communication to select an equilibrium in such a setting as "quasi-collusion;" likewise Bolle (1992) argues that coordination among firms to select the most profitable equilibrium should be viewed as a form of collusion.

The literature predicts two main reasons why electricity firms might secretly communicate with each other. In the following examples, communication can facilitate coordination between a firm who makes a quantity sacrifice, and a rival who benefits from a resulting higher market price (the rival may agree to this if the first firm agrees to switch places with it in the future). This allows for a higher market price than if firms fail to coordinate. We draw our predictions from the literature rather than create our own model, as uniform multi-unit auctions can exhibit complicated strategies and multiple equilibria, particularly when there are many heterogeneous firms. Each major firm could be analyzed with its own model, which would be outside the scope of this chapter.

The first prediction is the selection from among asymmetric equilibria, each with a different firm assuming the role of price-setter (and each firm prefers a different equilibrium). In the duopoly from Crawford et al. (2007), there is no equilibrium where both firms are the price-setter, as either one could unilaterally undercut and produce at full capacity. In Fabra et al. (2006), the static non-cooperative duopoly equilibrium has the price-setter making a high offer and the rival a low one to prevent undercutting, but without mention of how roles are determined. Fabra (2003) and Dechenaux and Kovenock (2007) predict a similar outcome in a collusive setting (and with dynamics, collusion can be sustained if firms alternate roles, which can distinguish this outcome from non-cooperative equilibrium selection).

Figure 3.2 shows a hypothetical duopoly where the price-setting firm B offers $999.23 and produces at partial capacity, where the .23 ending signals its intention to stay at a high offer for the time being (B's offer is not limited by any rival above it in the merit order). Firm A reacts by making a low offer to prevent undercutting.[5] The following day, firm B could set the same ending again, or use a predictable pricing pattern (for example) to signal its intention to continue pricing high, or it could break the pattern with an entirely new ending to signal that it will lower its offer. Analogously, firm A could communicate its intention to price low through signals of its own, such as its .47 ending. Firms' offers in this scenario are expected to exhibit large differences.

The second reason for communication is to allow the marginal firm to increase price. In Fabra et al. (2006) and Porter and Zona (1999), an electricity firm or school dairy provider (respectively) is predicted to raise its bid to the marginal cost of the next highest rival, which raises price if the first firm becomes marginal. In Figure 3.3, firms A, B and C have respective marginal

[5] In a duopoly with high demand, an equilibrium where the price-setter offers at or near the price cap and the rival offers low is consistent with von der Fehr and Harbord (1993).

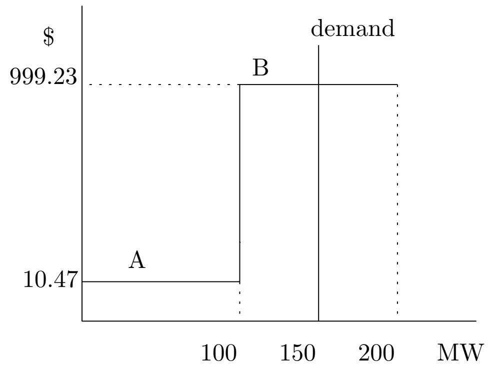

Figure 3.2: Equilibrium with B as price-setter

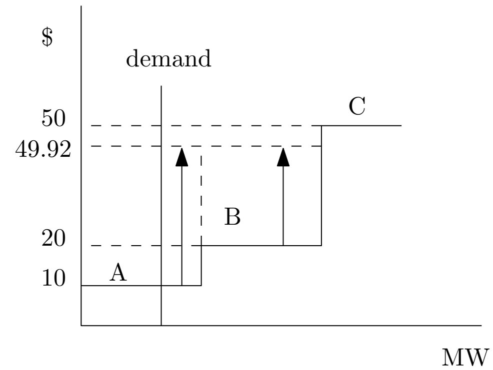

Figure 3.3: Marginal firm raising the market price

costs of \$10 and \$20, and \$50, which (for the purposes of this example) they offer. Since firm A is marginal, it can raise market price from \$10 by offering \$19.99, undercutting B. If B were to undercut C by offering \$49.92, where the .92 ending signals it will remain at that level, A could further raise market price by subsequently offering \$49.91 (a similar phenomenon is described in Basiliauskas et al. (2011)). Under this scenario firms are expected to cluster their price offers close together.

An example of how firms selling a homogeneous good with publicly observable prices might communicate is shown in Lewis (2015). Certain gas stations frequently use the odd price endings 5 and 9, which are positively correlated with high price levels. These endings are hypothesized to be focal points not to be undercut by rivals (this could be signaled by the firm making a one-cent decrease to an odd price ending). In an electricity context, price endings (including combinations thereof across time) can be used to coordinate the events in Figures 3.2 or 3.3.

Crawford et al. (2007) extend the von der Fehr and Harbord (1993) duopoly setting to allow firms to bid multiple blocks corresponding to different generating units with heterogeneous costs. Equilibria are again asymmetric: one firm acts as the price-setter and withholds capacity, while the rival offers all units at marginal cost. Provided firms are not too asymmetric, in equilibrium either one could be the price-setter.

Dechenaux and Kovenock (2007) allow each firm to offer a single price-quantity pair; while a firm must offer all its output at a single price, it can choose to physically withhold, offering a quantity less than total capacity. While Nash equilibria of the one-shot game differ according to demand and firm capacities and according to the market-clearing rule, depending on parameter values, in equilibrium firms may play asymmetric strategies in which one firm sets the market price while others offer quantities below their capacity at low prices to deter undercutting from the price-setter. The authors allow for $n > 2$ firms, while other papers in both collusive and non-cooperative settings (Fabra (2003), Fabra et al. (2006), Crawford et al. (2007)) focus on duopoly, because of the complexities involved in modeling an oligopoly.

Similar asymmetric strategies also emerge in models of collusion. In Fabra (2003), two firms each bid the price at which they offer their entire capacity, and the perfectly collusive strategies that minimize the incentive to deviate involve firms alternating in the role of the price-setter. Each period, one firm establishes the collusive price, while its rival sets a low price that prevents deviating. In the supergame version of the model analyzed in Dechenaux and Kovenock (2007), each firm offers a single block when the market price must be one offered by one of the firms. The perfectly collusive strategies involve one firm establishing the monopoly price, while the other firms offer their share of the monopoly quantity at lower prices. A coordination problem again emerges regarding the identity of the price-setter.[6] When firms can offer multiple blocks, the most sustainable collusive strategies are symmetric, with each firm offering a small amount at the monopoly price and the rest of their share of monopoly output at a low price.

In almost all of the papers discussed (and in contrast to the behaviour described by the MSA), clustering of offers of different firms around the market price is not observed. In both non-cooperative and collusive settings, incentive to deviate is reduced when one firm establishes the market price and the others set lower prices (such as marginal cost), because demand is assumed uncertain over a small support. But for a wider support, the strategies cease to be Nash equilibria, and the only equilibria will be in mixed strategies.

There is a small empirical literature on collusion in electricity markets. Sweeting (2007) and Macatangay (2002) study the two largest electricity firms in England & Wales; bid functions are shown to be interdependent across time and consistent with collusion, sacrificing individual profit through high bids and withheld output. Hortaçsu and Puller (2008) show in the Texas market

[6]When the market price need not be offered by one of the firms, optimal collusion has all firms offering their share of the monopoly output at low prices.

that large firms bid at the theoretical benchmark of individual static profit-maximization, while small firms bid high and forego positive profits, possibly due to participation costs to which large firms are not subject (economies of scale, information gathering).

The aforementioned Crawford et al. (2007) examine bidding asymmetries between price-setting and non-price-setting firms in the British market, using marginal cost and market data from 1993 to 1995. Regressions of the unit-level log markup (bid minus marginal cost) show markups increase with inframarginal capacity, and this effect is greater for price-setting firms, who bid strategically. Non-price-setters bid close to marginal cost. Note that none of these empirical papers consider communication or signaling between firms, nor the process through which firms agree on a price-setter and a market price.

3.3.2 Price leadership

Scherer and Ross (1990, page 248) define price leadership as "(...) a set of industry practices or customs under which list price changes are normally announced by a specific firm accepted as a leader by others, who follow the leader's initiatives."

Much of the literature assumes the leader makes a binding price commitment, instead of sending a retractable signal. Similar to the leadership mechanism in MSA (2013a), firms in Marshall et al. (2008) make "pre-announcements" that can be retracted if rivals do not follow the price increase.[7]

[7] The MSA alleges a firm's high price offers in low demand hours (which are unlikely to

The empirical literature on price leadership has provided some evidence on the mechanism through which firms lead price changes. Atkinson (2009) and Lewis (2012) observe Edgeworth cycles in the Guelph, Ontario and American gasoline markets respectively: an abrupt price increase is followed by a gradual decrease as firms undercut each other, followed by another abrupt increase and so on. Major brands controlling prices at many stations lead price restorations, as the increased visibility reduces the chance that no one follows, with small stations leading the undercutting. Andreoli-Versbach and Franck (2015) and Lewis (2015) find that large, infrequent price changes by the leader station can serve as focal points for the followers, who match the observed changes.

The literature considers only simple markets in which firms set single prices on homogeneous or differentiated products. To our knowledge, no work has explored price leadership in a multi-unit auction with more complicated strategies (offer curves consisting of many blocks, which have more potential to signal future prices), nor in the context of coordination between multiple equilibria.

3.4 The MSA allegations

The MSA's concern is that the Historical Trading Report allows firms to coordinate their offers in a way that results in "sharply higher wholesale prices" (MSA (2013, page iii)). In their August 2013 report they briefly discuss ten days from the 2011-2013 period on which they believe the HTR allowed firms to coordinate prices. The focus is on days that were expected to have "higher

be dispatched) serve to pre-announce offers for similar volumes in later high-demand hours.

than normal" prices regardless of coordination, and for which preceding days likely provided little information on firms' strategies for the day in question.

In general, the examples describe events unfolding as follows. Early in the day or late in the night, a firm establishes a "shelf" in the merit order: a flat portion comprised of similarly-priced offers, such that the merit order is highly inelastic at slightly lower quantities. The firm setting the shelf "tags" its offers so its identity is revealed. This is important because rivals might recognize the firm, and from repeated interactions understand it will not reduce the shelf level to compete over the course of the day. Rivals change offers on certain blocks to slightly undercut the shelf, which widens it (similar to Figure 3.3 from Section 3.3.1). Rivals wish to price these units as high as possible without pricing themselves out of the market (see von der Fehr and Harbord (1993)), resulting in higher prices than would otherwise obtain.

The marginal firm's ability to raise its offer (and potentially the market price) is limited by the offer of the next highest firm in the dispatch. If the lowest non-dispatched firm raises its offer, this allows the marginal firm to raise the price while remaining in the market. Baziliauskas et al. (2011) mention that, with frequent and repeated interaction, the non-dispatched firm may agree to this with the expectation that the roles will be reversed in a later hour, consistent with collusion between firms alternating as the price-setter. The HTR would allow firms to identify the non-dispatched firm, and to monitor whether implicit price offer agreements are maintained.

As an example, MSA (2013a) describes events from March 4, 2013. In HE 24 the previous night, a firm identified only as participant A offered 647 MW between $974.00 and $980.00, possibly for withholding purposes (subsequent data work reveals that participant A is Capital Power, and B is Transcanada). According to the MSA, thanks to the HTR, rivals determined with reasonable certainty that the capacity was offered by firm A thanks to A's tagging of its offers. Participant B offered 433 MW at fluctuating prices, settling between $490.18 and $690.63 by HE 14. A third firm (shown by the data to be TransAlta) offered 274 MW at $899.00, most of which was known from previous hours to be unavailable to produce. In HE 18, at which point all the above was known, participant B raised its 433 MW to prices between $895.18 and $899.00, undercutting the rival 274 MW (which was not expected to respond competitively).

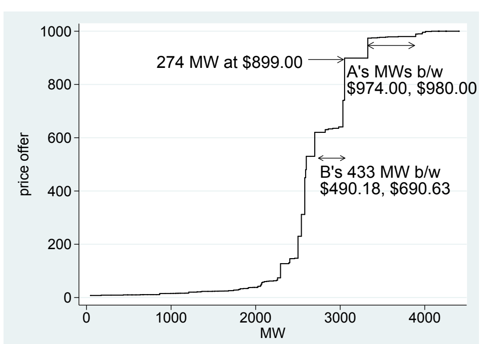

Figure 3.4: Before firm B's price offer increase (HE 17 of March 4, 2013, offers> $0)

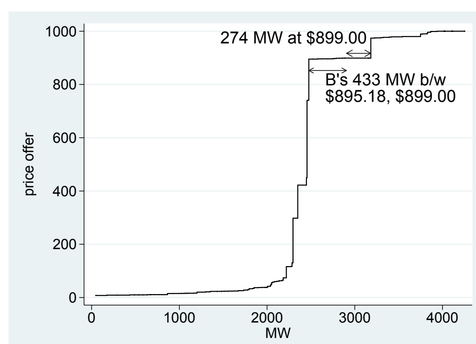

Figure 3.5: After firm B's price offer increase (HE 18, offers> $0)

Figures 3.4 and 3.5 show the market merit orders (limited to strictly positive offers) before and after participant B's change. The MSA alleges that without the HTR, B would not have known the identities of the rivals making the high offers, nor would it have known to offer within a narrow price range of less than four dollars. (The pool price in HE 17 was $130.58; in HE 18 it rose to $390.92.) In a more general sense, this example may show that excessive market transparency can lead to high market prices and market failure, owing to behaviour like that depicted in Figure 3.3.

On April 17, 2013 the MSA consulted with stakeholders to gather feedback on proposed changes to the HTR that would reduce opportunities for coordination, publishing the mostly negative comments on May 9, 2013. On August 7, 2013 the MSA submitted its final recommendation to the AESO and to the Alberta Utilities Commission (AUC, responsible for utilities regulation): the publication of the frequency of price offers would occur within aggregated price bands, released on the same schedule as the incumbent HTR, with more detailed price bands released the following day.

In January 2015 the AESO announced changes to the HTR: the full version would be released 12 hours after real time, and the information released in accordance with the incumbent schedule would have offers combined into $200 bands above $250.00 (with the highest band from $850.01 to $999.99). In April 2015 the AESO was served with a court application by the Independent Power Producers Society of Alberta, challenging the proposed changes (see AESO (2015a) and AESO (2015b)). In March 2016 the court declined to make a decision, deferring to the expertise of the AUC (Bankes (2016)), who is scheduled to meet with the MSA in October 2016 for further discussion.[8] As of this writing, no changes to the HTR have been implemented.

3.5 Firms' tagging behaviour

This section investigates firms' use of "tagging strategies" as a method of self-identification through the HTR, which could allow firms to coordinate price offers as described in Section 3.3.1. We show first examples of how firms tag their offers, and second the extent to which they can be recognized by rivals, to show how market transparency affects (potential for) coordination. In this section and those that follow, a firm's generating assets will refer to those under its offer control either through ownership or through PPAs.

3.5.1 Transcanada's tagging rule

Transcanada appears to employ a complex pricing rule between January 1 and July 15, 2013, violations of which account for only 0.7% of its offers during this period and display no discernible pattern. Table 3.2 shows an example, limited for brevity to a subset of offers that illustrate the pattern, with assets (and block numbers in parentheses). On January 1, the difference between any two of its price offer endings is a multiple of nine. The next day, a given offer's ending changes by either one or ten cents, maintaining the multiple-of-nine difference for that day, and then again the day after that, etc. After seven days, the cycle resets (on January 8) and the endings are drawn from

[8] See `http://www.auc.ab.ca/applications/hearings/Lists/Hearings%20Calendar/DispForm.aspx?ID=569`.

the same set used on the first day. On January 1 in Table 3.2, an ending of .08 would violate the pattern.

Table 3.2: Selection of Transcanada's price offers, January 1 2013 to January 8 2013

Asset	Jan 1	Jan 2	Jan 3	Jan 4	Jan 5	Jan 6	Jan 7	Jan 8
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
SH2(4)	33.33	33.34	33.35	33.36	33.46	33.56	33.66	33.33
SH2(5)	33.42	33.43	33.44	33.45	-	-	-	-
SH1(4)	33.42	33.43	33.44	33.45	33.55	33.65	33.75	33.42
SH1(5)	33.51	33.52	33.53	33.54	-	-	-	-
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮
TC01(1)	989.15	989.16	989.17	989.18	989.28	989.38	989.48	989.15
BCRK(1)	990.06	990.07	990.08	990.09	990.19	990.29	990.39	990.06
Number of distinct non-zero price offers used by TC								
	27	28	32	37	48	38	43	47

Note: Block numbers are listed in parentheses after the asset.

Figure 3.6 graphs Transcanada's daily price endings from January to September 2013. On a given day up until July, the vertical distance between two price endings is a multiple of \$.09. The following day the endings increase by \$.01 or \$.10 and the points move to the north-east, repeating with a seven-day cycle.

The pattern in Figure 3.6 is also notable because Transcanada's use of price endings starts exhibiting irregularities in mid-July, and by mid-August any semblance of a pattern abruptly breaks down altogether. It can be shown through visual inspection of the data that starting July 15, on a given day the nine-cent increment rule is maintained but the day-to-day change is irregular (no longer one or ten-cent increases), and starting August 8 the aforementioned rule ceases, with about two dozen distinct endings used per day. From August 15 onwards the endings on a given day span almost the entire range from .00

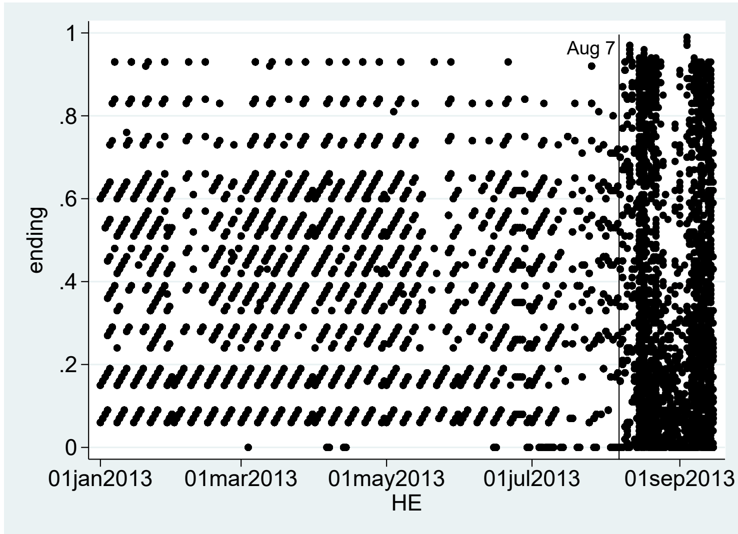

Figure 3.6: Transcanada's daily price endings

to .99, save for a period in late August and early September when endings are concentrated on low values. It is notable that the MSA formally recommended a less transparent version of the HTR on August 7 (MSA (2013a)), which could have precipitated the end of Transcanada's nine-cent increment rule the next day. Other firms do not display such a stark change in their use of pricing rules within the full sample period.

Another visualization of the pattern change can be seen through the number of distinct endings used by Transcanada, shown in Figure 3.7. The number of endings is low for most of the sample period, increases slightly on August 8, and then increases sharply on August 15.

Transcanada typically keeps its price endings intact when changing the price level of different blocks. In the March 4 example from MSA (2013a) described in Section 3.4, Transcanada (firm B) moved 433 MW from a low

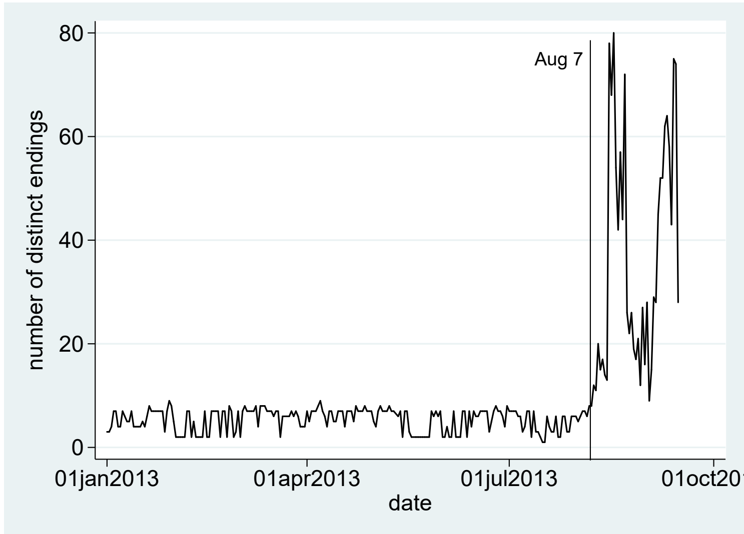

Figure 3.7: Transcanada's number of distinct endings per day

price range in HE 17 to a high range in HE 18, the top end of which was exactly equal to the $899.00 offers from TransAlta, the rival being undercut. Transcanada preserved all its endings, save for two 25 MW blocks going from $640.54 and $640.63 (the top end of the HE 17 price range) to both offered at $899.00 in HE 18.

During our sample period, 2,071 MW of Transcanada's offer control were through PPAs. The assets were SD1, SD2 (Sundance A, owned by TransAlta), SD3, SD4 (Sundance B, also owned by TransAlta), SH1 and SH2 (Sheerness, owned by TransAlta and ATCO); see MSA (2013b) and Kendall-Smith (2013). Transcanada's remaining offer control accounted for 462 MW.

3.5.2 Description of simple tagging rules

Firms' offers are shown to follow simple patterns or rules; we describe some of these and evaluate firms' ability to identify each other through offer behaviour.

Examples of simple rules are repeated use of a capacity block size or price offer decimal ending; more complex ones include combinations of sizes and endings or patterns over time. This so-called tagging behaviour can be difficult to detect by an outside observer because of the many ways it may be done.

Unless otherwise indicated, the data for Section 3.5 are from January 1 2013 to May 31 2013. Prior to this period, the AESO did not report the firm controlling a particular asset, making it difficult to examine individual firm behaviour. The MSA's announcement in June 2013 of potential changes to the HTR may have affected firm behaviour after this period (subsequent sections will consider the period after June 2013). The data are limited to offers above \$100 (to remove the influence of units with high shutdown costs that set low offers with high dispatch probability, and of marginal cost offers), and strictly below the price cap of \$999.99.

Table 3.3: Most frequently used block sizes in MW by firm, price offer $\in (100.00, 999.99)$

Rank	ATCO	CP	Enmax	TA	TC
1st	13 (12.0)	10 (23.8)	40 (13.0)	40 (15.5)	25 (18.8)
	56.5	**62.2**	**26.7**	**35.7**	**50.4**
2nd	34 (10.3)	70 (13.9)	20 (12.1)	80 (9.3)	35 (12.3)
	87.7	**85.4**	**43.1**	**71.5**	**31.2**
3rd	25 (5.0)	27 (13.5)	41 (11.3)	230 (7.5)	52 (11.1)
	17.9	**79.0**	**82.8**	**100**	**94.2**
4th	47 (4.5)	43 (9.0)	25 (10.9)	270 (6.6)	18 (10.2)
	90.7	**60.7**	**17.3**	**100**	**63.6**
5th	20 (3.9)	35 (8.9)	42 (10.2)	70 (3.4)	21 (9.5)
	31.2	**26.1**	**58.2**	**12.0**	**85.9**

Note: The first number is the block size, followed in parentheses by the percentage frequency out of all that firm's block sizes; the percentage of occurrences of this size belonging to the firm in question is in bold.

A basic tagging method is through capacity block sizes, with the most commonly used sizes for each large firm (ATCO, Capital Power, Enmax, TransAlta and Transcanada) shown in Table 3.3. The percentage frequency within the firm's portfolio is in parentheses, and the firm's share of all offers of that size is in bold. The five firms' respective top five block sizes account for anywhere from 36% to 69% of that firm's portfolio offered within the specified price range. Each firm has at least one size where they are the majority user. Block sizes also have physical constraints which may limit signaling capability.

Another tagging method is through price offer endings, which are unlikely to affect merit order position or market price, with the most common ones shown in Table 3.4. Each large firm's respective top five endings account for 59% to 87% of the firm's total endings, save for Transcanada's, which account for 20%. Transcanada is also the only large firm whose most used ending is not .00.[9] As with block sizes, firms have at least one ending where they are the majority user.[10]

MSA (2013a) alluded to the use of price endings as signaling devices, but does not present evidence such as Tables 3.3 and 3.4, which suggest that individual firms employ specific endings that may have signaling capability. A caveat about price endings is that a firm with a high ending frequency may

[9]Figures A.1 through A.5 in Appendix A show each firm's cumulative usage frequency of individual endings.

[10]A firm observing a rival price ending or block size eliminates its own offers/blocks containing that value when assessing whether it came from a particular rival. Hence the firm assigns to its rivals higher probabilities than those in Tables 3.3 and 3.4, which are assigned by an outside observer.

Table 3.4: Most frequently used price offer endings by firm, price offer $\in (100.00, 999.99)$

Rank	ATCO	CP	Enmax	TA	TC
1st	.00 (53.1)	.00 (62.5)	.00 (50.8)	.00 (37.0)	.08 (4.4)
	21.4	**21.8**	**9.0**	**7.4**	**82.6**
2nd	.99 (2.0)	.50 (8.9)	.99 (5.7)	.99 (27.8)	.07 (4.4)
	29.7	**70.7**	**37.4**	**91.5**	**83.3**
3rd	.69 (1.4)	.01 (4.8)	.30 (3.7)	.24 (11.1)	.06 (4.2)
	75.3	**62.7**	**42.0**	**75.5**	**77.1**
4th	.01 (1.3)	.98 (4.0)	.20 (3.6)	.12 (5.8)	.09 (3.6)
	20.2	**7.3**	**51.7**	**64.7**	**75.9**
5th	.67 (1.3)	.02 (3.9)	.10 (3.2)	.15 (5.3)	.15 (3.3)
	82.3	**63.4**	**58.1**	**44.0**	**40.5**

Note: The numbers in parentheses and in bold are analogous to those in Table 3.3.

be repeating a given price, which tends to be true of Capital Power. Table 3.5 shows how often certain of Capital Power's endings are used with a single price offer; eg. of all its offers greater than \$100.00 ending in .51, 67% of them are \$949.51. The second ending of each sequence (.01, .51) is more concentrated on a particular price offer than the first one (.00, .50); the second ending could simply be part of a repeated price offer without intent to signal.

Table 3.5: Frequency of price offers with a given ending by a given firm (price $\in$ (\$100.00,\$999.99))

Ending	Price (\$)	Firm	Frequency (%)
.00	976.00	Capital Power	6.2
.01	975.01	Capital Power	47.1
.50	976.50	Capital Power	34.1
.51	949.51	Capital Power	67.2

3.5.3 More complex rules

There are other patterns beyond the simple use of endings and block sizes, some of which are described here (other identified patterns that do not seem to have strong signaling ability are omitted). In Table 3.6, a second facet of Transcanada's pricing rule has pairs of identical price offers staggered with identical block sizes. Going up the merit order, every second price ending also seems to be nine cents higher than the immediately preceding one. (The pattern does not hold throughout this hour.) The pairs of identical endings belong to the Sheerness 1 and 2 assets (SH1, SH2). The two entries that break the pattern belong to Sundance 3 (SD3) and Redwater Cogen (TC02), and may be part of a different signal.

Table 3.6: Example of Transcanada's tagging rule: HE 11 of March 15, 2013 (excluding price offers of $0)

Asset ID	Price offer ($)	Price ending	Block size (MW)
SH2	15.06	.06	65
SH1	15.15	.15	65
SH2	20.15	.15	50
SH1	20.24	.24	50
SH2	825.24	.24	62
SH1	825.33	.33	62
SH2	835.33	.33	18
SH1	835.42	.42	18
SH2	859.42	.42	35
SH1	859.51	.51	35
SD3	865.15	.15	53
SH2	900.51	.51	25
SH1	900.60	.60	25
TC02	989.06	.06	4

Capital Power's tagging rule involves price offers with the endings .00/.01

or .50/.51. For example, on February 15, 2013, in every hour from HE 8 to HE 23 its portfolio included the offers \$949.50 and \$949.51. Coupled with instances where it offers one of its top five block sizes, this ending pattern accounts for 71% of Capital Power's offers.[11] The MSA (2013a) March 4 example also shows Capital Power (firm A) making the series of offers \$974.00, \$975.00,. . ., \$980.00 in a given hour. This pattern of consecutive integer offers coupled with one of its top block sizes accounts for 72% of Capital Power's offers; the integer pattern alone accounts for 13%.

3.5.4 How well do the different patterns reveal firm identities?

We examine candidate tagging rules for the five big firms. ATCO's, Enmax's and TransAlta's proposed rules are simply their respective top five capacity block sizes, while Capital Power's and Transcanada's (two versions each) are combinations of block sizes and price endings.

1. ATCO: block size is one of 13, 34, 25, 47, 20 MW.

2. Capital Power (first): block size is one of 10, 70, 27, 43, 35 MW, or one of the price ending sequences (0, .01) or (.50, .51).

3. Capital Power (second): block size is one of 10, 70, 27, 43, 35 MW, or either three or four consecutive price offers increasing in one dollar increments.

[11] Removing the influence of the prices in Table 3.5 has little effect on results.

4. Enmax: block size is one of 20, 41, 40, 25, 42 MW.

5. TransAlta: block size is one of 40, 80, 230, 270, 70 MW.

6. Transcanada (first): block size is one of 25, 21, 52, 35, 18 MW, or consecutively-offered identical block sizes and consecutively offered price offers with identical endings (example in Table 3.6).

7. Transcanada (second): seven-day cycling strategy, price endings on a given day differ by a multiple of $.09 (example in Table 3.2, Figure 3.6).

While ATCO, Enmax and TransAlta are only assigned block size tagging rules, they may be employing price ending patterns that were not detected by visual inspection of the data. Hence this list is not exhaustive, but shows that there are tagging rules allowing firms to identify each other through the HTR.

The probabilities that a block size or price offer consistent with one of the tagging rules described above comes from the corresponding firm (or not) are shown in Table 3.7.[12] In each two-by-two set of probabilities, the bottom-left entry is a type 1 error (false positive), and the top-right is a type 2 error (false negative). Upon observing an ending or block size from a given tagging rule, the probability the ending/size came from the firm to which the rule is assigned ranges from 34% to 57%. A given rule is therefore not specific to the firm in question, and other firms employ it as well (intentionally or not). However upon observing an element not part of it, the probability it did *not*

[12] As with Tables 3.3 and 3.4, these are probabilities assigned by an outside observer.

Table 3.7: Probability of being correct when predicting firm identities upon observing some price ending or quantity (column percentages)

	Item 1	
	Predict firm is ATCO	Predict not ATCO
Firm is ATCO	.435	.141
Firm is not ATCO	.565	.859
	Item 2	
	Predict firm is CP	Predict not CP
Firm is CP	.567	.059
Firm is not CP	.433	.941
	Item 3	
	Predict firm is CP	Predict not CP
Firm is CP	.501	.057
Firm is not CP	.499	.943
	Item 4	
	Predict firm is Enmax	Predict not Enmax
Firm is Enmax	.336	.041
Firm is not Enmax	.664	.959
	Item 5	
	Predict firm is TA	Predict not TA
Firm is TA	.536	.057
Firm is not TA	.464	.943
	Item 6	
	Predict firm is TC	Predict not TC
Firm is TC	.546	.058
Firm is not TC	.454	.942
	Item 7	
	Predict firm is TC	Predict not TC
Firm is TC	.439	.001
Firm is not TC	.561	.999

Note: The first column is conditional on observing an ending/block size that belongs to a strategy from the given firm; the second column is conditional on observing one that does not. The "column percentages" apply to each pair of rows in the table, and not to the table as a whole. So for ATCO at the top of the table, the numbers in each column sum to 100%. Tagging rules were described in Section 3.5.4.

come from the associated firm is at least 86%. Removing the effect of the repeated prices such as those in Table 3.5 has little effect.

This section showed that firms adopt certain tagging strategies that respective rivals seldom use. They range from individual price endings or block sizes, to complicated combinations thereof over time (Capital Power and Transcanada). Transcanada had a detailed pricing rule involving nine cent increments between different endings, which it seemingly abandoned partway through the full sample period, possibly in anticipation of or in reaction to the MSA's recommendation about the HTR. Moreover, it is reasonable to assume that a firm, conditional on knowing what patterns to look for, could identify individual rivals through their endings and block sizes listed in the HTR, which can facilitate communication and coordination.

3.6 Characterization of pricing in the Alberta electricity market

The following sections search for evidence of the price clustering within a time delay of four or more hours that was part of the MSA's allegations. We first define two methods of representing a firm's (or set of firms') hourly strategy with a single price offer, to remove the influence of offers with little or no strategic component. Then we analyze hourly changes in each large firm's representative price offer relative to those of its rivals, to verify the extent to which they seem to react to or undercut each other within a given time frame to test for clustering.

3.6.1 Defining the kink price

This section creates a measure of each firm's hourly strategy, to determine if knowledge of rival identities affects pricing strategies as described in Section 3.3.1. The intuition for the so-called "kink price" as a focal point for coordination is as follows: a firm j offers a large amount of capacity at a high price in the early morning, and continues to do so for the duration of the day, establishing its kink price below which the merit order is steep. A rival firm i becomes aware of this gesture (eg. through tagging), and subsequently undercuts by setting its own kink price just below j's, confident that j's capacity will remain high. This allows i to raise the market price if marginal while maintaining its merit order position.

We model the price at which the merit order undergoes a rapid increase in elasticity, reducing a firm's (or group of firms') hourly strategy to a representative price to isolate the strategic component. This concept is motivated by Macatangay (2002), in which electricity firms in the UK are said to collude by offering steep offer curves: MWs at low prices are followed by MWs at high prices, with little in between. It is also motivated by MSA (2013, page 9), which describes "a market participant establishing a high price offer ledge below which the merit order is very steep".

We consider two different methods of identifying the kink price. For quantity $q(p)$ and price offers p and p', kink prices 1 and 2 are defined as

$$\text{kp1} \equiv \underset{p\in[100.00,999.99]}{\text{argmax}} \{p - p' | q(p) - q(p') = 100 \text{ MW} \cap p > p'\}, \tag{3.1}$$

$$\text{kp2} \equiv \underset{p\in[100.00,999.99]}{\text{argmax}} \{q(p + \$100) - q(p)\}. \tag{3.2}$$

In words, kink price 1 (kp1) is the point in the merit order at the top of the steepest dollar increase occurring within a 100 MW horizontal band, while kink price 2 (kp2) is the point at the base of the largest amount of MWs offered within a $100 vertical band.

Consider ATCO's merit order for HE 17 of January 21 in Figure 3.8 as an example. Kink price 1 occurs at a price of $689.14 and cumulative capacity of 775 MW; by moving leftwards by 100 MW, we end up at point A to the southwest, a price of $34.99. This vertical difference ($689.14 – $34.99) is the largest such jump in the merit order.

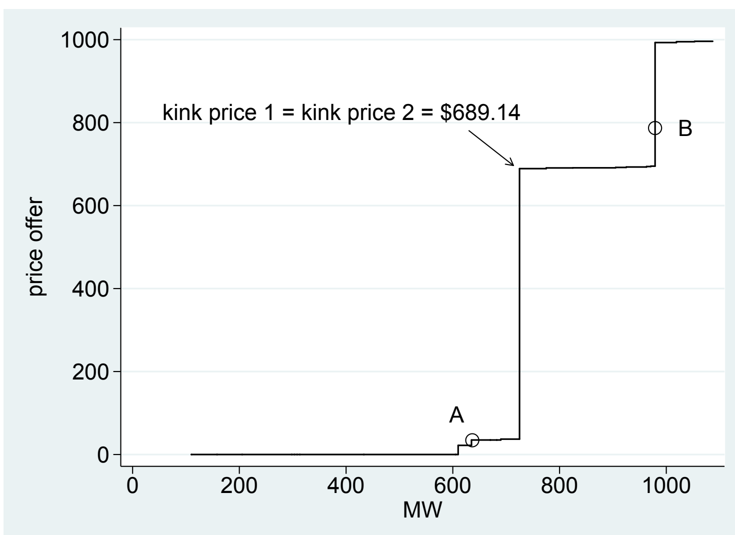

Figure 3.8: ATCO's merit order with kink prices (January 21, HE 17)

Kink price 2 also occurs at $689.14. By moving upwards by $100, we end up at point B to the northeast, at a cumulative capacity of 1,019 MW. The horizontal difference between these points (1,019 MW$-$775 MW) is the largest such difference in the merit order. Kink prices 1 and 2 can apply to an individual firm (as in Figure 3.8) or to the market, and can also occur at different prices in a given hour. They are also limited to offers of $100.00 and above to remove the influence of units offered low due to must-run constraints.

Large firms' price offers can be shown in broad terms to follow the pattern described at the beginning of this section. Table 3.8 shows the frequency with which each firm makes an offer within a given price band over the full sample. Over 65% of each of the five firms' offers are below $200, consistent with constrained-on or marginal cost offers. Most of the remaining offers occur at high prices above $800. A firm's merit order thus tends to be flat and at low prices for most of its available MWs, before rising sharply to high prices for the remaining MWs.

Table 3.8: Percentage of MWs offered in different price bands (January 1-September 15, 2013)

Price band ($)	ATCO	CP	Enmax	TA	TC
offer=0	31.0	23.9	26.9	46.5	37.8
0<offer≤200	38.3	43.0	59.1	24.9	44.3
200<offer≤800	5.5	9.2	6.6	1.4	4.4
offer>800	25.2	23.8	7.4	27.2	13.5

The extent to which firms' price offers follow the defined rules can be quantified with some informal rules similar to those used for kink prices 1 and 2. Consider the rule where an individual merit order exhibits a vertical jump of at least \$300, and all offers above the top of that jump are contained within a band of \$200. This rule accounts for 88% of ATCO's hourly merit orders within the sample period, 75% of Capital Power's, 44% of Enmax's, 93% of TransAlta's, and 89% of Transcanada's.

The shortcoming of the kink price approach is that neither version simultaneously captures the steep jump and the flat part of the merit order, both of which are necessary to identify the point with the greatest elasticity increase which serves as a potential focal point for firms. Doing so would require defining more arbitrary parameters. Since, to the best of our knowledge, the literature has not yet attempted to model multi-unit auction price offers in this manner, the kink prices are a first attempt.

If collusion of the form shown in Figure 3.3 is occurring, certain firms will set a kink price (either kink price 1 or 2) that is consistently lower by a small amount than the kink prices of particular rivals, and within a delay of at least four hours.

Figures 3.9 through 3.13 show the cumulative distributions of kink price 1 for each of the five firms in all hours over the full sample period. In broad terms, firms' kink prices are concentrated on high values. ATCO's, TransAlta's and Transcanada's kink prices are concentrated near the price cap, hence may be less likely to undercut rivals (Enmax also offers high, though to a lesser extent). Conversely, those three firms can be price clustering, though they can also be simply offering near the price cap independently of each other. Capital Power places weight on lower values, and could be a candidate undercutter.

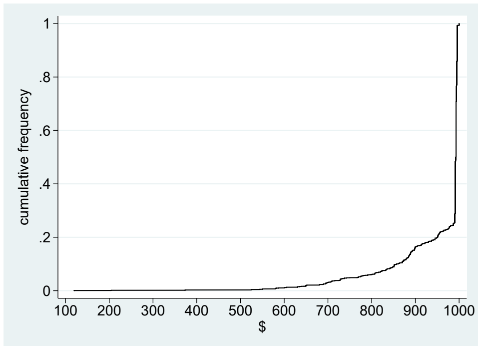

Figure 3.9: Distribution of ATCO's kink price 1

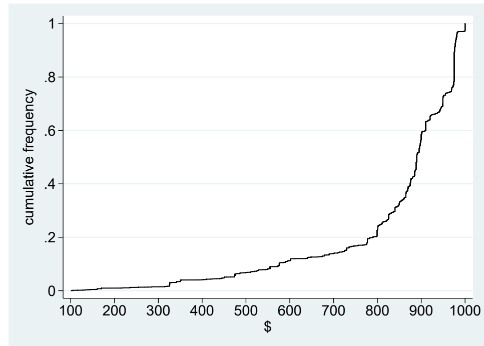

Figure 3.10: Distribution of CP's kink price 1

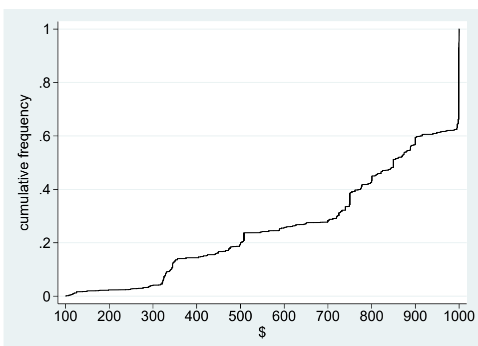

Figure 3.11: Distribution of Enmax's kink price 1

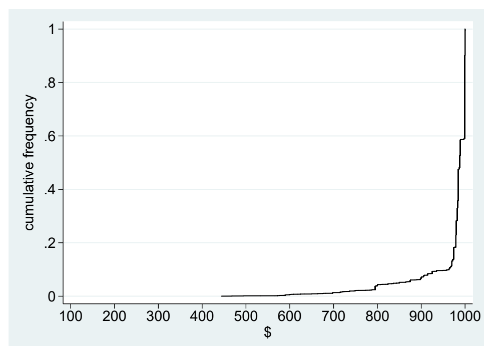

Figure 3.12: Distribution of TA's kink price 1

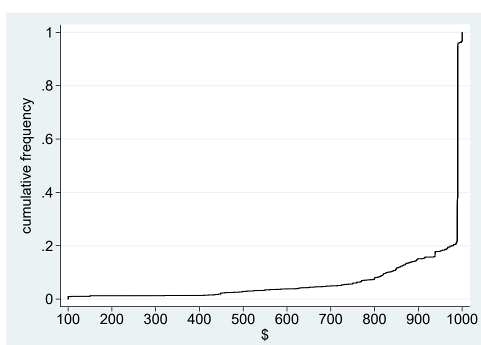

Figure 3.13: Distribution of TC's kink price 1

3.6.2 Summary statistics

We analyze the timing of kink price changes and the offer values to which they change. If price clustering is occurring, then certain pairs of firms are expected to coordinate their kink price changes and values within a certain time frame (with one firm setting kink prices that are consistently undercut by a particular rival within four or more hours).

Table 3.9 shows the frequency with which a rival made a kink price change between $h-6$ and $h-4$, followed at h by a kink price change by a given firm; each cell shows the instances for kink prices 1 and 2 respectively. The sample is from January to May inclusively (as in Section 3.5), accounting for the period leading up to the MSA's announcement in June of possible changes to the HTR. Transcanada changes its kink price after the rivals the most often, while Enmax seldom does. The most frequent leader of changes is either Capital Power (kink price 1) or Transcanada (kink price 2), with Capital Power often leading changes by Transcanada.

Table 3.9: Number of instances where leader (row) changes kink price four to six hours prior to follower (column) changing its kink price, low supply cushion days, January 1 to May 31, 2013

Lead\Follow	ATCO	CP	Enmax	TA	TC	Sum
ATCO	-	105/102	25/26	69/41	104/121	303/290
CP	99/93	-	32/30	88/46	131/130	350/299
Enmax	64/59	73/70	-	58/32	86/86	281/247
TA	67/43	86/61	15/12	-	87/62	255/178
TC	96/99	108/117	23/34	79/61	-	306/311
Sum	326/294	372/350	95/102	294/180	408/399	

Note: In each cell, kink price 1 is listed first, followed by kink price 2.

The MSA also alleges that firms sets price offers to undercut the next highest rival in the merit order. To test this, Table 3.10 shows the frequency with which a firm undercuts a rival by \$50 or less, conditional on the firm making a kink price change four to six hours after the rival. Transcanada undercuts its rivals often, and Enmax seldom undercuts, similarly to the pattern in Table 3.9. Transcanada seemingly follows ATCO frequently in both tables.[13]

Table 3.10: Number of instances where follower undercuts leader by \$50 or less, conditional on having made a kink price change four to six hours after the leader, low supply cushion days, January 1 to May 31, 2013

Lead\Follow	ATCO	CP	Enmax	TA	TC	Sum
ATCO	-	14/24	2/1	20/5	51/43	87/73
CP	5/10	-	6/6	14/4	27/21	52/41
Enmax	15/8	10/11	-	12/3	10/12	47/34
TA	19/3	11/4	0/0	-	31/18	61/25
TC	7/14	21/25	1/3	20/17	-	49/59
Sum	46/35	56/64	9/10	66/29	119/94	

Note: In each cell, kink price 1 is listed first, followed by kink price 2.

A certain firm's role as leader (of kink price changes or of undercutting) could be underestimated if it prices capacity high and leaves it there throughout the day, as suggested by the MSA (2013a) March 4 example for Capital Power. Hence the full extent of rivals' undercutting of Capital Power's kink price may not be captured in Tables 3.9 and 3.10. Meanwhile Enmax tends to set low price offers possibly because of its vertical integration (which reduces market power incentive).[14]

[13]As an example, in Figure A.13 in Appendix A, Transcanada's kink price 1 on a given day is consistently within \$20 below ATCO's save for HE 8 and HE 9.

[14]As a robustness check, Tables 3.9 and 3.10 are repeated at the individual asset level for the five large firms (a firm owns different generating assets, each of which offers up to seven blocks per hour). An asset's representative price offer per hour is taken alternatively to be

Table 3.11: Number of instances where leader changes kink price four to six hours prior to follower changing its kink price, low supply cushion days, July 15 to September 15, 2013

Lead\Follow	ATCO	CP	Enmax	TA	TC	Sum
ATCO	-	46/37	29/37	22/10	132/87	229/171
CP	48/27	-	35/50	21/11	137/91	241/179
Enmax	43/30	40/42	-	17/15	131/136	231/223
TA	26/11	26/13	20/24	-	92/42	164/90
TC	80/48	89/61	80/89	48/17	-	297/215
Sum	197/116	201/153	164/200	108/53	492/356	

Note: Numbers in each cell are analogous to those in Table 3.9.

Tables 3.9 and 3.10 can also be repeated for the time period after July 15, the point at which Transcanada ceased its nine-cent tagging strategy (recall Figure 3.6). In Tables 3.11 and 3.12, Transcanada is again the most frequent follower in both tables, though it does not seem to follow TransAlta often (TransAlta in general seldom leads rivals). ATCO is undercut the most often.

Table 3.12: Number of instances where follower undercuts leader by \$50 or less, conditional on having made a kink price change four to six hours after the leader, low supply cushion days, July 15 to September 15, 2013

Lead\Follow	ATCO	CP	Enmax	TA	TC	Sum
ATCO	-	8/7	4/3	14/5	78/29	104/44
CP	4/7	-	2/6	1/3	13/13	20/29
Enmax	18/4	4/4	-	9/5	61/35	92/48
TA	0/1	7/5	1/1	-	3/2	11/9
TC	5/6	23/9	6/6	35/8	-	69/29
Sum	27/18	42/25	13/16	59/21	155/79	

Note: Numbers in each cell are analogous to those in Table 3.10.

To summarize, Transcanada stands out because it seems to follow rivals most frequently (both in terms of changing its kink price after the rivals, or

the maximum one, and the smallest one above \$100. Results (not shown) are similar to the firm-level statistics: the leader-follower relationship between assets belonging to two firms is similar to that between the firms themselves.

undercutting them), and tends to lead as well. ATCO and Capital Power lead to a lesser degree, while Enmax does not often follow rivals. There do not appear to be consistent leader-follower pairings, hence limited evidence for price leadership based on known identities. After July 15, Enmax is followed by its rivals more frequently than before. Transcanada follows and undercuts rivals the most often, more so after July 15; it is therefore a candidate for the undercutter in the event that price clustering is occurring, and its change in price endings could be signaling a different pricing scheme.

3.6.3 Convergence of high offers during the day

A key element of the coordination mechanism described by the MSA is that over the course of a day, price offers increasingly cluster around price shelves observed earlier in the day. This mechanism was described in section 3.4. We briefly examine the extent to which this behaviour is observed generally throughout the sample, focusing on peak hours (HE 8 through HE 23) when demand is higher and market power is more likely to occur.

Different methods can be used to measure the degree of clustering, and how it changes over the day. The MSA allegations were specifically that firms observe a price offer above which the merit order is flat, and below which it is steep; over the day they increase their own offers to slightly undercut it. Initially, we employ two different methods of identifying that price offer: kink prices 1 and 2 defined in Section 3.6.1.

Figures 3.14 and 3.15 show the average hourly number of MWs priced within \$100 above or below each of the two kink prices on days when the supply cushion is below the 25th percentile, within the January 1-May 31 period. Neither shows signs of the convergence suggested by the MSA. Alternative measures include the standard deviation of offers above \$100 (weighted by the MW associated with each one) and the hourly proportion of MWs offered at \$800 or higher.[15] Again, no trend towards smaller standard deviations nor higher offers later in the day are observed (see Figures A.6 and A.7).

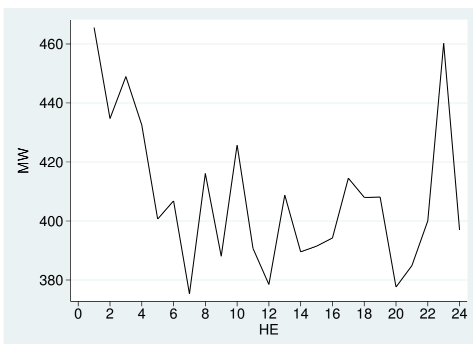

Figure 3.14: Average MWs within \$100 of kink price 1

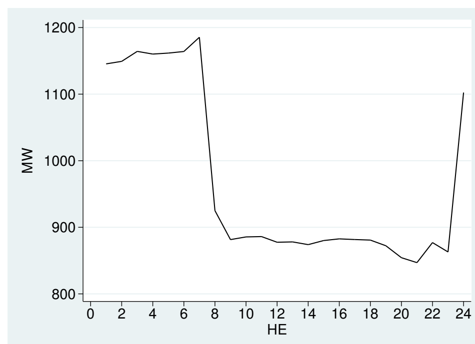

Figure 3.15: Average MWs within \$100 of kink price 2

Various versions of the measures described above were computed using data only for high demand days (where the maximum demand for the day was in the top 75th or 90th percentile) and for days with low supply cushions, yielding similar conclusions. Hence, we observe little evidence that increasing clustering during the day occurs except on rare occasions (some of which are discussed in MSA (2013a)). When clustering does occur, it is usually in the early morning hours, and when the market kink price is high (above \$900).

[15]These measures account for the clustering observed on March 4 from Section 3.4; (Figure A.8 exhibits a jump in clustering at HE 18).

While the MSA included examples from 2013, it had commented publicly on the clustering of prices as early as 2011. We did not observe such clustering in 2011 nor 2012 (see Figures A.9 to A.12 in Appendix A). Hence evidence of phenomena such as in Figure 3.3 does not get stronger as the day progresses and demand increases.

A caveat is that, as noted in the theoretical discussion, economic theory is unclear on whether collusion would in fact require such convergence. While a firm may undercut the next highest rival by a small amount to raise price, collusion may be more sustainable with one firm setting the market price and the others setting low offers to prevent deviations.

3.7 Econometric analysis of coordination between firms

3.7.1 Firms' tendency to coordinate their price offer changes

This section investigates whether the predicted outcomes from 3.3.1 arise, controlling for effects that were not accounted for in 3.6.2. We test whether some firms coordinate their kink price changes (a prerequisite for both predicted outcomes), and whether they undercut each other (a prerequisite for clustering), taking into account the market's timing structure.[16] Data are restricted to hours/days where price leadership *might* occur, based on the existence of a

[16]This is based on the Lewis (2012) American gasoline model. He tests the relative tendencies of retailers to initiate Edgeworth cycle price restorations, in which a dummy for whether a station "jumped" its price by five cents or more from one day to the next is regressed on retailer fixed effects.

candidate leader, and we check the extent to which it does occur; namely they are limited to observations in hour h where a large firm made a kink price change between $h-6$ and $h-4$.[17] Data are further limited to peak hours (HE 8 to 23) and to days when the minimum supply cushion is below the median, to focus on high demand periods when strategic behaviour is likely to occur. Periods before and after July 15 (when Transcanada appeared to make its first tagging pattern change) are considered.

The firm-level data contain hourly kink prices for each of the five large firms. The linear probability model will have the dependent variable "change$_{ihd}$," a firm-level dummy for whether firm i made a change to kink price 1 (kp1) in hour h that was preceded by a rival change between $h-6$ and $h-4$ on day d (i is precluded from following itself).[18] Formally,

$$\begin{aligned} \text{change}_{ihd} = 1 \text{ if } \text{kp1}_{ihd} \neq \text{kp1}_{i,h-1,d} \text{ and} & \\ (\text{kp1}_{j,h-4,d} \neq \text{kp1}_{j,h-5,d} \text{ or } \text{kp1}_{j,h-5,d} \neq \text{kp1}_{j,h-6,d} \text{ or} & \\ \text{kp1}_{j,h-6,d} \neq \text{kp1}_{j,h-7,d}), & \qquad (3.3) \end{aligned}$$

where i, $j \in$ {ATCO, CP, Enmax, TA, TC} and $i \neq j$. If ATCO, Capital Power, Enmax or TransAlta made a kink price change between HE 8 and HE 10 and Transcanada made a change in HE 14, then $\text{change}_{\text{TC},14,d} = 1$. On the righthand side of the model in equation (3.4), "ATCO$_{ihd}$" is a dummy equaling one if the observation belongs to ATCO, and so on (Transcanada

[17] An alternative to dropping observations is to include an interaction dummy for the hours in question, which avoids the risk of dropping relevant data. This option is left for future work to explore.

[18] Recall that firm i can only react to a rival action at h by $h+4$ at the earliest.

excluded). The "lead_AT$_{hd}$" dummy equals one if ATCO made a kink price change between the hours $h-6$ and $h-4$, identifying ATCO as a candidate leader for rival actions occurring at h (analogously for "lead_CP$_{hd}$" etc., with Transcanada excluded).

$$\begin{aligned}\text{change}_{ihd} &= \alpha + \text{ATCO}_{ihd}\beta_{\text{AT}} + \text{CP}_{ihd}\beta_{\text{CP}} + \text{Enmax}_{ihd}\beta_{\text{En}} + \text{TA}_{ihd}\beta_{\text{TA}} \\ &\quad + \text{lead\_AT}_{hd}\beta_{\text{l\_AT}} + \text{lead\_CP}_{hd}\beta_{\text{l\_CP}} + \text{lead\_En}_{hd}\beta_{\text{l\_En}} + \text{lead\_TA}_{hd}\beta_{\text{l\_TA}} \\ &\quad + X_{hd}\beta_X + \varepsilon_{ihd}. \end{aligned} \tag{3.4}$$

The X_{hd} vector contains control variables. Time dummies (for month, day of week, and hour) control for temporal trends. There is a dummy henceforth called "recent react" for whether a firm made a kink price change in the past three hours that was preceded four to six hours prior by a rival's change, controlling for whether a possible past reaction affects the tendency to react in the present. The hourly supply cushion and its hourly changes are also included; suppose firm i's leadership of rival j is consistently higher in HE 12 than in HE 2 (with i having made a kink price change four hours earlier in each case). This could be an artifact of the lower market supply cushion at HE 12 rather than of changes to i's price offers leading to that hour, when j may behave strategically because of the higher market price. Because of the firm and time fixed effects, we avoided employing a logit or a probit for (3.4).

Standard errors ε_{ihd} are clustered to allow for correlations within a given firm's observations (hence we do not test for heteroskedasticity). It is reasonable to assume error terms belonging to a given firm are not independent; factors such as technological capabilities, generation capacity, and unit availability are not expected to vary within a firm over the sample period (though they can vary between firms).

A second, analogous variable "undercut$_{ihd}$" is similar to (3.3), with the added condition that the firm i's kink price at hour h undercuts the earlier rival one by \$50 or less, shown on the lefthand side of (3.5). Likewise, the "recent react" dummy in X_{hd} requires the firm with the later kink price change to undercut the earlier rival by \$50 or less in order to equal one.

$$\begin{aligned}\text{undercut}_{ihd} &= \alpha + \text{ATCO}_{ihd}\beta_{\text{AT}} + \text{CP}_{ihd}\beta_{\text{CP}} + \text{Enmax}_{ihd}\beta_{\text{En}} + \text{TA}_{ihd}\beta_{\text{TA}} \\ &\quad + \text{lead\_AT}_{hd}\beta_{\text{l\_AT}} + \text{lead\_CP}_{hd}\beta_{\text{l\_CP}} + \text{lead\_En}_{hd}\beta_{\text{l\_En}} + \text{lead\_TA}_{hd}\beta_{\text{l\_TA}} \\ &\quad + X_{hd}\beta_X + \varepsilon_{ihd}. \end{aligned} \tag{3.5}$$

If the type of behaviour depicted in Figure 3.3 is occurring, certain firms should be following and undercutting particular rivals. This would be seen through the firm dummies, which show whether individual firms tend to follow and undercut rivals within the given time frame, and through the "lead ATCO," "lead CP" etc. dummies, which show firms' tendency to be followed and undercut.

In Table 3.13, specifications 1 and 2 show results for equations (3.4) and (3.5) respectively, for the time period from January 1, 2013 to May 31, 2013 (same as the tagging Section 3.5). Specifications 3 and 4 are for those same

Table 3.13: Relative probabilities of following or undercutting a rival's change to kink price 1 from 4-6 hours ago (standard errors clustered within firms)

Variable	(1)	(2)	(3)	(4)
ATCO	-.052*	-.060*	-.281*	-.214*
	$(.477 \cdot 10^{-14})$	$(.097 \cdot 10^{-14})$	$(3.360 \cdot 10^{-14})$	$(2.170 \cdot 10^{-14})$
CP	-.007*	-.054*	-.269*	-.202*
	$(.481 \cdot 10^{-14})$	$(.089 \cdot 10^{-14})$	$(3.360 \cdot 10^{-14})$	$(2.160 \cdot 10^{-14})$
Enmax	-.161*	-.094*	-.291*	-.243*
	$(.481 \cdot 10^{-14})$	$(.148 \cdot 10^{-14})$	$(3.360 \cdot 10^{-14})$	$(2.160 \cdot 10^{-14})$
TA	-.074*	-.052*	-.382*	-.188*
	$(.500 \cdot 10^{-14})$	$(.088 \cdot 10^{-14})$	$(3.410 \cdot 10^{-14})$	$(1.880 \cdot 10^{-14})$
Lead ATCO	.038*	.028	-.0.18	.055
	(.007)	(.020)	(.014)	(.043)
Lead CP	.023	.003	.047	.014
	(.012)	(.008)	(.030)	(.014)
Lead Enmax	.019	.011	.058	.060
	(.021)	(.013)	(.078)	(.053)
Lead TA	.031	.038*	.013	.041
	(.023)	(.013)	(.026)	(.032)
Recent react	.048*	.004	-.008	.013
	(.022)	(.005)	(.025)	(.017)
Supply cush.	$-.356 \cdot 10^{-4*}$	$-.160 \cdot 10^{-4*}$	$.932 \cdot 10^{-4}$	$.479 \cdot 10^{-4}$
	$(.137 \cdot 10^{-4})$	$(.067 \cdot 10^{-4})$	$(.492 \cdot 10^{-4})$	$(.594 \cdot 10^{-4})$
S.c. diff.	$-.090 \cdot 10^{-4}$	$-.021 \cdot 10^{-4}$	$-.112 \cdot 10^{-4}$	$-.125 \cdot 10^{-4}$
	$(.337 \cdot 10^{-4})$	$(.147 \cdot 10^{-4})$	$(.476 \cdot 10^{-4})$	$(.299 \cdot 10^{-4})$
Constant	.582*	.146*	.623*	.289
	(.099)	(.050)	(.209)	(.161)
# obs.	4,105	4,105	2,080	2,080
% neg.	.05	.14	.06	.19
R^2	.096	.050	.175	.152

Note: A * indicates statistical significance at the 5% level.
The dependent variable in specification 1 is a dummy for whether a firm made a kink price change that follows that of a rival 4-6 hours in the past for the January 1-May 31 period, and likewise with specification 2 with the added condition that the present kink price undercut the earlier one by $50 or less. Columns 3 and 4 are analogous, for the July 15-September 15 period.
Omitted output: dummies for months, day of week, and hour.

equations from July 15, 2013 to September 15, 2013 to account for Transcanada's change in its tagging strategy (recall Figure 3.6). The "% neg."

shows the proportion of fitted values that fall outside the [0,1] interval.

The coefficients for the firm dummies (the first four regressors) show the probabilities relative to Transcanada of the firm in question following or undercutting a rival. Similarly to the column sums in Tables 3.9 through 3.12, Transcanada follows rival kink price changes and undercuts the most often, and Enmax does so the least often. Among the "lead" regressors, ATCO's past kink price change increases the probability that firms follow rival changes by .038 (specification 1), and TransAlta's past change increases the probability of undercutting by .038 (specification 2), both for the January-May period.

The coefficients for the latter sample period (specifications 3 and 4) are larger in absolute value than for the earlier one, suggesting that after Transcanada's rule change, Transcanada is following/undercutting rivals more often relative to rivals' tendencies to do the same. This result is similar to that from Section 3.6.2, suggesting that, conditional on there being price clustering, Transcanada could be the undercutter. Conversely, under the asymmetric equilibrium outcome, Transcanada could be signaling its intention to be the high price-setter (hence this result cannot rule out either outcome). Support for price clustering itself is modest, and neither outcome (Figures 3.3 and 3.2) can be confirmed nor discounted.[19]

[19] For kink price 2, a firm's tendency to lead its rivals' kink price changes (the ranking of the row sums in Tables 3.9 through 3.12) is also supported econometrically; results are similar to kink price 1, hence not shown.

3.7.2 Firms' undercutting of high price offers from individual rivals

We test whether a firm i's decision to undercut a given price offer depends on how much capacity a rival j offers at or above that level (capacity which i may trust to remain high based on a signal from j). Evidence of such behaviour would support price clustering (Figure 3.3). Hourly data are limited to hours h where a large firm made a kink price change in $h-4$ (robustness checks will account for lags five and six).[20] They are further limited to peak demand hours (HE 8 to HE 23) and to days when the minimum supply cushion is below the median, similarly to Section 3.7.1. The full sample period is considered in the following regression; an interaction term will account for the periods before and after July 15, the possible date of Transcanada's tagging change.

Consider an hourly dummy variable "$\text{dum\_}i_{hd}$" that equals one if firm i undercut its collective rivals' kink price from $h-4$ by \$50 or less. It is regressed on a series of variables "$\text{prop\_}j_{h-4,d}$" which measure the proportion of MWs offered at or above the collective rival kink price belonging to a large rival $j \neq i$ at $h-4$. Regression (3.6) shows an example with $i = \text{ATCO}$.

$$\begin{aligned}\text{dum\_ATCO}_{hd} &= \alpha + \text{prop\_CP}_{h-4,d}\beta_{\text{CP}} + \text{prop\_En}_{h-4,d}\beta_{\text{En}} \\ &\quad + \text{prop\_TA}_{h-4,d}\beta_{\text{TA}} + \text{prop\_TC}_{h-4,d}\beta_{\text{TC}} + (\text{prop\_TC}_{h-4,d} \cdot \text{date}_d)\beta_{\text{TCjuly}} \\ &\quad + X_{hd}\beta_X + \varepsilon_{hd}. \qquad (3.6)\end{aligned}$$

[20] As mentioned in 3.7.1, an interaction term could be used rather than dropping observations.

This regression is run as a Prais-Winsten estimation, which corrects for first order serial correlation. In other words, the error term ε_{hd} is assumed to have the form $\varepsilon_{hd} = \rho\varepsilon_{h-1,d} + u_{hd}$, where $|\rho| < 1$ and u_{hd} is independently and identically distributed as $N(0, \sigma^2)$ (see Davidson and MacKinnon (1993)). The ρ is estimated by iterating to convergence through a process called the Cochrane-Orcutt transformation, where the independent and dependent variables are solved for repeatedly until the change in ρ is sufficiently small.[21] Parameters are estimated through generalized least squares using ρ. With hourly data and firms' knowledge of their own past actions, it is reasonable to assume that the error term at h is correlated with the error term at $h - 1$.

Without loss of generality, suppose for illustrative purposes that ATCO (firm i) knows when Capital Power (firm j) has a lot of capacity above ATCO's rival kink price, and is confident it will not retaliate to being undercut with further undercutting. ATCO has incentive to undercut Capital Power if this belief is stronger in regards to the latter than to other rivals, hence "prop_CP$_{h-4,d}$" would have a positive coefficient. These predictions generalize to each of the other four large firms as the undercutter i.

The dummy variable "date$_d$" equals 1 up to but not including July 15, and 0 afterwards. It is interacted with prop_TC$_{h-4,d}$, and the coefficient reflects the effect of Transcanada's use of its nine-cent tagging pattern with regular day-to-day ending increases (which ended on that date) on ATCO's undercutting.

[21] See `http://www.stata.com/manuals13/tsprais.pdf`.

The vector X_{hd} in (3.6) contains the following control variables:

- srmc_ATCO$_{hd}$ = capacity-weighted marginal cost of ATCO's units in hour h of day d;
- sc$_{hd}$ = supply cushion in MW for hour h of day d (the market's total available but undispatched capacity);
- sc_diff$_{hd}$ = hourly change in the supply cushion;
- inf_ATCO$_{hd}$ = number of inframarginal MWs offered at least 400 MW away from the intersection between the aggregate marginal cost curve and demand that belong to ATCO in hour h of day d;
- size_ATCO$_{hd}$ = ATCO's capacity in MWs in hour h of day d;
- monthly dummy variables for February through September 2013 (January excluded);
- hourly dummy variables for HE 9 through HE 23 (HE 8 excluded).

The marginal cost variable (see Appendix B for methodology) accounts for the possibility that ATCO sets offers for cost recovery rather than for strategic purposes. The size variables account for whether or not a firm undercuts rivals when it has units on outage. A firm's amount of inframarginal capacity offered at low prices can influence its incentive to undercut to raise market price, as that price is earned on all MWs offered below the pool price.[22] The supply

[22]The 400 MW boundary is scaled down for the Alberta market from 3,000 MW boundary for the UK used in Crawford et al. (2007).

cushion measures the market's ability to respond to rapid demand increases; a negative parameter would suggest undercutting occurs in high demand (low supply cushion) hours. The monthly and hourly dummies account for changes in offer behaviour through time. Data on firms' forward positions are not available, hence not included.

The regressions from Capital Power's, Enmax's, TransAlta's and Transcanada's respective points of view are analogous to (3.6) (Transcanada's does not contain the interacted regressor on the righthand-side).

Table 3.14 shows the Prais-Winsten regressions based on (3.6). The top row shows the candidate undercutter; for example the ATCO column shows ATCO's tendency to undercut its collective rivals depending on which individual rivals offer high (measured by the proportion regressors in the columns). Output for the time controls is omitted. The number of observations varies between regressions because certain firms do not have a kink price (defined above \$100) in all peak hours, hence the lefthand-side variable is undefined.

The positive, significant coefficient for "prop_TA" in the TC column suggests that Transcanada offers below the rival kink price when TransAlta offers at or above it. This matches the example in Figure 3.5 from Section 3.4, where Transcanada's MWs are increased from one hour to the next from below \$700.00 to \$895.18-\$899.00, at or just below TransAlta's capacity at \$899.00.[23] This raises the possibility that Transcanada's ending pattern in

[23]Section 3.6.2 showed evidence of Transcanada undercutting rivals by small amounts, but not of TransAlta as the firm being undercut (at least not in comparison to other rivals).

Table 3.14: Prais-Winsten regressions for column firm's tendency to undercut collective rivals' kink price 1, based on which rivals make high offers, four-hour lag (standard errors in parentheses)

Variable	ATCO	CP	Enmax	TA	TC
prop_AT		-.552	.164	-.285*	.434
		(.477)	(.258)	(.075)	(.477)
prop_CP	.117		-.141	-.382*	.824
	(.348)		(.240)	(.067)	(.450)
prop_En	.126	-.518		-.181*	.653
	(.381)	(.485)		(.081)	(.502)
prop_TA	.488	.017	-.024		1.225*
	(.335)	(.416)	(.229)		(.429)
prop_TC	.226	-.469	-.049	-.426*	
	(.379)	(.480)	(.265)	(.077)	
prop_TC	-.162	.636*	-.051	.102	
×date	(.209)	(.285)	(.157)	(.055)	
Srmc	.001	.016	$.617{\cdot}10^{-4}$	$-.894{\cdot}10^{-4}$	-.011*
	(.006)	(.023)	(.001)	$(.870{\cdot}10^{-4})$	(.005)
Sup. cush.	$-1.045{\cdot}10^{-4}$*	$-.615{\cdot}10^{-4}$	$-.335{\cdot}10^{-4}$	$-.034{\cdot}10^{-4}$	$-1.098{\cdot}10^{-4}$
	$(.438{\cdot}10^{-4})$	$(.559{\cdot}10^{-4})$	$(.300{\cdot}10^{-4})$	$(.166{\cdot}10^{-4})$	$(.565{\cdot}10^{-4})$
S.c. diff.	$1.503{\cdot}10^{-4}$*	$.746{\cdot}10^{-4}$	$-.087{\cdot}10^{-4}$	$.234{\cdot}10^{-4}$	$1.110{\cdot}10^{-4}$
	$(.561{\cdot}10^{-4})$	$(.657{\cdot}10^{-4})$	$(.303{\cdot}10^{-4})$	$(.242{\cdot}10^{-4})$	$(.621{\cdot}10^{-4})$
Infram.	$1.485{\cdot}10^{-4}$	$-.403{\cdot}10^{-4}$	$.028{\cdot}10^{-4}$	$.280{\cdot}10^{-4}$	$.919{\cdot}10^{-4}$
	$(.857{\cdot}10^{-4})$	$(.756{\cdot}10^{-4})$	$(.396{\cdot}10^{-4})$	$(.197{\cdot}10^{-4})$	$(.616{\cdot}10^{-4})$
Size	$-1.231{\cdot}10^{-4}$	$.247{\cdot}10^{-4}$	$1.236{\cdot}10^{-4}$	$-.493{\cdot}10^{-4}$	$2.472{\cdot}10^{-4}$*
	$(1.537{\cdot}10^{-4})$	$(1.110{\cdot}10^{-4})$	$(.677{\cdot}10^{-4})$	$(.347{\cdot}10^{-4})$	$(1.039{\cdot}10^{-4})$
Constant	.046	-.241	-.111	.321*	-1.163*
	(.345)	(.951)	(.241)	(.089)	(.435)
ρ	.368	.464	.601	.206	.500
R^2	.104	.069	.069	.069	.141
# obs.	954	953	951	954	954

Note: A * denotes statistical significance at the 5% level. Data are limited to observations in hour h where a large firm made a change to kink price 1 in $h-4$, and to peak hours from January 1 to September 15. Output for time controls is omitted.

Figure 3.6 could be an identity signal to TransAlta to prevent a competitive response. Re-running the regressions with lags five or six or with kink price 2 does not greatly change results (hence both kink prices capture similar ten-

Hence the regression (3.6) could have accounted for effects that were ignored in the summary statistics.

dencies, or lack thereof, to cluster based on the proportion variables). The date interaction term shows that Transcanada's rule change is positively correlated with Capital Power's undercutting of Transcanada (it does not shed light however on Transcanada's undercutting of its rivals).

Other pairs of firms in Table 3.14 do not show a clustering relationship; in fact, the negative significant coefficients in TransAlta's column suggest the firm actively avoids offering just below rivals that offer high. Hence there is partial support for the price clustering hypothesis, but the asymmetric equilibrium cannot be ruled out as a possibility, especially for other sets of firms.

The regressions in Tables 3.13 and 3.14 have low R^2 values, meaning only a small proportion of the variation in each respective dependent variable is explained by the associated independent variables. This could be due to the vast number of ways firms can interact with each other in a uniform multi-unit auction, and the various strategies that can be employed. Section 3.3.1 raised two possible outcomes, but there could be others. Alternate models are expected to exhibit a similar shortcoming. While our results can be informative, from a purely statistical viewpoint they have limited explanatory power.

3.8 Conclusion

This chapter investigated the Alberta electricity market's transparency, and the extent to which the large firms could identify each other through tagging strategies, as well as how price leadership and offer decisions are made conditional on known identities. We found evidence that firms use tagging rules, some simple and some complex, which can reasonably be assumed to allow firms to identify the rival that offered a certain price offer or block size. Transcanada had a particularly detailed tagging rule, which it employed consistently before abruptly stopping partway through the sample period; this coincided with the MSA's formal recommendation of decreased market transparency. This example and others suggest that firms might be secretly communicating, and that public price offer information may be employed in ways contrary to its purpose of price forecasting and (reasonable) risk-mitigation.

The literature predicted two outcomes, both of which could be achieved with coordination arising from communication between firms. The first was an asymmetric equilibrium in either a collusive or a non-cooperative setting, where a price-setter sets a high offer and a rival sets a low one to prevent undercutting. Firms could require a coordination mechanism to determine which one of them becomes the price-setter, who only produces at partial capacity. The second outcome had the price-setter increase its offer to just below that of the next highest rival, increasing market price; the rival could communicate its intention to collude and to not respond competitively. The MSA had made a similar claim to the second outcome about the Alberta electricity market.

The empirical section showed evidence of Transcanada offering slightly below TransAlta when the latter was offering high, consistent with the second predicted outcome; the MSA's proposal to reduce the HTR's transparency could prevent such occurrences. However this behaviour was not observed within other sets of firms; for these firms the asymmetric equilibrium outcome remains a possibility. If such is the case, the recommended course of action would depend on the objective of the coordination. In a static, non-cooperative setting, no action may be required. In a dynamic collusive setting where firms take turns as the price-setter to maintain high prices over time, reduced transparency can again provide mitigation.

Our research can be expanded upon in future work. There are other tagging rules that were not identified, owing to the many possible ways of tagging, as well as alternate ways to identify the kind of information being communicated (if at all). The tagging data had also revealed an abrupt change in Transcanada's detailed pricing pattern, and there was evidence that a change occurred the day after the MSA's announcement of proposed changes to the HTR on August 7, 2013. The data set could be extended beyond September 15, with tests for additional structural breaks. A difficulty with such an approach is to reliably identify pattern changes after the announcement date as being caused by the announcement, or accounting for delayed reactions (Transcanada's starkest pattern change only occurred on August 15).

Brander and Ross (2006) identify further problems with detecting changes in firm behaviour in a price-fixing context. The collection of data covering a sufficiently long time period can inadvertently include external factors, such as productivity increases. Price-fixing may have been more successful in some periods than in others, confounding the instances where it did or did not occur. And biases are possible if the price-fixing arose from a period of above-average price competition, or if firms anticipate the threat of being held liable for damages and act within the rules.

Another avenue is to develop a direct method of testing for communication to coordinate on an asymmetric equilibrium, with firms making different offers and potentially taking turns over time being the high or low firm, as described in Fabra (2003) and Crawford et al. (2007). This could be tested by modeling a firm's probability of being the price-setter, defined as the owner of the offer that sets the SMP, as well as the identity of firms that offer more than a certain number of dollars below the SMP. Consistent sets of firms that include a price-setter and one or more low-offering rivals would support the asymmetric equilibrium hypothesis.

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Appendix A

Additional figures for Chapter 3

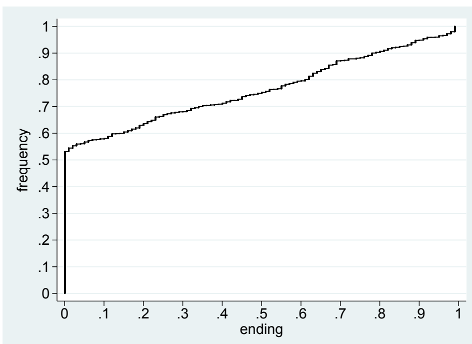

Figure A.1: Cumulative frequency of ATCO's price endings, January 1 to May 31, 2013, price ∈ (\$0,\$999.99)

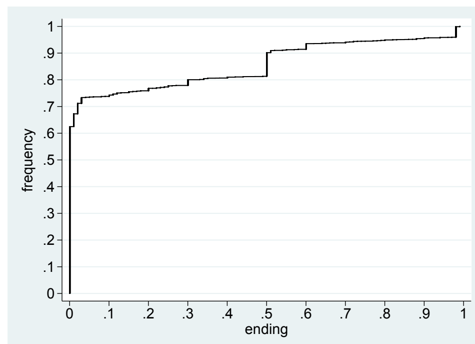

Figure A.2: Cumulative frequency of Capital Power's price endings

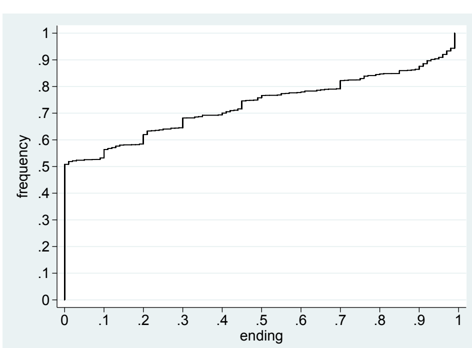

Figure A.3: Cumulative frequency of Enmax's price endings

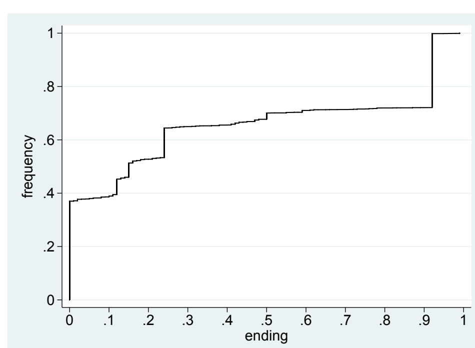

Figure A.4: Cumulative frequency of TransAlta's price endings

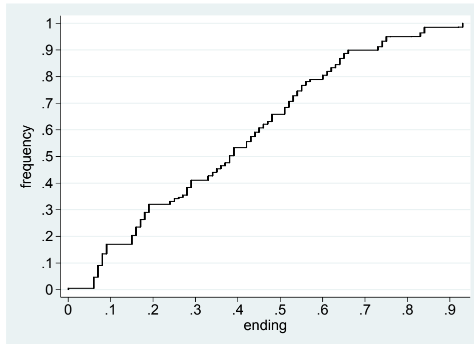

Figure A.5: Cumulative frequency of Transcanada's price endings

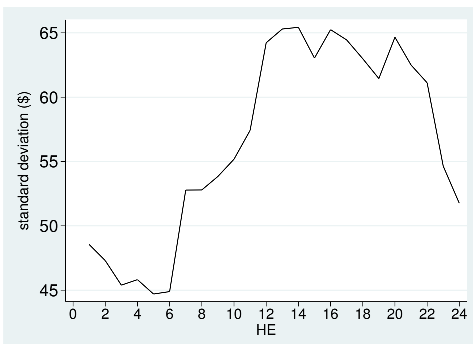

Figure A.6: Average standard deviation of price offers above $100

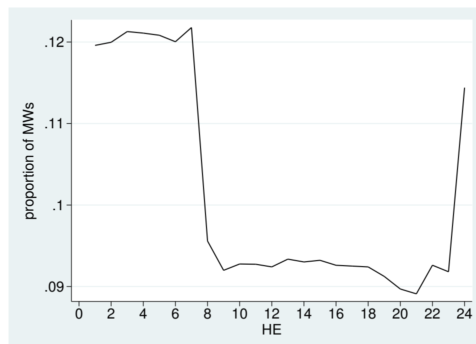

Figure A.7: Average hourly proportion of MWs offered above $800

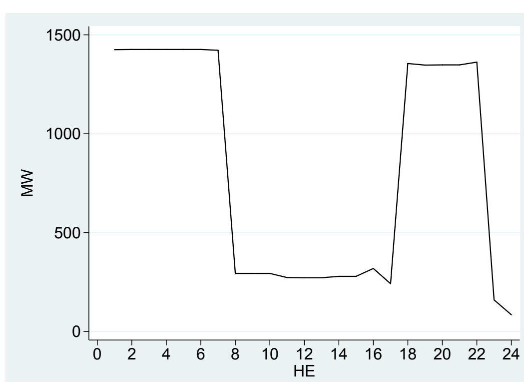

Figure A.8: $100 clustering around market kink price 1, March 4, 2013

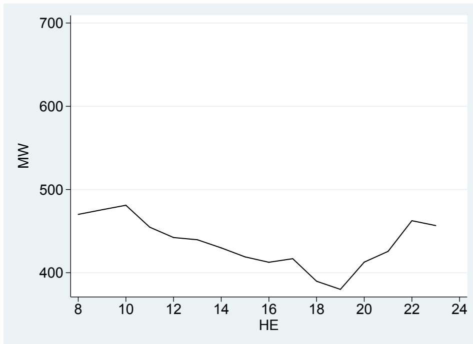

Figure A.9: Clustering around market kink price 1 in 2011, high demand days

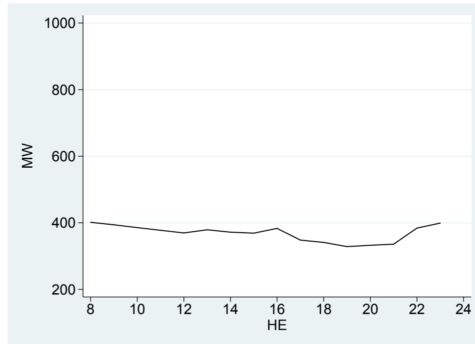

Figure A.10: Clustering around market kink price 1 in 2012, high demand days

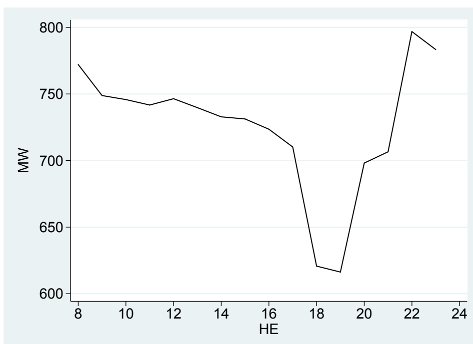

Figure A.11: Clustering around market kink price 2 in 2011, high demand days

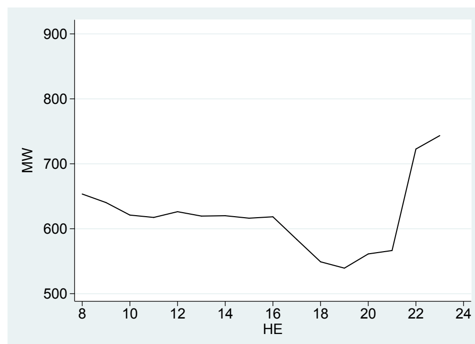

Figure A.12: Clustering around market kink price 2 in 2012, high demand days

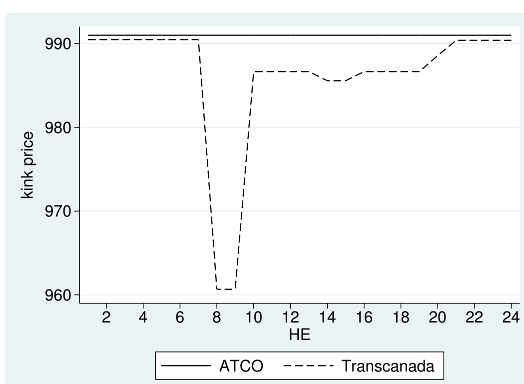

Figure A.13: Kink price 1 for ATCO and Transcanada, April 28, 2013

Appendix B

Measuring firms' marginal costs

MSA (2012) on the assessment of static efficiency proposes different methods for calculating a generator's short run marginal cost, which they define on page 16 as "the added cost of producing a unit increment of output or, equivalently, the avoided cost of producing a unit decrement of output holding at least one factor of production [...] constant, e.g., the capacity of a generator." For natural gas, an estimate of the generator's heat rate in GJ/MWh is multiplied by the natural gas price in $/GJ. Coal marginal costs are approximated by the fifth percentile of the lowest non-zero price offers in hours when the supply cushion (undispatched capacity) exceeds 1,500 MW, as offers during low demand hours are expected to reflect marginal costs. Coal generation costs cannot be modeled the same way as for natural gas because of data limitations.

We calculate natural gas marginal costs in a similar manner, multiplying heat rates obtained from MSA (2012) by Alberta natural gas prices from NGX.[1] We also add estimates of variable operations and maintenance costs

[1] Available at `http://www.ngx.com/?page_id=243`.

from Table 1 of EIA (2013) on updated capital cost estimates, as well as compliance costs with Alberta's Specified Gas Emitters Regulation (Table 4 from Pfeifenberger and Spees (2011)).

There are cogeneration units employing natural gas to produce useful heat and industrial on-site electricity, and sell their excess to the grid. Units that submit offers of zero are assumed to have marginal costs of zero, while the marginal costs of those submitting positive offers in view of earning profits are modeled using the same method as natural gas generators described above.

To calculate coal marginal costs, we also focus on the lowest non-zero price offers on low demand hours from coal generators. A cumulative distribution function is established for said price offers from each generator over the course of the sample period. Using a uniform random number generator, the average of 100 draws from each function is the estimate of the marginal cost (see Brown and Olmstead (2016)).

There are several small hydro generators, which are assumed to offer at marginal cost. Remaining generator types offer at zero, and are also assumed to be offering at marginal cost, save for three particular biomass units with positive offers, whose costs are modeled the same way as coal generators.